# *Open Access Transmission Tariff, Sixth Revised Volume No. 1*

***Southwest Power Pool***
***Open Access Transmission Tariff, Sixth Revised Volume No. 1***

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SECTION I. INTRODUCTION ..... 560

1. WFEC's Formula Rate Template and these Protocols together comprise the filed rate for transmission service in Zone 13 of the SPP footprint. The Formula Rate will become effective for recovery of WFEC's ATRR upon the effective date authorized by FERC. ..... 560

2. WFEC will follow the instructions specified in the Formula Rate to calculate its ATRR upon which the rates for NITS and PTP in SPP Zone 13 are based. ..... 560

3. Recovery of costs associated with existing and new facilities will be consistent with Attachment AI and Attachment J, respectively, of the SPP Tariff, as well as with the Formula Rate. ..... 560

4. Defined terms are set forth in section III below. ..... 560

SECTION II. ANNUAL UPDATE ..... 560

1. THE FORMULA RATE WILL BE APPLICABLE TO SERVICE ON AND AFTER JULY 1 OF EACH CALENDAR YEAR THROUGH JUNE 30 OF THE FOLLOWING CALENDAR YEAR, SUBJECT TO REVIEW, CHALLENGE AND REFUNDS OR SURCHARGES WITH INTEREST, TO THE EXTENT PROVIDED HEREIN. THE ATRR WILL BE DETERMINED USING THE MOST RECENT HISTORICAL CALENDAR YEAR FINANCIAL AND OPERATING DATA. ..... 560

2. On or before April 15 of each calendar year, WFEC will (a) calculate the ATRR for the Rate Year starting July 1 of that

calendar year in accordance with the Formula Rate utilizing the most recent historical calendar year financial and operating data; (b) calculate, for illustrative purposes, the corresponding rates for NITS and PTP in SPP's Zone 13 for the Rate Year; and (c) provide its Annual Update to SPP and cause such information to be accessible on SPP's website and OASIS. ..... 560

3. Concurrent with the Annual Update posting, WFEC will provide a notice of such posting to Interested Parties through the email Service List maintained by SPP. ..... 560

4. The Annual Update will: ..... 560

(a) Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update with the most recent historical calendar year financial and operating data along with the underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data; ..... 560

(b) Be based on the independently audited books and records of WFEC for the most recent historical calendar year including its RUS Financial and Operating Report – Electric Power Supply (formerly known as the RUS Form No. 12); ..... 561

(c) Include WFEC's completed RUS Financial and Operating Report – Electric Power Supply for the most recent calendar year; ..... 561

(d) Provide sufficient information to enable Interested Parties to replicate the calculation of the results from the Formula Rate; ..... 561

(e) Identify changes in accounting that affect the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, including: ..... 561

i. Any accounting changes, such as the initial implementation of an accounting standard or policy, the initial implementation of accounting practices for unusual or unconventional items where the RUS has not provided specific direction, or the correction of errors and prior period adjustments that impact the ATRR; ..... 561

ii. Any items included in the Formula Rate at an amount other than a historical cost basis; ..... 561

iii. Individual impact of any changes in section II.4(e)i above on charges billed under the Formula Rate; and ..... 561

iv. Accounting changes related to any reorganization or merger transaction and the effect of those changes on inputs to the formula rate; and ..... 561

(f) Not seek to modify the Formula Rate. ..... 561

5. Any modification to the Formula Rate will require a filing under FPA Section 205 or FPA Section 206. ..... 561

**Section III. Definitions** ..... 561

(a) "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services for WFEC under the SPP Tariff (Zone 13) calculated, posted and filed in accordance with the Formula Rate. ..... 561

(b) "Annual Meeting" means the meeting hosted by WFEC for the purpose of exchanging information with Interested Parties regarding the Annual Update. ..... 562

(c) "Annual Update" means WFEC's annual posting of its Formula Rate, in a working Excel™ format, in accordance with these Protocols. ..... 562

(d) "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and federal holidays. ..... 562

(e) "Critical Energy Infrastructure Information" or "CEII" has the meaning set forth in 18 C.F.R. § 388.113(c)(1). ..... 562

(f) "Customers" means the customers taking NITS service, service under Grandfathered Agreements, or PTP service. ..... 562

(g) "FERC" or "Commission" means the Federal Energy Regulatory Commission. ..... 562

(h) "Final Posting" means the Annual Update information posted to the SPP website and OASIS with changes agreed to during the Review Period, as set forth in section IV.B.5 below. ..... 562

(i) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with the

Commission, and served on WFEC by electronic service on the date of such filing. ..... 562

(j) "Formula Rate" means these Protocols together with the Formula Rate Template. ..... 562

(k) "Formula Rate Template" means the WFEC transmission formula rate template incorporated in the SPP Tariff and accepted by FERC. ..... 562

(l) "FPA" means Federal Power Act. ..... 562

(m) "Grandfathered Agreement" means those agreements listed in Attachment W of the SPP Tariff to which WFEC is a party. ..... 562

(n) "Informal Challenge" means written notification by an Interested Party to WFEC, during the Review Period, of any specific challenge to the Annual Update. ..... 562

(o) "Information Request" means a written request submitted by an Interested Party to WFEC during the Review Period in accordance with these Protocols. ..... 562

(p) "Informational Filing" means WFEC's annual filing with the Commission of the information specified in these Protocols. ..... 562

(q) "Initial Posting" means the Annual Update data and information which WFEC posts, or causes to be posted, to the SPP website and OASIS in accordance with section II.2 of these Protocols. ..... 562

(r) "Initial Posting Date" means the date on which the Initial Posting is actually made. ..... 563

(s) "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or successor regulation. ..... 563

(t) "Interested Party" includes but is not limited to Customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. ..... 563

(u) "Mistake" means errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors, but excluding matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the Annual Update review process. ..... 563

(v) "NITS" means Network Integration Transmission Service as defined in the SPP Tariff. ..... 563

(w) "OASIS" means SPP's Open Access Same-Time Information System. ..... 563

(x) "Protocols" means these Transmission Formula Rate Protocols, as they may be amended from time to time. ..... 563

(y) "PTP" means Point-to-Point Transmission Service as defined in the SPP Tariff. ..... 563

(z) "Rate Year" means July 1 of a given year through June 30 of the subsequent year. ..... 563

(aa) "Review Period" means, unless otherwise extended in writing by WFEC, the period that begins on the Initial Posting Date and ends 60 days after the Initial Posting Date. ..... 563

(bb) "RUS" means the Rural Utilities Service. ..... 563

(cc) "Service List" means the email service list maintained by SPP for distribution of formula rate notices. ..... 563

(dd) "SPP" means Southwest Power Pool, Inc. ..... 563

(ee) "SPP Tariff" means SPP's Open Access Transmission Tariff. ..... 563

(ff) "Stated Values" means inputs to the Formula Rate that are fixed and not subject to change in an Annual Update, including: (i) the base return on equity, (ii) any approved adders to the base return on equity, (iii) any return on equity incentives for SPP regional transmission projects, (iv) depreciation and amortization rates, and (v) the hypothetical equity ratio floor established in Docket No. ER16-1774-000. ..... 563

(gg) "USoA" means the RUS Uniform System of Accounts. ..... 564

(hh) "WFEC" means Western Farmers Electric Cooperative. ..... 564

SECTION IV. REVIEW OF ANNUAL UPDATE ..... 564

**A.** Annual Meeting ..... 564

**B.** Information Exchange & Final Posting ..... 564

1. During the Review Period, Interested Parties may submit to WFEC reasonable requests for information, data and work papers

supporting the Annual Update that was posted on the Initial Posting Date that commenced such Review Period. Information Requests will be limited to that which is necessary to determine: ..... 564

(a) The extent or effect of an accounting change; ..... 564

(b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data; ..... 564

(c) The proper application of the Formula Rate and procedures in these Protocols; ..... 564

(d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies; ..... 564

(e) The effect of any change to the underlying USoA or Formula Rate Template; and ..... 564

(f) Any other information that may reasonably have a substantive effect on the calculation of the ATRR pursuant to the Formula Rate. ..... 564

2. WFEC WILL MAKE A GOOD FAITH EFFORT TO RESPOND TO EACH INFORMATION REQUEST WITHIN 7 BUSINESS DAYS OF RECEIPT OF THE INFORMATION REQUEST. ..... 565

3. WFEC WILL POST, OR CAUSE TO BE POSTED, ON A PUBLICLY ACCESSIBLE PORTION OF THE SPP OASIS ALL INFORMATION REQUESTS FROM INTERESTED PARTIES AND WFEC'S RESPONSE(S) TO SUCH INFORMATION REQUESTS, AND A LINK TO THE WEBSITE WILL BE ELECTRONICALLY SERVED BY WFEC ON ALL INTERESTED PARTIES VIA THE EMAIL SERVICE LIST MAINTAINED BY SPP AND PROVIDED TO WFEC. IF RESPONSES TO INFORMATION REQUESTS CONTAIN INFORMATION DEEMED BY WFEC TO BE COMMERCIALLY SENSITIVE OR OTHERWISE CONFIDENTIAL OR CEII, SUCH RESPONSES WILL NOT BE PUBLICLY POSTED BUT WILL BE MADE AVAILABLE BY SEPARATE MEANS TO INTERESTED PARTIES THAT HAVE EXECUTED A NON-DISCLOSURE AGREEMENT WITH WFEC. ..... 565

4. ANY CHANGES OR ADJUSTMENTS TO THE ANNUAL UPDATE RESULTING FROM THE INFORMATION REQUEST PROCEDURES THAT ARE AGREED TO BY WFEC AND RESOLVED PRIOR TO THE END OF THE REVIEW PERIOD WILL BE REPORTED IN A REVISED AND FINAL POSTING OF THE ANNUAL UPDATE ON THE SPP OASIS. ..... 565

5. ANY CHANGES OR ADJUSTMENTS TO THE ANNUAL UPDATE RESULTING FROM THE INFORMATION REQUEST PROCEDURES THAT ARE AGREED TO BY WFEC AFTER THE REVIEW PERIOD WILL BE REPORTED IN THE INFORMATIONAL FILING MADE WITH FERC AND WILL BE REFLECTED IN THE ANNUAL UPDATE FOR THE FOLLOWING RATE YEAR. ..... 565

6. IF THE REVIEW PERIOD ENDS ON A WEEKEND OR HOLIDAY, THE REVIEW PERIOD WILL BE EXTENDED TO THE NEXT BUSINESS DAY..... 565

7. WFEC WILL POST, OR CAUSE TO BE POSTED, THE FINAL POSTING ON A PUBLICLY ACCESSIBLE PORTION OF THE SPP OASIS, AND A LINK TO THE WEBSITE WILL BE ELECTRONICALLY SERVED BY WFEC ON ALL INTERESTED PARTIES VIA THE EMAIL SERVICE LIST MAINTAINED BY SPP. THE FINAL POSTING WILL BE MADE WITHIN 15 DAYS AFTER THE END OF THE REVIEW PERIOD (OR THE FIRST BUSINESS DAY THEREAFTER IF THE 15TH DAY FALLS ON A WEEKEND OR HOLIDAY)..... 565

**C.** Informal Challenge Procedures ..... 565

1. Interested Parties will have until the conclusion of the Review Period to notify WFEC in writing (which may be electronically) of any Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocation calculations, or other information to which the Interested Party objects, and provide an appropriate explanation and documents to support the objection. WFEC will make a good faith effort to respond to any Informal Challenge within 20 calendar days of receipt of such Informal Challenge. WFEC, and if appropriate SPP, will appoint senior representatives to work with the Interested Party to resolve the Informal Challenge. ..... 565

2. WFEC will post, or cause to be posted, on a publicly accessible portion of the SPP OASIS all Informal Challenges from Interested Parties and WFEC's responses to the Informal Challenges, and a link to the website will be electronically served by WFEC on all Interested Parties via the email Service List maintained by SPP. If responses to Informal Challenges contain information deemed by WFEC to be commercially sensitive or otherwise confidential or CEII, such information will not be publicly posted but will be made available by separate means to Interested Parties that have executed a non-disclosure agreement with WFEC. ..... 565

3. Any changes or adjustments to the Annual Update resulting from the Informal Challenge procedures that are agreed to by WFEC and resolved prior to the end of the Review Period will be

reported in the Final Posting on the SPP OASIS. Any changes or adjustments to the Annual Update resulting from the Informal Challenge procedures that are agreed to by WFEC after the Review Period will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year. An Interested Party that pursues or fails to pursue an Informal Challenge does not implicitly waive its rights to raise a Formal Challenge with FERC or file a complaint under FPA Section 206. ..... 566

**D.** Formal Challenges ..... 566

1. A Formal Challenge will: ..... 566

(a) Clearly identify the action or inaction which is alleged to violate the Formula Rate; ..... 566

(b) Explain how the action or inaction violates the Formula Rate; ..... 566

(c) Set forth the business, commercial, economic, or other issues presented by the action or inaction as they relate to or affect the Interested Party filing the Formal Challenge, including: ..... 566

i. The extent or effect of an accounting change; ..... 566

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data; ..... 566

iii. The proper application of the Formula Rate Template and the procedures in these Protocols; ..... 566

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies; ..... 566

v. The effect of any change to the underlying USoA or Formula Rate Template; and ..... 566

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate; ..... 566

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the Interested Party filing the Formal Challenge as a result of the action or inaction; ..... 566

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum; ..... 567

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief; ..... 567

(g) Include all information and documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and ..... 567

(h) State whether the Interested Party utilized the Informal Challenge procedures described in these Protocols with regard to any issue. ..... 567

2. Formal Challenges will be filed with FERC, either in the FERC docket assigned to the Informational Filing or via Section 206 of the FPA, and must be served upon WFEC contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in WFEC's Informational Filing. ..... 567

**E.** Modification of Formula Rate or Annual Update ..... 567

1. ANY MODIFICATION TO THE FORMULA RATE WILL REQUIRE A FILING UNDER FPA SECTION 205 OR FPA SECTION 206. THE PROCEDURES FOR THE ANNUAL UPDATE, INFORMAL CHALLENGES, AND FORMAL CHALLENGES SET FORTH IN THESE PROTOCOLS MAY NOT BE USED TO MODIFY THE FORMULA RATE. ..... 567

2. The Stated Values in the Formula Rate may not be modified through the Annual Update, Informal Challenge, or Formal Challenge procedures. Modifications to the Stated Values require a filing with FERC pursuant to the FPA Section 205 or FPA Section 206. ..... 567

3. If WFEC makes a correction to a Mistake during a Rate Year that would affect the ATRR for that Rate Year, such corrections and any resulting refunds or surcharges will be reflected in the Annual Update for the next Rate Year with Interest. ..... 568

4. Any changes to the Formula Rate data inputs or to the Formula Rate that are the result of a Section 205 or Section 206 proceeding will be incorporated into the Formula Rate, and the charges

produced by the Formula Rate, in the Annual Update for the next Rate Year. ..... 568

5. Any refund required as a result of changes to the ATRR as provided in this section IV.E will include Interest calculated in accordance with 18 C.F.R. § 35.19a(a)(2). ..... 568

**F.** FERC Informational Filing ..... 568

1. NO LATER THAN 15 DAYS AFTER THE FINAL POSTING, WFEC WILL SUBMIT TO FERC AN INFORMATIONAL FILING OF ITS ANNUAL UPDATE. ..... 568

2. The Informational Filing must include the information that is reasonably necessary to determine: ..... 568

(a) That input data under the Formula Rate is properly recorded in any underlying work papers; ..... 568

(b) That WFEC has properly applied the Formula Rate Template and the procedures in these Protocols; ..... 568

(c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and ..... 568

(d) The extent of accounting changes that affect Formula Rate inputs. ..... 568

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**I. ANNUAL TRUE-UP AND ANNUAL PROJECTION** ..... 2054

1. The Formula Rate Template set forth in Attachment H, Addendum 6, of Southwest Power Pool's ("SPP") Open Access Transmission Tariff ("OATT") and these Formula Rate Implementation Protocols comprise the filed rate by SPP for calculating Lincoln Electric System's ("LES") Zonal Annual Transmission Revenue Requirement ("ATRR") for Transmission Service under the SPP OATT. LES shall follow the instructions specified in the Formula Rate Template to calculate annually its ATRR and the rates for its Network Integration Transmission Service and Point-to-Point transmission service, and the ATRR for Base Plan Upgrades and other network upgrades. These protocols shall apply to LES's calculation of its ATRR, including the calculation of the Annual True-Up ("Annual True-Up") and the projected net revenue requirement ("Annual Projection"). ..... 2054

2. The Formula Rate shall be calculated annually with resulting rates applicable to service on and after January 1st through December 31st of each calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein. ..... 2054

3. On or before June 1st, LES shall provide its Annual True-Up to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, LES shall request SPP to cause notice on the SPP exploder list titled "Formula Rate Posting Information Notification" or similar exploder list. Interested Parties may contact SPP to subscribe to the SPP exploder list. For

purposes of these protocols, the term Interested Party includes, but is not limited to, customers under the SPP OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. ..... 2054

4. On or before October 15th, LES shall provide its Annual Projection to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, LES shall request SPP to cause notice on the exploder list titled "Formula Rate Posting Information Notification" or similar exploder list. Interested Parties can contact SPP to subscribe to the SPP exploder list. ..... 2054

5. LES shall submit to the Federal Energy Regulatory Commission ("FERC" or the "Commission") an Informational Filing as provided in Section V of these protocols. ..... 2054

6. If the date for posting the Annual True-Up or Annual Projection falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the Annual True-Up or Annual Projection will result in an equivalent extension of time for the submission of Information Requests discussed in Section II of the protocols. ..... 2054

7. A change to the Formula inputs related to revised depreciation rates or the fixed margin requirement may not be made absent an appropriate filing with FERC. ..... 2054

8. The Annual True-Up shall ..... 2055

   (i) Be based on actual data for the prior calendar year, and, to the extent specified in the Formula, upon the audited books and records of LES; ..... 2055

   (ii) Identify all material adjustments made to the data in determining formula inputs. ..... 2055

9. The Annual True-Up and Annual Projection shall: ..... 2055

   (i) Include a workable data-populated Formula Rate Template in native format with all formulas and links intact; ..... 2055

   (ii) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used; ..... 2055

(iii) Provide sufficient information to enable Interested Parties to replicate the calculation;..... 2055

(iv) Identify any changes in the formula references; ..... 2055

(v) With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):..... 2055

(1) Identify any Accounting Changes, including:..... 2055

(2) The implementation of new estimation methods or policies that change prior estimates. Identify items included in the calculation at an amount other than on a historical cost basis (e.g., fair value adjustments); identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs.. ..... 2055

(3) Provide, for each item identified pursuant to items I.9.v.1 - I.9.v.2 of these protocols, a narrative explanation of the individual impact of such changes on the calculation. ..... 2055

10. LES shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") after the Annual True-Up Publication Date but no sooner than seven (7) days from the Publication Date and no later than July 15th. No less than twenty (20) days prior to such Annual True-Up Meeting, LES shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual True-Up Meeting and LES shall request SPP to provide notice of such meeting to the SPP email exploder list titled "Formula Rate Posting Information Notification" or similar exploder list. ..... 2055

11. The Annual True-Up Meeting will be hosted by LES in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. LES shall provide remote access for Interested Parties to participate in the meeting. The Annual True-Up Meeting shall (i) permit LES to explain and clarify its Annual True-Up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from LES about the Annual True-Up. ..... 2056

12. LES shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") after the Annual Projection Publication Date but no sooner than seven (7) days from the Publication Date and no later than November 30th. No less than twenty (20) days

prior to such Annual Projected Rate Meeting, LES shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual Projected Rate Meeting and LES shall request SPP to provide notice of such meeting to the SPP email exploder list titled, "Formula Rate Posting Information Notification" or similar exploder list. ..... 2056

13. The Annual Projected Rate Meeting will be hosted by LES in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. LES shall provide remote access for Interested Parties to participate in the meeting. The Annual Projected Rate Meeting shall (i) permit LES to explain and clarify its Annual Projection and (ii) provide Interested Parties an opportunity to seek information and clarifications from LES about the Annual Projection. ... 2056

14. Each year LES shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects. ..... 2056

**II. INFORMATION EXCHANGE PROCEDURES** ..... 2056

1. Interested Parties shall have seventy-five (75) days following the Annual True-Up Meeting to serve reasonable information and document requests related to the Annual True-Up; and sixty (60) days following the Annual Projection Publication Date to serve reasonable information and document requests on LES related to the Annual True-Up and Annual Projection ("Information Exchange Period"). If either of these dates falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine: ..... 2056

   (i) that LES has properly calculated its rate pursuant to the Formula Rate and the procedures in the Protocols; ..... 2057

   (ii) that input data under the Formula Rate are properly recorded in any underlying workpapers; ..... 2057

(iii) the accuracy of data and the consistency with the Formula Rate of the actual Net Revenue Requirement (including any True-Up Adjustment) under review; ..... 2057

(iv) the extent of accounting changes that affect Formula Rate inputs;..... 2057

(v) the prudence of actual costs and expenditures; and..... 2057

(vi) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula. ..... 2057

2. LES shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day. ..... 2057

3. LES will cause to be posted on SPP's website and OASIS all information requests from Interested Parties and LES's response(s) to such requests; except, however, if responses to information and document requests include material deemed by LES to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by LES and the requesting party. ..... 2057

4. LES shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the results of the LES's Annual True-Up's or Annual Projection's incorporation into the SPP Tariff. ..... 2057

**III. CHALLENGE PROCEDURES**..... 2057

1. Interested Parties shall have until January 31st following the Publication Date to review the inputs, supporting explanations, allocations and calculations and to notify LES in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or Annual Projection. The period of time from the Publication Date until January 31st shall be referred to as the Review Period. If January 31st falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same

Annual True-Up or Annual Projection as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual True-Up or Annual Projection. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual True-Up or Annual Projection, the Interested Party is barred from pursuing a Formal Challenge with respect to any issue for that Annual True-Up or Annual Projection but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or Annual Projection. ..... 2057

2. A party submitting an Informal Challenge to LES must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. LES shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. If LES disagrees with such challenge, LES will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31st, and LES must respond to all Informal Challenges by no later than February 28th. ..... 2058

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section III. ..... 2058

4. Informal Challenges shall be limited to all issues that may be necessary to determine: (1) that LES has properly calculated its rate pursuant to the Formula Rate and the procedures in the Protocols; (2) that input data under the Formula Rate are properly recorded in any underlying workpapers; (3) the accuracy of data and the consistency with the Formula Rate of the actual Net Revenue Requirement (including any True-Up Adjustment) under review; (4) the extent of accounting changes that affect Formula Rate inputs; (5) the prudence of actual costs and expenditures; and (6) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula. ..... 2058

5. LES will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and LES's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by LES to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by LES and the requesting party. ..... 2058

6. Any changes or adjustments to the Annual True-Up or Annual Projection resulting from the Information Exchange and Informal Challenge processes that are agreed to by LES will be reported in the Informational Filing required pursuant to Section V of these protocols. Any such changes or adjustments agreed to by LES on or before November 30th will be reflected in the Annual Projection for the upcoming Rate Year. Any changes or adjustments agreed to by LES after November 30th will be reflected in the following year's Annual True-Up, as discussed in Section IV of these protocols..... 2059

7. An Interested Party shall have until March 31st (unless such date is extended with the written consent of LES to continue efforts to resolve the Informal Challenge) to make a Formal Challenge to the Annual True-up or Annual Projection posted in the previous calendar year. ..... 2059

8. Formal Challenges shall be filed against SPP pursuant to these protocols and shall satisfy all of the following requirements. ..... 2059

   (i) A Formal Challenge shall:..... 2059

      (1) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;..... 2059

      (2) Explain how the action or inaction violates the filed rate formula or protocols; ..... 2059

      (3) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including: ..... 2059

      (4) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;..... 2060

      (5) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum; ..... 2060

      (6) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief; ..... 2060

(7) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and ..... 2060

(8) State whether the filing party utilized the Informal Challenge procedures described in these protocols with regard to any issue. ..... 2060

(ii) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on LES. Service to LES must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on LES's Informational Filing required under Section V of these protocols. ..... 2060

9. A Formal Challenge shall be filed in the same docket as LES's Informational Filing discussed in Section V of these protocols. LES shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit any Informal Challenge during the applicable Review Period. ..... 2060

10. In any proceeding initiated by FERC concerning the Annual True-Up or Annual Projection or in response to a Formal Challenge, LES shall bear the burden of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges. ..... 2060

11. The implementation of any changes or adjustments resulting from any Formal Challenge made with FERC shall be subject to SPP Tariff Section 39.1. ..... 2060

12. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of LES to request SPP to file unilaterally, pursuant to section 205 of the Federal Power Act and the regulations thereunder, to change the Formula Rate o any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder. ..... 2060

13. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these protocols and the Annual True-Up and Annual Projection shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing before FERC. ..... 2061

**IV. CHANGES TO ANNUAL TRUE-UP OR ANNUAL PROJECTION** ..... 2061

1. Except as provided in Section III.6 of these protocols, any changes to the data inputs, or as the result of any FERC proceeding to consider the Annual True-Up or Annual Projection, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Projection for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VI of these protocols. ..... 2061

2. In the event that LES identifies an error in the Annual True-Up, or is required by applicable law to correct an error, LES shall correct such error in good faith and without regard to whether the correction increases or decreases LES's revenue requirements. Nothing in these protocols should or may be construed as preventing Interested Parties or FERC from protesting such correction as inappropriate. ..... 2061

**V. INFORMATIONAL FILINGS** ..... 2061

1. By March 15th of each year, LES shall submit to FERC an informational filing ("Informational Filing") of its Annual Projection for the Rate Year, including its Annual True-Up. The Informational Filing will be for administrative and informational purposes only, and will not submit LES to the jurisdiction of the Commission under the Federal Power Act. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that LES has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during the Review Period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. LES shall request SPP to provide notice of

the Informational Filing via an email exploder list and by posting the docket number assigned to LES's Informational Filing on SPP's website and OASIS. ..... 2061

2. Any challenges to the implementation of the Attachment H-LES Formula Rate must be made through the Challenge Procedures described in Section III of these protocols, and not in response to the Informational Filing. ..... 2061

**VI. CALCULATION OF TRUE-UP ADJUSTMENT FOR THE ANNUAL TRUE-UP** ..... 2062

1. The Projected Revenue Requirement for the previous year, not including any prior year True-Up Adjustment, shall be compared to the Actual Revenue Requirement calculated in accordance with LES's Formula Rate for the previous year using data for that same year, and, to the extent specified in the Formula, upon the audited books and records of LES, to determine any over or under recovery plus interest ("True-Up Adjustment"). The True-Up Adjustment and related calculations shall be posted as part of LES's Annual True-Up to SPP's website and OASIS no later than June 1st (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day). ..... 2062

   (i) Interest on any over recovery of the net revenue requirement or any over recovery due to volume changes shall be determined based on the Commission's regulation at 18 C.F.R. § 35.19a. Interest on any under recovery of the net revenue requirement or any under recovery due to volume changes shall be calculated on the basis of LES's actual short-term debt costs capped at the applicable FERC refund interest rate as provided in 18 C.F.R. § 35.19a. In either case, the interest payable shall be calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the revenue requirement or volume changes exists. The interest rate to be applied to the over or under recovery amounts will be determined using the average rate for the nineteen (19) months preceding August of the current year. The interest amount will be included in the projected costs made available October 15. ..... 2062

2. The Net ATRR for transmission services for the following year shall be the sum of the projected revenue requirement for the following year minus Total Transmission Revenue Credits, plus or minus the True-up Adjustment from the previous year, if any, including interest. ..... 2062

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< 5 KV ..... 731

≤ 500 KW ..... 731

≤ 500 KW ..... 731

≥ 5 KV AND < 15 KV ..... 731

≤ 2 MW ..... 731

≤ 3 MW ..... 731

≥ 15 KV AND < 30 KV ..... 731

≤ 3 MW ..... 731

≤ 4 MW ..... 731

≥ 30 KV AND ≤ 69 KV ..... 731

≤ 4 MW ..... 731

≤ 5 MW ..... 731

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1. AMOUNT OF BOND. SURETY UNCONDITIONALLY AND IRREVOCABLY AGREES TO PAY SPP AMOUNTS NOT TO EXCEED AN AGGREGATE OF **[AMOUNT]**, IN ACCORDANCE WITH THE TERMS OF THIS SURETY BOND. ..... 1

2. PAYMENT UPON DEMAND. SURETY SHALL PAY SUCH AMOUNT AS SPECIFIED BY SPP UPON RECEIPT OF A DEMAND FOR PAYMENT NOTICE (“DEMAND FOR PAYMENT NOTICE”). SUCH DEMAND FOR PAYMENT NOTICE SHALL BE: (I) SIGNED BY AN OFFICER OR AUTHORIZED AGENT OF SPP, (II) DATED THE DATE OF PRESENTATION, AND (III) BE IN THE FORM AS SET FORTH IN EXHIBIT A, EXHIBIT B, OR EXHIBIT C, AS APPLICABLE. ..... 1

3. VALIDATION. SPP MAY DEMAND PAYMENT PURSUANT TO THIS SURETY BOND WITHOUT PRIOR DEMONSTRATION OF THE VALIDITY OF THE DEMAND. ..... 1

4. MULTIPLE DRAWS. SPP MAY DEMAND MULTIPLE PAYMENTS PURSUANT TO THIS SURETY BOND; *PROVIDED, HOWEVER*, THAT THE TOTAL AMOUNT OF SURETY’S OBLIGATION HEREUNDER SHALL NOT EXCEED AN AGGREGATE OF **[AMOUNT]**. ..... 1

5. TIME AND FORM OF PAYMENT. SURETY SHALL PAY AMOUNTS OWED PURSUANT TO THIS SURETY BOND IN FULL NOT LATER THAN THE FIRST BUSINESS DAY FOLLOWING RECEIPT OF SPP’S WRITTEN DEMAND FOR PAYMENT TO THE ACCOUNT DESIGNATED THEREIN. ..... 1

6. OBLIGATIONS UNCONDITIONAL. THIS SURETY BOND IS NOT CONDITIONED UPON SPP FIRST ATTEMPTING TO COLLECT PAYMENT, RESORTING TO ANY OTHER MEANS OF SECURITY OR COLLATERAL, OR PURSUING ANY OTHER REMEDIES IT MAY HAVE. THE OBLIGATIONS OF SURETY HEREUNDER ARE INDEPENDENT OF THE OBLIGATIONS OF PRINCIPAL, AND SPP MAY BRING AN ACTION AGAINST SURETY WITHOUT BRINGING AN ACTION AGAINST PRINCIPAL. SPP MAY FROM TIME TO TIME, WITHOUT

NOTICE OR DEMAND, AND WITHOUT AFFECTING SURETY'S LIABILITY HEREUNDER, TAKE AND HOLD OTHER SECURITY FOR PRINCIPAL'S OBLIGATIONS TO SPP AND EXCHANGE, WAIVE, RELEASE, OR APPLY SUCH SECURITY AS SPP DEEMS APPROPRIATE IN ITS SOLE DISCRETION. SURETY'S LIABILITY UNDER THIS SURETY BOND IS NOT CONDITIONED UPON THE VALIDITY OR ENFORCEABILITY OF PRINCIPAL'S OBLIGATIONS TO SPP. ..... 1

7. TERM OF SURETY BOND. THE TERM OF THIS SURETY BOND SHALL BEGIN ON THE DATE OF ITS ISSUANCE, AS SET FORTH ABOVE, AND SHALL CONTINUE IN FULL FORCE AND EFFECT UNTIL ALL AMOUNTS OWED BY PRINCIPAL PURSUANT TO THE AGREEMENTS, AS THAT TERM IS DEFINED IN THE OATT, ARE PAID IN FULL, INCLUDING ANY AMOUNTS OWED AS A RESULT OF TRUE-UPS OR OTHER CORRECTIONS TO PREVIOUS SETTLEMENTS; *PROVIDED, HOWEVER,* THAT SURETY MAY TERMINATE THIS SURETY BOND AS PROVIDED IN PARAGRAPH 8, BELOW..... 2

8. TERMINATION. SURETY MAY TERMINATE THIS SURETY BOND UPON NINETY (90) DAYS WRITTEN NOTICE TO SPP; *PROVIDED, HOWEVER,* THAT: (I) SURETY'S LIABILITY HEREUNDER SHALL SURVIVE SUCH TERMINATION AND REMAIN IN FULL FORCE AND EFFECT AS TO OBLIGATIONS INCURRED BY PRINCIPAL DURING THE TERM OF THIS SURETY BOND; AND (II) IN THE EVENT THAT PRINCIPAL FAILS TO PROVIDE AN ACCEPTABLE FORM OF REPLACEMENT FINANCIAL SECURITY TO SPP AT LEAST EIGHTY SEVEN (87) DAYS PRIOR TO THE TERMINATION OF THIS SURETY BOND, SURETY SHALL, UPON DEMAND, WITHOUT ANY NOTICE OTHER THAN SUCH DEMAND, AND WITHOUT ANY FURTHER ACTION BY SPP DELIVER CASH DEPOSIT TO SPP NOT LATER THAN THE NEXT BUSINESS DAY IN THE AMOUNT OF THE FULL REMAINING VALUE OF THIS SURETY BOND AS SECURITY FOR PRINCIPAL'S OBLIGATIONS TO SPP. A CASH DEPOSIT PROVIDED TO SPP BY SURETY AND NOT APPLIED BY SPP TO SATISFY UNPAID OBLIGATIONS OF PRINCIPAL SHALL BE RETURNED TO SURETY AT SUCH TIME AS: (I) PRINCIPAL PROVIDES ADEQUATE REPLACEMENT FINANCIAL SECURITY TO SPP OR (II) ALL AMOUNTS OWED BY PRINCIPAL TO SPP ARE PAID IN FULL, INCLUDING AMOUNTS OWED AS A RESULT OF TRUE-UPS OR OTHER CORRECTIONS TO PREVIOUS SETTLEMENTS. ..... 2

9. PRINCIPAL PAYS BOND COSTS. PRINCIPAL SHALL PAY ALL COMMISSIONS AND CHARGES FOR THIS SURETY BOND. PRINCIPAL'S FAILURE TO PAY ANY SUCH CHARGES SHALL NOT BE GROUNDS FOR TERMINATION OF THIS SURETY BOND, EXCEPT AS PROVIDED IN PARAGRAPH 8, ABOVE. ..... 2

10. EXPENSES. SURETY SHALL PAY ALL REASONABLE COSTS INCURRED BY SPP IN THE ENFORCEMENT OF THIS SURETY BOND, INCLUDING ATTORNEY FEES AND EXPENSES. SURETY'S OBLIGATION TO PAY SUCH COSTS SHALL BE IN ADDITION TO OTHER AMOUNTS OWED PURSUANT TO THIS SURETY BOND AND SHALL NOT BE LIMITED BY THE MAXIMUM STATED AMOUNT OF THIS SURETY BOND. ..... 2

11. COMMUNICATIONS. DEMANDS, NOTICES, AND OTHER COMMUNICATIONS SHALL BE DEEMED EFFECTIVE WHEN RECEIVED, SHALL BE IN WRITING, AND SHALL BE DELIVERED BY COURIER WITH RECEIPT OF DELIVERY OR BY REGISTERED MAIL, CERTIFIED MAIL, OR FACSIMILE TO THE FOLLOWING ADDRESSES:..... 2

Surety, SPP, or Principal may change the address provided for receipt of communications pursuant to this Surety Bond by providing written notice to the other parties. ..... 3

12. REPRESENTATIONS AND WARRANTIES. SURETY REPRESENTS AND WARRANTS TO SPP THAT:..... 3

13. ASSIGNMENT. SPP MAY ASSIGN ITS RIGHTS UNDER THIS SURETY BOND WITHOUT IN ANY WAY DIMINISHING SURETY'S OBLIGATIONS HEREUNDER. SURETY SHALL NOT BE PERMITTED TO ASSIGN OR TRANSFER ITS RIGHTS UNDER THIS SURETY BOND WITHOUT PRIOR WRITTEN CONSENT OF SPP. ..... 3

14. AMENDMENT AND WAIVER. THE TERMS AND PROVISIONS OF THIS SURETY BOND MAY NOT BE AMENDED OR WAIVED EXCEPT IN A WRITING SIGNED BY SPP AND SURETY. ELECTION NOT TO EXERCISE, FAILURE TO EXERCISE, OR DELAY IN EXERCISING ANY RIGHTS UNDER THIS SURETY BOND SHALL IN NO WAY OPERATE AS A WAIVER OF ANY RIGHTS OF SPP UNDER THIS SURETY BOND.... 3

15. ENTIRE AGREEMENT. THIS SURETY BOND EMBODIES THE ENTIRE AGREEMENT BETWEEN SURETY AND SPP WITH RESPECT TO THE MATTERS SET FORTH HEREIN AND SUPERSEDES ALL PRIOR SUCH AGREEMENTS. ..... 3

16. SEVERABILITY. SHOULD ANY PROVISION OF THIS SURETY BOND BE DETERMINED BY A COURT OF COMPETENT JURISDICTION TO BE UNENFORCEABLE, ALL OF THE OTHER PROVISIONS SHALL REMAIN EFFECTIVE..... 3

17. CHOICE OF LAW; JURISDICTION; VENUE; AND SERVICE OF PROCESS. THIS SURETY BOND SHALL BE GOVERNED BY THE LAWS OF THE STATE OF ARKANSAS WITHOUT REGARD TO

CONFLICT OF LAWS PRINCIPLES. SURETY IRREVOCABLY SUBMITS TO THE JURISDICTION OF ANY ARKANSAS COURT OR ANY UNITED STATES COURT SITTING IN ARKANSAS OVER ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO THIS SURETY BOND AND IRREVOCABLY AGREES THAT ALL CLAIMS IN SUCH ACTION OR PROCEEDING MAY BE HEARD AND DETERMINED BY SUCH COURT. SURETY AGREES THAT A FINAL JUDGMENT IN ANY SUCH ACTION OR PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW. SURETY WAIVES ANY OBJECTION TO VENUE ON THE BASIS OF FORUM NON CONVENIENS. SURETY IRREVOCABLY CONSENTS TO THE SERVICE OF PROCESS IN ANY ACTION OR PROCEEDING BY THE MAILING OF COPIES OF SUCH PROCESS TO SURETY AT ITS ADDRESS SET FORTH HEREIN. NOTHING HEREIN SHALL AFFECT THE RIGHT OF SPP TO BRING ANY ACTION OR PROCEEDING AGAINST SURETY OR ITS PROPERTY IN THE COURTS OF ANY OTHER JURISDICTIONS. 3

18. WAIVER OF JURY TRIAL. SURETY IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS SURETY BOND. 4

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Sections I, II and III of this Attachment Z2 shall be applicable only to those Network Upgrades with an agreement authorizing construction of the upgrade that is executed on or before July 1, 2020. If such authorizing agreement is filed with the Commission unexecuted, then the applicable date is the effective date granted by the Commission in an order accepting the agreement. An Upgrade Sponsor for such a Network Upgrade is eligible to receive revenues from revenue crediting to the extent provided in Sections I, II, and III of this Attachment Z2 unless the Upgrade Sponsor selects and qualifies for candidate ILTCRs in accordance with Section IV of this Attachment Z2. For all Network Upgrades with an agreement authorizing construction of the upgrade with an execution date, or effective date granted by the Commission if filed unexecuted, after July 1, 2020 and for which an Upgrade Sponsor incurs Directly Assigned Upgrade Costs, any compensation of the Upgrade Sponsor shall be available only through candidate ILTCRs in accordance with Section IV of this Attachment Z2 and such upgrades shall not be Creditable Upgrades. ..... 76

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On a monthly basis, the Transmission Provider calculates and posts a Regulation Base Demand Price as a function of the cost to commit a Resource to provide ramp or capacity to the market in accordance with the following rules: ..... 770

(1) Regulation Base Demand Price is the average cost per MW for all Resources to recover their qualified cold start-up, no-load, and Energy costs at their Minimum Normal Operating Limit or Minimum Discharge Limit, as applicable. ..... 770

(2) For each interval and Resource, a cold start-up time must be less than or equal to 10 minutes and the Real-Time commitment status must be Market, Reliability, or Self for the Resource costs to qualify for inclusion in the calculation. ..... 770

(3) By interval and Resource, the average cost per MW is based on the costs (cold start-up, no-load, and Energy) that would be incurred at the minimum load and minimum run time from three months of historical offer data. ..... 770

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# I. COMMON SERVICE PROVISIONS

# 1 Definitions

## A - Definitions

**Accredited Revenue Requirements:** The revenue requirements calculated for Service Upgrades and previously approved Base Plan Upgrades, Balanced Portfolios and/or Zonal Reliability Upgrades that are deferred or displaced due to a subsequently identified transmission upgrade.

**Affiliate:** With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Aggregate Facilities Study:** A Facilities Study performed under the Aggregate Transmission Service Study process described in Attachment Z1.

**Aggregate Transmission Service Study:** Transmission facilities studies as described in Attachment Z1 that aggregate Transmission Service requests received over an open season. These requests are evaluated simultaneously to provide for optimization of transmission expansion.

**Ancillary Services:** Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's and Transmission Owner's(s) Transmission System in accordance with Good Utility Practice.

**Annual Transmission Cost:** The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

**Application:** A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

**Attachment Facilities:** Facilities that serve to interconnect a generating unit with a Transmission Owner’s transmission facilities.

## B - Definitions

**Balanced Portfolio:** A set of transmission upgrades that provides economic benefits across the SPP Region that meet the requirements in Sections IV.3 and IV.4 of Attachment O.

**Balanced Portfolio Region-wide Annual Transmission Revenue Requirement:** The annual transmission revenue requirement for an approved Balanced Portfolio determined in accordance with Attachment J to this Tariff.

**Balancing Authority:** The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time in order to:

(1) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(2) Maintain scheduled interchange with other Balancing Authority Areas, within the limits of Good Utility Practice;

(3) Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(4) Provide for sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

**Balancing Authority Area:** The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

**Base Plan Region-wide Annual Transmission Revenue Requirement:** The sum of the annual transmission revenue requirement for each Base Plan Upgrade and of the Accredited Revenue Requirement(s), if any, that are allocated to the SPP Region in accordance with Attachment J to this Tariff.

**Base Plan Upgrades:** Those upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System. Base Plan Upgrades shall also include: (i) those Service Upgrades required for new or changed Designated Resources to the extent allowed for in Attachment J to this Tariff, (ii) Network Upgrades required pursuant to the study results under Attachment AQ to this Tariff, (iii) ITP Upgrades that are approved for construction by the SPP Board of Directors, (iv) high priority upgrades, excluding Balanced Portfolios, that are approved for construction by the SPP Board of Directors, and (v) Network Upgrades due to the retirement of a Resource in accordance with Attachment AB to this Tariff. For Zones 1 through 15, all such upgrades shall specifically exclude planned Transmission System facilities identified in the SPP Transmission Expansion Plan that are: (i) placed in service during the 2005 calendar year or (ii) required to be in service to meet the SPP Criteria and the NERC Reliability Standards for the summer of 2005. For Zones 16, 17, and 18, all such upgrades shall specifically exclude planned Transmission System facilities in those zones identified in the SPP Transmission Expansion Plan Report (2009 – 2018) that are required to be in service to meet the SPP Criteria and the NERC Reliability Standards for the summer of 2008 or which are in operation prior to January 1, 2009, except for those upgrades that are in service prior to January 1, 2009 and are components of Phase 1 of the NPPD 345kV Norfolk to Lincoln (ETR) project or OPPD Sub 1255/3455 Transformer project. Network Upgrades that are components of Phase 1 of the NPPD 345kV Norfolk to Lincoln (ETR) project or OPPD Sub 1255/3455 Transformer project that are in service prior to January 1, 2009 will be Base Plan Upgrades, however, the Zonal component of the costs shall be 100% allocated to the respective host zone. The Base Plan Upgrades in Zones 1 through 18 identified by the Transmission Provider with a need date prior to October 1, 2015 shall not be allocable to Zone 19. The upgrades in Zone 19 identified by the Transmission Provider with a need date prior to October 1, 2015, shall not constitute Base Plan Upgrades. The facilities identified in Schedule 2 to Attachment J are expressly deemed to be Base Plan Upgrades pursuant to Attachment J, Section III.A.2.

**Base Plan Zonal Annual Transmission Revenue Requirement:** For each Zone, the sum of the annual transmission revenue requirement for each Base Plan Upgrade and of the Accredited Revenue Requirement(s), if any, that are allocated to the Zone in accordance with Attachments J and S to this Tariff.

**Base Plan Zonal Charge:** Zonal component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the revenue requirement of facilities classified as Base Plan Upgrades.

**Base Plan Zonal Load Ratio Share:** Ratio of a Network Customer's or Transmission Owner's Resident Load in a Zone to the total load in that Zone computed in accordance with Section II.B to Schedule 11 of this Tariff and calculated on a calendar year basis, for the prior calendar year. Customer loads used to determine the Base Plan Zonal Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.

**Base Plan Zonal Rate:** Zonal component of the rate (per kW of Reserved Capacity for Point-To-Point Transmission Service) assessed by the Transmission Provider in accordance with Schedule 11 to recover the revenue requirement of facilities classified as Base Plan Upgrades.

**Business Day:** A day on which the Federal Reserve System is open for business.

## C - Definitions

**Calendar Day:** Any day including Saturday and Sunday.

**Commission:** The Federal Energy Regulatory Commission.

**Completed Application:** An Application that satisfies all of the information and other requirements of the Tariff, including a Credit Application and any required Financial Security.

**Credit Policy:** The Credit Policy set forth in Attachment X to the Tariff.

**Creditable Upgrade:** Any Network Upgrade which meets the requirements of Section I of Attachment Z2.

**Curtailment:** A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

## D - Definitions

**Day-Ahead Market:** The market for Energy and Operating Reserve that is conducted on the day prior to the Operating Day.

**Delivering Party:** The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

**Delivery Point Transfer:** The transfer of responsibility for serving an existing delivery point (i) from one Network Customer or Transmission Customer to a different Network Customer or Transmission Customer; or (ii) from one Service Agreement to another Service Agreement with the same Network Customer or Transmission Customer.

**Designated Agent:** Any entity that performs actions or functions required under the Tariff on behalf of the Transmission Provider, a Transmission Owner, an Eligible Customer, or the Transmission Customer.

**Designated Resource:** Any designated generation resource owned, purchased or leased by a Transmission Customer to serve load in the SPP Region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis.

**Designated Transmission Owner ("DTO"):** A Transmission Owner that has been designated by the Transmission Provider pursuant to Attachment Y of this Tariff to construct a transmission project.

**Directly Assigned Upgrade Costs:** An Eligible Customer's share of the cost of a Service Upgrade or Network Upgrade, or a Project Sponsor's share of the cost of a Sponsored Upgrade, determined in accordance with Attachments J, V and Z1, which includes any Network Upgrade costs that are (i) directly assigned to an Eligible Customer

for a Service Upgrade in excess of the normally applicable transmission access charges for the associated transmission service; (ii) directly assigned to an Eligible Customer that are in excess of the Safe Harbor Cost Limit for Service Upgrades associated with new or changed Designated Resource; (iii) directly assigned to a Project Sponsor for a Sponsored Upgrade; or (iv) directly assigned to a Generation Interconnection Customer resulting from a request for generation interconnection.

**Direct Assignment Facilities:** Facilities or portions of facilities that are constructed by any Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer or a particular group of customers or a particular Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreements that govern service to the Transmission Customer(s) and Generation Interconnection Customer(s) and shall be subject to Commission approval.

## E - Definitions

**Eastern Interconnection:** A major alternating-current electrical grid in North America. The Eastern Interconnection reaches from Central Canada eastward to the Atlantic coast (excluding Quebec), south to Florida, and back west to the foot of the Rockies (excluding most of Texas).

**Effective Date:** For Short-Term Firm and Non-Firm Point-To-Point Transmission Service the Effective Date of this Tariff is June 1, 1998. For Long-Term Firm Point-To-Point Transmission Service the Effective Date of this Tariff is April 1, 1999. For Network Integration Transmission Service the Effective Date of this Tariff is February 1, 2000.

**Electric Storage Resource ("ESR")**

A resource capable of receiving electric energy and storing it for later injection of electric energy to the grid. A resource that is either (1) physically incapable of injecting electric energy to the Transmission System due to its design or configuration or (2) contractually barred from injecting electric energy to the Transmission System is excluded from this definition.

**Eligible Customer:** (i) Any electric utility (including the Transmission Owner(s) and any power marketer), Federal Power Marketing Agency, or any person generating electric energy for sale for resale. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that a Transmission Owner offer the unbundled transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner. (ii) Any retail customer or eligible person taking unbundled transmission service pursuant to a state requirement that a Transmission Owner offer the transmission service, or pursuant to a voluntary offer of such service by a Transmission Owner, is an Eligible Customer under the Tariff.

**Emergency Condition:** A condition or situation determined by the Transmission Provider that is imminently likely to cause a material adverse effect on the security of, or damage to the Transmission System.

**Energy:** As defined in Attachment AE to this Tariff.

**Energy and Operating Reserve Markets**: The Day-Ahead Market and Real-Time Balancing Market, including the Reliability Unit Commitment processes.

**Export Interchange Transaction:** As defined in Attachment AE to this Tariff.

**External Resource:** A Resource, other than a Designated Resource, located outside of the SPP Balancing Authority that is included in the SPP Balancing Authority through an External Resource Pseudo-Tie.

**External Resource Pseudo-Tie:** A non-physical electrical interconnection point between Balancing Authorities, whereby all or a portion of an External Resource is electronically moved from a Balancing Authority external to the SPP Balancing Authority. Energy delivered from an External Resource to the SPP Balancing Authority is treated as a Balancing Authority interchange from the source Balancing Authority to the SPP Balancing Authority.

## F - Definitions

**Facilitating Transmission Owner:** The Facilitating Transmission Owner is responsible for the Zonal Planning Criteria responsibilities as described in Attachment O of this Tariff. By April 2nd, the Network Customer with the largest total Network Load in the Zone, computed in accordance with Sections 34.4 and 34.5 of the Tariff on an average calendar year basis for the prior calendar year, shall designate a Transmission Owner with a Zonal Annual Transmission Revenue Requirement for facilities in the Zone as the Facilitating Transmission Owner for the Zone each year. Zonal Planning Criteria for Zone 10 shall be subject to Attachment AD of the Tariff.

**Facilities Study:** An engineering study conducted by the Transmission Provider in collaboration with the affected Transmission Owner(s) to determine the required modifications to the Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service or Generator Interconnection Service. The Transmission Provider shall have the ultimate responsibility for any such studies. However, the Transmission Provider's final decision must be consistent with Good Utility Practice. Facilities studies for any facilities not under the operational control of the Transmission Provider shall be performed by the Transmission Owner or any entity it designates to perform the studies.

**Feasibility Study:** A coordinated preliminary determination by the Transmission Provider and the affected Transmission Owner(s) of the Attachment Facilities, other Direct Assignment Facilities, and system upgrades that are needed to accept power into the grid at the interconnection receipt point, that will be necessary to accommodate a Generator Interconnection Request made under Attachment V.

**Federal Power-Southwestern:** All power and energy generated at reservoir projects under the control of the Department of the Army in the marketing area of the Southwestern Power Administration (Southwestern) plus power and energy delivered to Southwestern from other sources for the purpose of fulfilling Southwestern's contractual

obligations for the sale of power and energy pursuant to Southwestern's Federal power allocations.

**Federal Power–Western-UGP:** All power and energy generated at reservoir projects under the control of the Department of the Army or the Bureau of Reclamation in the marketing area of the Western-UGP for the purpose of fulfilling Western-UGP's Statutory Load Obligations for the sale of power and energy. This shall also include any power and energy delivered to or from Western-UGP under the grandfathered bi-directional agreement with Southwestern Power Administration through Associated Electric Cooperative, Inc. ("AECI") for delivery and receipt at AECI's Maryville Substation. Western-UGP's deliveries to Southwestern shall be considered part of Western-UGP's Statutory Load Obligations, and receipts from Southwestern to Western-UGP will be considered as coming from Federal resources. Federal Power-Western-UGP resources shall be eligible to be considered as Designated Resources.

**Federal Power Marketing Agency:** This term shall include the term "Federal Power Marketing Administration" and have the same definition that is set forth in the Federal Power Act at 16 U.S.C. § 796(19), which defines "Federal power marketing agency" as "any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy[.]"

**Federal Service Exemption:** Western-UGP's exemption from certain charges described in Section 39.3(e) of this Tariff.

**Firm Point-To-Point Transmission Service:** Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

## G - Definitions

**Generation Interconnection Customer:** An entity that submits a Generator Interconnection Request under Attachment V.

**Generator Interconnection Agreement:** Shall be as defined in Attachment V.

**Generator Interconnection Request:** Shall be defined as "Interconnection Request" in Attachment V.

**Generator Interconnection Service:** Shall be as defined as "Interconnection Service" in Attachment V.

**Generator Owner:** Shall be as defined in Attachment AA.

**Generator Retirement Process:** Process by which retirement of a Resource is evaluated and analyzed pursuant to Attachment AB of this Tariff.

**Generator Retirement Upgrade:** A Network Upgrade identified and analyzed through the Generator Retirement Process described in Attachment AB of this Tariff.

**Good Utility Practice:** Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

**Grandfathered Agreements or Transactions:** Grandfathered Agreements or Transactions include (1) agreements providing long term firm transmission service executed prior to April 1, 1999 and Network Integration Transmission Service executed prior to February 1, 2000; (2) bundled wholesale contracts (that reserve transmission as part of the contract); (3) short-term firm and non-firm point-to-point transmission transactions which were accepted and confirmed prior to the Effective Date; (4) existing or new contracts entered into by the Southwestern Power Administration on behalf of the United States for the use of transmission facilities of the Southwestern Power Administration that are constructed or acquired by purchase or other agreement, as authorized under Section 5 of the Flood Control Act of 1944, for the transmission of Federal Power-Southwestern; (5) contracts executed before the Effective Date, regardless of term, entered into by the Southwestern Power Administration on behalf of the United States for the transmission of power or energy across transmission facilities owned and operated by the Southwestern Power Administration; (6) contracts entered into by a Nebraska or South Dakota public-power entity prior to the transfer of functional control of its transmission facilities to the Transmission Provider; (7) existing contracts entered into by a Member which is a Nebraska or South Dakota public-power entity with any retail or wholesale electric utility customer that has a right under state law to obtain electric transmission service or energy service from such Member; (8) new contracts entered into by a Member which is a Nebraska or South Dakota public-power entity with any retail or wholesale electric utility customer that has a right under state law to obtain electric transmission service or energy service from such Member to the extent that provision of service under the Tariff would not satisfy such Member's obligation under state law; (9) agreements entered into by Southwestern Public Service Company (SPS) and Public Service Company of Colorado (PSCo) for transmission service across the Lamar HVDC Tie Line to integrate generation resources and loads pursuant to the Xcel Energy Operating Companies Joint Operating Agreement and other service under the Xcel Energy Operating Companies Open Access Transmission Tariff pursuant to FERC orders on the merger of the Xcel Energy Operating Companies, Public Service Company of Colorado, et al., 75 FERC ¶ 61,325 (1996), Order Conditionally Approving Settlement and Conditionally Authorizing Merger, 78 FERC ¶ 61,267 (1997); Cheyenne Light, Fuel

and Power Co., et al., 78 FERC ¶ 61,268 (1997); and Northern States Power Company, et. al., 90 FERC ¶ 61,020 (2000), and the FERC approved Offers of Settlement in Docket Nos. ER04-1174-000 et al. and ER08-313-000 et al.; and (10) contracts executed by Western-UGP prior to the transfer of functional control of Western-UGP transmission facilities to the Transmission Provider, regardless of term, for the transmission of power or energy. These agreements are set forth on the list which is Attachment W to this Tariff. Umbrella service agreements are specifically not Grandfathered.

## I - Definitions

**Import Interchange Transaction:** As defined in Attachment AE to this Tariff.

**Incremental Long-Term Congestion Right ("ILTCR"):** An instrument that entitles an Upgrade Sponsor to a Transmission Congestion Right that results from the incremental ATC created from the portion of an upgrade for which there is a Directly Assigned Upgrade Cost, which is awarded during the Transmission Provider's annual LTCR allocation process.

**Integrated Marketplace:** As defined in Attachment AE to this Tariff.

**Integrated Transmission Planning Assessment:** Shall be as defined in Section III of Attachment O.

**Integrated Transmission Planning Manual:** Shall be as defined in Section II of Attachment O.

**Interregional Planning Process:** The process whereby an Interregional Project is evaluated and approved for construction by the participating Interregional Planning Regions in accordance with the procedures identified in Attachment O.

**Interregional Planning Region(s):** A Commission approved planning region as identified in Section VIII of Attachment O.

**Interregional Project:** A Network Upgrade that has been approved through the Interregional Planning Process in accordance with Attachment O.

**Interruption:** A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

**ITP Upgrades:** Those upgrades identified and analyzed through the Integrated Transmission Planning Assessment described in Section III of Attachment O.

## L - Definitions

**Load Ratio Share:** Ratio of a Transmission Customer's Network Load in a Zone to the total load in that Zone computed in accordance with Sections 34.4 and 34.5 of the Network Integration Transmission Service under Part III of this Tariff and calculated on a calendar year basis, for the prior calendar year. Customer loads used to determine the Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.

**Load Shedding:** The systematic reduction of system demand by temporarily decreasing load in response to Transmission System or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

**Long-Term Firm Point-To-Point Transmission Service:** Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

**Long-Term Service:** Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service of one year or longer.

## M - Definitions

**Market Participant:** An entity that generates, transmits, distributes, purchases, or sells electricity or provides Ancillary Services with respect to such services (or contracts to perform any of the foregoing activities) within, into, out of, or through the Transmission System or an Upgrade Sponsor receiving Incremental LTCRs. Market Participant expressly includes:

(a) Transmission Owner(s) and any of their Affiliates including Transmission Owners providing transmission service to: (i) bundled retail load for which such Transmission Owners are taking neither Network Integration Transmission Service nor Firm Point-To-Point Transmission Service under this Tariff; and (ii) load being served under Grandfathered Agreements for which such Transmission Owners are taking neither Network Integration Transmission Service nor Firm Point-To-Point Transmission Service under this Tariff, (b) Transmission Customers, (c) Network Customers, (d) Generation Interconnection Customers, (e) any Eligible Customer offering Resources for sale into the Energy and Operating Reserve Markets that executes the Service Agreement specified in Attachment AH, or on whose behalf an unexecuted Service Agreement has been filed at the Commission, (f) any retail customer or eligible person that is not precluded under the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s) from participating directly in wholesale demand response programs in the Energy and Operating Reserve Markets and that is technically qualified to offer Demand Response Load (as defined in Attachment AE of this Tariff) into the Energy and Operating Reserve Markets or an aggregator of such retail customers that offers qualified Demand Response Load into the Energy and Operating Reserve Markets under Section 2.8 of Attachment AE, (g) an entity that executes the Service Agreement specified in Attachment AH and registers the assets of one or more Asset Owners, and (h) an Upgrade Sponsor that executes the Service Agreement specified in Attachment AH.

**Market Protocols:** The protocols implementing the Integrated Marketplace as amended from time to time in accordance with the SPP Membership Agreement.

**Market Storage Resource ("MSR")**

As defined in Attachment AE of this Tariff.

**Member:** A member of SPP.

## N - Definitions

**Native Load Customers:** The wholesale and retail power customers of the Transmission Owner(s) on whose behalf the Transmission Owner(s), by statute, franchise, regulatory requirement, or contract, has (have) undertaken an obligation to construct or operate the Transmission Owner's(s') system(s) to meet the reliable electric needs of such customers. In addition, Native Load Customers also may include the customers of the Federal Government on whose behalf the Government, by policy, statute, regulatory requirement, or contract, delivers Federal capacity and energy to meet all or a portion of the reliable electric needs of such customers.

**Network Customer:** An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

**Network Customer Transmission Credits:** Financial credits applied against a Network Customer’s monthly demand charges under Schedule 9 of this Tariff in accordance with the provisions of Section 30.9 of the Tariff.

**Network Integration Transmission Service:** The transmission service provided under Part III of the Tariff.

**Network Load:** The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

**Network Operating Agreement:** An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

**Network Resource:** Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program.

**Network Upgrades:** All or a portion of the modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all Users of such Transmission System.

**Next-Hour-Market Service:** Non-firm transmission service that (a) is reserved for one clock hour and (b) is requested within sixty (60) minutes before the start of the next clock hour for service commencing at the start of that clock hour.

**Non-Firm Point-To-Point Transmission Service:** Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

**Non-Firm Sale:** An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

**Notification to Construct ("NTC"):** A written notice from the Transmission Provider directing an entity that has been selected to construct one or more transmission

project(s)to begin or continue implementation of the transmission project(s) in accordance with Attachment Y.

## O - Definitions

**OATT:** See "Tariff."

**Open Access Same-Time Information System (OASIS):** The information system and Internet location where the Transmission Provider posts the information required by 18 C.F.R. § 37 of the Commission's regulations, and where the Transmission Provider may also post the information required to be posted on its Internet website by 18 C.F.R. § 358 of the Commission's regulations.

**Operating Reserve Only Resource:** A Resource that cannot be cleared or dispatched for Energy that is qualified to provide any or all of the Operating Reserve products: Regulation-Up, Regulation-Down, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, or Ramp Capability Down.

**Oversight Committee:** The organizational group defined in Section 6.4 of the SPP Bylaws.

## P - Definitions

**Part I:** Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

**Part II:** Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**Part III:** Tariff Sections 28 through 36 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

**Part IV:** Tariff Sections 37 through 39 pertaining to special Tariff provisions related to the applicability of the Tariff during and after the Transition Period and special Tariff provisions related to participation by the United States.

**Part V:** Tariff Sections 40 through 42, and related Schedules and Attachments, pertaining to recovery of costs for Base Plan Upgrades and approved Balanced Portfolios.

**Parties:** The Transmission Provider and the Transmission Customer receiving service under the Tariff.

**Point(s) of Delivery:** Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

**Point(s) of Receipt:** Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the

Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

**Point-To-Point Transmission Service:** The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

**Power Purchaser:** The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

**Pre-Confirmed Application:** An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

**Project Sponsor:** One or more entities that voluntarily agree to bear a portion or all of the costs of a Sponsored Upgrade.

**Public Policy Requirements:** Requirements established by local, state or federal laws or regulations, including duly enacted statutes or regulations promulgated by a relevant jurisdiction, whether within a state, or at the federal level.

## R - Definitions

**Real-Time:** As defined in Attachment AE to this Tariff.

**Real-Time Balancing Market (RTBM):** The market operated by the Transmission Provider continuously in real-time to balance the system through deployment of Energy and to clear Regulation-Up, Regulation-Down, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, and Ramp Capability Down.

**Receiving Party:** The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

**Region-wide Annual Transmission Revenue Requirement:** The sum of the annual transmission revenue requirements as set forth in Attachment H, Table 2-A and Table 2-B.

**Region-wide Charge:** Regional component of the charge assessed by the Transmission Provider in accordance with Schedule 11 to recover the Region-wide Annual Transmission Revenue Requirement.

**Region-wide Load Ratio Share:** For application to Section I, Table 2-A of Attachment H, the ratio of a Network Customer’s or Transmission Owner’s Resident Load to total Resident Load in Zones 1 through 18, computed in accordance with Section II.B to Schedule 11 of this Tariff, and calculated on a calendar year basis for the prior calendar year. For application to Section I, Table 2-B of Attachment H, the ratio of a Network Customer's or Transmission Owner’s Resident Load to total Resident Load in the SPP Region, with both numerator and denominator limited to Resident Loads subject to the Region-wide Charge, computed in accordance with Section II.C to Schedule 11 of this Tariff, and calculated on a calendar year basis for the prior calendar year. Customer loads used to determine the Region-wide Load Ratio Share shall be adjusted for real power losses in accordance with the provisions set out in Section 28.5 of this Tariff.

**Region-wide Rate:** Regional component of the rate per kW of Reserved Capacity assessed by the Transmission Provider in accordance with Schedule 11 to recover the Region-wide Annual Transmission Revenue Requirement.

**Regional State Committee:** A voluntary organization comprised of one designated commissioner from each participating state regulatory commission having jurisdiction over an SPP Member, established to collectively provide both direction and input on all matters pertinent to the participation of the Members in SPP pursuant to the SPP Bylaws.

**Regional Transmission Group (RTG):** A voluntary organization of Transmission Owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

**Reliability Unit Commitment:** As defined in Attachment AE of this Tariff.

**Reserve Sharing System:** The Transmission Provider’s computer system that receives and records contingency events and requests for assistance by Reserve Sharing Group members, calculates and communicates the appropriate reserve capacity obligations and reserve energy responsibilities for events to all Reserve Sharing Group members and creates applicable Energy schedules for deployment by the Reserve Sharing Group members.

**Reserved Capacity:** The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

**Resident Load:** The load specified in Section 41 of the Tariff.

**Resource:** An asset that injects energy into the transmission grid or reduces the withdrawal of energy from the transmission grid including a Demand Response Resource, a Variable Energy Resource, a Dispatchable Resource, and External Resource, External Dynamic Resource.

**Revenue Requirements and Rates File (RRR File):** A file posted on the SPP website as a reference to: (i) Annual Transmission Revenue Requirements (ATRRs) for Network Integration Transmission Service, as referenced in Attachment H to this Tariff; (ii) Base Plan ATRR allocation; (iii) allocation factors for Base Plan funded projects; (iv) notes on the calculation of Base Plan ATRR amounts on a Region-wide and Zonal basis; (v) ATRR reallocation for Balanced Portfolio projects; (vi) the calculation of Base Plan Point-To-Point Transmission Service rates on a Region-wide and Zonal basis in accordance with Schedule 11; and (vii) the rates for Point-To-Point Transmission Service as referenced in Attachment T in accordance with Schedules 7 and 8.

## S - Definitions

**Screening Study:** A study conducted pursuant to Attachment AR of the Tariff to evaluate potential Long-Term Service request options or a proposed Delivery Point Transfer.

**Screening Study Agreement:** An agreement between Transmission Provider and a Network Customer or Transmission Customer for the performance of a Screening Study pursuant to Attachment AR of the Tariff.

**Service Agreement:** The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

**Service Commencement Date:** The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

**Service Upgrades:** Network Upgrades required to provide transmission service requested by an Eligible Customer in accordance with Attachment Z1 to this Tariff.

**Short-Term Firm Point-To-Point Transmission Service:** Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

**Short-Term Service:** Short-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service of less than one year.

**Sponsored Upgrades:** Network Upgrades, requested by a Transmission Customer or other entity, which do not meet the definition of any other category of Network Upgrades.

**SPP:** The Southwest Power Pool, Inc.

**SPP Bylaws:** The Bylaws of SPP filed at FERC that set forth the governance structure and other organizational authorities and obligations for SPP.

**SPP Criteria:** The SPP Planning Criteria and SPP Operating Criteria collectively, as approved by the Board of Directors in accordance with the SPP Bylaws, and posted on the SPP website.

**SPP Membership Agreement:** The Southwest Power Pool Membership Agreement detailing the rights and obligations of the SPP and SPP Members.

**SPP Region:** The geographic area of the Transmission System.

**SPP Transmission Expansion Plan (STEP):** The plan that describes the transmission expansion projects being considered over the planning period and developed through the stakeholder process in accordance with this Tariff and approved by the SPP Board.

**Statutory Load Obligations**: Western-UGP's power marketing function obligations under Federal law to deliver power and energy from the output of the Federal hydroelectric projects operated by the Department of the Army and the Bureau of Reclamation to loads which include project use loads, preference power customer loads in Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota located in a marketing area defined pursuant to a power marketing plan, and other loads required to be served under Federal law.

**System Condition:** A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-To-Point Transmission Service using the

curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

**System Impact Study:** A coordinated assessment by the Transmission Provider and the affected Transmission Owner(s) of (i) the adequacy of the Transmission System to accommodate Short-Term Service or (ii) to determine the Attachment Facilities, other Direct Assignment Facilities, and system upgrades that are needed to accept power into the grid at the interconnection receipt point, required to accommodate a request for generation interconnection in accordance with Attachment V and (iii) whether any additional costs may be incurred in order to provide transmission service or generation interconnection.

## T - Definitions

**Tariff:** The Open Access Transmission Tariff or "OATT", including all schedules or attachments thereto, of the Transmission Provider as amended from time to time and approved by the Commission.

**Third-Party Sale:** Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

**Transition Period:** The period from the Effective Date of this Tariff for the provision of Network Integration Transmission Service to the last day of the fifth year thereafter. The Transition Period for a Member that is a Nebraska public-power entity shall be the period from the effective date of the transfer of functional control to the last day of the fifth year thereafter.

**Transmission Congestion Rights:** As defined in Attachment AE to this Tariff.

**Transmission Customer:** Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

**Transmission Owner:** Each Member of SPP that has executed an SPP Membership Agreement as a Transmission Owner and therefore has the obligation to construct, own, operate, and maintain transmission facilities as directed by the Transmission Provider and: (i) whose Tariff facilities (in whole or in part) make up the Transmission System; or (ii) who has accepted a Notification to Construct but does not yet own transmission facilities under SPP's functional control. Those Transmission Owners that are not

regulated by the Commission shall not become subject to Commission regulation by virtue of their status as Transmission Owners under this Tariff; provided, however, that service over their facilities classified as transmission and covered by the Tariff shall be subject to Commission regulation.

**Transmission Provider:** The Southwest Power Pool, Inc., acting in its role as administrator of this Tariff.

**Transmission Provider's Monthly Transmission System Peak:** The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

**Transmission Service:** Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

**Transmission System:** The facilities used by the Transmission Provider to provide transmission service under Part II, Part III and Part IV of the Tariff.

## U - Definitions

**Upper Missouri Zone:** The Upper Missouri Zone ("UMZ" or "Zone 19") is the rate pricing zone initially consisting of the following facilities that meet the requirements of Attachment AI, upon the transfer of those facilities to the functional control of the Transmission Provider: (i) the facilities of Western-UGP within the Eastern and Western Interconnections; (ii) the facilities owned or leased by Basin Electric Power Cooperative or Heartland Consumers Power District within the Eastern Interconnection; (iii) a portion of the facilities owned or leased by Basin Electric Power Cooperative within the Western Interconnection; and (iv) other facilities of the Western Area Power Administration in the Eastern Interconnection transferred to the functional control of the Transmission Provider, not included in the facilities of Western-UGP in (i) above.

**Users:** Transmission Customers or other entities that are parties to transactions under the Tariff.

**Upgrade Sponsor:** A Transmission Customer, Network Customer, Generation Interconnection Customer, or Project Sponsor paying Directly Assigned Upgrade Costs for a Network Upgrade.

## V – Definitions

**Virtual Energy Bid:** As defined in Attachment AE to this Tariff.

**Virtual Energy Offer:** As defined in Attachment AE to this Tariff.

## W - Definitions

**Western Area Power Administration-Rocky Mountain Region ("Western-RMR"):** A division of the Western Area Power Administration that markets and transmits Federal power generated from certain U.S. Bureau of Reclamation hydroelectric facilities collectively known as the Loveland Area Projects. Western-RMR also operates the Western Area Colorado Missouri Balancing Authority Area, known as WACM, and the Western Area Lower Colorado Balancing Authority Area, known as WALC, and provides transmission services, including, but not limited to, transmission service across Western-owned transmission facilities within the two Balancing Authority Areas.

**Western Area Power Administration-Upper Great Plains Region ("Western-UGP"):** A division of the Western Area Power Administration that markets and transmits Federal power from reservoir projects under the control of the Department of the Army or the U.S. Bureau of Reclamation. Western-UGP operates the WAUW Balancing Authority Area in the Western Interconnection, where certain of its transmission facilities are located. Western-UGP has transferred Federal transmission facilities in both the Eastern Interconnection and Western Interconnection to the functional control of the Transmission Provider.

**Western Interconnection:** A major alternating current power grid in North America. The Western Interconnection stretches from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains. Western Interconnection is comprised of the states of Washington, Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, portions of Montana, South Dakota, Nebraska, New Mexico and Texas in the United States, the Provinces of British Columbia and Alberta in Canada, and a portion of the Comisión Federal de Electricidad's system in Baja California in Mexico.

**Wholesale Distribution Service:** The provision of service over a Transmission Owner's Distribution Facilities necessary to effectuate Network Integration Transmission Service or Point-To-Point Transmission Service under this Tariff. To the extent such Wholesale

Distribution Service is required; it shall be specified in the Service Agreement for the associated service being provided under the Tariff. The charges for Wholesale Distribution Service are described in Schedule 10.

## XYZ - Definitions

**Zonal Annual Transmission Revenue Requirement:** The revenue requirements for facilities in each Zone and the Accredited Revenue Requirement(s), if any, that are allocated to the Zone in accordance with Attachment J to this Tariff as set forth in Attachment H, Table 1, Column (3).

**Zonal Planning Criteria:** In each Zone, the set of measuring systems and performance standards that is used for assessing the actual or projected ability of the Transmission System to deliver power to load reliably. Zonal Planning Criteria for Zone 10 shall be subject to Attachment AD of the Tariff.

**Zonal Reliability Upgrades:** Those upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System identified because of application of Zonal Planning Criteria. Zonal Planning Criteria for Zone 10 shall be subject to Attachment AD of the Tariff.

**Zone:** The geographic area of the facilities of a Transmission Owner or a specific combination of Transmission Owners as specified in Schedules 7, 8, and 9.

# 2 Initial Allocation and Renewal Procedures

## 2.1 Initial Allocation of Available Transfer Capability:

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the Effective Date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by the Transmission Provider shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

**2.2 Reservation Priority For Existing Firm Service Customers:**

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more, and retail) of the Transmission Owner(s) or Transmission Provider have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Owner(s) or elects to purchase capacity and energy from another supplier. The existing customer must notify the Transmission Provider no later than one year prior to the end of the term of its firm transmission contract that it is exercising its transmission reservation priority; otherwise it shall forfeit the transmission reservation priority associated with the contract. If at the time of this notification, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have the right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of this transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised in the manner specified above at the end of all firm contract terms of five years or longer. This reservation priority only applies to the facilities of the Transmission Owner(s) where such facility costs have been included as part of the firm service rates that the firm service customer has been paying. If competing existing firm service requirements customers apply for service that cannot be fully provided, the priority rights will be ranked in accordance with first-come, first-served principles. If firm service customers tie, then the capacity for which they receive priority rights under this Tariff shall be apportioned on a pro rata basis.

## 3 Ancillary Services

As shown on Schedules 1 and 2, the Transmission Provider will provide Scheduling and Tariff Administration Service and will facilitate and arrange for the supply of Reactive Supply and Voltage Control from Generation or Other Sources Service. All Transmission Customers are required to purchase these two services from the Transmission Provider based on the charges in Schedules 1 and 2. In addition, the Transmission Owners may continue to provide Scheduling, System Control and Dispatch Services related to transmission service under this Tariff. Each Transmission Owner must maintain a schedule showing the charges for such services. Any amounts charged the Transmission Provider by a Transmission Owner for such service shall be passed through to the Transmission Customer without mark-up. Each Transmission Owner's schedules for Scheduling, System Control and Dispatch Service and for Reactive Supply and Voltage Control from Generation or Other Sources Service shall be available through the SPP OASIS.

The Transmission Provider also shall maintain the Ancillary Service schedules which provide (1) Regulation and Frequency Response Service, (2) Energy Imbalance Service, (3) Operating Reserve - Spinning Reserve Service, and (4) Operating Reserve - Supplemental Reserve Service as described under Schedules 3, 4, 5 and 6 respectively. Transmission Customers shall pay the Transmission Provider providing any of these services directly for the service. The Transmission Customer serving load within the SPP Balancing Authority Area is required to acquire these four Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply. The Transmission Customer may not decline the Transmission Provider’s offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source.

A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve. The Transmission Provider shall determine whether the Transmission Customer has adequately demonstrated that it has acquired the Ancillary Services from another source. If the

Transmission Provider determines that the Transmission Customer is taking Ancillary Services that it has not paid for or otherwise has not made adequate arrangements for Ancillary Services, then the Transmission Provider may impose a penalty equal to 200% of the applicable Ancillary Service charge for the entire length of the reserved period but not exceeding one month.

A Transmission Customer that is serving load utilizing Network Integration Transmission Service will not require any additional transmission service arrangements for the delivery of Ancillary Services.

A Transmission Customer with load not served under Network Integration Transmission Service must have sufficient transmission service arrangements for the delivery of all services including Ancillary Services.

## 4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding the Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information Systems), 18 C.F.R. § 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities), and 18 C.F.R. § 358 of the Commission's regulations (Standards of Conduct for Transmission Providers). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and on its public website an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standard and practices that are not included in this Tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

# 5 Local Furnishing Bonds

## 5.1 Transmission Owners That Own Facilities Financed by Local Furnishing or Other Tax-Exempt Bonds or that are Tax Exempt Entities:

This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds") or facilities with other bonds the interest on which is excluded from gross income under Section 103 of the Internal Revenue Code ("other tax-exempt bonds"), or that are tax-exempt entities, described in Section 501(c) of the Internal Revenue Code. Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance a Transmission Owner's facilities that would be used in providing such transmission service or would jeopardize the tax-exempt status of the tax-exempt entity.

## 5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance a Transmission Owner's facilities that would be used in providing such transmission service or would jeopardize the tax-exempt status of the Transmission Owner, the Transmission Provider shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider and the relevant Transmission Owner, within ten (10) days of receiving a copy of the Section 211 application, will waive any rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's and/or Transmission Owner's waiver of rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service over the affected Transmission Owner's facilities in accordance with the terms and conditions of this Tariff.

## 6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to all the Transmission Owners on similar terms and conditions over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy in interstate commerce owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision

## 7 Billing and Payment

This Section 7 shall not apply to the Integrated Marketplace. All billing and payment matters associated with the Integrated Marketplace shall be as specified in Attachment AE.

**7.1 Billing Procedure**:

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for services furnished under the Tariff. The invoice shall be paid by the Transmission Customer within fifteen (15) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider. Invoices may be issued using estimated data, to the extent actual data is not available by the fifth (5th) working day of the month following service. Adjustments reflecting the difference in billing between the estimated and actual data will be included on the next regular invoice, with such adjustment being due when that invoice is due. Any other corrections found to be necessary will be made on the next regular monthly invoice.

Bills will be adjusted to correct for all provable meter errors. Billing adjustments for reasons other than (a) the replacement of estimated data with actual data for service provided, or (b) provable meter error, shall be limited to those corrections and adjustments found to be appropriate for such service within one year after rendition of the bill reflecting the actual data for such service. Adjustments shall be made for any billing with a monetary impact in excess of 2% of the billing for the relevant period for an individual Transmission Customer or any aggregation thereof. At its sole discretion, the Transmission Provider may make billing adjustments for lesser amounts.

## 7.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (not including amounts held by SPP as Financial Security) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

## 7.3 Financial Security Held By SPP:

All monies deposited by a Customer as Financial Security with SPP pursuant to the Credit Policy or otherwise will be held by SPP in a separate, interest-bearing, account in SPP's name and within SPP's sole control subject to the conditions and provisions in the Credit Policy. One Hundred percent (100%) of the interest earned will accrue to the benefit of that Customer. Interest shall be calculated from the date of the receipt of deposit until the date that the deposit is returned or converted into another form of Financial Security. When deposits are made by mail, they shall be considered having been paid on the date of receipt by the Transmission Provider.

## 7.4 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within two (2) business days of receipt by the Transmission Customer of a written notice to cure such failure sent by the Transmission Provider, via any normal means of business communication, a default by the Transmission Customer shall be deemed to exist. The written notice to cure may be delivered by Certified mail, or by other means where receipt of the notice by the addressee is confirmed in writing. This notice shall include a copy of the unpaid invoice for which the accompanying notice is being sent to the Transmission Customer. Upon the occurrence of such a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. Any such default or termination shall not relieve the Transmission Customer of its obligation to compensate the Transmission Provider for all amounts owed for the full term of the Service Agreement as if such default or termination had not occurred. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intent to suspend service in sixty (60) days, in accordance with Commission policy.

## 8 Accounting for Use of the Tariff

The Transmission Provider and Owner(s) shall record the following amounts, as outlined below, where applicable.

## 8.1 Study Costs and Revenues:

The Transmission Provider and each Transmission Owner shall include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred in the performance of any System Impact Studies or Facilities Studies which the Transmission Provider and/or the Transmission Owner(s) conduct or is(are) involved in to determine if construction of new facilities or upgrades are required for the uses of the Transmission Owner(s), including third party sales under the Tariff. The Transmission Provider and each Transmission Owner shall include in a separate operating revenue account or subaccount the revenues the Transmission Provider and Transmission Owner(s) received for its (their) role in conducting such System Impact Studies or Facilities Studies.

## 9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider or Transmission Owner(s) to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder; provided, however, the Transmission Provider and the Transmission Owners are restricted in their ability to make certain changes as detailed in the SPP Membership Agreement.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

# 10 Force Majeure and Indemnification

**10.1 Force Majeure:**

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental, military, or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider, the Transmission Owner(s), nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

**10.2 Liability:**

(a) The Transmission Provider shall not be liable for money damages or other compensation to any Transmission Customer or Users for actions or omissions by the Transmission Provider or Transmission Owner in performing its obligations under this Tariff or any Service Agreement thereunder, except to the extent such act or omission by the Transmission Provider is found to result from its gross negligence or intentional wrongdoing.

(b) A Transmission Owner shall not be liable for money damages or other compensation to any Transmission Customer or Users for actions or omissions by such Transmission Owner or Transmission Provider in performing its obligations under this Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Transmission Owner is found to result from its gross negligence or intentional wrongdoing.

(c) A Transmission Customer or Users may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of the Transmission Provider or a Transmission Owner or Affiliate of either solely by reason of their status as directors, members, shareholders, officers, employees or agents of the Transmission Provider or a Transmission Owner or Affiliate of either. Notwithstanding the foregoing, a Transmission Customer or Users shall be liable to the Transmission Provider for all amounts owed for the full term of any Service Agreement under the Tariff.

(d) In no event shall the Transmission Provider, a Transmission Owner or any Transmission Customer or Users be liable for any incidental, consequential, punitive, special, exemplary or indirect damages, attorney's fees and costs, loss of revenues or profits, arising out of, or connected in any way with the performance or non-performance under this Tariff or any Service Agreement thereunder.

### 10.3 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider and Transmission Owner(s) harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's or Transmission Owner's(s') performance of obligations under this Tariff on behalf of the Transmission Customer, except in cases of gross negligence or intentional wrongdoing by the Transmission Provider or a Transmission Owner. If the Transmission Provider engages in gross negligence or intentional wrongdoing, but the Transmission Owner(s) does (do) not, that will not affect the indemnification of the Transmission Owner(s) under this Section 10.3 and vice-versa.

**10.4 Further Limitation of Liability:**

Neither the Transmission Owner nor the Transmission Provider shall be liable for damages arising out of services provided under this Tariff including, but not limited to any act or omission that results in an interruption, deficiency or imperfection of service, occurring as a result of conditions or circumstances beyond the control of the Transmission Owner or Transmission Provider, as applicable, or resulting from electric system design common to the domestic electric utility industry or electric system operation practices or conditions common to domestic electric utility industry. Transmission Owners shall not be liable for acts or omissions done in compliance or good faith attempts to comply with directives of Transmission Provider.

### 10.5 Transmission Provider Recovery:

To the extent that the Transmission Provider is required to pay any money damages or compensation or pay amounts due to its indemnification of any other party, the Transmission Provider shall be allowed to recover any such amounts (subject to crediting all amounts recovered by Transmission Provider through insurance or through any indemnification it receives) under Schedule 1-A of this Tariff as part of the Administrative Charges, provided that the cap in Schedule 1-A shall not apply to or prohibit the recovery of these amounts.

## 10.6 Limitation on Claims:

Except as otherwise specified in Section 7.1 of this Tariff or Sections 10.1 or 10.3 of Attachment AE to this Tariff, or as may be required to comply with the requirements of this Tariff or applicable Commission directives:

(a) No claim seeking an adjustment in the billing for any service, transaction, or charge under the Tariff may be asserted if more than two years has elapsed since the first date upon which the billing for that week or month occurred. The Transmission Provider shall make no adjustment to billing with respect to any service, transaction, or charge under this Tariff if more than two years has elapsed since the first date upon which the billing for that week or month occurred, unless a claim seeking such adjustment had been received by the Transmission Provider prior to the end of the two-year period.

(b) For claims that arose prior to the effective date of Section 10.6 of the Tariff, the claimant shall have two years from the effective date of Section 10.6 to assert such claims.

## 11. Creditworthiness:

The Transmission Provider will specify its Creditworthiness procedures in Attachment X.

# 12 Dispute Resolution Procedures

**12.1 Internal Dispute Resolution Procedures:**

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

## 12.2 External Arbitration Procedures:

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel, except that if more than two Parties are involved, the Parties shall agree on procedures to choose these two arbitrators. If the Parties are unable to agree, then the American Arbitration Association shall be asked to appoint the arbitrator(s) who must be knowledgeable in matters involving the electric power industry. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

### 12.3 Arbitration Decisions:

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction; provided, however, that final decisions with the Federal Government as one of the parties are nonbinding. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

**12.4 Costs:**

Each Party shall be responsible for its own costs, including its attorney's fees and costs, incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party or Parties to sit on the three member panel and its equal share of the cost of the third arbitrator chosen; or

(ii) its equal share of the cost of the single arbitrator jointly chosen by the Parties.

## 12.5 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

# II. POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

# 13 Nature of Firm Point-To-Point Transmission Service

**13.1 Term:**

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

**13.2 Reservation Priority:**

(i) Long-Term Firm Point-To-Point Transmission Service shall be available based on the results of an aggregate study. Requests will be aggregated during an open season and all Point-To-Point service requests and designated network resource requests received during that time shall be deemed received at the same time if they are not using a contractually limited interface (e.g. a DC-Tie). For contractually limited interfaces, the first-come, first-served principles shall apply for the purpose of allocating limited interface capacity only. The allocation of remaining ATC on contractually limited interfaces shall occur as if all requests are received at the same time.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation and relative impact on available transfer capability. However, Pre-Confirmed Applications for Short-Term Point-To-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration, as relevant, and pre-confirmation status (pre-confirmed, confirmed or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. This right of preemption only applies, however, if the longer term service involves the same Points of Receipt and Delivery as the shorter term service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service with a

lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff or non-firm transmission service under Grandfathered Agreements. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

### 13.3 Use of Firm Transmission Service by the Transmission Owners:

Each Transmission Owner will be subject to the rates, terms and conditions of Part II of the Tariff when making third-party sales under (i) agreements executed on or after the Effective Date of the Tariff or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled after the Effective Date of the Tariff.

**13.4 Service Agreements:**

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Transactions under the Short-Term Firm Point-To-Point Transmission Service Agreement shall be arranged by providing the information listed in Section 17.2 of the Tariff and on the confirmation sheet contained in Attachment Q. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement.

**13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs:**

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with a(the) Transmission Owner's(s') ability to meet prior firm contractual commitments to others, the relevant Transmission Owner(s) will be obligated to expand or upgrade its (their) Transmission System(s) pursuant to the terms of Section 15.4 of this Tariff. The Transmission Customer must agree to pay the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27 of this Tariff. Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service. To the extent that the Transmission Provider can relieve a system constraint by redispatching resources registered to participate in the Energy and Operating Reserve Markets, it shall do so. Any redispatch costs incurred to relieve a system constraint to be charged to the Transmission Customer shall be collected and paid as part of the Energy and Operating Reserve Market settlement procedures described under Attachment AE of this Tariff. Transmission Customers having Firm Point-To-Point Transmission Service subject to redispatch will be eligible to nominate Candidate Auction Revenue Rights associated with that service only for those times of the year and for only the amounts of service that are not subject to redispatch. Long-Term Firm Point-to-Point Transmission Service with a redispatch requirement will not be eligible for any Candidate Long-Term Congestion Rights because it does not have continuous service covering the entirety of the associated Transmission Congestion Right year.

**13.6 Curtailment of Firm Transmission Service:**

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such System and the systems directly and indirectly connected with the Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. The Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment R. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail (or cause to be curtailed) service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Owner's(s') Native Load Customers, and to transmission customers taking firm transmission service under Grandfathered Agreements. All Curtailments will be made on a non-discriminatory basis; however, Non-Firm Point-To-Point Transmission Service as well as any non-firm transmission service provided under Grandfathered Agreements shall be subordinate to Firm Point-To-Point Transmission Service. When the Transmission Provider determines that an electrical emergency exists on the Transmission System and implements emergency procedures to curtail firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to curtail or to effect the Curtailment of, in whole or in part, any firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of the Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. In the event that the Transmission Customer fails to cease or reduce service in response to a directive by the Transmission Provider, the Transmission Customer shall pay any applicable charges and the following penalty (in addition to the charges for all of

the firm capacity used): 100% of the Firm Point-To-Point Transmission Service charges under Schedules 7 and 11 for the entire length of the reserved period but not exceeding one month. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive.

**13.7 Classification of Firm Transmission Service:**

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.3.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are interconnected to the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless (i) the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt, or (ii) the generating units or plants comprise a registered Resource Hub as defined in Attachment AE in which case the units or plants also would be considered as a single Point of Receipt. In the event of a change in the ownership or control of generation resources previously aggregated as a single Point of Receipt under this provision, such generation may be disaggregated and treated as multiple Points of Receipt, provided that all other terms of this Tariff and the Service Agreement are met.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for short-term firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a

corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for short-term firm Transmission Service. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 7 and 11. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including third-party sales by a Transmission Owner) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, except for an MSR under instruction as specified in Section 2.17 of Attachment AE, the Transmission Customer shall pay the following penalty (in addition to the applicable charges for all of the firm capacity actually used): 100% of the Firm Point-To-Point Transmission Service charges under Schedules 7 and 11 for the period for which the unreserved service was actually used. The charges for the unreserved service shall be based upon the duration of the period when the unreserved capacity was used. For example, one hour shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of the amount distributed to Transmission Owners shall be used to reduce the

Schedule 1-A1 charges collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 1-A1 charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to Transmission Customers on a pro-rata basis of each Transmission Customer's monthly Schedule 1-A1 charge, except for the penalized Transmission Customer, for the next billing period ending at least 15 calendar days after the date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding reserved capacity, the Transmission Customer also must purchase losses as required by this Tariff.

**13.8 Scheduling of Firm Point-To-Point Transmission Service**:

All scheduling practices and schedules submitted by Transmission Customers will comply with applicable North American Electric Reliability Council Policies and SPP Criteria. Transmission Customers shall submit all schedules electronically in a form specified by the Transmission Provider. Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service associated with transactions into, out of or through the SPP Balancing Authority Area must be submitted to the Transmission Provider in accordance with the times in Attachment P. Schedules submitted after the applicable time specified on Attachment P will be accommodated, if practicable. Customers may schedule intra-hour Firm Point-To-Point Transmission Service in whole-minute increments. Hour-to-hour and intra-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within a Transmission Owner's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be accommodated as provided in Attachment P. However, in the event of a system contingency such as a generation or transmission outage, or curtailment or interruption of transmission service, scheduling changes will be implemented as soon as practicable. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party and shall deliver the capacity and energy provided by the Delivering Party. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

# 14 Nature of Non-Firm Point-To-Point Transmission Service

**14.1 Term:**

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

**14.2 Reservation Priority**:

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers, and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service and customers under other transmission tariffs or agreements taking network or firm point-to-point transmission service from the Transmission Owner(s). A higher priority will be assigned first to requests or reservations with a longer duration of service involving the same Points of Receipt and Delivery and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration involving the same Points of Receipt and Delivery will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service; provided, however, this provision assigning priority based upon the highest price offered shall not affect the priority of transmission contracts not under this Tariff. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in Section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers and for network customers under Grandfathered Agreements involving the affected Transmission Owner(s) from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the second lowest reservation priority under the Tariff, and Non-Firm Point-To-Point Transmission Service used

for Next-Hour-Market Service will have the lowest reservation priority under the Tariff.

### 14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Owner(s):

Each Transmission Owner will be subject to the rates, terms and conditions of Part II of the Tariff when making third-party sales under (i) agreements executed on or after the Effective Date of the Tariff or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled after the Effective Date of the Tariff.

**14.4 Service Agreements:**

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Transactions under this Non-Firm Point-To-Point Transmission Service Agreement shall be arranged by providing the information on the confirmation sheet which is contained in Attachment Q. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

**14.5 Classification of Non-Firm Point-To-Point Transmission Service:**

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider and Transmission Owners undertake no obligation under the Tariff to plan the Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 8 and 11. In the event that a Transmission Customer (including third-party sales by a Transmission Owner) exceeds its non-firm capacity reservation, except for an MSR under instruction as specified in Section 2.17 of Attachment AE, the Transmission Customer shall pay the following penalty (in addition to the charges for all of the non-firm capacity used): 100% of the Non-Firm Point-To-Point Transmission Service charges under Schedules 8 and 11 for the duration of the period when the additional service was used as specified below not to exceed one month for the amount in excess of such capacity reservation. An excess of one hour or less shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Non-Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of the amount distributed to Transmission Owners shall be used to reduce the Schedule 1-A1 charges collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 1-A1 charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to Transmission Customers on a pro-rata basis of each Transmission Customer's monthly Schedule 1-A1 charge, except for the penalized Transmission Customer, for the next billing period ending at least 15

calendar days after the date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must purchase losses as required by this Tariff. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedules 8 and 11.

**14.6 Scheduling of Non-Firm Point-To-Point Transmission Service:**

All scheduling practices and schedules submitted by Transmission Customers will be consistent with applicable North American Electric Reliability Council Policies and SPP Criteria. Transmission Customers shall submit all schedules electronically in a form specified by the Transmission Provider. Schedules for Non-Firm Point-To-Point Transmission Service, other than for Next-Hour-Market Service, associated with transactions into, out of or through the SPP Balancing Authority Area must be submitted to the Transmission Provider in accordance with the times in Attachment P. Schedules submitted after the applicable time specified in Attachment P will be accommodated if practicable. Schedules for Non-Firm Point-To-Point Transmission Service for Next-Hour-Market Service must be submitted to the Transmission Provider no later than 20 minutes and no earlier than 60 minutes before the start of the next clock hour. Schedules submitted less than 20 minutes prior to the start of the next clock hour will be accommodated, if practicable. Customers may schedule intra-hour Non-Firm Point-To-Point Transmission Service in whole-minute increments. Hour-to-hour and intra-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour. Transmission Customers within a Transmission Owner's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be accommodated in accordance with Attachment P. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party and shall deliver the capacity and energy provided by the Delivering Party. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

**14.7 Curtailment or Interruption of Service:**

The Transmission Provider reserves the right to curtail (or cause to be Curtailed), in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when, an emergency or other unforeseen condition threatens to impair or degrade the reliability of the Transmission System or the systems directly or indirectly interconnected with the Transmission Provider's Transmission System. The Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment R. The Transmission Provider reserves the right to Interrupt(or to effect the Interruption of), in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for firm Transmission Service under this Tariff or for firm transmission service provided by a Transmission Owner under a Grandfathered Agreement, (2) a request for Non-Firm Point-To-Point Transmission Service, from the same Point of Receipt to the same Point of Delivery, of greater duration under this Tariff or for non-firm transmission of greater duration provided by a Transmission Owner under a Grandfathered Agreement, (3) a request for Non-Firm Point-To-Point Transmission Service, from the same Point of Receipt to the same Point of Delivery, of equal duration with a higher price under this Tariff or for non-firm transmission of equal duration, from the same Point of Receipt to the same Point of Delivery, with a higher price provided by a Transmission Owner under a Grandfathered Agreement, or (4) transmission service for Network Customers from non-designated resources under this Tariff or under a Grandfathered Agreement. Point-To-Point Transmission Service for Next-Hour-Market Service will always have the lowest priority. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to

firm Transmission Service under this Tariff or firm transmission service provided by a Transmission Owner under Grandfathered agreements. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made first to Next-Hour-Market Service and then to remaining transactions beginning with those to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a higher priority than Next-Hour-Market Service, but will have a lower priority than any other Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice. In the event that the Transmission Customer fails to cease or reduce service in response to a directive by the Transmission Provider, the Transmission Customer shall pay any applicable charges and the following penalty (in addition to the charges for all of the non-firm capacity used): 100% of the Non-Firm Point-To-Point Transmission Service charge under Schedules 8 and 11 for the entire length of the reserved period not to exceed one month for the amount in excess of such capacity reservation. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive.

# 15 Service Availability

## 15.1 General Conditions:

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

## 15.2 Determination of Available Transfer Capability:

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a Short Term Service request, the Transmission Provider will respond by offering to perform or cause to be performed a System Impact Study. Long-Term Service requests will be evaluated by the Transmission Provider through an Aggregate Transmission Service Study in accordance with the procedures set forth in Attachment Z1 to this Tariff.

### 15.3 Initiating Service in the Absence of an Executed Service Agreement:

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate Financial Security in accordance with the terms of Section 17.3.

**15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System:**

If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on the Transmission System, the Transmission Provider and the affected Transmission Owner(s) will use due diligence to expand or modify the Transmission System to provide the requested firm Transmission Service, consistent with its planning obligations in Attachment O, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider and the affected Transmission Owner(s) will conform to Good Utility Practice and its planning obligations in Attachment O, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the affected Transmission Owner(s) has (have) the right to expand or modify.

**15.5 Deferral of Service:**

The Transmission Provider may defer providing service until construction is completed of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

## 15.6 Other Transmission Service Schedules:

Eligible Customers receiving transmission service under Grandfathered Transactions may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

### 15.7 Real Power Losses:

Real power losses are associated with all Transmission Service. As stated in Schedules 7 and 8, the Transmission Customer shall be responsible for any real power losses in accordance with Attachment M.

# 16 Transmission Customer Responsibilities

## 16.1 Conditions Required of Transmission Customers:

Point-To-Point Transmission Service shall be provided under this Tariff only if the following conditions are satisfied by the Transmission Customer:

a. The Transmission Customer has pending a Completed Application for service;

b. The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

d. The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

e. The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment O; and

f. The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

**16.2 Transmission Customer Responsibility for Third-Party Arrangements:**

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

# 17 Procedures for Arranging Firm Point-To-Point Transmission Service

**17.1 Application:**

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must be submitted on the Transmission Provider's OASIS, consistent with Section 2.2, no later than one year prior to the end of the term of its firm transmission contract for renewals under Section 2.2 and for new Long-Term Service in accordance with Attachment Z1. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed in Section 17.2 on the Transmission Provider's OASIS.

**17.1a Time Requirements:**

Attachment P lists the time requirements applicable to when the requests must be made, the evaluation of the requests, and the Transmission Customer responses. Requests for Long-Term Service received during any specified open season shall be processed in accordance with Attachment Z1 to this Tariff.

**17.2 Completed Application:**

A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, by law or by statute, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transfer capability requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transfer capability requirement.

(ix) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service

Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment O.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

### 17.3 Credit Arrangements:

A Completed Application for Firm Point-To-Point Transmission Service also shall include all information required for SPP to complete a Credit Assessment pursuant to its Credit Policy set out in Attachment X, and satisfaction of all requirements set out therein. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), all Financial Security shall be returned with accrued interest, if any, less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. All Financial Security also will be returned with accrued interest, if any, less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, all Financial Security shall be returned in full, with accrued interest, if any, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the returned Financial Security, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Financial Security associated with construction of new facilities is subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, all Financial Security, including accrued interest, if any, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Credit Policy.

**17.4 Notice of Deficient Application:**

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service of the reasons for such failure within the applicable time period shown in Attachment P for responding to Applications. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with all Financial Security, with accrued interest, if any. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

**17.5 Response to a Completed Application:**

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer within the applicable times listed in Attachment P after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study for Short-Term Service requests or (ii) if a System Impact Study is needed to evaluate the impact of the Application for Short-Term Service requests pursuant to Section 19.1. For Long-Term Service requests, the Transmission Provider will evaluate Completed Applications within the Aggregate Transmission Service Study in accordance with procedures specified in Attachment Z1 to this Tariff. Responses by the Transmission Provider must be made as soon as practicable to all Completed Applications (including Applications by the Transmission Owner(s') own merchant function) and the timing of such responses must be made on a nondiscriminatory basis.

**17.6 Execution of Service Agreement:**

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer within the applicable time periods allowed to determine available capacity as shown in Attachment P after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement or the confirmation of a Completed Application, whichever is applicable. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, or to confirm a Completed Application (subject to completion of the System Impact Study), whichever is applicable, within the time frames shown in Attachment P will be deemed a withdrawal and termination of the Application and any Financial Security submitted shall be refunded with accrued interest, if any. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

**17.7 Extensions for Commencement of Service:**

The Transmission Customer can obtain, subject to availability up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for firm Transmission Service for each year or fraction thereof within 15 days of notifying the Transmission Provider it intends to extend the commencement of service. For extensions of one (1) year or more, the Transmission Customer must request the extension no later than ninety (90) days before the Service Commencement Date. For extensions of less than one (1) year, the Transmission Customer must request the extension no later than sixty (60) days before the Service Commencement Date. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

## 17.8 Designated Resources Using Long-Term Firm Point-To-Point Transmission Service

If a Transmission Customer requests Long-Term Firm Point-To-Point Transmission Service to deliver the output from a Designated Resource to a load in the SPP Region, the Transmission Customer shall provide to the Transmission Provider all the information required in Section 29.2 for (i) its load in the SPP Region and (ii) its Designated Resources. This information shall be used for the purposes of (i) performing Aggregate Transmission Service Studies in accordance with Attachment Z1, (ii) classifying Service Upgrades associated with Designated Resources as Base Plan Upgrades pursuant to Section III.B of Attachment J and (iii) developing the SPP Transmission Expansion Plan pursuant to Attachment O. The requirements for Network Resources in Sections 30.1, 30.2 and 30.7 shall apply to Designated Resources using Long-Term Firm Point-To-Point Transmission Service.

## 17.9 Interconnection of Delivery Points

The addition, modification, or abandonment of any delivery point in conjunction with the provision of Point-To-Point Transmission Service shall be governed by the applicable provisions of Sections 31.2, 31.3, and Attachment AQ.

# 18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

**18.1 Application:**

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to The Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS.

**18.2 Completed Application:**

A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, by law or statute, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating that, if the Eligible Customer submits to a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

**18.3 Timing of Requests and Responses Regarding Reservation of Non-Firm Point-To-Point Transmission Service:**

Attachment P lists the time requirements applicable to when the requests must be made, the evaluation of the requests, and the Transmission Customer responses and requests for Next-Hour-Market Service shall be submitted no earlier than 60 minutes before the start of the next clock hour. Requests for service, except for Next-Hour-Market Service, received later than the applicable time prior to the day service is scheduled to commence and requests for Next-Hour-Market Service submitted later than 20 minutes before the start of the next clock hour will be accommodated if practicable.

**18.4 Determination of Available Transfer Capability:**

Following receipt of a tendered schedule, the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made in accordance with the applicable time periods set forth in Attachment P.

## 19 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

Study procedures for Short-Term Firm Point-To-Point Transmission Service requests shall be performed in accordance with the System Impact Study provisions of Section 19 and in accordance with Attachment AC to this Tariff. Facilities Studies are not performed for requests of less than one year. Study procedures for Long-Term Firm Point-To-Point Transmission Service requests shall be performed using the Aggregate Transmission Service Study process in accordance with Attachment Z1 to this Tariff and the Facilities Study provisions of Section 19 to this Tariff. System Impact Studies are not performed for Long Term Firm Point-To-Point Transmission Service requests.

**19.1 Notice of Need for System Impact Study:**

After receiving a request for Short-Term Firm Point-To-Point Transmission Service, the Transmission Provider shall determine based on Attachment AC whether a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D.

**19.2 System Impact Study Agreement and Cost Reimbursement:**

The Eligible Customer's completion of the OASIS reservation with the following statement in the customer comment field "exercise System Impact Study option" shall provide the Transmission Provider with the required notification that the Eligible Customer elects to move forward with the System Impact Study option, as provided in Attachment AC of this Tariff. Completing the reservation in this manner constitutes Eligible Customer's agreement to pay for all System Impact Studies necessary to support the evaluation of the service.

### 19.3 System Impact Study Procedures:

The System Impact Study for Short-Term Firm Point-To-Point Transmission Service shall be in accordance with Attachment AC of this Tariff.

**19.4 Facilities Study Procedures:**

Study procedures for Long-Term Firm Point-To-Point Transmission Service requests shall be performed using the Aggregate Transmission Service Study process in accordance with Attachment Z1 of this Tariff.

**19.5 Facilities Study Modifications:**

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider or the affected Transmission Owner(s) that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

**19.6 Due Diligence in Completing New Facilities:**

The Transmission Provider and the affected Transmission Owner(s) shall use due diligence to add necessary facilities or upgrade the Transmission System within a reasonable time. The Transmission Provider will not allow the upgrade to the existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

**19.7 Partial Interim Service:**

If the Transmission Provider determines that there will not be adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

**19.8 Expedited Procedures for New Facilities:**

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider and affected Transmission Owner(s) for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Service Agreement covering all of the above-specified items within the time limits set forth in Attachment P from the time it receives the results of the System Impact Study or Aggregate Transmission Service Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider and affected Transmission Owner(s) agree to provide the Eligible Customer with their best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider and affected Transmission Owner(s) for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

**19.9 Reporting Failure to Meet Study Deadlines:**

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider

completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

# 20 Procedures if the Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

**20.1 Delays in Construction of New Facilities:**

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer and affected Transmission Owner(s) to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider and affected Transmission Owner(s) that is reasonably needed by the Transmission Customer to evaluate any alternatives.

### 20.2 Alternatives to the Original Facility Additions:

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider together with the affected Transmission Owner(s) shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

### 20.3 Refund Obligation for Unfinished Facility Additions:

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any Financial Security posted by the Transmission Customer shall be returned with accrued interest, if any. However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider and the affected Transmission Owner(s) through the time construction was suspended.

# 21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

## 21.1 Responsibility for Third-Party System Additions:

The Transmission Provider and the Transmission Owners shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider and the affected Transmission Owner(s) will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

## 21.2 Coordination of Third-Party System Additions:

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the affected Transmission Owner(s) in coordination with the Transmission Provider shall have the right to coordinate construction on its (their) own system(s) with the construction required by others. The Transmission Provider together with the affected Transmission Owner(s), after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before construction of new facilities will be initiated or resumed. Within sixty (60) days of receiving written notification by the Transmission Provider of the intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

# 22 Changes in Service Specifications

**22.1 Modifications On a Non-Firm Basis:**

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the provision of transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement for long-term firm Transmission Service or the confirmed Application for Short-Term Transmission Service ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge (except as provided in Section 22.2) or executing a new Service Agreement for long-term firm Transmission Service or submitting a new Application for short-term firm Transmission Service, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or under any other transmission tariff or agreement where the service is being provided by the Transmission Owner or by the Transmission Owner on behalf of its (their) Native Load Customers.

(b) The sum of all Firm and Non-Firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement for Long-Term Firm Transmission or Application for Short-Term Firm Transmission Service under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement for long-term firm Transmission Service or Application for short-term firm Transmission Service in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to

transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

**22.2 Additional Charge To Prevent Abuse:**

If a Transmission Customer making the modifications in Section 22.1 takes service over a transmission path that costs more than the path the Transmission Customer initially reserved, then for the service the Transmission Customer schedules, the Transmission Customer shall pay in addition to the amounts based on its initial reservation the additional costs (i.e., the difference between the zonal rates) associated with the new path. In addition, the Transmission Customer shall be responsible for losses (in accordance with Attachment M) and pay for any redispatch costs (as determined in accordance with Attachment K) based on the actual transmission path used.

**22.3 Modification On a Firm Basis:**

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement for long-term firm Transmission Service or confirmed Application for short-term firm Transmission Service. In any instance where the remaining term of service, after modification pursuant to this provision, is less than twelve (12) months the Transmission Customer will maintain existing rights of reservation priority on the original reservation.

# 23 Sale or Assignment of Transmission Service

**23.1 Procedures for Assignment or Transfer of Service:**

A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement ("Reseller's Service Agreement"), but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller, and the portion of service reassigned is hereafter referred to as the Reassigned Service. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a Service Agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the Reassigned Service commences.

If the Reseller has not obtained a release from its obligations with respect to the Reassigned Service under Section 23.4, the Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. The Transmission Provider may also require the Assignee to pay the amount in excess of the Transmission Provider's rates directly to the Reseller. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement for Long-Term Firm Transmission Service or original confirmed Application for Short-Term Firm Transmission Service, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

If the Reseller has obtained a release from its obligations with respect to the Reassigned Service under Section 23.4, the Transmission Provider shall

charge the Assignee for the Reassigned Service at the rates established in the Assignee's Service Agreement with the Transmission Provider, which shall not be less than the rates established in the Reseller's Service Agreement.

**23.2 Limitations on Assignment or Transfer of Service:**

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement for long-term firm Transmission Service or original confirmed Application for short-term firm Transmission Service, the Transmission Provider will consent to such change subject to the provisions of the Tariff and the Transmission Customer's or the Assignee's agreement to pay any additional charges consistent with Section 22 of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Owner's(s') generation, transmission, or distribution systems. The Assignee shall pay the Transmission Provider for the costs of performing any System Impact Study or Aggregate Transmission Service Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement or as provided in Section 23.4 of the Tariff.

### 23.3 Information on Assignment or Transfer of Service:

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the Reassigned Service commences and are subject to Section 23.1. Resellers may also use Transmission Provider's OASIS to post transfer capability available for resale.

### 23.4 Release of Reseller

To the extent that the Reseller assigns all of its rights and obligations under the Reseller's Service Agreement with respect to the Reassigned Service, the Reseller may request a release from the Reseller's Service Agreement with respect to the Reassigned Service. Upon the Transmission Provider's determination that the Assignee satisfies all of the terms and conditions of this Tariff, including but not limited to the requirements set forth in the Credit Policy in Attachment X of this Tariff, and the Assignee has executed a Service Agreement governing the Reassigned Service, the Transmission Provider will release the Reseller of its obligations under the Reseller's Service Agreement with respect to the Reassigned Service.

# 24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

**24.1 Transmission Customer Obligations:**

Unless otherwise agreed, the Transmission Customer shall be responsible for the cost of installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Unless otherwise specified in an agreement for the construction of facilities, such equipment installed on the Transmission Customer's system shall remain the property of the Transmission Customer. Unless otherwise specified in an agreement for the construction of facilities, such equipment installed on the Transmission Owner's(s') system shall remain the property of the Transmission Owner(s).

### 24.2 Transmission Provider Access to Metering Data:

The Transmission Provider or its agent shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

### 24.3 Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range specified by the Transmission Provider, in consultation with the appropriate Transmission Owners, pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

## 25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). In addition the Transmission Customer shall pay any applicable Ancillary Service costs, Wholesale Distribution Service charges (Schedule 10), Base Plan Zonal Charges (Schedule 11), and Region-wide Charges (Schedule 11).

## 26 Stranded Cost Recovery

This Tariff does not affect in any way the right of any Transmission Owner to seek and receive stranded cost recovery or the right of anyone to oppose such stranded cost recovery. Thus, the Transmission Owner(s) may seek to recover stranded costs from the User(s) in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Owner(s) must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act. If the Commission approves stranded cost charges to be recovered through schedules to be implemented by the Transmission Provider, the Transmission Provider as agent for the Transmission Owner(s) shall charge and collect the appropriate charge(s) from the relevant User(s) and distribute the appropriate amounts directly to the relevant Transmission Owner(s).

## 27 Compensation for New Facilities and Redispatch Costs

a) Whenever an Aggregate Facilities Study performed by the Transmission Provider in connection with the provision of Long-Term Firm Point-To-Point Transmission Service identifies the need for new facilities, the recovery of such costs shall be governed by Attachments J and Z1 of this Tariff. Whenever an Aggregate Facilities Study performed by the Transmission Provider in connection with the provision of Long-Term Firm Point-To-Point Transmission Service identifies capacity constraints that may be relieved by redispatching electric generating resources to eliminate such constraints, redispatch will be handled in accordance with Attachment K of this Tariff.

b) Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Short-Term Firm Point-To-Point Transmission Service identifies capacity constraints that may be relieved by redispatching electric generating resources to eliminate such constraints, redispatch will be handled in accordance with Attachment K of this Tariff.

# III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Owners utilize the Transmission System to serve their Native Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff. The Transmission Provider shall recognize the requirements of the Federal Service Exemption to allow Western-UGP to meet its Statutory Load Obligations.

# 28 Nature of Network Integration Transmission Service

**28.1 Scope of Service:**

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

**28.2 Transmission Provider and Transmission Owners Responsibilities:**

The Transmission Provider and Transmission Owners will plan, operate, and cause to be maintained its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment O in order to provide the Network Customer with Network Integration Transmission Service over the Transmission System. The Transmission Owners, on behalf of their Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in Transmission System planning and shall, consistent with Good Utility Practice and Attachment O, endeavor to cause to be constructed and placed into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Owner(s') delivery of electric generating and purchased resources to Native Load Customers.

### 28.3 Network Integration Transmission Service:

The Transmission Provider will provide firm transmission service over the Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Owner(s') use of the Transmission System to reliably serve Native Load Customers.

**28.4 Secondary Service:**

The Network Customer may use the Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, with no additional charges imposed under Schedules 7, 8, 9, or 11. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff or any non-firm point-to-point service under any other transmission tariff or agreement where the service is being provided by a Transmission Owner. A Network Customer seeking to utilize such secondary service to deliver energy to its Network Load must submit a request on the Transmission Provider's OASIS for each transaction. For any single hour scheduling period of time, a Network Customer's total Reserved Capacity for secondary service shall not exceed the greater of (i) 200 MW or (ii) 125 percent times the Network Customer's average of the highest hourly non-firm network schedules from four (4) separate days for the previous twelve (12) calendar month period or (iii) 25% of the Network Customer's peak Network Load from the prior calendar year; provided, however, that the Reserved Capacity for such secondary service shall not exceed 110 percent of the Network Customer's peak Network Load from the prior calendar year. For the first twelve (12) calendar months that a new Network Customer is receiving Network Integration Transmission Service, the new Network Customer's Reserved Capacity for secondary service shall not exceed 110 percent of its peak Network Load from the prior calendar year. If requested by the Network Customer, the Transmission Provider shall determine on a non-discriminatory basis whether an exception to the limits to secondary service set forth in this Section shall be granted.

### 28.5 Real Power Losses:

Real power losses are associated with all Network Integration Transmission Service. As stated in Schedule 9, the Network Customer shall be responsible for any real power losses associated with all Network Integration Transmission Service in accordance with Attachment M.

### 28.6 Restrictions on Use of Service:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System except for service where the purchaser is a Network Customer of the Transmission Provider. In the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve its Network Load, it shall pay the penalty set forth in Section 13.7 for the amount of the service used to facilitate the wholesale sale.

# 29 Initiating Service

**29.1 Condition Precedent for Receiving Service:**

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider in coordination with the affected Transmission Owner(s) complete(s) the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

**29.2 Application Procedures:**

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, which includes all information required for SPP to complete a Credit Assessment pursuant to its Credit Policy set out in Attachment X and satisfaction of all requirements set out therein. Unless subject to the procedures in Section 2, Completed Applications for new or changed designated Network Resources, having a term of one year or longer, associated with Network Integration Transmission Service will be part of the Aggregate Transmission Service Study as defined in Attachment Z1. Completed Applications for new designated Network Resources, having a term of less than one year, will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the

conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- Regulation Qualified resource capability
- Spin Qualified resource capability
- Supplemental Qualified resource capabilty
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
    - Any periods of restricted operations through-out the year
    - Maintenance schedules
    - Minimum loading level of unit
    - Normal operating level of unit
    - Any must-run unit designations required for system reliability - or contract reasons
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Balancing Authority Area, where only a portion of unit output is designated as a Network Resource:

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the Balancing Authority Area from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)

- Operating restrictions, if any
- Any periods of restricted operations thoughout the year
- Maintenance schedules
- Minimum loading level of unit
- Normal operating level of unit
- Any must-run designations required for system reliability or contract reasons

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's ties with Balancing Authority Areas other than the SPP Balancing Authority Area;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year; however, if service is provided hereunder pursuant to a state retail pilot program, the minimum term may be the lesser of one year or the remainder of the pilot, but not less than one month;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the Network Resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider’s planning process established in Attachment O.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations. The Transmission

Provider may, on a non-discriminatory basis, waive the requirements of subsections 29.2 (iii), (iv), (v) and (vi), to the extent such information is not applicable or, in the case of service being requested for retail access load, is unknown at the time of the Application.

### 29.3 Technical Arrangements to be Completed Prior to Commencement of Service:

Network Integration Transmission Service shall not commence until the Transmission Provider, the affected Transmission Owner(s), and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider and the affected Transmission Owner(s) shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

### 29.4 Network Customer Facilities:

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

### 29.5 Filing of Service Agreement:

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

# 30 Network Resources

### 30.1 Designation of Network Resources:

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

### 30.2 Designation of New Network Resources:

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new Network Resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient Application as described in Section 29.2 of the Tariff.

Requests for new or changed Network Resources having a term of one year or longer associated with Network Integration Transmission Service shall be part of the Aggregate Transmission Service Study as specified in Attachment Z1. The Transmission Provider shall combine all transmission service requests, having a term of one year or longer, received during the open season as specified in Section III of Attachment Z1, into a single and distinct Aggregate Transmission Service Study. Requests for new or changed Network Resources, having a term of less than one year, shall be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority.

#### 30.2.1 Transfer of Designation:

The designation of a Network Resource may be transferred to a different generator at the same electrical point of interconnection without study by submitting a request to the Transmission Provider no later than 30 days prior to the termination date of the Network Resource in the NITS agreement. The request for transfer of designation shall include the information specified in Section 29.2 part (v) and (viii). The amount of capacity designated as a Network Resource to be transferred to the new generator must be less than or equal to the amount of capacity designated as a Network Resource from the existing generator. In order to designate additional capacity from the new generator, a new request must be submitted pursuant to Section 30.2 for the additional capacity.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response will be sent to the Eligible Customer. If request to transfer designation fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting the transfer within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the request through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the request without prejudice to the Eligible Customer filing a new or revised request that fully complies with the requirements of this section.

Upon confirmation of receipt of a valid request to transfer designation, the Transmission Provider will amend the NITS agreement to reflect the transfer of designation.

**30.3 Termination of Network Resources:**

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through the OASIS as soon as reasonably practicable. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the Network Resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the Network Resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient Application as described in Section 29.2 of the Tariff.

### 30.4 Operation of Network Resources:

The Network Customer shall not operate its designated Network Resources such that the output of those facilities exceeds its designated Network Load, plus Non-Firm sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider through normal operation of the Energy and Operating Reserve Markets as described under Attachment AE or to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-To-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. In the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-To-Point Transmission Service, it shall pay the penalty set forth in Section 13.7 for the amount of the service exceeding the Network Resource's designated capacity.

### 30.5 Network Customer Redispatch Obligation:

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2 and in accordance with the Energy and Operating Reserve Markets procedures in Attachment AE.

### 30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider:

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

### 30.7 Limitation on Designation of Network Resources:

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

### 30.8 Use of Interface Capacity by the Network Customer:

There is no specific limitation upon a Network Customer's use of the Transmission System at the interface(s) to the SPP Balancing Authority Area (where the Network Customer's load is located) to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the interface capacity with other transmission systems may not exceed the Network Customer's Load or the applicable interface capacity.

**30.9 Network Customer Owned Transmission Facilities:**

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of a Transmission Owner to serve the Transmission Owner's power and transmission customers. For facilities added by the Network Customer subsequent to May 14, 2007, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission System; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Owners, would be eligible for inclusion in the Transmission Owners' Annual Transmission Revenue Requirement as specified in Attachment H. The revenue requirements for Network Customer Transmission Credits and the application of Network Customer Transmission Credits to the Network Customer's transmission service charges shall be in accordance with Section III. of Attachment H of this Tariff. The eligible Network Customer is only entitled to receive the value of Network Customer Transmission Credits netted against but not to exceed, the Network Customer's monthly transmission charges, and shall not be entitled to additional payments for transmission service sold on its transmission facilities that would otherwise be recoverable by a Transmission Owner under the Tariff. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties. This crediting provision does not apply to Network Customer transmission facilities that are reflected in the rates for service under this Tariff.

# 31 Designation of Network Load

### 31.1 Network Load:

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

## 31.2 Delivery Points Connected with the Transmission Provider:

With respect to physical load connections to the Transmission System, the addition, modification, or abandonment of any delivery point shall be governed by the provisions of Section 31.2 and Attachment AQ. The Network Customer shall provide the Transmission Provider and the Transmission Owner with as much advance notice as reasonably practicable of any physical addition or abandonment of a delivery point, or any modifications requiring action by the Transmission Owner to existing delivery points. Such notice shall be provided in writing by the Network Customer and generally in a manner and form as shown in the Sample Request for Change in Local Delivery Facilities attached to this Tariff as Addendum 1 to Attachment AQ, Delivery Point Assessment Process.

**31.2a New Delivery Point:**

When a Network Customer requests a new delivery point to be built to serve its load such notification and processing of the request shall be governed by the provisions of Attachment AQ.

**31.2b Abandonment of a Delivery Point:**

In the event that a Network Customer desires to abandon an existing delivery point, it shall initiate the process of abandonment by notifying the Transmission Provider and Transmission Owner. Such notification and processing of such request shall be governed by the provisions of Attachment AQ. In the event that there are modifications to other delivery points associated with the abandonment, all such desired changes in delivery point configuration shall be noticed and processed simultaneously.

**31.2c Modification of Delivery Points:**

In the event that a Network Customer desires to modify an existing delivery point in a manner requiring action by a Transmission Owner, it shall initiate such modification by notifying the Transmission Provider and Transmission Owner of this desired change. Such notification, processing and cost recovery of all facilities associated with such request shall be governed by the provisions of Section 31.2a. above and Attachment AQ hereto.

### 31.2d Construction and Cost Recovery

The costs related to the construction, operation, maintenance and/or retirement of a Network Customer's delivery point(s), other than any required Network Upgrades, shall be charged to the Network Customer in accordance with this Tariff and Commission policies. In the event that Network Upgrades are required pursuant to the study results of Attachment AQ make changes in delivery point facilities to upgrade, retire, replace or establish a delivery point, such Network Upgrades shall be to ensure the reliability of the Transmission System and funded pursuant to the provisions of Section III of Attachment J. The Transmission Provider together with affected Transmission Owner(s) will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer.

### 31.2e Delivery Point Transfers

Requests for Delivery Point Transfers will be studied in accordance with Section 32.4 of the Tariff (the Aggregate Transmission Service Study process), except that, upon request of a Network Customer, the Transmission Provider alternatively will evaluate a proposed Delivery Point Transfer in accordance with the Screening Study process set forth in Section 3 of Attachment AR if the Network Customer is able to serve the additional load without changing its Designated Resources. If, upon completion of the Screening Study, the Transmission Provider determines that no third party issues and no Network Upgrades for thermal or voltage mitigations are indicated as a result of the Delivery Point Transfer, no further studies will be required pursuant to Section 32.4 of the Tariff and the Network Customer proposing the Delivery Point Transfer will be tendered a Service Agreement and any necessary supplemental documents reflecting the transferred delivery point(s) and the Network Customer or Transmission Customer serving the load prior to the Delivery Point Transfer will be tendered a Service Agreement and any necessary supplemental documents with the transferred delivery point(s) removed. If the results of the Screening Study indicate that the Delivery Point Transfer will have third party issues or require Network Upgrades for thermal or voltage mitigations, then the Transmission Provider will not tender the Network Customer a Service Agreement, but rather will notify the Network Customer: (i) of results of the Screening Study; and (ii) that to proceed with its Delivery Point Transfer request, the Delivery Point Transfer must be studied pursuant to the Aggregate Transmission Service Study process pursuant to Section 34.2 of the Tariff.

**31.3 Taxes on Contributions in Aid of Construction:**

When the Network Customer funds the construction of Host Transmission Owner-owned facilities pursuant to a contribution in-aid of construction ("CIAC"), the Network Customer also shall reimburse Host Transmission Owner for the tax effect of such CIAC (a "Tax Effect Recovery Factor" or "TERF"), where such payment is considered taxable income and subject to income tax under the Internal Revenue Service (IRS) and/or a state department of revenue (State) requirements. The TERF shall be computed consistent with the methodology set forth in Ozark Gas Transmission Corp., 56 F.E.R.C ¶ 61,349 as reflected in the following formula: TERF = (Current Tax Rate x (Gross Income Amount - Present Value of Tax Depreciation))/(1-Current Tax Rate). The Present Value of Tax Depreciation Amount shall be computed by discounting Host Transmission Owner's anticipated tax depreciation deductions with respect to the constructed property by Host Transmission Owner's current weighted average cost of capital. If, based on current law, Host Transmission Owner determines such contribution by the Network Customer shall not be taxable, Host Transmission Owner will not charge a TERF; however, in the event that such contribution is later determined by the IRS or state tax authority to be taxable, the Network Customer shall reimburse Host Transmission Owner in the amount of the TERF, including any interest and penalty charged to Host Transmission Owner by the IRS and/or state. Such reimbursement is due within thirty (30) Calendar Days of the date upon which Host Transmission Owner notifies the Network Customer of such determination. If, based on current law, Host Transmission Owner determines such contribution by the Network Customer is taxable, Host Transmission Owner will charge a TERF; however, in the event that such contribution is later determined by the IRS or state tax authority not to be taxable, the Host Transmission Owner shall reimburse Network Customer in the amount of the TERF, including any interest calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii). Such reimbursement is due within thirty (30) Calendar Days of the date upon which the

IRS or state tax authority notifies Host Transmission Owner of such determination.

At Network Customer's request and expense, Host Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any CIAC paid, or to be paid, by Network Customer to Host Transmission Owner is subject to federal income taxation. Network Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Network Customer's knowledge. Host Transmission Owner and Network Customer shall cooperate in good faith with respect to the submission of such request. Host Transmission Owner shall keep Network Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS that authorizes Network Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Host Transmission Owner shall allow Network Customer to attend all meetings with IRS officials about the request and shall permit Network Customer to prepare the initial drafts of any follow-up letters in connection with the request.

If Network Customer shall have reimbursed Host Transmission Owner for the TERF, upon request by Network Customer and at Network Customer’s expense, Host Transmission Owner shall contest the taxability of such CIAC; provided, however, that Host Transmission Owner shall not be required to contest such taxability if Host Transmission Owner waives the payment by Network Customer of any amount that might otherwise be payable by Network Customer.

**31.4 Delivery Points Not Physically Interconnected with the Transmission Provider:**

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission System. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. Notwithstanding the provisions of any agreement Network Customer may have with the other transmission provider, the addition, modification, or abandonment of any delivery point shall be governed by the provisions of this section and, as applicable, Attachment AQ hereto. To the extent that the Network Customer gives notice of its intent to add a new delivery point as part of its Network Load pursuant to this section and such request for the addition of a new delivery point involves the use of existing Designated Resources across an interface where preexisting transmission service rights to serve existing delivery points from an existing Designated Resource exist, such new delivery point shall be governed by the applicable provisions in Sections 31.2a through 31.2d and Attachment AQ hereto. In the case where there are no preexisting transmission service rights from an existing Designated Resource across the interface to serve the new delivery point, such request for a new delivery point must be made through a modification of service pursuant to a new Application.

### 31.5 Changes in Service Requests:

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities caused to be constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

**31.6 Annual Load and Resource Information Updates:**

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment O. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

## 32 Additional Study Procedures For Network Integration Transmission Service Requests

Study procedures for Network Integration Transmission Service requests of less than one year shall be performed in accordance with the System Impact Study provisions of Section 32 and in accordance with Attachment AC to this Tariff. Facilities Studies are not performed for requests of less than one year. Study procedures for Network Integration Transmission Service requests of one year or more shall be performed using the Aggregate Transmission Service Study process in accordance with Attachment Z1 and the Facilities Study provisions of Section 32 to this Tariff. System Impact Studies are not performed for Long-Term Service requests.

### 32.1 Notice of Need for System Impact Study:

After receiving a request of less than one year for service, the Transmission Provider shall determine based on Attachment AC whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D.

### 32.2 System Impact Study Agreement and Cost Reimbursement:

The Eligible Customer's completion of the OASIS reservation with the following statement in the customer comment field "exercise System Impact Study option" shall provide the Transmission Provider with the required notification that the Eligible Customer elects to move forward with the System Impact Study option, as provided in Attachment AC of this Tariff. Completing the reservation in this manner constitutes Eligible Customer's agreement to pay for all System Impact Studies necessary to support the evaluation of the service.

## 32.3 System Impact Study Procedures:

The System Impact Study for Network Integration Transmission Service requests of less than one year shall be in accordance with Attachment AC of the Tariff.

### 32.4 Facilities Study Procedures:

Study procedures for Network Integration Transmission Service requests of one year or longer shall be performed using the Aggregate Transmission Service Study process in accordance with Attachment Z1 of this Tariff.

## 32.5 Penalties for Failure to Meet Study Deadlines:

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

**32.6 Facilities Study Modifications:**

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider or the affected Transmission Owner(s) that significantly affect the final cost of new facilities or upgrades to be charged to the Eligible Customer pursuant to the provisions of Part III of the Tariff.

## 32.7 Due Diligence in Completing New Facilities:

The Transmission Provider and the affected Transmission Owner(s) shall use due diligence to add necessary facilities or upgrade the Transmission System within a reasonable time. The Transmission Provider will not allow the upgrade to the existing or planned Transmission System in order to provide the requested Firm Network Integration Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service

### 32.8 Partial Interim Service:

If the Transmission Provider determines that there will not be adequate transfer capability to satisfy the full amount of a Completed Application for Firm Network Integration Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Network Integration Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Network Integration Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

**32.9 Expedited Procedures for New Facilities:**

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider and affected Transmission Owner(s) for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an Expedited Service Agreement covering all of the above-specified items within the time limits set forth in Attachment P from the time it receives the results of the System Impact Study or Aggregate Transmission Service Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider and affected Transmission Owner(s) agree to provide the Eligible Customer with their best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider and affected Transmission Owner(s) for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

**32.10 Delays in Construction of New Facilities:**

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Eligible Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Eligible Customer of such delays, convene a technical meeting with the Eligible Customer and affected Transmission Owner(s) to evaluate the alternatives available to the Eligible Customer. The Transmission Provider also shall make available to the Eligible Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider and affected Transmission Owner(s) that is reasonably needed by the Eligible Customer to evaluate any alternatives.

### 32.11 Alternatives to the Original Facility Additions:

When the review process of Section 32.10 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider together with the affected Transmission Owner(s) shall present such alternatives for consideration by the Eligible Customer. If upon review of the alternatives, the Eligible Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Network Integration Transmission Service. The alternative approach may include redispatch in accordance with Attachment K to this Tariff. In the event the Transmission Provider concludes that no reasonable alternative exists and the Eligible Customer disagrees, the Eligible Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

# 33 Load Shedding and Curtailments

## 33.1 Procedures:

Prior to the Service Commencement Date, the Transmission Provider, in coordination with the affected Transmission Owner(s), and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with the Transmission System. The Parties including the affected Transmission Owner(s) will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers and affected Transmission Owners in a timely manner of any scheduled Curtailment.

### 33.2 Transmission Constraints:

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission System, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission System. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources on a least cost basis without regard to the ownership of such resources in accordance with the Energy and Operating Reserve Markets procedures in Attachment AE. Any redispatch under this section may not unduly discriminate between the Transmission Owners' use of the Transmission System on behalf of their Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

### 33.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever the Transmission Provider implements least cost redispatch procedures in response to a transmission constraint, all Transmission Owners and Network Customers shall pay their share of redispatch costs as determined through the operation and settlement of the Energy and Operating Reserve Markets as described in Attachment AE.

### 33.4 Curtailments of Scheduled Deliveries:

If the Transmission Provider determines that it is necessary to curtail scheduled deliveries, the Parties and the affected Transmission Owner(s) shall curtail such schedules in accordance with the Network Operating Agreement and pursuant to the Transmission Loading Relief procedures specified in Attachment R.

### 33.5 Allocation of Curtailments:

The Transmission Provider shall, on a non-discriminatory basis, curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the affected Transmission Owner(s) and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to curtail schedules to an extent greater than the Transmission Provider would curtail the Transmission Owner's schedules under similar circumstances.

### 33.6 Load Shedding:

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the affected Transmission Owner(s) and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

**33.7 System Reliability:**

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to curtail Network Integration Transmission Service without liability on the Transmission Provider's or Transmission Owner's part for the purpose of making necessary adjustments to, changes in, or repairs on the Transmission Owner's lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Owner's use of the Transmission System on behalf of its (their) Native Load Customers. In the event that the Network Customer (or any Transmission Owner that is not a Network Customer with regard to its bundled load) fails to respond to established Load Shedding and Curtailment procedures or to cease or reduce service in response to a directive by the Transmission Provider, the Network Customer shall pay any applicable charges and the following penalty (in addition to the charges for all of the service used): For the applicable month, 100% of the Network Integration Transmission Service charge under Schedule 9 plus 100% of the charges assessed under Schedule 11. This penalty shall apply only to the portion of the service that the Transmission Customer fails to curtail in response to a Curtailment directive. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Network Integration Transmission

Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service.

## 34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Directly Assigned Upgrade Costs, Ancillary Services, Base Plan Zonal Charges (Schedule 11), Region-wide Charges (Schedule 11) and applicable study costs, consistent with Commission policy, along with the following:

**34.1 Monthly Demand Charge:**

For all Network Load served by the Transmission Provider, except as provided under Sections 34.2, 34.3, and 34.9, the Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Zonal Annual Transmission Revenue Requirement ("Zonal ATRR") specified in Attachment H less:

1) any amount reallocated in accordance with Section IV.A of Attachment J of this Tariff; and

2) any revenues for the previous calendar year (i) distributed to each Transmission Owner in the Zone under Attachment L resulting from charges under Schedules 7 and 8, and (ii) distributed to each Transmission Owner in the Zone under Section IV of Attachment AU and allocated in proportion to Schedule 7 and 8 revenues under Section V of Attachment AU, subject to the limitations in subsections a and b below. Any such adjustment made by the Transmission Provider shall be set forth in the RRR File.

   a. For each Transmission Owner utilizing a formula rate, the Transmission Provider shall not make an adjustment for Schedule 7 and 8 revenues and for revenues distributed and allocated under Attachment AU if the Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU are credited and updated on an annual basis in the Transmission Owner formula rate in a manner that reduces the Zonal ATRR.

   b. For each Transmission Owner utilizing a stated rate or utilizing a formula rate without annual update of the revenue credits, the revenue adjustment described in this Section 34.1(2) shall be *only the difference, whether positive or negative, between the previous calendar year Schedule 7 and 8 revenues and* the amount of Schedule 7 and 8 revenues and revenues distributed and allocated

under Attachment AU, if any, already credited in the calculation of the Zonal ATRR shown in Table 1, Section I of Attachment H. The amount of Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU already credited in calculation of the Zonal ATRR shown in Table 1, Section I of Attachment H for such Transmission Owner is shown in Table 3, Section I of Attachment H.

**34.2 Monthly Demand Charge – Zone 1:**

For Network Load located within Zone 1, the Network Customer shall pay a monthly Demand Charge. The component of such Demand Charge for American Electric Power's revenue requirement shall be calculated in accordance with Addendum 1 to Attachment H. The components of such Demand Charge for other Transmission Owners' revenue requirements in Zone 1 shall be calculated in accordance with Section 34.1 of this Tariff. All components of the Demand Charge for Zone 1 shall be adjusted as provided in Section 34.1 for any amount reallocated in accordance with Section IV.A of Attachment J and for any Schedule 7 and 8 revenues distributed to each Transmission Owner in the Zone under Attachment L and for any revenues distributed and allocated in accordance with Attachment AU.

**34.3 Monthly Demand Charge – Zone 11:**

For Network Load located within Zone 11, the Network Customer shall pay a monthly Demand Charge. The component of such Demand Charge for Southwestern Public Service's revenue requirement shall be calculated in accordance with Addendum 5 of Attachment H. The components of such Demand Charge for other Transmission Owners' revenue requirements in Zone 11 shall be calculated in accordance with Section 34.1 of this Tariff. All components of the Demand Charge for Zone 11 shall be adjusted as provided in Section 34.1 for any amount reallocated in accordance with Section IV.A of Attachment J and for any Schedule 7 and 8 revenues distributed to each Transmission Owner in the Zone under Attachment L and for any revenues distributed and allocated in accordance with Attachment AU.

**34.4 Determination of Network Customer's Monthly Network Load:**

The Network Customer's monthly Network Load is its hourly load (60 minute, clock-hour); provided, however, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone where the Network Customer load is physically located. Where a Network Customer has Network Load in more than one Zone, the monthly Network Load will be determined separately for each Zone. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.4, the Network Customer's monthly Network Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 9.

**34.5 Determination of Transmission Provider's Monthly Zone Transmission Load:**

The Transmission Provider's monthly Transmission System load shall be determined for each Zone on a non-coincident basis. The Transmission Provider’s monthly Zone transmission load is the Zone's Monthly Transmission System Peak.

## 34.6 Network Customer Obligations for Redispatch Costs:

Any redispatch costs incurred to relieve a system constraint to be charged to the Network Customer shall be collected and paid as part of the Energy and Operating Reserve Market settlement procedures described under Attachment AE of this Tariff. Network Customers having Network Service subject to redispatch (until requisite transmission upgrades are placed into service ) will be eligible to nominate Candidate Auction Revenue Rights associated with that service only for those times of the year and for only the amounts of service that are not subject to redispatch. Network Service with a redispatch requirement (until requisite transmission upgrades are placed into service) will not be eligible for any Candidate Long-Term Congestion Rights because it does not have continuous service covering the entirety of the associated Transmission Congestion Right year.

The Candidate Auction Revenue Rights and Candidate Long-Term Congestion Rights eligibility limitations set forth herein shall apply prospectively to Candidate Auction Revenue Rights and Candidate Long-Term Congestion Rights granted after October 19, 2017. All Auction Revenue Rights granted prior to October 19, 2017 shall remain in effect until the end of the allocation year. Long-Term Congestion Rights granted prior to October 19, 2017 shall remain in effect, unless surrendered pursuant to Section 7.2.4 of Attachment AE of this Tariff.

## 34.7 Stranded Cost Recovery:

This Tariff does not affect in any way the right of any Transmission Owner to seek and receive stranded cost recovery or the right of anyone to oppose such stranded cost recovery. Thus, the Transmission Owner(s) may seek to recover stranded costs from the User(s) in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Owner(s) must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act, if FERC jurisdictional. If the Commission approves stranded cost charges to be recovered through schedules to be implemented by the Transmission Provider, the Transmission Provider as agreed shall charge and collect the appropriate charge(s) from the relevant User(s) and distribute the appropriate amounts directly to the relevant Transmission Owner(s).

## 34.8 SPP Costs:

The Network Customer shall pay SPP's administrative costs in accordance with Schedule 1-A.

**34.9 Monthly Demand Charge – Zone 10:**

A. Calculation of the Monthly Demand Charge

1. For all Network Load located within Zone 10, the Network Customer shall pay monthly Demand Charges, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the total Zonal ATRR for Zone 10.

2. The total Zonal ATRR for Zone 10 for purposes of the Monthly Demand Charge for Network Integration Transmission Service shall be calculated in accordance with the following:

a. The component of the total Zonal ATRR associated with Southwestern Power Administration's Non-Federal Transmission Service ("NFTS") ATRR shall be the NITS ATRR shown in 10a(i) of Column (3) of Table 1 of Attachment H of the Tariff and shall be calculated in accordance with Section II.8 of Attachment H of the Tariff.

b. The component of the total Zonal ATRR for a Transmission Owner other than Southwestern Power Administration in Zone 10 shall be as provided in Table 1 of Attachment H of the Tariff.

B. Reduction of Network Integration Transmission Service Charges for Deliveries of Federal Power-Southwestern

1. A Network Customer taking Network Integration Transmission Service in Zone 10 may have its Network Load reduced for deliveries of Federal Power-Southwestern. The Transmission Provider shall apply a reduction of the Network Customer's monthly zonal Demand Charge under Schedule 9 and Schedule 11 of this Tariff for the amount of energy scheduled under Transmission Transactions (as defined in Attachment AD of this Tariff) during the hour of the monthly Zonal peak.

2. Such reduction shall be one hundred percent (100%) of the scheduled deliveries of Federal Power-Southwestern to the Network Customer's charges for only Schedule 9 and Schedule 11 of this Tariff. All other Tariff

charges, as applicable, shall be based on the total Network Load of the Network Customer.

3. The reduction of Network Integration Transmission Service charges provided pursuant to this Section 34.9.B shall only be provided to Network Customers where the point of delivery identified for deliveries of Federal Power-Southwestern shall also be a point of delivery identified in the Network Customer's Service Agreement which is physically connected to Southwestern Power Administration transmission facilities located in Zone 10.

# 35 Operating Arrangements

**35.1 Operation under the Network Operating Agreement:**

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

**35.2 Network Operating Agreement:**

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties, including the affected Transmission Owner(s), to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) satisfy its Balancing Authority Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (ii) satisfy its Balancing Authority Area requirements, including all necessary Ancillary Services requirements, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the Electric Reliability Organization and SPP Criteria. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

## 36. Scheduling

Each Network Customer shall ensure that all necessary information required for the Energy and Operating Reserve Markets is submitted in accordance with Attachment AE.

# IV. SPECIAL RULES ON USE OF TARIFF

# 37. During Transition Period

**37.1 Service Not Required for Bundled Customers or Customers Under Retail Access Programs**:

A Transmission Owner shall not be obligated to take Network Integration Transmission Service or Point-To-Point Transmission Service from the Transmission Provider in accordance with this Tariff for (1) bundled retail load not having a choice of power suppliers or (2) for bundled retail load it continues to serve that had the right to choose a different power supplier under a state retail access program or legislation and that was retail load served by the Transmission Owner prior to the retail load receiving the right to choose a different supplier.

## 37.2 Availability of Network Integration Transmission Service:

All Transmission Owners shall have the option of electing Network Integration Transmission Service for retail loads or customers whether or not such loads or customers have the right to choose a different power supplier during the Transition Period.

### 37.3 Unbundled Wholesale:

A Transmission Owner shall be obligated to take Network Integration Transmission Service or Point-To-Point Transmission Service from the Transmission Provider in accordance with this Tariff for any sales to wholesale load the Commission requires to be unbundled unless such service is arranged by another entity or is pursuant to a Grandfathered Agreement.

## 37.4 Grandfathered Transactions:

During the Transition Period, transmission provided pursuant to Grandfathered Agreements shall continue to term in accordance with the provisions of the Grandfathered Agreement unless the parties agree otherwise. Grandfathered Transactions are defined in Section 1.14a.

# 38 After Transition Period

## 38.1 Applicability to Retail Load Having Choice:

Beginning on the first day after the end of the Transition Period, this Tariff shall be applicable to all transmission service over the Transmission System provided for retail loads having the right to choose a different power supplier except for deliveries made pursuant to Grandfathered Agreements.

## 38.2 Applicability to Retail Load Not Having Choice:

Beginning at the end of the fifth year after the last day of the Transition Period, the Transmission Owner or in the case of a Nebraska public-power entity beginning after the fifth year of the transfer of functional control of such entity's transmission facilities to the Transmission Provider, shall take Network Integration Transmission Service or Point-To-Point Transmission Service from the Transmission Provider in accordance with this Tariff for sales to retail customers not having the right to choose a different power supplier.

## 38.3 Grandfathered Agreements:

Transmission Service provided pursuant to Grandfathered Agreements shall continue to term in accordance with the provisions of the Grandfathered Agreements unless the parties agree otherwise. Grandfathered Agreements are defined in Section 1 of this Tariff.

# 39. Applicability of Non-Rate Terms and Conditions

## 39.1 Subject to State Laws and Regulations and Public Power Rate Schedules

The participation in this Tariff by a Transmission Owner that is not a public utility under the Federal Power Act, but rather is a public-power entity, is subject in all respects to the laws and regulations of the state of its creation and to rate schedules adopted by its governing board under state law. The Commission has exclusive jurisdiction to interpret the provisions of this Tariff and how the provisions apply to such public-power entity(ies). However, in the event that the governing board of such public-power entity(ies), subject to state court review, determines that a conflict exists between the applicable state law, regulations, or rate schedules, and provisions of this Tariff as interpreted by the Commission, such state law, regulations, or rate schedules shall govern with respect to the application of this Tariff to such public-power entity(ies). Should the governing board of such public-power entity(ies) determine that such a conflict exists, the public-power entity(ies) must file, with the Commission, such necessary documents notifying the Commission of the governing board determination of such a conflict and explaining both the conflict (including what state law, regulations, or rate schedules, and what Tariff provisions are at issue) and what actions the governing board is taking in response to that determination.

### 39.2 Bundled Retail and Grandfathered Load:

Notwithstanding Sections 37 and 38 of this Tariff, each Transmission Owner (which is not otherwise taking Network Integration Transmission Service) is subject to the non-rate and conditions of this Tariff for: (1) its bundled retail load not having a choice of power suppliers; (2) its bundled retail load that had the right to choose a different power supplier under a state retail access program or legislation and that was retail load served by the Transmission Owner prior to the retail load receiving the right to choose a different supplier; and (3) its bundled load under Grandfathered Agreements. For purposes of this provision the non-rate terms and conditions are those that would apply to Network Customers. In addition, unless a Transmission Owner executes a Service Agreement under this Part III, it will not be considered as taking Network Integration Transmission Service.

## 39.3 Participation by Western Area Power Administration Subject to Federal Laws and Regulations

### (a) Subject to Acts of Congress

The participation by the United States through Western-UGP and/or Western-RMR in this Tariff is subject in all respects to acts of Congress and to regulations of the Secretary of Energy established thereunder, and to rate schedules promulgated by the Secretary of Energy. This reservation includes, but is not limited to, the statutory limitations upon the authority of the Secretary of Energy to submit disputes arising under this Tariff to arbitration. In the event of a conflict between these Federal participation provisions in Section 39.3 of this Tariff and any other provision of this Tariff, these Federal participation provisions shall have precedence with respect to the application of this Tariff to Western-UGP and/or Western-RMR.

### (b) Contingent Upon Appropriations and Authorization

Where activities provided for in this Tariff extend beyond the current fiscal year, continued expenditures by the United States through Western-UGP and/or Western-RMR are contingent upon Congress making the necessary appropriations required for the continued performance of the obligations of the United States under this Tariff. In case such appropriation is not made, the Parties hereby release the United States from its contractual obligations under this Tariff and from all liability due to the failure of Congress to make such appropriation.

### (c) Employment Practices; Contractor Agreement

For the purpose of this Federal participation provision, the term "Contract" shall mean this Tariff and the term "Contractor" shall mean a Party having transactions with Western-UGP and/or Western-RMR. During the performance of this Contract, the Contractor agrees to the provisions set forth in Section 39.3 and its subdivisions. In addition, the Contractor will include the following provisions in every subcontract or purchase order involving Western-UGP and/or Western-RMR unless exempted by rules, regulations, or order of the Secretary of Labor.

#### (i) Equal Opportunity Employment Practices

Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference

in the Contract by reference to same as if the specific language had been written into the Contract, except that Indian Tribes and tribal organizations may apply Indian Preference to the extent permitted by federal law.

**(ii) Contract Work Hours and Safety Standards**

The Contract, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act ("Act"), 40 U.S.C. § 3701, as amended or supplemented, is subject to the provisions of the Act, 40 U.S.C. § 3701-3708, as amended or supplemented, and to regulations promulgated by the Secretary of Labor pursuant to the Act.

**(iii) Use of Convict Labor**

The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the Contract except as provided by 18 U.S.C. § 3622(c), as amended or supplemented, and Executive Order No. 11755, 39 Fed. Reg. 779 (1973), as amended or supplemented.

**(d) Western-UGP Co-supply Arrangement**

If Western-UGP is a Network Customer and designates Network Load within Zone 19, or outside of the Transmission Provider's Transmission System, the amount of Western-UGP's Network Load shall be based upon its Statutory Load Obligations. Western-UGP's Statutory Load Obligations to its customers are limited because it is not the full-requirements power supplier, except in certain limited cases, and therefore, Western-UGP generally does not serve the total load at a delivery point. The portion of load that exceeds Western-UGP's obligation at a delivery point must be served by another transmission customer ("Co-Supplier"). A Co-Supplier to load in excess of Western-UGP's Statutory Load Obligations shall be allowed to designate its portion of the total load at a delivery point as Network Load. In such case, that Co-Supplier's Network Load shall be the total load at each delivery point less Western-UGP's Statutory Load Obligations.

**(e) Western-UGP Federal Service Exemption**

The Federal Service Exemption applies to transmission of Federal Power-Western-UGP to the Statutory Load Obligations under this Tariff. Western-UGP was established on December 21, 1977, pursuant to Section 302 of the Department of Energy Organization Act, Public Law 95-91, dated August 4, 1977. By law, Western-UGP markets Federal Power-Western-UGP to meet its Statutory Load Obligations. Western-UGP's transmission system was built

primarily to enable the delivery of Federal power to satisfy these obligations. Use of transmission facilities that Western-UGP owns, operates, or to which it has contract rights for delivery of Federal long-term firm capacity and energy to project use and firm electric service customers is a Western-UGP responsibility under the terms and conditions of marketing criteria and electric service contracts implementing Statutory Load Obligations to market Federal power. This is complementary with the provisions of transmission service under the Tariff. Capacity in transmission facilities provided by Western-UGP under this Tariff is solely for the use of Available Transfer Capability in excess of the capability Western-UGP requires for the delivery of long-term firm capacity and energy to Statutory Load Obligations. Western-UGP retains the Available Transfer Capability from its Federal Power-Western-UGP in the UMZ to deliver to its Statutory Load Obligations.

**(i)** Western-UGP shall be exempt from the Region-wide Charge associated with Western-UGP's delivery of Federal Power-Western-UGP to Statutory Load Obligations internal to the UMZ or external to the Transmission Provider. The Transmission Provider will not assess load served by Western UGP in the Western Interconnection for the Region-wide Charge, associated with transmission facilities in the Eastern Interconnection, to the extent that load that is located in the Western Interconnection is served only by resources in the Western Interconnection.

**(ii)** Western-UGP shall be exempt from congestion and marginal loss charges in accordance with Attachment AE of this Tariff for deliveries from Federal Power-Western-UGP resources across the UMZ to Western-UGP's Statutory Load Obligations. Western-UGP shall be responsible for providing the Transmission Provider real power losses for the energy delivered from the Federal Power-Western-UGP resources under the Federal Service Exemption across Zone 19 in accordance with Attachment M of this Tariff.

**(f) Federal Projects**

The individual hydroelectric projects from which the Western-UGP markets power and energy are owned and controlled by the Department of the Army or the U.S. Bureau of Reclamation. These projects are operated to satisfy multiple purposes such as irrigation, navigation, flood control, fish and wildlife, and recreation, as well as power production. Any operation of, and maintenance, modification or addition to such projects is subject to the requirements and express approval of either the Department of the Army or the U.S. Bureau of

Reclamation. Western-UGP's transmission system is integrated at various locations through switchyard facilities owned and operated by the Department of the Army or U.S. Bureau of Reclamation. Any operation of, and maintenance, modification, or addition to such facilities, including the funding of such activities, is subject to the requirements and express approval of the Department of the Army or U.S. Bureau of Reclamation. Western-UGP shall communicate and coordinate with the Department of the Army on any operation of, and maintenance, modification, or addition to the Department of the Army or the U.S. Bureau of Reclamation facilities as requested by the Transmission Provider; provided that compliance with the Transmission Provider's request shall be within the discretion of, and subject to the approval of, the Department of the Army or the U.S. Bureau of Reclamation. In the event the Transmission Provider requests changes to a hydroelectric generation facility due to redispatch, operation, maintenance or addition to hydroelectric generation owned and operated by the Department of the Army or U.S. Bureau of Reclamation and marketed by Western-UGP, Western-UGP shall coordinate its operations with the Department of the Army and U.S. Bureau of Reclamation to accommodate the Transmission Provider's request to the extent allowed by the Department of the Army or U.S. Bureau of Reclamation. Nothing in this section is intended to change the Department of the Army or U.S. Bureau of Reclamation obligations pursuant to their registration with NERC.

**(g) Federal Projects as Designated Resources**

The Federal Power-Western-UGP resources will be deemed to be eligible as Western-UGP Designated Resources.

**(h) Transmission Expansion, Interconnections, Modifications, and Additions**

As a Federal agency, Western-UGP must comply with various environmental and natural resource laws regulating the construction, operation and maintenance of its transmission facilities, including but not limited to the National Historic Preservation Act, 16 U.S.C. § 470 to 470x-6, the National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321-4347 ("NEPA"), the Endangered Species Act, 16 U.S.C. §§ 1531-1544, and the Archaeological Resources Protection Act of 1979, 16 U.S.C. § 470aa-470mm (2006); and regulations and Executive Orders implementing these laws, as they may be amended or supplemented, as well as any other existing or subsequent applicable laws, regulations and Executive Orders. The Transmission Provider shall assist Western-UGP in complying with the environmental laws, regulations and resource protection measures that apply to Western-UGP for changes to the Western-UGP transmission facilities. Transmission expansion, interconnections, modifications and additions of, and or

to, Western-UGP's transmission facilities are dependent on Western-UGP's conclusions and decisions reached in the record of decision under NEPA, or other such appropriate NEPA document, concerning the respective project. Western-UGP's NEPA review could result in a decision not to take action or to delay action. Transmission Provider agrees to abide by such decision and it shall not be subject to the dispute resolution procedures of this Tariff.

**(i) Advance Funding**

In the absence of appropriated funds, Western-UGP requires advance deposit of funds when it is required to perform any work for third parties. As such, Western-UGP must receive an advance deposit of funds pursuant to Federal law prior to Western-UGP committing to perform any work pursuant to the Tariff.

**(j) Liability**

Western-UGP and/or Western-RMR, each in the capacity of a Transmission Customer as defined in Part I of this Tariff cannot indemnify, defend, and save harmless the Transmission Provider and Transmission Owner(s) pursuant to Section 10.3 of this Tariff due to the Antideficiency Act, 31 U.S.C. § 1341, et seq, as amended or supplemented. Western-UGP's and/or Western-RMR's liability as a Transmission Customer is instead determined in accordance with the Federal Tort Claims Act, 28. U.S.C. § 1346(b), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

**(k) Western-UGP Rate Review**

Western-UGP's transmission service rates and revenue requirements shall only be reviewed in accordance with Delegation Order No. 00-037.00A from the Secretary of Energy to the Federal Power Marketing Agencies and the Commission, as superseded or amended, and in accordance with the regulations implementing the review authority found in 10 C.F.R. Part 903 and 18 C.F.R. Part 300, as superseded or amended.

**(l) Inapplicability of Section 39.1 to a Federal Power Marketing Agency**

Section 39.1 of this Tariff shall not apply to Western-UGP.

**(m) No Expansion of Jurisdiction, Waiver Of Defenses, Liability For Penalties, Or Inconsistent Obligations**

Western-UGP and/or Western-RMR have/has not waived or conceded any defense, including sovereign immunity, intergovernmental immunity, or lack of subject matter jurisdiction in any action against it by an Enforcement Authority,

nor has either Western-UGP and/or Western-RMR accepted any liability, responsibility, or obligation to pay any civil monetary penalties or fines imposed by an Enforcement Authority to which it would not have been subject in the absence of this Tariff. “Enforcement Authority” means the Commission, Electric Reliability Organization (ERO), or Regional Entities with enforcement authority pursuant to a delegation from an ERO or Commission for the purpose of proposing and enforcing reliability standards. The Transmission Provider does not concede or accept responsibility for any portion of a penalty or fine attributable to the actions or omissions of Western-UGP and/or Western-RMR. The Transmission Provider will identify the amount of any penalty or fine that the Transmission Provider allocates to Western-UGP and/or Western-RMR or that the Transmission Provider determines is attributable to Western-UGP and/or Western-RMR and will identify that amount to FERC as uncollectable and not otherwise owed by the Transmission Provider.

## 39.4 Applicability to Rural Electric Cooperatives

The participation in this Tariff by a Transmission Owner that is an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 et seq.) is subject in all respects to the laws and regulations of the state of its creation and to rate schedules adopted by its governing board under state law. The Commission has exclusive jurisdiction to interpret the provisions of this Tariff and how the provisions apply to such entity. However, in the event that the governing board of such entity, subject to state court review, determines that a conflict exists between the applicable state law, regulations, or rate schedules, and provisions of this Tariff as interpreted by the Commission, such state law, regulations, or rate schedules shall govern with respect to the application of this Tariff to such entity. Should the governing board of such entity determine that such a conflict exists, the entity must file with the Commission such necessary documents notifying the Commission of the governing board's determination of such a conflict and explaining both the conflict (including what state law, regulations, or rate schedules and what Tariff provisions are at issue) and what actions the governing board is taking in response to that determination.

# V. RECOVERY OF COSTS FOR BASE PLAN UPGRADES AND APPROVED BALANCED PORTFOLIOS

## 40. Base Plan Zonal Charge and Region-wide Charge

The Transmission Provider shall assess Base Plan Zonal Charges and Region-wide Charges specified in Schedule 11 to recover the Base Plan Zonal Annual Transmission Revenue Requirements and the Region-wide Annual Transmission Revenue Requirement.

## 41. Applicability to Resident Load

### A. Resident Load in Zones 1 through 9 and 11 through 19

Base Plan Zonal Charges and Region-wide Charges shall be determined in accordance with Schedule 11 and assessed to:

(1) Network Customers taking Network Integration Transmission Service to serve their Network Load under the Tariff; and

(2) Transmission Owners providing transmission service to: (a) bundled retail load for which such Transmission Owners are not taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff; and (b) load being served under Grandfathered Agreements for which such Transmission Owners are not taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff. Load being served under Grandfathered Agreements shall be treated as Resident Load only in the Zone of the Point of Delivery or the point of exit from the SPP Region, as applicable, and shall not be treated as Resident Load if its continuous transmission path includes one or more segments with Firm Point-To-Point Transmission Service under this Tariff.

### B. Resident Load in Zone 10

Base Plan Zonal Charges and Region-wide Charges shall be determined in accordance with Schedule 11 and assessed to loads defined in Sections 41.A.(1) and (2), except that the determination of Resident Load for Zone 10 shall not include:

(1) Transmission Transactions (as defined in Attachment AD of this Tariff) related to Grandfathered Agreements of Southwestern Power Administration listed in Attachment W of this Tariff; and

(2) Scheduled deliveries of Federal Power-Southwestern to Network Customers pursuant to Section 34.9 of this Tariff.

### C. Reporting Resident Load

For the purposes of Schedule 11, the load defined in Sections 41.A and 41.B shall be classified as Resident Load. All entities responsible for reporting Resident Load information to the Transmission Provider, for the purpose of determining charges under Schedule 11, shall

provide such information no later than January 25 of each year for the twelve months of the prior calendar year. If January 25 falls on a weekend, the information shall be provided no later than the immediately preceding Friday. The Transmission Provider shall post on its website and/or communicate to the membership of the Markets and Operations Policy Committee the reporting status of the entities responsible for reporting Resident Load information.

## 42. Applicability to Point-To-Point Transmission Service

Base Plan Zonal Charges and Region-wide Charges shall be determined in accordance with Schedule 11 and assessed to Transmission Customers taking Point-To-Point Transmission Service under the Tariff.

# VI. MISCELLANEOUS PROVISIONS

**43. Market Import Service** Market Import Service is used by a Market Participant to submit offers to sell energy from a generating resource external to the SPP Balancing Authority Area into the Day-Ahead Market or Real-Time Balancing Market for use by the Transmission Provider to serve Network Load from a non-designated generating resource. Market Import Service is available to a Market Participant that is a Transmission Customer (as that term is used in Part I of the Tariff), on an as-available basis, with no charges imposed under Schedules 7, 8, 9, or 11 of this Tariff. Market Import Service shall carry a reservation priority equivalent to non-designated Network Service. A Market Participant must reserve and schedule Market Import Service in accordance with the procedures specified in the SPP Business Practices. Market Import Service is not available for energy withdrawals out of the SPP Balancing Authority Area or to support a Third-Party Sale or purchase. Use of Market Import Service for any other purpose than defined in this Section 43 shall subject the Market Participant to unreserved use penalties pursuant to Section 14.5 of this Tariff.

## SCHEDULE 1
## SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is required to operate a Transmission Owner's Tariff facilities and schedule movement of power through, out of, within or into the Transmission Provider's Balancing Authority Area and certain parts of the Transmission System not located within the Transmission Provider's Balancing Authority Area.

A. Through and Out Transactions

1) For Transmission Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for through and out transactions, the Schedule 1 charge shall be the product of the capacity reserved, expressed in MW and the appropriate rate set forth in the Revenue Requirements and Rates File ("RRR File"), Schedule 1 tab, posted on the SPP website. The yearly rate for such transactions is computed as the ratio of the sum of the accepted or approved revenue requirements most recently determined for each Transmission Owner having a Schedule 1charge and the prior calendar year's average of the 12 monthly peaks of the total Resident Load (expressed in MW) in the SPP Region.

On-Peak:

Monthly Rate/MW: the yearly rate divided by 12

Weekly Rate/MW: the yearly rate divided by 52

Daily Rate/MW: the yearly rate divided by 260

Hourly Rate/MW: the yearly rate divided by 4160

Off-Peak:

Daily Rate/MW: the yearly rate divided by 365

Hourly Rate/MW: the yearly rate divided by 8760

On-Peak and Off-Peak Periods

Off-Peak days shall be Saturdays and Sundays and all NERC holidays. All other days shall be On-Peak. All hours during Off-Peak days shall be Off-Peak. On-Peak hours during On-Peak days shall be all hours from HE 0700 through HE 2200 Central Prevailing Time. All other hours during On-Peak days shall be Off-Peak.

2) For Network Customers taking Network Integration Transmission Service for Load not physically interconnected with the Transmission System, designated as Network Load

pursuant to Section 31.4, the Network Customer's Schedule 1 charge shall be the charge computed pursuant to the approved rate of the Zone to which the Network Load is located or assigned in accordance with Section 31.4.

B. Transactions Sinking within the Transmission System

1) For Transmission Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for transactions into and within the Transmission System, the Schedule 1 charge shall be the charge computed pursuant to the approved rate of the Zone that is the Point of Delivery.

2) For Network Customers taking Network Integration Transmission Service, the Schedule 1 charge shall be the charge computed pursuant to the approved rate of the Zone in which the load is located.

C. Multi-owner Zones

For those Zones with more than one Transmission Owner with approved or accepted Schedule 1 rates, the Transmission Provider shall calculate a Schedule 1 rate for that Zone by summing the rates set forth in the Zonal Sch 1 tab of the RRR file of each Transmission Owner in that Zone.

D. Adjustments to the Schedule 1 Revenue Requirements

The revenue requirements listed in Table 1 ("Schedule 1 RR") shall be adjusted for any Schedule 1 revenue received by the Transmission Owner for Point-to-Point transactions. Any such adjustment made by the Transmission Provider shall be set forth in the RRR File.

1) The Transmission Provider shall not adjust a Transmission Owner's Schedule 1 RR if that Transmission Owner has a formula rate calculation which updates its Schedule 1 RR annually and reduces: (i) its Schedule 1 RR or (ii) its other gross revenue requirement for any Schedule 1 Point-to-Point revenues received by that Transmission Owner.

2) For each Transmission Owner utilizing a stated rate or utilizing a formula rate calculation without an annual update of the Schedule 1 revenue credits, the Transmission Provider shall reduce the Schedule 1 RR by the difference between the previous calendar year Schedule 1 Point-to-Point revenues and the amount of Schedule 1 Point-to-Point already credited in the calculation of the Schedule 1 RR. The amount of Point-to-Point revenues

already credited in each Transmission Owner's Schedule 1 RR shall be posted in Table 2 of Schedule 1 of this Tariff.

| **TABLE 1** | |
|---|---|
| **Revenue Requirements for the Allocation of Through And Out Transactions** | |
| **Transmission Owner** | **Revenue Requirement** |
| AEP West Transmission Companies (AEP Oklahoma Transmission Company, Inc and AEP Southwestern Transmission Company, Inc) | See RRR File |
| American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | See RRR File |
| Arkansas Electric Cooperative Corporation-1 | See RRR File |
| Arkansas Electric Cooperative Corporation-7 | See RRR File |
| City Utilities of Springfield | See RRR File |
| Corn Belt Power Cooperative | See RRR File |
| Empire District Electric Company | See RRR File |
| Evergy Kansas Central, Inc. (Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.) | See RRR File |
| Evergy Metro, Inc. | See RRR File |
| Evergy Missouri West, Inc. | See RRR File |
| Grand River Dam Authority | See RRR File |
| Kansas City Board of Public Utilities | See RRR File |
| Lincoln Electric System | See RRR File |
| Midwest Energy, Inc | See RRR File |
| Missouri Joint Municipal Electric Utility Commission | See RRR File |
| Nebraska Public Power District | See RRR File |
| Oklahoma Gas and Electric | See RRR File |
| Omaha Public Power District | See RRR File |
| Southwestern Power Administration Zonal ATRR (Non-Federal Transmission Service ATRR) | See RRR File |
| Southwestern Public Service Company | See RRR File |
| Sunflower Electric Power Corporation | See RRR File |
| Tri-State G&T Association | See RRR File |
| Western Farmers Electric Cooperative | See RRR File |
| Western-UGP | See RRR File |
| **TOTAL** | See RRR File |

| **TABLE 2** | |
|---|---|
| **Schedule 1 Point-to-Point ("PTP") Revenue Credit** | |
| | |
| **Transmission Owner** | **Schedule 1 PTP Revenue Credit** |
| AEP West Transmission Companies (AEP Oklahoma Transmission Company, Inc and AEP Southwestern Transmission Company, Inc) | N/A |
| American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | N/A |
| Arkansas Electric Cooperative Corporation-1 | $0 |
| Arkansas Electric Cooperative Corporation-7 | $0 |
| City Utilities of Springfield | N/A |
| Corn Belt Power Cooperative | N/A |
| Empire District Electric Company | $0 |
| Evergy Kansas Central, Inc. (Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.) | $0 |
| Evergy Metro, Inc. | N/A |
| Evergy Missouri West, Inc. | N/A |
| Grand River Dam Authority | $0 |
| Kansas City Board of Public Utilities | N/A |
| Lincoln Electric System | N/A |
| Midwest Energy, Inc | N/A |
| Missouri Joint Municipal Electric Utility Commission | N/A |
| Nebraska Public Power District | N/A |
| Oklahoma Gas and Electric | N/A |
| Omaha Public Power District | N/A |
| Southwestern Power Administration Zonal ATRR (Non-Federal Transmission Service ATRR) | $0 |
| Southwestern Public Service Company | N/A |
| Sunflower Electric Power Corporation | N/A |
| Tri-State G&T Association | $0 |
| Western Farmers Electric Cooperative | N/A |
| Western-UGP | N/A |

# SCHEDULE 1-A
# TARIFF ADMINISTRATION SERVICES

The Transmission Provider shall provide administration services described in this Schedule 1-A to carry out its responsibilities under this Tariff. Transmission Customers and Market Participants must purchase these services from the Transmission Provider. Unless otherwise collected under this Tariff, the Transmission Provider will recover 100% of its budgeted costs for the fiscal year in which services are provided, including an adjustment for over or under recovery for prior fiscal years ("Schedule 1-A Recoverable Costs"). Schedule 1-A Recoverable Costs divided by the total billing determinants of Schedule 1-A1, shall not exceed $0.465.

## 1. Schedule 1-A1 Transmission Administration Service

Transmission administrative service is provided by the Transmission Provider to all Transmission Customers under this Tariff and includes the provision of: (1) reliability coordination; (2) transmission scheduling; (3) system control; and (4) transmission planning services ("Schedule 1-A1 Service").

### a. Schedule 1-A1 Service Rate Calculation

The Schedule 1-A1 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 1-A1 Service.

#### i. Costs

The costs associated with providing Schedule 1-A1 Service will be recovered under this Schedule 1-A1, as identified in the formula rate template in Addendum 1 of this Schedule 1-A ("Schedule 1-A1 Costs").

#### ii. Billing Determinants

For Network Integration Transmission Service, the billing determinants in each Zone where the load is located are the sum of the prior calendar year's average of the twelve (12) monthly coincident peak demands multiplied by the number of all hours of the applicable month for the following:

(1) Network Customer's total Network Load;

(2) bundled retail load for which Transmission Owners are not taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff; and

(3) load being served under Grandfathered Agreements for which Transmission Owners are not taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff. Load being served under Grandfathered Agreements shall be included only in the Zone of the Point of Delivery or the point of exit from the SPP Region, as applicable, and shall not be included if its continuous transmission path includes one or more segments with Firm Point-To-Point Transmission Service under this Tariff.

For Point-to-Point Transmission Service, the billing determinants are the MW hours reserved.

**iii. Rate Formula**

Annually, the Transmission Provider will determine the Schedule 1-A1 Service rate for each calendar year as described in Addendum 1 of this Schedule 1-A.

**iv. Charges to Transmission Customers**

The Schedule 1-A1 charge is the product of the Schedule 1-A1 rate and the Transmission Customer's billing determinants.

**2. <u>Transmission Service Request Charges</u>:**

The Transmission Customer shall pay the Transmission Provider a charge for each new Transmission Service Request as follows:

(a) For Firm Point-To-Point Transmission Service:
Reservations less than one month: $100
Reservations one month or longer: $200

(b) For Non-Firm Point-To-Point Transmission Service:
Each Reservation: $0.

However, the Transmission Customer shall have this fee rebated to it once the Transmission Customer becomes legally obligated to pay the applicable Firm Point-To-Point Transmission Service charges under this Tariff or if the requested Firm Point-To-Point Transmission Service is denied by the Transmission Provider.

## 3. Schedule 1-A2 Transmission Congestion Rights Administration Service

Transmission Congestion Rights ("TCR") administration service is provided by the Transmission Provider to all Market Participants that hold TCRs issued and settled by the Transmission Provider ("TCR Holder"). This service includes the provision of: (1) TCR administration through allocation, assignment, auction or any other process under this Tariff; (2) simultaneous feasibility tests and other applicable studies to determine the total TCRs that can be accommodated by the Transmission System; (3) TCR tools; and (4) a secondary market for TCRs ("Schedule 1-A2 Service").

### a. Schedule 1-A2 Service Charge

The Schedule 1-A2 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 1-A2 Service.

#### i. Costs

The costs associated with providing Schedule 1-A2 Service will be recovered under this Schedule 1-A2, as identified in the formula rate template in Addendum 1 of this Schedule 1-A ("Schedule 1-A2 Costs").

#### ii. Billing Determinants

The Schedule 1-A2 billing determinant is the total amount of TCR volume in MWh for all TCR Holders.

#### iii. Rate Formula

Annually, the Transmission Provider will determine the Schedule 1-A2 Service rate for each calendar year as described in Addendum 1 of this Schedule 1-A.

### b. Charges To TCR Holders

The Schedule 1-A2 charge is the product of the Schedule 1-A2 rate and the TCR Holder's billing determinants.

## 4. Schedule 1-A3 Integrated Marketplace Clearing Administration Service

Integrated Marketplace clearing administration service is provided by the Transmission Provider to all Market Participants that participate in transactions pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision of: (1) market settlements; (2) credit evaluation and risk mitigation services; (3) market monitoring functions; (4) information technology support; and (5) customer service ("Schedule 1-A3 Service").

### a. Integrated Marketplace Clearing Administration Service Charge

The Schedule 1-A3 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 1-A3 Service.

#### i. Costs

The costs associated with providing Schedule 1-A3 Service will be recovered under this Schedule 1-A3, as identified in the formula rate template in Addendum 1 of this Schedule 1-A ("Schedule 1-A3 Costs").

#### ii. Billing Determinants

The Schedule 1-A3 billing determinants as expressed in MWh are:

(1) all Real-Time Energy injected into and withdrawn from the Transmission System;

(2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time; and

(3) all cleared Virtual Energy Bids and all cleared Virtual Energy Offers.

#### iii. Rate Formula

Annually, the Transmission Provider will determine the Schedule 1-A3 Service rate for each calendar year as described in Addendum 1 of this Schedule 1-A.

### b. Charges To Market Participants

The Schedule 1-A3 charge is the product of the Schedule 1-A3 rate and the Market Participant's billing determinants.

**5. Schedule 1-A4 Integrated Marketplace Facilitation Administration Service**

Integrated Marketplace facilitation administration service is provided by the Transmission Provider to all Market Participants that participate in transactions, except for cleared Virtual Energy Bids and cleared Virtual Energy Offers, pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision and operation of the: (1) Day-Ahead Market; (2) Real-Time Balancing Market; and (3) Reliability Unit Commitment processes ("Schedule 1-A4 Service").

**a. Integrated Marketplace Facilitation Administration Service Charge**

The Schedule 1-A4 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 1-A4 Service.

**i. Costs**

The costs associated with providing Schedule 1-A4 Service will be recovered under this Schedule 1-A4, as identified in the formula rate template in Addendum 1 of this Schedule 1-A ("Schedule 1-A4 Costs").

**ii. Billing Determinants**

The Schedule 1-A4 billing determinants are:

(1) all Real-Time Energy injected into and withdrawn from the Transmission System; and

(2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time.

**iii. Rate Formula**

Annually, the Transmission Provider will determine the Schedule 1-A4 Service rate for each calendar year as described in Addendum 1 of this Schedule 1-A.

**b. Charges To Market Participants**

The Schedule 1-A4 charge is the product of the Schedule 1-A4 rate and the Market Participant's billing determinants.

# Addendum 1 to Schedule 1-A

# Formula Rate Template

**Summary Sch 1-A1 to 1-A4 Rates**

| Line No. | | |
|---|---|---|
| 1 | **Total Schedule 1-A1 Rate/MWh** | (Schedule 1-A1 - Rate) |
| 2 | **Total Schedule 1-A2 Rate/MWh** | (Schedule 1-A2 - Rate) |
| 3 | **Total Schedule 1-A3 Rate/MWh** | (Schedule 1-A3 - Rate) |
| 4 | **Total Schedule 1-A4 Rate/MWh** | (Schedule 1-A4 - Rate) |

**These rates cannot be summed together to calculate a single rate**

**Rate Schedule 1-A1 Rate**

| Line No. | | | |
|---|---|---|---|
| 1 | Scheduling, System Control, and Dispatch Costs | (Schedule 1-A1 - COST-1) | $ - |
| 2 | Reliability Planning & Standards Development Costs | (Schedule 1-A1 - COST-2) | $ - |
| 3 | **Total Schedule 1-A1 Costs** | (ln 1 + ln 2) | $ - |
| 4 | **Prior Year Over or Under Recovery** | | |
| 5 | Budgeted Schedule 1-A1 Revenue | Supporting WPs-"**RS 1 Over/Under Recovery**" | |
| 6 | Forecasted Schedule 1-A1 Revenue | Supporting WPs-"**RS 1 Over/Under Recovery**" | |
| 7 | Budgeted Schedule 1-A1 Net Revenue | Supporting WPs-"**RS 1** | |

| | | | |
|---|---|---|---|
| | Requirement **("NRR")** | **Over/Under Recovery**" Supporting WPs-"**RS 1 Over/Under Recovery**" | |
| 8 | Forecasted Schedule 1-A1 NRR | | |
| 9 | **Adjustment for Prior Year Over or (Under) Recovery** | ((ln 6 - ln 5) + (ln 7 - ln 8)) | $ - |
| 10 | **Total Schedule 1-A1 Net Revenue Requirement** | (ln 3 - ln 9) | $ - |
| 11 | **Divisor** | | |
| 12 | Average 12 Coincident Peak Adjusted (MWhs) | (Schedule 1-A1 - Divisor) | - |
| 13 | **RATE/MWhs** | (ln 10 / ln 12) | |

**Rate Schedule 1-A1 - Scheduling, System Control, & Dispatch Costs**

| Line No. | | | | |
|---|---|---|---|---|
| 1 | **Salary and Benefits & Employee Direct Expenses** | | | |
| 2 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ | - |
| 3 | **Other Direct Costs** | | | |
| 4 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ | - |
| 5 | Network and Communications Expense | (Network & Comm Alloc) | $ | - |
| 6 | Outside Service Expenses | (Outside Services Alloc) | $ | - |
| 7 | Other Direct Expenses | (Other Direct Alloc) | $ | - |
| 8 | Debt Service | (Debt Service Alloc) | $ | - |
| 9 | Bad Debt | (Bad Debt Alloc) | $ | - |

| | | | | |
|---|---|---|---|---|
| 10 | Total Other Direct Costs | (sum lns 4 to 9) | $ | - |
| 11 | Total Direct Costs | (ln 2 + ln 10) | $ | - |
| 12 | Corporate Overhead Allocation | (Corp OH Alloc) | | |
| 13 | **Total Scheduling, System Control, & Dispatch Costs** | (ln 11 + ln 12) | $ | - |

**Rate Schedule 1-A1 - Reliability Planning & Standards Development Costs**

| Line No. | | | | |
|---|---|---|---|---|
| 1 | **Salary and Benefits & Employee Direct Expenses** | | | |
| 2 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ | - |
| 3 | **Other Direct Costs** | | | |
| 4 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ | - |
| 5 | Network and Communications Expense | (Network & Comm Alloc) | $ | - |
| 6 | Outside Service Expenses | (Outside Services Alloc) | $ | - |
| 7 | Other Direct Expenses | (Other Direct Alloc) | $ | - |
| 8 | Debt Service | (Debt Service Alloc) | $ | - |
| 9 | Bad Debt | (Bad Debt Alloc) | $ | - |
| 10 | Total Other Direct Costs before Revenues | (sum lns 4 to 9) | $ | - |
| 11 | **LESS:** Revenues Associated with Engineering Studies | (Rev Assoc with Eng Studies) | $ | - |
| 12 | Total Other Direct Costs (Net) | (ln 10 - ln 11) | $ | - |

| | | | | |
|---|---|---|---|---|
| 2 | | | | |
| 13 | Total Direct Costs | (ln 2 + ln 12) | $ | - |
| 14 | Corporate Overhead Allocation | (Corp OH Alloc) | | |
| 15 | **Total Reliability Planning & Standards Development Costs** | (ln 13 + ln 14) | $ | - |

**Revenues Associated with Engineering Studies**

| Line No. | SPP Account No. | | | |
|---|---|---|---|---|
| 1 | Dept 0440- Acc Series 49100-49120 | GI Studies Revenues | Note A | |
| 2 | Dept 0420- Acc Series 49100-49120 | Transmission Service Studies Revenue | Note A | |
| 3 | Dept 0410- Acc Series 49100-49120 | DPA Studies Revenues | Note A | |
| 4 | Various Depts - Acc #s | Miscellaneous Study Revenues | Note A | |
| 5 | **Total Revenues Associated with Engineering Studies** | | (sum lns 1 to 4) | $ - |

| Note | |
|---|---|
| A | As presented in Supporting WPs - "**Revenue Allocation**" |

**Schedule 1-A1 - Divisor**

**Zonal Transmission System Peak Loads**
**August to December from the two years prior and January to July from the one year prior**

**Monthly Peak for Network Integration Transmission (MWs) and Point-to-Point Transmission Service Load (MWhs)**

| Line No | Zone | | Year NOTE A | August YR-2 | September YR-2 | October YR-2 | November YR-2 | December YR-2 | January YR-1 | February YR-1 | March YR-1 | April YR-1 | May YR-1 | June YR-1 | July YR-1 | Total (Sum Cols D to O) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AEP | | | | | | | | | | | | | | | - |
| 2 | EDE KCLP - GMO | | | | | | | | | | | | | | | - |
| 3 | GRDA | | | | | | | | | | | | | | | - |
| 4 | KCPL | | | | | | | | | | | | | | | - |
| 5 | | | | | | | | | | | | | | | | - |

| | | | | |
|---|---|---|---|---|
| 6 | LES | | | - |
| 7 | MKEC | | | - |
| 8 | MIDW | | | - |
| 9 | NPPD | | | - |
| 10 | OKGE | | | - |
| 11 | OPPD | | | - |
| 12 | SECI | | | - |
| 13 | SPRM | | | - |
| 14 | SPS | | | - |
| 15 | WFEC | | | - |
| 16 | WR | | | - |
| 17 | SPA | | | - |
| 18 | UMZ w/FSE | | | - |
| 19 | Total | (Col Q, sum lns 1 to 18) | | - |
| 20 | NITS Average MWs | (Col Q, ln 19/12) | | - |
| 21 | NITS Average | (ln 20*87 | | - |

| | | | | |
|---|---|---|---|---|
| | MWhs | 60) | | |
| 22 | Adjustment for Known Future Impacts to Load | Source of data input (Col D to O)* 8760 | | - |
| 23 | PTP MWhs | Invoiced MWhs of PTP Service | | - |
| 23 | Average 12 Coincident Peak Adjusted (MWhs) | (ln 21 + ln 22 + ln 23) | | - |

Not

| | |
|---|---|
| e | |
| A | For NTIS Load: August (YR-2) to December (YR-2) two years prior from the last RRR file for the following year<br>For NITS Load: January (YR-1) to July (YR-1) one year prior from the Settlement System |
| | For example:<br>For Budget Year 2021, the YR-1 would be 2020 and YR-2 would 2019.<br>Aug 2019 (YR-2) to Dec 2019 (YR-2) NITS Load will be from the last 2020 RRR file<br>Jan 2020 (YR-1) to Jul 2020 (YR-1) NITS Load will be from the Settlement System |

| Line No. | | | **Rate Schedule 1-A2 Rate** |
|---|---|---|---|
| 1 | TCR Administration Costs | (Schedule 1-A2 - COST) | $ - |
| 2 | **Total Schedule 1-A2 Costs** | (ln 1) | $ - |
| 3 | **Prior Year Over or Under Recovery** | | |
| 4 | Budgeted Schedule 1-A2 Revenue | Supporting WPs-"**RS 2 Over/Under Recovery**" | |
| 5 | Forecasted Schedule 1-A2 Revenue | Supporting WPs-"**RS 2 Over/Under Recovery**" | |
| 6 | Budgeted Schedule 1-A2 Net Revenue Requirement ("NRR") | Supporting WPs-"**RS 2 Over/Under Recovery**" | |
| 7 | Forecasted Schedule 1-A2 NRR | Supporting WPs-"**RS 2 Over/Under Recovery**" | |
| 8 | **Adjustment for Prior Year Over or (Under) Recovery** | ((ln 5 - ln 4) + (ln 6 - ln 7)) | $ - |
| 9 | **Total Schedule 1-A2 Net Revenue Requirement** | (ln 2 - ln 8) | $ - |
| 10 | **Divisor** | | |
| 11 | TCR Volume MWh | (Schedule 1-A2 - Divisor) | - |
| 12 | **RATE/MWh** | (ln 9 / ln 11) | |

**Rate Schedule 1-A2 - TCR Administration Costs**

| Line No. | | | | |
|---|---|---|---|---|
| 1 | **Salary and Benefits & Employee Direct Expenses** | | | |
| 2 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ | - |
| 3 | **Other Direct Costs** | | | |
| 4 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ | - |
| 5 | Network and Communications Expense | (Network & Comm Alloc) | $ | - |
| 6 | Outside Service Expenses | (Outside Services Alloc) | $ | - |
| 7 | Other Direct Expenses | (Other Direct Alloc) | $ | - |
| 8 | Debt Service | (Debt Service Alloc) | $ | - |
| 9 | Bad Debt | (Bad Debt Alloc) | $ | - |
| 10 | Total Other Direct Costs | (sum lns 4 to 9) | $ | - |
| 11 | Total Direct Costs | (ln 2 + ln 10) | $ | - |
| 12 | Corporate Overhead Allocation | (Corp OH Alloc) | | |
| 13 | **Total TCR Administration Costs** | (ln 11 + ln 12) | $ | - |

**Rate Schedule 1-A**
**2 Divisor**

| Line No. | | | **Actuals MWhs** |
|---|---|---|---|
| 1 | August (YR-2) | (Note B) | |
| 2 | September (YR-2) | (Note B) | |
| 3 | October (YR-2) | (Note B) | |
| 4 | November (YR-2) | (Note B) | |
| 5 | December (YR-2) | (Note B) | |
| 6 | January (YR-1) | (Note A) | |
| 7 | February (YR-1) | (Note A) | |
| 8 | March (YR-1) | (Note A) | |
| 9 | April (YR-1) | (Note A) | |
| 10 | May (YR-1) | (Note A) | |
| 11 | June (YR-1) | (Note A) | |
| 12 | July (YR-1) | (Note A) | |
| 13 | **Volume of TCRs (Note C)** | (sum lns 1 to 12) | - |
| 14 | **Adjustment for Known Future Impacts to TCR Volume** | Source of data input | |
| 15 | **TCR volume (Adjusted)** | (ln 13 + ln 14) | - |

| Note Letter | |
|---|---|
| A | YR-1 represents the year prior to budget year |
| B | YR-2 represents 2 years prior to budget year<br>i.e. For Budget Year 2021, the YR-1 would be 2020 and YR-2 would 2019. |
| C | All TCR instruments cleared across all hours (billing determinant - "TcrHrlyQty") |

| Line No. | | | **Rate Schedule 1-A3 Rate** |
|---|---|---|---|
| 1 | Market Clearing Costs | (Schedule 1-A3 - COST) | $ - |
| 2 | **Total Schedule 1-A3 Costs** | (ln 1) | $ - |
| 3 | **Prior Year Over or Under Recovery** | | |
| 4 | Budgeted Schedule 1-A3 Revenue | Supporting WPs-"**RS 3 Over/Under Recovery**" | |
| 5 | Forecasted Schedule 1-A3 Revenue | Supporting WPs-"**RS 3 Over/Under Recovery**" | |
| 6 | Budgeted Schedule 1-A3 Net Revenue Requirement ("NRR") | Supporting WPs-"**RS 3 Over/Under Recovery**" | |
| 7 | Forecasted Schedule 1-A3 NRR | Supporting WPs-"**RS 3 Over/Under Recovery**" | |
| 8 | **Adjustment for Prior Year Over or (Under) Recovery** | ((ln 5 - ln 4)+(ln 6 - ln 7)) | |
| 9 | **Total Schedule 1-A3 Net Revenue Requirement** | (ln 2 - ln 8) | $ - |
| 10 | **Divisor** | | |
| 11 | Real Time Gen/Load, Import/Exports, and Virtuals MWh | (Schedule 1-A3 - Divisor) | - |
| 12 | **RATE/MWh** | (ln 9 / ln 11) | |

**Rate Schedule 1-A3 - Market Clearing Costs**

| Line No. | | | | |
|---|---|---|---|---|
| 1 | **Salary and Benefits & Employee Direct Expenses** | | | |
| 2 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ | - |
| 3 | **Other Direct Costs** | | | |
| 4 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | N/A | |
| 5 | Network and Communications Expense | (Network & Comm Alloc) | N/A | |
| 6 | Outside Service Expenses | (Outside Services Alloc) | N/A | |
| 7 | Other Direct Expenses | (Other Direct Alloc) | N/A | |
| 8 | Debt Service | (Debt Service Alloc) | N/A | |
| 9 | Bad Debt | (Bad Debt Alloc) | N/A | |
| 10 | Total Other Direct Costs | (sum lns 4 to 9) | $ | - |
| 11 | Total Direct Costs | (ln 2 + ln 10) | $ | - |
| 12 | Corporate Overhead Allocation | (Corp OH Alloc) | | |
| 13 | **Total Market Clearing Costs** | (ln 11 + ln 12) | $ | - |

| Line No. | | | (A) Real Time Generation Actuals MWhs | (B) Real Time Load Actuals MWhs | (C) Real Time Imports Actuals MWhs | (D) Real Time Exports Actuals MWhs | (E) Cleared Virtual Offers Actuals MWhs | (F) Cleared Virtual Bids Actuals MWhs | Rate Schedule 1-A 3 Divisor (G) Total (A) to (F) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | August (YR-2) | (Notes B and C) | | | | | | | - |
| 2 | September (YR-2) | (Notes B and C) | | | | | | | - |
| 3 | October (YR-2) | (Notes B and C) | | | | | | | - |
| 4 | November (YR-2) | (Notes B and C) | | | | | | | - |
| 5 | December (YR-2) | (Notes B and C) | | | | | | | - |
| 6 | January (YR-1) | (Notes A and C) | | | | | | | - |
| 7 | February (YR-1) | (Notes A and C) | | | | | | | - |
| 8 | March (YR-1) | (Notes A and C) | | | | | | | - |
| 9 | April (YR-1) | (Notes A and C) | | | | | | | - |
| 10 | May (YR-1) | (Notes A and C) | | | | | | | - |
| 11 | June (YR-1) | (Notes A and C) | | | | | | | - |
| 12 | July (YR-1) | (Notes A and C) | | | | | | | - |
| 13 | **Volume of Market Billing Determinants (Note C)** | (sum lns 1 to 12, col G) | | | | | | | - |

| | | | |
|---|---|---|---|
| 14 | **Adjustment for Known Future Impacts to Market Determinants** | Source of data input | |
| 15 | **Market Billing Determinants - Adjusted** | (ln 13 + ln 14) | - |

| Note Letter | |
|---|---|
| A | YR-1 represents the year prior to budget year |
| B | YR-2 represents 2 years prior to budget year<br>i.e. For Budget Year 2021, the YR-1 would be 2020 and YR-2 would 2019. |
| C | Utlizing billing determinants as described below -<br>• Real-time Billing Meter MW Quantity (RtBilMtr5minQty) for generation and loads<br>• Real-time Import and Export MW Quantity (RtImpExp5minQty) for all import and exports<br>• Cleared Virtual MW Quantity (DaClrdVHrlyQty) for all cleared energy bids and offers. |

**Rate Schedule 1-A4 Rate**

| Line No. | | | |
|---|---|---|---|
| 1 | Market Facilitation Costs | (Schedule 1-A4 - COST) | $ - |
| 2 | **Total Schedule 1-A4 Costs** | (ln 1) | $ - |
| 3 | **Prior Year Over or Under Recovery** | | |
| 4 | Budgeted Schedule 1-A4 Revenue | Supporting WPs-"**RS 4 Over/Under Recovery**" | |
| 5 | Forecasted Schedule 1-A4 Revenue | Supporting WPs-"**RS 4 Over/Under Recovery**" | |
| 6 | Budgeted Schedule 1-A4 Net Revenue Requirement ("NRR") | Supporting WPs-"**RS 4 Over/Under Recovery**" | |
| 7 | Forecasted Schedule 1-A4 NRR | Supporting WPs-"**RS 4 Over/Under Recovery**" | |
| 8 | **Adjustment for Prior Year Over or (Under) Recovery** | ((ln 5 - ln 4)+(ln 6 - ln 7)) | $ - |
| 9 | **Total Schedule 1-A4 Net Revenue Requirement** | (ln 2 - ln 8) | $ - |
| 10 | **Divisor** | | |
| 11 | Real Time Gen/Load and Import/Exports MWh | (Schedule 1-A4 - Divisor) | - |
| 12 | **RATE/MWh** | (ln 9 / ln 11) | |

**Rate Schedule 1-A4 - Market Facilitation Costs**

| Line No. | | | |
|---|---|---|---|

| | | | |
|---|---|---|---|
| 1 | **Salary and Benefits & Employee Direct Expenses** | | |
| 2 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ - |
| 3 | **Other Direct Costs** | | |
| 4 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ - |
| 5 | Network and Communications Expense | (Network & Comm Alloc) | $ - |
| 6 | Outside Service Expenses | (Outside Services Alloc) | $ - |
| 7 | Other Direct Expenses | (Other Direct Alloc) | $ - |
| 8 | Debt Service | (Debt Service Alloc) | $ - |
| 9 | Bad Debt | (Bad Debt Alloc) | $ - |
| 10 | Total Other Direct Costs | (sum lns 4 to 9) | $ - |
| 11 | Total Direct Costs | (ln 2 + ln 10) | $ - |
| 12 | Corporate Overhead Allocation | (Corp OH Alloc) | |
| 13 | **Total Market Facilitation Costs** | (ln 11 + ln 12) | $ - |

| Line No. | | | **(A)** Real Time Generation **Actuals MWhs** | **(B)** Real Time Load **Actuals MWhs** | **(C)** Real Time Imports **Actuals MWhs** | **(D)** Real Time Exports **Actuals MWhs** | **Rate Schedule 1-A 4 Divisor** **(E)** Total (A) to (D) |
|---|---|---|---|---|---|---|---|
| 1 | August (YR-2) | (Notes B and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 2 | September (YR-2) | (Notes B and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 3 | October (YR-2) | (Notes B and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 4 | November (YR-2) | (Notes B and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 5 | December (YR-2) | (Notes B and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 6 | January (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 7 | February (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 8 | March (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 9 | April (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 10 | May (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 11 | June (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 12 | July (YR-1) | (Notes A and C), (Schedule 1-A3 Divisor) | - | - | - | - | - |
| 13 | **Volume of Market Billing Determinants (Note C)** | (sum lns 1 to 12, col E) | | | | | - |
| 14 | **Adjustment for Known Future Impacts to Market Determinants** | Source of data input | | | | | |
| 15 | **Market Billing Determinants - Adjusted** | (ln 13 + ln 14) | | | | | - |

Note Le

| tter | |
|---|---|
| A | YR-1 represents the year prior to budget year |
| B | YR-2 represents 2 years prior to budget year<br>i.e. For Budget Year 2021, the YR-1 would be 2020 and YR-2 would 2019. |
| C | Utlizing billing determinants as described below -<br>• Real-time Billing Meter MW Quantity (RtBilMtr5minQty) for generation and loads<br>• Real-time Import and Export MW Quantity (RtImpExp5minQty) for all import and exports |

| Line No. | Department | Note A | TOTAL | RS1 Scheduling | RS1 Planning | RS2 TCR | RS3 Clearing | RS4 Markets | OH | Salary & Benefits & Direct Employee Allocator |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Operations Analysis & Support | | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 | $ 0 | 100.00% |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (800) | | .00% | | 0% | | 0% | | 0% | | 0% | | 0% | | | | | | |
| 2 | Interregional Affairs (200) | | 100.00% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100.00% | | | | |
| 3 | Systems Operations (820) | | 81.00% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 19.00% | $ - | 0% | $ - | 100.00% | | | | |
| 4 | Engineering Operations Support (860) | | 80.00% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 20.00% | $ - | 0% | $ - | 100.00% | | | | |
| 5 | Operations Seams & AFC Support (885) | | 50.00% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 50.00% | $ - | 0% | $ - | 100.00% | | | | |
| 6 | Operations Market Support & Analysis (895) | | 0.00% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100.00% | $ - | 0% | $ - | 100.00% | | | | |
| 7 | Market Operations (840) | | 44.00% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 56.00% | $ - | 0% | $ - | 100.00% | | | | |

| | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | Engineering Planning (8000,410,430,460,480,485) | | 0% | $ - | 100% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100.00% | | |
| 16 | Congestion Hedging (450) | | 0% | $ - | 0% | $ - | 100% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100.00% | | |
| 17 | Interregional Relations (8200) | | 0% | $ - | 100% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100.00% | | |
| 18 | Market Policy (700) | | 0% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100% | $ - | 0% | $ - | 100.00% | | |
| 19 | Market Design (710) | | 0% | $ - | 0% | $ - | 0% | $ - | 0% | $ - | 100% | $ - | 0% | $ - | 100.00% | | |
| 20 | Market Monitoring Unit (720) | | 0% | $ - | 0% | $ - | 0% | $ - | 100% | $ - | 0% | $ - | 0% | $ - | 100.00% | | |
| 21 | All Remaining Departments | | 0.00% | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% | $ - | 0.00% | $ - | 100.00% | $ - | 100.00% | | |
| 22 | **Total Salary & Benefits & Direct Employee Costs** | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | $ - |

| Note Letter | | | Check Total $ - Sum 1-A2 to 1-A4 $ - | Corp OH |
|---|---|---|---|---|
| A | Amounts from the following Supporting WPs - "**Alloc – Salary, Benefits & EE**" | | | |
| | | **System & Facilities Maintenance Expense Allocators** | | |
| Li | SPP | | | |

| Line No. | Account No. | | | Amount |
|---|---|---|---|---|
| 1 | 0500-67800-4020-9350-00 | System & Facilities Maintenance Expense for Rate Schedule 1-A1-1 | (Note B) | |
| 2 | 0500-67700-4020-9350-00 | System & Facilities Maintenance Expense for Rate Schedule 1-A1-2 | (Note B) | |
| 3 | 0500-67930-4020-9350-00 | System & Facilities Maintenance Expense for Rate Schedule 1-A2 | (Note B) | |
| 4 | | System & Facilities Maintenance Expense for Rate Schedule 1-A3 | | N/A |
| 5 | 0500-67600-4020-9350-00<br>0720-67500-4020-9350-00 | System & Facilities Maintenance Expense for Rate Schedule 1-A4 | (Note B) | |
| 6 | | **TOTAL** | (sum lns 1 to 5) | $ - |
| 7 | 67000 account series | Total System & Facilities Maintenance Expense Budgeted | Supporting WPs – **"Maintenance Allocation"** | |
| 8 | | Total System & Facilities Maintenance Expense Allocated Above | (ln 6) | $ - |
| 9 | | Total System & Facilities Maintenance Expense Allocated to Corporate Overhead | (ln 7 - ln 8) | $ - |

| Note | |
|---|---|
| A | Not Used |
| B | Directly assignable budget costs as illustrated in |

the Supporting WPs - "**Maintenance Allocation**"

| Line No. | SPP Account No. | | | % | **Network and Communications Expense Amount** |
|---|---|---|---|---|---|
| 1 | 0585-66330-4010-5611-00 and 0585-66120-4010-5611-00 | Network and Communications Expense for Rate Schedule 1-A1-1 | (Note A) (ln 6 * ln 1 %) | 50% | $ - |
| 2 | | Network and Communications Expense for Rate Schedule 1-A1-2 | (ln 6 * ln 2 %) | 0% | $ - |
| 3 | | Network and Communications Expense for Rate Schedule 1-A2 | (ln 6 * ln 3 %) | 0% | $ - |
| 4 | | Network and Communications Expense for Rate Schedule 1-A3 | | | N/A |
| 5 | 0585-66330-4010-5611-00 and 0585-66120-4010-5611-00 | Network and Communications Expense for Rate Schedule 1-A4 | (Note A) (ln 6 * ln 5 %) | 50% | $ - |
| 6 | | **TOTAL** | Supporting WPs - "**Network and Comm Allocation**" | 100% | |
| 7 | Various Depts, 66000 segment | Network and Communications Expense Budgeted | Supporting WPs – **"Network & Comm Allocation"** | | |
| 8 | | Network and Communications Expense Allocated Above | (ln 6) | | $ - |

| | | | |
|---|---|---|---|
| 9 | Network and Communications Expense Allocated to Corporate Overhead | (ln 7 - ln 8) | $ - |

Note A: Sum of Accounts 0585-66330-4010-5611-00 and 0585-66120-4010-5611-00 allocated 50% each to Rate Schedules 1-A1 and 1-A4 as illustrated in the Supporting WPs - "**Network and Comm Allocation**"

| Line No. | | | **Outside Service Expense Allocator** **Amount** |
|---|---|---|---|
| 1 | Outside Service Expense for Rate Schedule 1-A1-1 | (Note A) | |
| 2 | Outside Service Expense for Rate Schedule 1-A1-2 | (Note C) | |
| 3 | Outside Service Expense for Rate Schedule 1-A1-2 | (Note D) | |
| 4 | Outside Service Expense for Rate Schedule 1-A2 | (Note E) | |
| 5 | Outside Service Expense for Rate Schedule 1-A3 | | N/A |
| 6 | Outside Service Expense for Rate Schedule 1-A4 | (Note B) | |
| 7 | **TOTAL** | (sum lns 1 to 6) | $ - |
| 8 | Outside Service Expense Budgeted | Supporting WPs – **"OS Services Allocation"** | |
| 9 | Outside Service Expense Allocated Above | (ln 7) | $ - |
| 10 | Outside Service Expense Allocated to Corporate Overhead | (ln 8 - ln 9) | $ - |

Note

| | |
|---|---|
| A | Directly assignable budget costs from IT department, 68000 account series (note that other costs in this department/account series are not uniquely assignable to this rate schedule nor other rate schedules) plus directly assignable budget costs for Operations related depts (68000 account series) plus 40% SOC 1 Expenses (Account No. 0240-68300-4010-9230-00), all detailed in Supporting WPs - "**OS Services Allocation**". |
| B | Directly assignable budget costs from Outside Services Accts (68000 series) for Market Operations related departments and other market driven departments (Design, Policy, etc) as detailed in the Supporting WPs - "**OS Services Allocation**" plus 60% SOC 1 Expenses |
| C | Directly assignable budget costs from Outside Services Accts (68000 series) for all Engineering departments (excluding Congestion Hedging and Engineering Ops Support) plus services associated with industry expert panel as illustrated in the Supporting WPs - "**OS Services Allocation**". |
| D | Approved RSC Budget as reported in the published budget document. |
| E | Directly assignable budget costs from Outside Services Accts (68000 series) for Congestion Hedging dept as illustrated in Supporting WPs - "**OS Services Allocation**". |

| Line No. | SPP Account No. | | | **Other Direct Expense Allocator** |
|---|---|---|---|---|
| | | | | **Amount** |
| 1 | | Other Direct Expense for Rate Schedule 1-A1-1 | (Note A) | |
| 2 | | Other Direct Expense for Rate Schedule 1-A1-2 | (Note A) | |
| 3 | | Other Direct Expense for Rate Schedule 1-A2 | (Note A) | |
| 4 | | Other Direct Expense for Rate Schedule 1-A3 | (Note A) | N/A |
| 5 | | Other Direct Expense for Rate Schedule 1-A4 | (Note A) | |

| | | | | |
|---|---|---|---|---|
| 6 | | **TOTAL** | (sum lns 1 to 5) | $ - |
| 7 | Various account numbers as detailed in Rate Template Supporting WPs - "**Administrative Allocation"** for insurance expense, property taxes, utilities, small equipment, bank charges, office expenses/advertising, and donations/contributions. | Administrative Services Expense | Supporting WPs - **"Administrative Allocation**" | |
| 8 | Dept 150, 65000-65099 account series | External Working Group Meeting Expense | Supporting WPs - **" Meetings Allocation**" | |
| 9 | | Non-Standard Adjustments | Supporting WPs - **" Other and Non-Standard Adjustments Allocation**" | |
| 10 | | Other Direct Expense | Supporting WPs - **" Other and Non-Standard Adjustments Allocation**" | |
| 11 | | Total Other Direct Expense Budgeted | (sum lns 7 to 10) | $ - |
| 12 | | Other Direct Expense Allocated Above | (ln 6) | $ - |
| 13 | | Other Expense Allocated to Corporate Overhead | (ln 11 - ln 12) | $ - |

Note

A Directly assignable budget costs as illustrated in the Supporting WPs - " **Other and Non-Standard Adjustments Allocation**", **“Administrative Allocation”, “Meetings Allocation”**

**Debt Service Allocator**

| Line No. | | | Amount |
|---|---|---|---|
| 1 | Debt Service for Rate Schedule 1-A1-1 | (Note A) | |
| 2 | Debt Service for Rate Schedule 1-A1-2 | (Note A) | |
| 3 | Debt Service for Rate Schedule 1-A2 | (Note A) | |
| 4 | Debt Service for Rate Schedule 1-A3 | | N/A |
| 5 | Debt Service for Rate Schedule 1-A4 | (Note A) | |
| 6 | **TOTAL** | (sum lns 1 to 5) | $ - |
| 7 | Debt Service Budgeted | Supporting WPs - "**Debt Service Allocation**" | |
| 8 | Debt Service Interest Expense Budgeted | Supporting WPs – **"Debt Service Allocation"** | |
| 9 | Debt Service Allocated Above | (ln 6) | $ - |
| 10 | Debt Service Allocated to Corporate Overhead | (ln 7 + ln 8 - ln 9) | $ - |

| Note | |
|---|---|
| A | Directly assignable budget costs and applicable interest expense as detailed in Supporting WPs - "**Debt Service Allocation**" |

| Line No. | | | **Bad Debt Allocator** **Amount** |
|---|---|---|---|
| 1 | Bad Debt for Rate Schedule 1-A1-1 | (Note A) | |
| 2 | Bad Debt for Rate Schedule 1-A1-2 | (Note A) | |
| 3 | Bad Debt for Rate Schedule 1-A2 | (Note A) | |
| 4 | Bad Debt for Rate Schedule 1-A3 | | N/A |
| 5 | Bad Debt for Rate Schedule 1-A4 | (Note A) | |
| 6 | **TOTAL** | (sum lns 1 to 5) | $ - |
| 7 | Bad Debt Budgeted | Supporting WPs - **"Bad Debt Allocation"** | |
| 8 | Bad Debt Allocated Above | (ln 6) | $ - |
| 9 | Bad Debt Allocated to Corporate Overhead | (ln 7 - ln 8) | $ - |

| Note | |
|---|---|
| A | Directly assignable budget costs as illustrated in Supporting WPs - "**Bad Debt Allocation**" |

| Line No. | | | **Corp OH Allocators** **Amount** | **%** |
|---|---|---|---|---|
| 1 | **Corporate Overhead to be Allocated (Net)** | (ln 28) | **$ -** | |
| 2 | **Direct Costs By Rate Schedule** | | | |
| 3 | Schedule 1-A1 - Cost-1 | (Schedule 1-A1 - Cost-1) | $ - | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 4 | Schedule 1-A1 - Cost-2 | (Schedule 1-A1 - Cost-2) | $ - | #DIV/0! |
| 5 | Schedule 1-A2 - Cost | (Schedule 1-A2 - Cost) | $ - | #DIV/0! |
| 6 | Schedule 1-A3 - Cost | (Schedule 1-A3 - Cost) | $ - | #DIV/0! |
| 7 | Schedule 1-A4 - Cost | (Schedule 1-A4 - Cost) | $ - | #DIV/0! |
| 8 | **TOTAL** | (sum lns 3 to 7) | $ - | #DIV/0! |
| 9 | **Corporate Overhead** | | | |
| 10 | 1-A1 - Cost - 1 | (ln 1 * ln 3%) | #DIV/0! | |
| 11 | 1-A1 - Cost - 2 | (ln 1 * ln 4%) | #DIV/0! | |
| 12 | 1-A2 - Cost | (ln 1 * ln 5%) | #DIV/0! | |
| 13 | 1-A3 - Cost | (ln 1 * ln 6%) | #DIV/0! | |
| 14 | 1-A4 - Cost | (ln 1 * ln 7%) | #DIV/0! | |
| 15 | **TOTAL** | (sum lns 10 to 14) | #DIV/0! | |
| | **Corporate Overhead Costs** | | | |
| | **Salary and Benefits & Employee Direct Expenses** | | | |
| 16 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ - | |
| 17 | **Other** | | | |
| 18 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ - | |
| 19 | Network and Communications Expense | (Network & Comm Alloc) | $ - | |
| 20 | Outside Service Expenses | (Outside Services Alloc) | $ - | |
| 21 | Other Direct Expenses | (Other Direct Alloc) | $ - | |
| 22 | Debt Service | (Debt Service Alloc) | $ - | |
| 23 | Bad Debt | (Bad Debt Alloc) | $ - | |
| 24 | **Total Other** | (sum lns 18 to 23) | $ - | |
| 25 | **Total Corporate Overhead** | (ln 16 + ln 24) | $ - | |

| | | | |
|---|---|---|---|
| 26 | **LESS: Revenues Other Than Admin Fees** | Supporting WPs - **"Revenue Allocation"** | |
| 27 | **LESS: Contract Services, Revenues Net of Expenses** | Supporting WPs - **"Contract Services"** | |
| 28 | **Corporate Overhead to be Allocated (Net)** | (ln 25 - ln 26 – ln 27) | $ - |

| Line No. | | | **Total Costs** |
|---|---|---|---|
| | **Costs Directly Assignable to Rate Schedules** | | |
| 1 | **Salary and Benefits & Employee Direct Expenses** | | |
| 2 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ - |
| 3 | **Other Direct Costs** | | |
| 4 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ - |
| 5 | Network and Communications Expense | (Network & Comm Alloc) | $ - |
| 6 | Outside Service Expenses | (Outside Services Alloc) | $ - |
| 7 | Other Direct Expenses | (Other Direct Alloc) | $ - |
| 8 | Debt Service | (Debt Service Alloc) | $ - |
| 9 | Bad Debt | (Bad Debt Alloc) | $ - |
| 10 | Total Other Direct Costs Before Revenues | (sum lns 4 to 9) | $ - |
| 11 | LESS: Revenues | (Rev Assoc w/ Engineering Studies) | $ |

| | | | |
|---|---|---|---|
| 1 | Associated with Engineering Studies | | - |
| 1 2 | **Total Other Direct Costs, Net** | (ln 10 - ln 11) | $ - |
| 1 3 | **Total Costs Directly Assignable to Rate Schedules** | (ln 2 + ln 12) | $ - |
| | **Corporate Overhead Costs** | | |
| 1 4 | **Salary and Benefits & Employee Direct Expenses** | | |
| 1 5 | **Total Salary & Benefits & Employee Direct Expenses** | (Salary Benefit EE Direct Alloc) | $ - |
| 1 6 | **Other Direct Costs** | | |
| 1 7 | System & Facilities Maintenance Expense | (Sys & Fac Maint Exp Alloc) | $ - |
| 1 8 | Network and Communications Expense | (Network & Comm Alloc) | $ - |
| 1 9 | Outside Service Expenses | (Outside Services Alloc) | $ - |
| 2 0 | Other Direct Expenses | (Other Direct Alloc) | $ - |
| 2 1 | Debt Service | (Debt Service Alloc) | $ - |
| 2 2 | Bad Debt | (Bad Debt Alloc) | $ - |
| 2 3 | **Total Other Direct Costs** | (sum lns 17 to 22) | $ - |
| 2 4 | **Corporate Overhead Before Revenues** | (ln 15 + ln 23) | $ - |
| 2 5 | **LESS: Revenues Other Than Admin Fees** | Supporting WPs - **"Revenue Allocation"** | $ - |
| 2 6 | **LESS: Contract Services, Revenues Net of Expenses** | Supporting WPs - **"Contract Services"** | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 27 | **Corporate Overhead to be Allocated (Net)** | (ln 24 - ln 25 – ln 26) | $ - | | |
| 28 | Total Directly Assignable Costs and Corp Overhead | (ln 13 + ln 27) | $ - | | |
| 29 | Total Schedule 1-A1 - Costs | (Schedule 1-A1 - Rate) | $ - | | |
| 30 | Total Schedule 1-A2 - Costs | (Schedule 1-A2 - Rate) | $ - | | |
| 31 | Total Schedule 1-A3 - Costs | (Schedule 1-A3 - Rate) | $ - | | |
| 32 | Total Schedule 1-A4 - Costs | (Schedule 1-A4 - Rate) | $ - | | |
| 33 | Total of Schedules 1-A1 to 1-A4 Costs | (sum lns 29 to 32) | $ - | $ - | Check |
| 34 | **Total Prior Year Over/(Under) Recovery – All Schedules** | **(Schedule 1-A1 – Rate) + (Schedule 1-A2 – Rate) + (Schedule 1-A3 – Rate) + (Schedule 1-A4 – Rate)** | $ - | | |
| 35 | CAP Check Projected Year Budget to be Recovered through Schedule 1-A | (ln 33 – ln 34) | $ - | | |
| 36 | Projected Year Divisor (MWh) | (Schedule 1-A1 – Rate – ln 12) | - | | |
| 37 | Projected Year Rate/MWh | (ln 35 / ln 36) | #DIV/0! | | |

# ANNUAL FORMULA RATE IMPLEMENTATION PROTOCOLS

## Section 1 Applicability

The formula rate template and these Annual Formula Rate Implementation Protocols (collectively, the "Formula Rate") comprise the Transmission Provider's filed Schedule 1-A Tariff Administration Services rates. The Transmission Provider shall follow the Formula Rate to calculate annually its Transmission Administration Service Rate ("Schedule 1-A1 Rate"), Transmission Congestion Rights Administration Service Rate ("Schedule 1-A2 Rate"), Integrated Marketplace Clearing Administration Service Rate ("Schedule 1-A3 Rate"), and Integrated Marketplace Facilitation Administration Service Rate ("Schedule 1-A4 Rate"); (collectively "Rates"). The Formula Rate and the charges produced thereunder shall be effective on and after January 1, 2021. Thereafter, the Formula Rate shall be applicable on and after January 1 of each calendar year for service from January 1 – December 31 of each calendar year (the "Rate Year"), subject to the true-up procedures of this Addendum 1.

## Section 2 Annual Updates

a. Within ten (10) business days after the Transmission Provider's annual budget is approved by the Transmission Provider's Board of Directors, the Transmission Provider, shall determine and post, its annual update to be effective during the next Rate Year, and shall consist of the following ("Annual Update"):

(i) a data-populated version of the Formula Rate template setting forth the projected Rates for the next Rate Year ("Projected Rates") including any applicable True-up Adjustment, as defined in Section 3, produced by operation of the Formula Rate;

(ii) supporting documentation, including, but not limited to, fully functioning Excel files (or such other native format files), required to support,

demonstrate and explain information upon which the Annual Update is based;

(iii) disclosure of the following changes to the extent any has taken effect since January 1, 2021, and materially affects the Formula Rate or calculation of the Annual Update or the allocation of costs or revenues to the Transmission Provider's Rates:

(a) any Federal Energy Regulatory Commission ("FERC" or "Commission") ratemaking orders applicable to the Transmission Provider's Formula Rate; and

(b) the accounting practices or procedures of the Transmission Provider.

Changes in items (a) and (b) collectively referred to as "***Material Changes***".

b. The Transmission Provider shall post the Annual Update on the Transmission Provider's website and notify interested parties via the Transmission Provider's email exploder titled "Formula Rate Posting Information Notification". The posting shall include fully functioning Excel file (or such other native format file) of all materials contained in the Annual Update.

c. The Annual Update for the new Rate Year shall:

(i) be based upon the Transmission Provider's most recent budget and other information for the new Rate Year, that reasonably projects costs to be recorded on the books and records of the Transmission Provider's consistent with, the Transmission Provider's practices or procedures, and the Transmission Provider's Tariff; and

(ii) compute the Projected Rates.

d. In the posting of the Annual Update, the Transmission Provider shall request written comments be provided for the period of two (2) weeks after the posting of the Annual Update.

e. The Transmission Provider shall file the revised Annual Update with the Commission in its submission of the annual operating budget informational filing.

**Section 3 True-up Adjustment**

Assuming an effective date of January 1, 2021, the true up process for the 2021 Rate Year will occur over the next two (2) Rate Years. During the 2022 budget process, the Transmission Provider will calculate the estimated over/under recovery for the 2021 Rate Year using forecasted data, consisting of actual data available for 2021 and forecasted data for the remainder of 2021. Comparing the forecasted data available for both tariff administrative fee revenue and net revenue requirement to the respective budgeted amounts, the Transmission Provider will arrive at a projected over/under recovery for 2021 to be included as a true-up adjustment in the 2022 Rate Year. During the determination for the 2023 Rate Year, the Transmission Provider will calculate the final over/under recovery for the 2021 Rate Year using actual results for the tariff administrative fee revenue and net revenue requirement in comparison to the 2021 approved budget. The final over/under recovery for the 2021 Rate Year will then be compared against the estimated true-up calculation included in the 2022 Rate Year, and the difference will be included as a true-up adjustment in the 2023 Rate Year. This process will continue in following Rate Years.

**Section 4 Changes to Formula Rate Initiated by the Transmission Provider**

Any changes to the Formula Rate initiated by the Transmission Provider, including any changes necessitated by Material Changes, may only be implemented as a result of a filing with FERC.

**Section 5 Changes to the Stated Inputs in the Formula Rate**

The following Formula Rate inputs shall be stated values to be used in the Formula Rate (both for the Annual Update and True-up Adjustment) until changed by a filing with FERC:

(a) the allocation percentages reflected in the Formula Rate to determine salary, benefits and direct employee cost; and

(b) the allocation percentages reflected in the Formula Rate to determine network and communication expenses.

# SCHEDULE 2
# REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE

## I. GENERAL

**1. Definitions (These definitions are to be used in this Schedule 2 only; to the extent of a conflict between these definitions and other definitions in the Tariff, these definitions control in the interpretation of this Schedule 2; other capitalized terms are defined elsewhere in this Tariff)**

**1.1 Dead Band (DB):** A contiguous range of Power Factor operation where an hourly PF is greater than or equal to 0.95 (lead or lag).

**1.2 Point of Interconnection (POI):** The location where the generator connects to the Transmission System.

**1.3. Power Factor (PF):** The power factor of a QG as measured or determined by the integrated hourly MW and MVAr values at its POI.

**1.4 Qualified Generator (QG):** A generator, or a single generator that is part of a group of generators at a single Point of Receipt, that has been recognized by the Transmission Provider as meeting the criteria specified in Section II to receive compensation under this Schedule 2.

**1.5 Reactive Compensation (RC):** The monthly amount as calculated in Section III.B.

**1.6 Reactive Compensation Rate (RCR):** The amount per MVArh specified in Section III.A.

**1.7 Reactive Power Inside Deadband (RPID):** As defined in Section III.B.2.

**1.8 Reactive Power Outside Deadband (RPOD):** As calculated in Section III.B.2.

**1.9 Through and Out Reactive Revenue (T&O Reactive Revenue):** The amount of reactive power revenue allocated to a Zone each month that was collected by the Transmission Provider from Through and Out transactions.

**1.10 Zonal Reactive Compensation (ZRC):** The monthly sum of the RC for all QGs in the pricing zone.

**1.11 Zonal Peak Demand:** The Zone's monthly transmission peak.

**1.12 Zone:** SPP pricing zone as defined in the SPP OATT.

**2. Purpose**

In order to maintain Transmission System voltages within acceptable limits, generation facilities and non-generation resources capable of providing this service that are connected to the Transmission System are operated to produce (or absorb) reactive power. Reactive Supply and Voltage Control from Generation or Other Sources Service (Reactive Supply) must be provided to support each transaction on the Transmission System. The amount of Reactive Supply required in real time to maintain Transmission System voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider will vary with conditions on the Transmission System. Generators operating within a range of 0.95 leading to 0.95 lagging PF will not receive compensation for supplying such reactive power. Generators meeting the requirements of this Schedule 2 will be compensated for producing reactive power outside the DB when such operation is at the direction of the Transmission Provider or the applicable transmission operator. This Schedule 2 provides the criteria specifying which generators qualify to receive compensation for reactive power and sets out the rates and charges necessary to comparably compensate all QGs for such operation.

## II. QUALIFIED GENERATOR REQUIREMENTS

**A. General:** All existing generation owners eligible to collect charges for Reactive Supply for generators connected to the Transmission System under a cost-based rate schedule on file with the Commission as of October 1, 2006, as well as non-jurisdictional generation owners operating generating facilities that are being compensated for the provision of reactive supply and voltage control services to SPP as of October 1, 2006, are deemed to have met the technical requirements of Section II.B and therefore are QGs. Initially, in order to receive compensation under this Schedule 2, all other owners of generation must apply to the Transmission Provider for QG status and provide the necessary operating data set

forth in Addendum 1 to this Schedule 2 to the Transmission Provider no later than 30 days following the final approval of this Schedule 2 by the Commission. Subsequently, owners of other generation must apply to the Transmission Provider for QG status and provide the necessary operating data to the Transmission Provider. The Transmission Provider shall recognize new QGs throughout the year if the generator meets the requirements set out in Section II.B. A new QG will be eligible for compensation at the beginning of the first month after SPP acceptance of the generation owner's application. To the extent the operating data requested in Addendum 1 has been previously provided to SPP pursuant to a generation interconnection agreement or through input for SPP transmission operational or planning models, that operating data shall not be required with the application. Once the QG provides the necessary operating data to SPP, it shall be eligible to receive compensation under this Schedule 2 as provided in Section III. The QG's RC will be included under this Schedule 2 in the first full billing month after the required information is received. The Transmission Provider shall have the right to remove the QG status of any generation resource that fails to meet any requirements of Section II.B.

**B. Technical:**

1. Each QG shall designate the entity that is to receive reactive dispatch instructions and the entity to receive compensation.
2. The generation resource must be able to produce reactive power outside the Dead Band at its Point of Interconnection with the Transmission System.
3. Each QG shall maintain the capability to provide MWh, MVArh and voltage data, by such means of transmittal, at such intervals and at such accuracy level as SPP shall require.
4. The generation resource must be able to follow a voltage schedule and respond to reactive dispatch instructions from the Transmission Provider and/or the applicable transmission operator.

## III. RATES, CHARGES, AND REVENUE DISTRIBUTION

The following sets forth the rates, charges and revenue distribution pursuant to this Schedule 2. All QGs shall be treated the same.

**A. Reactive Compensation Rate**

The RCR shall be based on the cost of reactive power production from recently constructed generators so as to reflect the upper end of such costs. The RCR shall be $2.26 per MVArh. The Transmission Provider may periodically review the RCR to determine whether it remains at or near the upper end of a reasonable range of cost of producing reactive power by generators recently connected to the Transmission System.

**B. Qualified Generator Compensation**

The compensation paid to QGs each month will be based on the calculations as set forth below.

1. Determine the integrated hourly values for real and reactive power generated by each Qualifying Generator for each month.
2. Calculate the Reactive Power Outside the Dead Band (RPOD). For each hour of each month, calculate the amount of Reactive Power inside the Dead Band (in MVArh) that the QG would have had to produce or absorb to maintain a PF of 0.95 at its actual real power output level (RPID). Then subtract the absolute value of the RPID from the absolute value of the actual reactive power output from the QG for that hour (in MVArh). If the absolute value of RPID is greater than the absolute value of the actual reactive power output of the QG, then the RPOD for that hour is zero. The monthly RPOD is the sum of the hourly RPOD calculations for each QG for each month.
3. Calculate the total compensation that the owner of each QG will receive for each month (RC) by multiplying the QG's monthly RPOD, times the RCR.

   RCmonthly = RCR * RPOD monthly

**C. Calculation of Rates**

The rates paid by Transmission Customers will be based on the calculations set forth below. All of the amounts calculated below shall be actuals for each month with no true-ups.

1. Calculate the amount of T&O Reactive Revenue allocated to each Zone by taking the total amount of revenue generated by this Schedule 2 from Through and Out transactions for each month and allocate it on a pro-rata share based on the ZRC for the same month.

2. Calculate the total amount of revenue to be collected for each month by Zone, by summing the RC for each QG by Zone less the T&O Reactive Revenue.

   ZRC = Σn=1 to x(RC)– T&O Reactive Revenue; where: x=Total number of QGs in the Zone

3. Calculate the Schedule 2 Rates, for each Zone, as shown below.
   a. Monthly Rate ($/MW/Mo) = ZRC / Zonal Peak Demand
   b. Weekly Rate ($/MW/Wk) = Monthly Rate times 12 / 52
   c. Daily Off-Peak Rate ($/MW/Day) = Weekly Rate / 7
   d. Daily On-Peak Rate ($/MW/Day) = Weekly Rate / 5
   e. Hourly Off-Peak Rate ($/MW/Hr) = Daily Off-Peak Rate / 24
   f. Hourly On-Peak Rate ($/MW/Hr) = Daily On-Peak Rate / 16

   The total charge in any day, pursuant to an hourly service reservation, shall not exceed the applicable rate for daily service specified above for the applicable Zone, times the highest amount of hourly service reserved in any hour during such day. In addition, the total charge in any week pursuant to a reservation for hourly or daily service shall not exceed the rate for weekly service specified above for the applicable Zone, times the highest amount of hourly or daily service reserved in any hour or day during such week.

   **On-Peak and Off Peak**

   Off-Peak days shall be Saturdays and Sundays and all NERC holidays. All other days shall be On-Peak. All hours during Off-Peak days shall be

Off-Peak. On-Peak hours during On-Peak days shall be all hours from HE 0700 through HE 2200 Central Prevailing Time. All other hours during On-Peak days shall be Off-Peak.

4. For the purposes of determining the charge applicable to transactions under this Tariff, the transaction will be charged based on the applicable zonal rate where the load is physically located.

5. If the service is a Through and Out transaction, the transaction will be charged based on the simple average of all zonal rates for the applicable period of service.

6. The data used in the calculations under this Section III. C. shall be from the same month as the monthly RPOD used to calculate the RC in Section III. B.

**D. Collection of Charges and Distribution of Revenues**

1. All load shall pay the Transmission Provider a charge for Reactive Supply determined by multiplying the applicable rate as calculated in Section III.C by the Reserved Capacity for the Transmission Customer taking Point-To-Point Transmission Service during that month or the Network Customer's and non-rate terms and conditions customer's coincident peak during the month. The billing units used herein will be for the same month as the month used to determine the RPOD. After it has sufficient data to calculate the monthly RPOD, SPP shall bill customers for monthly charges under this Schedule 2 in the next billing cycle. SPP also will post the applicable monthly Schedule 2 charges promptly after it possesses the data necessary to calculate such charges.

2. In the event that the monthly revenue collected for a Zone does not match the ZRC in a month, the revenues distributed that month to each QG in the affected Zone shall be based upon its RC for that month divided by the applicable ZRC for that month multiplied by total zonal revenues collected pursuant to this Schedule 2 for that month.

**E. Joint Owned Units**

The Transmission Provider will compensate the entity designated in II.B.1 for a jointly owned QG. The Transmission Provider is not responsible for disbursing revenue to other owners.

**F. Multiple Generators Behind a Common Meter**

If more than one generator exists behind a single meter, the Transmission Provider must individually certify all the generators behind the meter as QGs. Compensation will be handled in the same way as an owner with multiple units in the same Zone.

## IV. QUALIFIED GENERATOR STATUS

**A. Re-Evaluation of Qualified Generator Status**

1. If a QG fails to comply with the Transmission Provider's or transmission operator's voltage control requirements three or more times in a calendar month, or six or more times in the preceding twelve month period, for reasons other than planned or unscheduled outages, the transmission operator shall notify the Transmission Provider and the Transmission Provider shall determine whether the generation resource should continue to be a QG based on the criteria established in Section II.B of this Schedule 2.
2. In making a determination of whether a generation resource should continue to be a QG, the Transmission Provider will evaluate, among other factors, whether the generation resource was operated consistently with its design characteristics, if the QG responded in accordance with other agreements and whether system conditions prevented it from responding as required by the applicable transmission operator or Transmission Provider.
3. If the Transmission Provider determines that the generator should not continue to be a QG, the Transmission Provider shall notify the owner and stop providing reactive compensation to such generator owner.

**B. Regaining Qualified Generator Status:**

If a generator has had its status as a QG removed by the Transmission Provider, such generator may be reinstated to receive reactive compensation six (6) billing months after disqualification. If the owner of the generator desires to be reinstated, it must make application for such reinstatement to the Transmission Provider and demonstrate that the cause(s) for the disqualification has been remedied. The Transmission Provider shall waive the six month period and immediately reinstate the QG status if it determines that such status was erroneously removed.

## V. QUALIFIED GENERATOR DISPATCH CRITERIA

All QGs will be required to maintain reactive supply pursuant to a voltage schedule provided by the Transmission Provider or the applicable transmission operator. The Transmission Provider and the transmission operator shall issue voltage schedules to all QGs on a non-discriminatory basis. Voltage schedules issued by the transmission operator shall be made available to SPP in accordance with SPP Criteria.

In the event of a system contingency or emergency situation that requires specific attention to reactive production, the Transmission Provider or the applicable transmission operator will determine, based on real-time data and engineering studies of current and prospective conditions, the most effective solution to maintain transmission system reliability. For a circumstance that requires specific attention to reactive production, the Transmission Provider or the applicable transmission operator will perform an engineering study to determine the most effective operational plan. The Transmission Provider or the applicable transmission operator will issue reactive dispatch instructions or revised voltage schedules on a non-discriminatory basis based upon generator availability, location, and reactive capability, for such purpose. Reactive dispatch instructions or revised voltage schedules issued by the transmission operator shall be made available to SPP in accordance with SPP Criteria.

## ADDENDUM 1 TO SCHEDULE 2

### Operating Data to be Provided by Generator Operators Seeking QG Status

The following is the list of necessary operating data to be provided as part of an application to become a QG.

1. Nameplate data, certified factory test reports, and reactive capability curves for the generator.

2. Real and reactive power loads at maximum generator output for station service load served from the generator leads before delivery into the transmission system.

3. Nameplate data and copies of certified factory test reports for the generator step-up transformer. For transformers having tapped windings, identify the tap connections at which the transformer is operated.

4. One line schematics showing the connection of the generator to the SPP Transmission System, location of service to station service loads, and the location of metering and telemetry points.

5. Identification of the interconnection agreement governing the connection of the generator to the transmission system and citation to those provisions in the agreement that govern the production of reactive power and voltage regulation.

6. Self assessment (or certification) by generator owner of the ability of the generator to provide deliveries of real and reactive power to the SPP Transmission System, net of all loads served prior to the connection with the SPP Transmission System, with a power factor outside the +/- 95% deadband, to receive and follow reactive power dispatch instructions, and to regulate the voltage at a the point of interconnection with transmission system pursuant to a voltage schedule.

7. A copy of the most recent tests of the generator, the generator's protection system, the generator's control system and the generator's excitation system as performed in accord with the SPP Criteria.

# SCHEDULE 3
# REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will provide this service and the Transmission Customer will pay the Transmission Provider for this service through the operation and settlement of the Energy and Operating Reserve Markets as described in Attachment AE. The Transmission Provider will take into account the speed and accuracy of regulation Resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

## SCHEDULE 4
## ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between Energy cleared in the Day-Ahead Market and the actual delivery of Energy to/from the Transmission System over a single Dispatch Interval. The Market Participant must purchase this service from the Transmission Provider or make comparable alternate arrangements with another Market Participant who will purchase this service from the Transmission Provider. All loads on the Transmission System will be subject to settlement in the Real-Time Balancing Market. The Transmission Provider will obtain and provide this service and the Market Participant shall utilize this service in accordance with Attachment AE. Charges and payments for use and provision of this service shall be calculated by the Transmission Provider pursuant to Attachment AE.

# SCHEDULE 5
# OPERATING RESERVE - SPINNING RESERVE SERVICE

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will provide the service and the Transmission Customer will pay for this service through the operation and settlement of the Energy and Operating Reserve Markets as described in Attachment AE.

# SCHEDULE 6
# OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will provide this service and the Transmission Customer will pay for this service through the operation and settlement of the Energy and Operating Reserve Markets as described in Attachment AE.

# SCHEDULE 7
# LONG-TERM FIRM AND SHORT-TERM FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below in addition to other applicable charges specified in the Tariff. All effective rates under this schedule shall be posted on the SPP OASIS.

**1. Zonal Rates:** The Transmission Customer shall pay the zonal rate (per kW of reserved capacity) based upon the Zone where the load is located for Firm Point-To-Point Transmission Service where the generation source is outside the SPP Region and the load is located within the SPP Region and for Firm Point-To-Point Transmission Service where both the generation source and the load are located within the SPP Region. For Firm Point-To-Point Transmission Service where the generation source is located within the SPP Region and the load is located outside of the SPP Region, and for Firm Point-To-Point Transmission Service where both the generation source and the load are located outside of the SPP Region, the Transmission Customer shall pay the zonal rate (per kW of reserved capacity) for the Zone interconnected with the Balancing Authority Area, external to the SPP Region, that is the designated Point of Delivery. Where there is more than one Zone interconnected with such Balancing Authority Area, the lowest zonal rate of the interconnected Zones is applicable. The zonal rates are stated in Attachment T.

The Zones are as follows:

Zone 1: American Electric Power – West

Zone 2: Kansas City Board of Public Utilities

Zone 3: City Utilities of Springfield, Missouri

Zone 4: Empire District Electric Company

Zone 5: Grand River Dam Authority

Zone 6: Evergy Metro, Inc.

Zone 7: Oklahoma Gas & Electric Company

Zone 8: Midwest Energy, Inc.

Zone 9: Evergy Missouri West, Inc.

Zone 10: Southwestern Power Administration

Zone 11: Southwestern Public Service

Zone 12: Sunflower Electric Power Corporation

Zone 13: Western Farmers Electric Cooperative

Zone 14: Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc.)

Zone 15: Reserved for Future Use

Zone 16: Lincoln Electric System

Zone 17: Nebraska Public Power District

Zone 18: Omaha Public Power District

Zone 19: Upper Missouri Zone

No changes in Zones shall be made without submitting a filing to the Commission.

**2. Caps:** The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the weekly rate times the highest amount in kilowatts of Reserved Capacity in any day during such week.

**3. Real Power Losses:** The Transmission Customer shall be responsible for real power losses determined in accordance with Attachment M.

**4. a. Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule and Tariff. The annual costs of the facility shall be calculated by multiplying the levelized fixed charge rate of the Transmission Owner by the nondepreciated cost of the facility. Each month the Transmission Customer shall pay a charge based on such annual costs divided by twelve. Any such charge will be filed with the Commission.

**b. Directly Assigned Upgrade Costs:** Where a Facilities Study indicates the need to construct Network Upgrades to accommodate a request for Transmission Service, the Transmission Customer may be allocated Directly Assigned Upgrade Costs in accordance with Attachments J and Z1. Any such charge will be filed with the Commission. The Transmission Customer shall be charged the higher of (i) the charges specified in Schedules 7 and 11 or (ii) the Directly Assigned Upgrade Costs. The Transmission Customer shall also be charged any other applicable charges under the Tariff. If the Transmission Customer is charged the Directly

Assigned Upgrade Costs, upon completion of construction of such assigned upgrades, the Transmission Provider shall reconcile the Directly Assigned Upgrade Costs against the actual construction costs. Based on the reconciliation, the Transmission Customer's cost responsibility shall be adjusted as appropriate.

**5. Wholesale Distribution Service:** Where Wholesale Distribution Service is provided to effectuate Firm Point-To-Point Transmission Service, the Transmission Customer shall pay all charges levied pursuant to the Wholesale Distribution Service Agreement and Schedule 10.

**6. Base Plan Zonal Charges and Region-wide Charges:** The Transmission Customer shall pay all charges assessed pursuant to Schedule 11 to the extent the revenue from such charges is not recovered by the Transmission Provider from the Transmission Customer pursuant to Section 5.b of this Schedule.

**7. Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

# SCHEDULE 8
# NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below in addition to other applicable charges specified in the Tariff. All effective rates under this schedule shall be posted on the SPP OASIS.

**1. Zonal Rates:** The Transmission Customer shall pay the zonal rate (per KW of reserved capacity) based upon the Zone where the load is located for Non-Firm Point-To-Point Transmission Service where the generation source is outside the SPP Region and the load is located within the SPP Region and for Non-Firm Point-To-Point Transmission Service where both the generation source and the load are located within the SPP Region. For Non-Firm Point-To-Point Transmission Service where the generation source is located within the SPP Region and the load is located outside of the SPP Region, and for Non-Firm Point-To-Point Transmission Service where both the generation source and the load are located outside of the SPP Region, the Transmission Customer shall pay the zonal rate (per KW of reserved capacity) for the Zone interconnected with the Balancing Authority Area, external to the SPP Region, that is the designated Point of Delivery. Where there is more than one Zone interconnected with such Balancing Authority Area, the lowest zonal rate of the interconnected Zones is applicable. The zonal rates are stated in Attachment T.

The Zones are as follows:

Zone 1: American Electric Power – West
Zone 2: Kansas City Board of Public Utilities
Zone 3: City Utilities of Springfield, Missouri
Zone 4: Empire District Electric Company
Zone 5: Grand River Dam Authority
Zone 6: Evergy Metro, Inc.
Zone 7: Oklahoma Gas & Electric Company
Zone 8: Midwest Energy, Inc.
Zone 9: Evergy Missouri West, Inc.
Zone 10: Southwestern Power Administration
Zone 11: Southwestern Public Service

Zone 12: Sunflower Electric Power Corporation

Zone 13: Western Farmers Electric Cooperative

Zone 14: Evergy Kansas Central, Inc. (Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.)

Zone 15: Reserved for Future Use

Zone 16: Lincoln Electric System

Zone 17: Nebraska Public Power District

Zone 18: Omaha Public Power District

Zone 19: Upper Missouri Zone

No changes in Zones shall be made without submitting a filing to the Commission.

**2. Caps:** The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the weekly rate times the highest amount in kilowatts of Reserved Capacity in any day during such week. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the daily rate times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the weekly rate above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

**3. Redispatch Costs:** The redispatch costs shall be calculated in accordance with the formula and protocols shown on Attachment K.

**4. Discounts:** The Transmission Provider may offer discounts under this Schedule. Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the Transmission System. In offering discounts, the Transmission Provider's goal shall be to maximize transmission revenues.

**4(a) Next-Hour-Market Service:** The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed the applicable charges posted on OASIS. In the event that transmission service is curtailed or interrupted by the Transmission Provider, either acting directly or indirectly at the request of another transmission provider or a Security Coordinator, the Transmission Customer shall be charged only for that portion of the hour of actual transmission service used. The pro-rata portion must be agreed upon between the Transmission Provider and the Transmission Customer.

**5. Real Power Losses:** The Transmission Customer shall be responsible for real power losses determined in accordance with Attachment M.

**6. Wholesale Distribution Service:** Where Wholesale Distribution Service is provided to effectuate Non-Firm Point-To-Point Transmission Service, the Transmission Customer shall pay all charges levied pursuant to the Wholesale Distribution Service Agreement and Schedule 10.

**7. Base Plan Zonal Charges and Region-wide Charges:** The Transmission Customer shall pay all charges assessed pursuant to Schedule 11.

**8. Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

# SCHEDULE 9
# NETWORK INTEGRATION TRANSMISSION SERVICE

The Transmission Customer shall compensate the Transmission Provider for Network Integration Transmission Service at the applicable charges set forth below in addition to other applicable charges specified in the Tariff.

**1. Zonal Rates:** The Transmission Customer taking Network Integration Transmission Service shall pay a monthly demand charge for the Zone where the load is located. Each month, the Transmission Customer shall pay the Transmission Provider the applicable monthly zonal Demand Charge, determined in accordance with Section 34.1. If a Transmission Customer has load in multiple Zones, the Transmission Customer shall pay the monthly demand charge for each Zone in which its load is located. For load not physically interconnected with the Transmission System designated as Network Load pursuant to Section 31.3, the Network Customer shall pay the zonal Demand Charge for the Zone interconnected with the Balancing Authority Area, external to the SPP Region, that is the designated Point of Delivery. For Network Customers in Zones 1 through 18 designating load external to the SPP Region, where there is more than one Zone interconnected with such Balancing Authority Area, the lowest zonal Demand Charge of the interconnected Zones is applicable. For Network Customers in Zone 19 designating load external to the SPP Region, where there is more than one Zone interconnected with such Balancing Authority Area, the zonal Demand Charge of Zone 19 is applicable. For Network Customers in Zone 10 that receive deliveries of Federal Power-Southwestern from the Southwestern Power Administration, the Network Customer shall have its Demand Charge under this Schedule 9 reduced in accordance with the provisions of Section 34.9 of this Tariff. A Transmission Customer that is serving load on the Xcel Energy Operating Companies' transmission system taking Network Integration Transmission Service under the Xcel Energy Operating Companies' OATT and also takes transmission service under Part III of this Tariff to export over the Lamar Tie Line resources from the SPS Zone to serve load on the Public Service Company of Colorado (PSCo) transmission system shall have its zonal rate charges under this Schedule 9 reduced by 100%. A Transmission Customer that is serving load on the Xcel Energy Operating Companies' transmission system taking Network Integration Transmission Service under the Xcel Energy Operating Companies' OATT and also takes transmission service under Part III of this Tariff to import over the Lamar Tie Line resources to

serve its load in the SPS Zone shall be subject to the applicable charges under this Schedule 9, without reduction. The Zonal Annual Transmission Revenue Requirement of each Zone is stated in Attachment H. Notwithstanding anything to the contrary in this Tariff, a Transmission Owner taking Network Integration Transmission Service may elect not to pay (in whole or in part) the monthly demand charges specified in the preceding paragraph to the extent that the Transmission Owner would have received under Attachment L (revenue distribution) the amounts it seeks to not pay under this provision. A Transmission Owner electing this option shall remain obligated to pay any applicable charges for transmission services using any other Transmission Owner's facilities unless the transmission is provided pursuant to a Grandfathered Agreement (in which case compensation provisions under the Grandfathered Agreement control). A Transmission Owner electing this option shall remain responsible for any credits pursuant to Section 30.9 and for all other applicable charges under this Tariff. This election will only be effective through January 31, 2010.

The Zones are as follows:

Zone 1: American Electric Power - West

Zone 2: Kansas City Board of Public Utilities

Zone 3: City Utilities of Springfield, Missouri

Zone 4: Empire District Electric Company

Zone 5: Grand River Dam Authority

Zone 6: Evergy Metro, Inc.

Zone 7: Oklahoma Gas & Electric Company

Zone 8: Midwest Energy, Inc.

Zone 9: Evergy Missouri West, Inc.

Zone 10: Southwestern Power Administration

Zone 11: Southwestern Public Service

Zone 12: Sunflower Electric Power Corporation

Zone 13: Western Farmers Electric Cooperative

Zone 14: Evergy Kansas Central, Inc. (Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.)

Zone 15: Reserved for Future Use

Zone 16: Lincoln Electric System

Zone 17: Nebraska Public Power District

Zone 18: Omaha Public Power District

Zone 19: Upper Missouri Zone

No changes in Zones shall be made without submitting a filing to the Commission.

**2. Redispatch Costs:** The redispatch costs shall be calculated in accordance with the formula and protocols shown on Attachment K.

**3. Real Power Losses:** The Transmission Customer shall be responsible for real power losses determined in accordance with Attachment M.

**4. a.) Direct Assignment Costs:** Where a Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities in addition to the charges specified in this Schedule and Tariff. The annual costs of the facility shall be calculated by multiplying the levelized fixed charge rate of the Transmission Owner by the nondepreciated cost of the facility. Each month the Transmission Customer shall pay a charge based on such annual costs divided by twelve. Any such charge will be filed with the Commission.

**b.) Directly Assigned Upgrade Costs:** Where a Facilities Study indicates the need to construct Network Upgrades to accommodate a request for Transmission Service, the Transmission Customer may be allocated Directly Assigned Upgrade Costs in accordance with Attachments J and Z1. Any such charge will be filed with the Commission. The Transmission Customer shall be charged the Directly Assigned Upgrade Costs in addition to the charges specified in this Schedule and any other applicable charges under this Tariff. If the Transmission Customer is charged the Directly Assigned Upgrade Costs, upon completion of construction of such assigned upgrades, the Transmission Provider shall reconcile the Directly Assigned Upgrade Costs against the actual construction costs. Based on the reconciliation, the Transmission Customer's cost responsibility shall be adjusted as appropriate.

**5. Wholesale Distribution Service:** Where Wholesale Distribution Service is provided to effectuate Network Integration Transmission Service, the Network Customer shall pay all charges levied pursuant to the Wholesale Distribution Service Agreement and Schedule 10.

**6. Base Plan Zonal Charges and Region-wide Charges:** The Transmission Customer shall pay all charges assessed pursuant to Schedule 11.

# SCHEDULE 10
# WHOLESALE DISTRIBUTION SERVICE

Wholesale Distribution Service will be provided by the individual Transmission Owners as necessary to provide Point-To-Point Transmission Service or Network Integration Transmission Service under this Tariff. The transaction-specific information, including all customer-specific rates and charges, will be set forth in the Service Agreement between the Transmission Provider and the Transmission Customer for the associated service being provided pursuant to the Tariff. All rates and charges for Wholesale Distribution Service shall be on file with the appropriate agency as required by law or regulation. To the extent that a Service Agreement containing provisions for Wholesale Distribution Service is required to be filed with the Commission, the Transmission Provider, in consultation with the appropriate Transmission Owner, shall provide along with the filing, adequate cost support to justify the customer-specific rates and charges being assessed under this Schedule 10.

Wholesale Distribution Service will be provided subject to the same scheduling deadlines and procedures for alternative dispute resolution as apply to the associated service. Unless otherwise specified, the provision of Wholesale Distribution Service will commence on the same day as service for the associated transaction, and shall terminate on the same day as service for the associated transaction.

# SCHEDULE 11
# BASE PLAN ZONAL CHARGE AND REGION-WIDE CHARGE

## I. Introduction

Except as provided herein, pursuant to Part V of this Tariff, Base Plan Zonal Charges and Region-wide Charges shall be assessed to Network Customers and, where applicable, Transmission Owners based on Resident Load. Likewise, Base Plan Zonal Charges and the Region-wide Charge shall be assessed to each Transmission Customer taking Point-To-Point Transmission Service under the Tariff based on Reserved Capacity. These charges will be applied only to service taken in whole or in part within the Eastern Interconnection. Western-UGP shall be exempt from the Region-wide Charge under this Schedule 11 in accordance with Section 39.3(e) of this Tariff. For the purpose of determining the Region-wide Load Ratio Shares for application of Schedule 11, transmission of Federal Power-Western-UGP to the Statutory Load Obligations served by Western-UGP shall be excluded from the Transmission Provider's monthly Zone transmission load for Zone 19 used as a component of the divisor for all Zones and from the numerator used for Zone 19. The charges stated in Schedule 11 shall not be changed absent a filing with the Commission.

## II. Base Plan Zonal Charges and Region-wide Charge to Resident Load

### A. Calculation of Annual Transmission Revenue Requirement

In calculating the Base Plan Zonal Annual Transmission Revenue Requirements and Region-wide Annual Transmission Revenue Requirement, the Transmission Provider shall sum the applicable, Commission-approved annual transmission revenue requirements for upgrades eligible for cost recovery under this Schedule 11, as allocated in accordance with Attachment J of this Tariff. Subject to the limitations in subsections 1 and 2 below, such annual transmission revenue requirements shall be reduced by the previous calendar year’s amount of (i) point-to-point revenue received by each Transmission Owner resulting from charges under Section III of this Schedule 11 and (ii) revenue distributed to each Transmission Owner under Section IV of Attachment AU and allocated in proportion to Point-To-Point Transmission Service Schedule 11 revenue under Section V of Attachment AU. Any such adjustment for the previous calendar year point-to-point revenue shall be set forth in the RRR File.

**1.** For each Transmission Owner utilizing a formula rate, the Transmission Provider shall not make an adjustment of the Transmission Owner's annual transmission revenue requirements under this Section II.A if point-to-point revenue resulting from charges under Section III of this Schedule 11 and revenue distributed and allocated under Attachment AU is credited and updated on an annual basis in the Transmission Owner's formula rate in a manner that reduces the annual transmission revenue requirements for upgrades eligible for cost recovery under this Schedule 11.

**2.** For each Transmission Owner utilizing a stated rate or utilizing a formula rate without annual update of the Schedule 11 revenue credits, the revenue adjustment described in this Section II.A shall be only the difference, whether positive or negative, between the previous calendar year Point-To-Point Transmission Service Schedule 11 revenue and the amount of point-to-point revenue and revenue distributed and allocated under Attachment AU, if any, already credited in the calculation of the Transmission Owner's annual transmission revenue requirements included in the Base Plan Zonal Annual Transmission Revenue Requirements and Region-wide Annual Transmission Revenue Requirement. The amount of revenue resulting from charges under Section III of this Schedule 11 and revenue distributed and allocated under Attachment AU that is already credited in the calculation of the Transmission Owner's annual transmission revenue requirements included in the Base Plan Zonal Annual Transmission Revenue Requirements and Region-wide Annual Transmission Revenue Requirement is shown in Table 3, Section 1 of Attachment H.

**B. Base Plan Zonal Charge to Resident Load**

The Network Customer and the Transmission Owner shall pay a monthly Base Plan Zonal Charge, which shall be determined by multiplying its Base Plan Zonal Load Ratio Share by one twelfth (1/12) of the Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J for each Zone in which the Network Customer's or

Transmission Owner's Resident Load is physically located. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.3, Network Customer shall pay a monthly Zonal Base Plan Charge, which shall be determined by multiplying its Base Plan Zonal Load Ratio Share by one twelfth (1/12) of the Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J for the Zone that is the basis for charges under Schedule 11.

**1. Determination of Network Customer's and Transmission Owner's Monthly Zonal Resident Load**

The Network Customer's or Transmission Owner's monthly zonal Resident Load is its integrated hourly load coincident with the monthly peak of the Zone where the Resident Load is physically located. Where a Network Customer or Transmission Owner has Resident Load in more than one Zone, the monthly Resident Load will be determined separately for each Zone. Where a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.3, the Network Customer's monthly Resident Load will be its hourly load coincident with the monthly peak of the Zone that is the basis for charges under Schedule 11.

**2. Determination of Network Customer's and Transmission Owner's Monthly Zonal Resident Load for Zone 10**

The Network Customer's or Transmission Owner's monthly zonal Resident Load shall be calculated in accordance with Section B.1 of this Schedule 11; except that the Network Customer's monthly zonal Resident Load shall be reduced by the Federal-Power Southwestern as identified in Section 34.9 of this Tariff.

**3. Determination of Transmission Provider's Monthly Zone Transmission Load**

The Transmission Provider's monthly Transmission System load shall be determined in accordance with Section 34.5 of this Tariff.

**C. Region-wide Charge to Resident Load**

Network Customers and Transmission Owners shall pay a monthly Region-wide Charge, which shall be determined as (i) the product of its Region-wide Load Ratio Share

applicable to Section I, Table 2-A of Attachment H and one twelfth (1/12) of the Region-wide Annual Transmission Revenue Requirement specified in Section I, Table 2-A of Attachment H, plus (ii) the product of its Region-wide Load Ratio Share applicable to Section I, Table 2-B of Attachment H and one twelfth (1/12) of the Region-wide Annual Transmission Revenue Requirement specified in Section I, Table 2-B of Attachment H.

**1. Determination of Network Customer's and Transmission Owner's Monthly Regional Resident Load in Zones 1 through 9 and 11 through 18**

For Zones 1 through 9 and 11 through 18, the Network Customer's or Transmission Owner's monthly regional Resident Load is the sum of its monthly zonal Resident Load for each Zone, where the monthly zonal Resident Load is determined separately for each Zone coincident with the monthly peak of the Zone in accordance with Section II.B.1.

**2. Determination of Network Customer's and Transmission Owner's Monthly Regional Load in Zone 19**

For application of the Region-wide Charge under this Schedule 11, the Network Customer's or Transmission Owner's load for Zone 19 shall be the integrated hourly load coincident with the monthly peak of Zone 19 calculated in accordance with Section II.B.1 less: (i) load in the Western Interconnection to the extent that such load is served only by resources in the Western Interconnection, and (ii) service provided under the Western-UGP Federal Service Exemption.

**3. Determination of Network Customer's and Transmission Owner's Monthly Regional Load in Zone 10**

For application of the Region-wide Charge under this Schedule 11, the Network Customer's or Transmission Owner's load for Zone 10 shall be the integrated hourly load coincident with the monthly peak of Zone 10 calculated in accordance with Section II.B.2.

**4. Determination of Transmission Provider's Monthly Regional Transmission System Load**

The Transmission Provider's monthly regional Transmission System load is the sum of the monthly Zone transmission load for each Zone, where the monthly zone transmission load for each Zone is determined on a non-coincident

basis in accordance with Section II.B.2, but with (a) Zone 19 load modified in accordance with Section II.C.2 and (b) Zone 10 load modified in accordance with Section II.C.3.

**D. Special Provision for Non-Federal Service Exemption service to Western-UGP's Statutory Load Obligations**

Western-UGP's Statutory Load Obligations ordinarily served by Federal Power Western-UGP, may be served on occasion from resources where the Western-UGP Federal Service Exemption from Schedule 11 Region-wide Charges is not applicable. In any such instance, Region-wide Charges will be applied as calculated pursuant to Sections III.C.1.a and III.C.3 of this Schedule 11.

## III. Base Plan Zonal Charge and Region-wide Charge for Point-To-Point Transmission Service

### A. Base Plan Zonal Charge for Point-To-Point Transmission Service

The Base Plan Zonal Charge shall be assessed to Transmission Customers taking Firm or Non-Firm Point-To-Point Transmission Service under the SPP Tariff. The Transmission Customer shall pay the Base Plan Zonal Rate (per kW of Reserved Capacity) based upon the Zone where the load is located for Point-To-Point Transmission Service where the generation source is outside the SPP Region and the load is located within the SPP Region and for Point-To-Point Transmission Service where both the generation source and the load are located within the SPP Region. For Point-To-Point Transmission Service where the generation source is located within the SPP Region and the load is located outside of the SPP Region, and for Point-To-Point Transmission Service where both the generation source and the load are located outside of the SPP Region, the Transmission Customer shall pay the Base Plan Average Zonal Rate (per kW of Reserved Capacity). The Base Plan Zonal Rates and the Base Plan Average Zonal Rate shall be calculated in accordance with Section III.D and set forth in the RRR File posted on the SPP website.

### B. Region-wide Charge for Point-To-Point Transmission Service

The Region-wide Charge shall be assessed to Transmission Customers taking Firm or Non-Firm Point-To-Point Transmission Service under the SPP Tariff. The Transmission Customer shall pay the Region-wide Rate (per kW of Reserved Capacity) for Point-To-Point Transmission Service. The Region-wide Rate shall be calculated in accordance with Section III.C and set forth in the RRR File posted on the SPP website.

**C. Region-wide Rate for Point-To-Point Transmission Service**

**1. Determination of Annual Region-wide Rate**

a. The Region-wide Annual Transmission Revenue Requirement specified in Attachment H are the basis for the Region-wide Rate. Except for service where the load is located within Zone 19, the annual Region-wide Rate for Firm Point-To-Point Transmission Service shall be determined in accordance with the following formula:

RR = RATRR2A/MRTL 1 to 18 + RATRR2B/MRTL

in which

RR = the annual Region-wide Rate

RATRR2A = the Region-wide Annual Transmission Revenue Requirement specified in Table 2-A of Section I, Attachment H

RATRR2B = the Region-wide Annual Transmission Revenue Requirement specified in Table 2-B of Section I, Attachment H

MRTL 1 to 18 = the average of the monthly regional Transmission System loads in Zones 1 to 18 only, for the twelve months of the calendar year prior to the billing year. The monthly regional Transmission System load shall be determined in accordance with Section II.C.3 less the Zone 19 load modified in accordance with Section II.C.2.

MRTL = the average of the monthly regional Transmission System loads, for the twelve months of the calendar year prior to the billing year. The monthly regional Transmission System load is determined in accordance with Section II.C.3.

b. For service where the load is located within Zone 19, the annual Region-wide Rate for Firm Point-to-Point Transmission Service shall be determined in accordance with the following formula:

RR19= RATRR2B/MRTL

in which

RR19= the annual Region-wide Rate applicable to load in Zone 19

RATRR2B= as defined above

MRTL= as defined above

**2. Region-wide Rate for Firm Point-To-Point Transmission Service**

The Region-wide Rate for Firm Point-To-Point Transmission Service shall be:

| | |
|---|---|
| Per month = | annual Region-wide Rate divided by 12; |
| Per week = | annual Region-wide Rate divided by 52; |
| Per day "on-peak" = | the "per week" Region-wide Rate divided by 5; provided that the rate for 5 to 7 consecutive days may not exceed the "per week" Region-wide Rate; and |
| Per day "off-peak" = | the "per week" Region-wide Rate divided by 7. |

**3. Region-wide Rate for Non-Firm Point-To-Point Transmission Service**

The Region-wide Rate for Non-Firm Point-To-Point Transmission Service shall be:

| | |
|---|---|
| Per month = | annual Region-wide Rate divided by 12; |
| Per week = | annual Region-wide Rate divided by 52: |
| Per day "on-peak" = | the "per month" Region-wide Rate multiplied by 12 then divided by 260; |
| Per day "off-peak" = | the "per month" Region-wide Rate multiplied by 12 then divided by 365; |
| Per hour "on-peak" = | the "per month" Region-wide Rate multiplied by 12 then divided by 4160; and |
| Per hour "off-peak" = | the "per month" Region-wide Rate multiplied by 12 then divided by 8760. |

**4. Total Region-wide Charge**

The total Region-wide Charge paid by a Transmission Customer pursuant to a reservation for hourly delivery shall not exceed the above on-peak daily rate multiplied by the highest amount of Reserved Capacity in any hour during such day. The total Region-wide Charge in any week, pursuant to a reservation for hourly or daily delivery, shall not exceed the above Region-wide Rate specified

for weekly delivery multiplied by the highest amount of Reserved Capacity in any hour during such week.

**5. Rate Sheet for Region-wide Point-To-Point Transmission Service**

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the ("RRR File") posted on the SPP website.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File.

**D. Base Plan Zonal Rates for Point-To-Point Transmission Service**

**1. Determination of Annual Base Plan Zonal Rate**

The Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J is the basis for the Base Plan Zonal Rates. The annual Base Plan Zonal Rates for Firm Point-To-Point Transmission Service shall be determined in accordance with the following formula for each Zone.

BPZR = BPZATRR/MZTL

in which

BPZR = the annual Base Plan Zonal Rate for the Zone

BPZATRR = the Base Plan Zonal Annual Transmission Revenue Requirement for the Zone as specified in Attachment H less any amount reallocated in accordance with Section IV.A of Attachment J

MZTL = the average of the sum of the monthly Zone transmission load for the Zone for the twelve months of the calendar year prior to the billing year. The monthly Zone transmission load is determined in accordance with Section II.B.2.

**2. Base Plan Zonal Rate for Firm Point-To-Point Transmission Service**

The Base Plan Zonal Rate for Firm Point-To-Point Transmission Service for each Zone shall be:

Per month = annual Base Plan Zonal Rate for the Zone divided by 12;

Per week = annual Base Plan Zonal Rate for the Zone divided by 52;

Per day "on-peak" = the "per week" Base Plan Zonal Rate for the Zone divided by 5; provided that the rate for 5 to 7 consecutive days may not exceed the "per week" Base Plan Zonal Rate;

Per day "off-peak" = the "per week" Base Plan Zonal Rate for the Zone divided by 7.

**3. Base Plan Zonal Rate for Non-Firm Point-To-Point Transmission Service**

The Base Plan Zonal Rate for Non-Firm Point-To-Point Transmission Service for each Zone shall be:

Per month = annual Base Plan Zone Rate for the Zone divided by 12;

Per week = annual Base Plan Zonal Rate for the Zone divided by 52:

Per day "on-peak" = the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 260;

Per day "off-peak" = the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 365;

Per hour "on-peak" = the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 4160; and

Per hour "off-peak" = the "per month" Base Plan Zonal Rate for the Zone multiplied by 12 then divided by 8760.

**4. Base Plan Average Zonal Rate**

The total Base Plan Zonal Annual Transmission Revenue Requirement specified in Attachment H for all Zones less the total of all zonal amounts reallocated in accordance with Section IV.A of Attachment J is the basis for the Base Plan Average Zonal Rate. The annual Base Plan Average Zonal Rate for Firm Point-To-Point Transmission Service shall be determined in accordance with the following formula.

BPAZR = TBPZATRR/MRTL

in which

BPAZR = the annual Base Plan Average Zonal Rate

TBPZATRR = the total Base Plan Zonal Annual Transmission Revenue Requirement for all Zones as specified in Attachment H less the total of all zonal amounts reallocated in accordance with Section IV.A of Attachment J

MRTL = as defined in Section III.C.1

The Base Plan Average Zonal Rates for Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service for each month, week, day on-peak, day off-peak, hour on-peak, and hour off-peak shall be based on the annual Base Plan Average Zonal Rate and calculated consistently with the formulas shown in Sections III.D.2 and III.D.3.

**5. Total Zonal Base Plan Charge**

The total zonal charge paid by a Transmission Customer under this Schedule 11 pursuant to a reservation for hourly delivery shall not exceed the applicable on-peak daily rate multiplied by the highest amount of Reserved Capacity in any hour during such day. The total zonal charge under this Schedule 11 in any week, pursuant to a reservation for hourly or daily delivery, shall not exceed the applicable rate specified for weekly delivery multiplied by the highest amount of Reserved Capacity in any hour during such week.

**6. Rate Sheets for Base Plan Zonal Point-To-Point Transmission Service**

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File posted on the SPP website.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum

of the applicable charges set forth in the RRR File posted on the SPP website.

**E. On-Peak and Off-Peak**

Off-Peak days shall be Saturdays and Sundays and all NERC holidays. All other days shall be On-Peak. All hours during Off-Peak days shall be Off-Peak. On-Peak hours during On-Peak days shall be all hours from HE 0700 through HE 2200 Central Prevailing Time. All other hours during On-Peak days shall be Off-Peak.

# Reserved for Future Use

# Reserved for Future Use

# SCHEDULE 12
# FERC ASSESSMENT CHARGE

## 1. INTRODUCTION

As a public utility, the Transmission Provider is subject to annual charges assessed by the Commission, pursuant to Part 382 of its regulations (the "FERC Assessment"). For each public utility, such assessment is based on the actual megawatt-hours of energy transmitted in interstate commerce during a calendar year, as reported on FERC Form 582. This Schedule 12 provides for recovery of the estimated amount to be assessed by the Commission in the next year for transmission service, with subsequent true-up to actual cost, when such cost is known.

## 2. APPLICABILITY

This charge shall apply to all energy delivered under Point-To-Point Transmission Service and Network Integration Transmission Service and to all energy delivered to Bundled Retail and Grandfathered Loads to which Section 39.2 of this Tariff applies.

## 3. RATE CHARGED

Prior to March 1 of each year the Transmission Provider shall calculate the FERC Assessment Charge Rate (FACR) and post the results on the SPP website, based on the following formula:

$$FACR_y = \frac{FEC_{y+1} + (FEC_y - Balance_{y-1})}{EMWh_y}$$

Where:

*y* — Year in which charge is calculated.

FACR — FERC Assessment Charge Rate.

FEC — FERC Estimated Charge is the amount expected to be assessed by the Commission in a calendar year.

Balance — Amount in the Schedule 12 account at the end of the calendar year net of all payments to the Commission, collections from

customers, and interest earned for the year prior for which the FACR is calculated.

EMWh Estimated MWh in the calendar year for the categories of energy set forth in Section 2 of this Schedule 12. The estimated amount will be based on previous year amount and adjusted for any known or expected change in energy quantity for the current year.

**4. BILLING**

The Transmission Provider shall bill Transmission Customers and Transmission Owners covered by Section 39.2 the charges specified under this Schedule 12 in accordance with the procedures in Section 7 of this Tariff. The FERC Assessment Charge Rate shall be effective March 1 of each year.

**ATTACHMENT A**
**FORM OF SERVICE AGREEMENT FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE**

1.0 This Service Agreement, dated as of _____, is entered into, by and between Southwest Power Pool, Inc. ("The Transmission Provider"), and _____ ("Transmission Customer").

2.0 The Transmission Customer has been determined by The Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has completed all credit arrangements required pursuant to Section 17.3 and Attachment X of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by The Transmission Provider and the Transmission Customer.

5.0 The Transmission Customer agrees to supply information The Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

6.0 The Transmission Provider, as agent for the Transmission Owners, agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Parts I, II and V of the Tariff and this Service Agreement.

7.0 To the extent necessary to effectuate any transaction entered into pursuant to this Service Agreement, the following Transmission Owner(s) shall provide Wholesale Distribution Service over Distribution Facilities:

_____

8.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Southwest Power Pool:

_____

201 Worthen Drive

Little Rock, AR 72223-4936

Transmission Customer:

_____

_____

_____

9.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Southwest Power Pool:

By:_____ _____ _____
Name Title Date

Transmission Customer:

By:_____ _____ _____
Name Title Date

**Specifications For Long-Term Firm Point-To-Point Transmission Service**

l.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Balancing Authority Area in which the transaction originates.

_____

3.0 Point(s) of Receipt:_____

Delivering Party:_____

4.0 Point(s) of Delivery:_____

Receiving Party:_____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):_____

6.0 Designation of party(ies) subject to reciprocal service obligation:

_____

_____

_____

7.0 Name(s) of any Intervening Systems providing transmission service:

_____

_____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:_____

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

_____

8.5 Candidate Incremental LTCRs

* Source _____
* Sink _____
* Candidate Incremental LTCR MW _____
* Term (years from in-service date of Network Upgrade)_____

## ATTACHMENT A-1

## FORM OF SERVICE AGREEMENT FOR THE RESALE, REASSIGNMENT OR TRANSFER OF POINT-TO-POINT TRANSMISSION SERVICE

1.0 This Service Agreement, dated as of _____, is entered into, by and between _____ (the Transmission Provider), and_____ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff and has satisfied all terms and conditions of the Tariff, including but not limited to the requirements set forth in the Credit Policy in Attachment X of the Tariff.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, Point(s) of Receipt and Delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

_____

_____

_____

Assignee:

_____

_____

_____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: _____ _____ _____
Name Title Date

Assignee:

By: _____ _____ _____
Name Title Date

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: _____

Start Date: _____

Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Balancing Authority Area in which the transaction originates.

_____

3.0 Point(s) of Receipt:_____

Delivering Party:_____

4.0 Point(s) of Delivery:_____

Receiving Party:_____

5.0 Maximum amount of reassigned capacity: _____

6.0 Designation of party(ies) subject to reciprocal service obligation:

_____

_____

_____

7.0 Name(s) of any Intervening Systems providing transmission service:

_____

_____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:_____

_____

8.2 System Impact and/or Facilities Study Charge(s):

_____

_____

8.3 Direct Assignment Facilities Charge:_____

_____

8.4 Ancillary Services Charges: _____

_____

_____

_____

_____

_____

_____

8.5 Candidate Incremental LTCRs

* Source _____
* Sink _____
* Candidate Incremental LTCR MW _____
* Term (years from in-service date of Network Upgrade)_____

9.0 Name of Reseller of the reassigned transmission capacity:

_____

# ATTACHMENT B
# FORM OF SERVICE AGREEMENT FOR NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

1.0 This Service Agreement, dated as of _____, is entered into, by and between Southwest Power Pool, Inc.("The Transmission Provider"), and _____ (Transmission Customer).

2.0 The Transmission Customer has been determined by The Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by The Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information The Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider, as agent for the Transmission Owners, agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Parts I, II and V of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Southwest Power Pool:

_____

201 Worthen Drive

Little Rock, AR 72223-4936

Transmission Customer:

_____

_____

_____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Southwest Power Pool:

By:_____ _____ _____
Name Title Date

Transmission Customer:

By:_____ _____ _____
Name Title Date

# ATTACHMENT C
# METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

# 1. General

## 1.1 General Statement.

This Attachment C prescribes the specific methodology for calculating Available Transfer Capability ("ATC") posted on the Transmission Provider's OASIS, as required in Section 4 of this OATT. The Transmission Provider utilizes a Flowgate Methodology for calculating ATC. The Transmission Provider will develop and maintain implementation documents for the calculations specified below.

## 1.2 Definitions

The terms used in this Attachment C shall have the meanings as defined in this section 1.2 or as otherwise defined in this OATT.

### 1.2.1 Available Flowgate Capability ("AFC")

A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less ETC, less a CBM, less a TRM, plus Postbacks, and plus Counterflows.

### 1.2.2 Available Transfer Capability ("ATC")

A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as TTC less ETC (including retail customer service), less a CBM, less a TRM, plus Postbacks, plus Counterflows.

### 1.2.3 Available Transfer Capability Implementation Document ("ATCID")

A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.

### 1.2.4 Base Loading

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load from NR and impacts from existing OASIS commitments, including rollover rights as established in section 2.2 of the OATT.

### 1.2.5 Capacity Benefit Margin ("CBM")

The amount of firm transmission transfer capability preserved by the transmission provider for LSE, whose loads are located on the Transmission Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity

below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

1.2.6 Contractual Limit

Contractual arrangements among two or more Transmission Owners that define transfer capability.

1.2.7 Counterflows

Adjustments to AFC as determined by the Transmission Provider and specified in [the] its ATCID.

1.2.8 Designated Resource ("DR")

As defined in Section 1 of the Tariff.

1.2.9 Existing Transmission Commitments ("ETC")

Committed uses of the Transmission Provider's Transmission System considered when determining ATC or AFC.

1.2.10 Flowgate

A mathematical construct, comprised of one or more monitored transmission facilities and optionally one or more contingency facilities, used to analyze the impact of power flows upon the bulk electric system.

1.2.11 Load-Serving Entity ("LSE")

Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

1.2.12 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff. (OATT Section 1.20)

1.2.13 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff. (OATT Section 1.21)

1.2.14 Network Resource ("NR")

As defined in Section 1 of the Tariff.

1.2.15 Operating Procedure

A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified.

1.2.16 Outage Transfer Distribution Factor ("OTDF")

In the post-contingency configuration of the Transmission Provider's system, the electric PTDF with one or more system facilities removed from service (outaged).

1.2.17 Postbacks

Positive adjustments to ATC or AFC.

1.2.18 Power Transfer Distribution Factor ("PTDF")

In the pre-contingency configuration of the Transmission Provider's system, a measure of the responsiveness or change in electrical loadings on transmission system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.

1.2.19 Real-Time Response Factor Calculator ("RTRFCALC")

The application used for constructing models and calculating a component of ETC and DFs utilizing forecasted inputs and expected topology of future horizons for AFC calculations.

1.2.20 SPP Reliability Coordination Area

The collection of generation, transmission, and load that operate within the boundaries of the Balancing Authority Areas for which SPP provides Reliability Coordination services.

1.2. 21 Total Flowgate Capability ("TFC")

The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a Flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated system operating limit.

1.2.22 Distribution Factor ("DF")

The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate). Used interchangeably for either OTDF or PTDF.

1.2.23 Transmission Reliability Margin ("TRM")

The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

## 2. Flowgates

### 2.1 Identification of Flowgates

Flowgates are identified as a selected power transmission element or group of elements that act as a proxy for the power transmission system capability and represent potential thermal, voltage, stability and/or contractual system limits to power transfer. The Transmission Provider identifies and eliminates Flowgates through an annual review process set forth in Section 2.2 of this Attachment C. Flowgates also are identified through requests from reliability coordinators, transmission service providers, transmission owners, and transmission operators to protect equipment or maintain system reliability regardless of the ownership of the Flowgate.

Once a set of transmission facilities have been identified as potential transfer constraints they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the TFC of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce. The TFC values are consistent with those used for planning purposes.

### 2.2 Updating Flowgates

Updating the list of Flowgates is a continual process. Flowgate additions and eliminations and changes in TFC are the result of studies, analyses, and operating experience of the Transmission Provider and its member Transmission Owners. Additionally, at any time during the year, reliability coordinators, transmission service providers, transmission owners, and transmission operators may request that a Flowgate be added to protect equipment or maintain system reliability, regardless of the ownership of that Flowgate. Updating the Flowgate list may or may not require running a study. The following requirements apply when adding a Flowgate to the list:

- OTDF Flowgates may be added, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no Operating Procedures apply to that Flowgate.

- PTDF Flowgates may be added, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no Operating Procedures apply to that Flowgate.

- Flowgates may be added on a temporary or permanent basis when required to maintain system reliability.

#### 2.2.1 Addition or Elimination of an Internal Flowgate

The Transmission Provider uses the following procedure to add or eliminate an internal Flowgate in its AFC Calculations.

(1) The Transmission Provider will add a permanent or temporary internal Flowgate at the request of the SPP Reliability Coordinator. The Transmission Provider will eliminate a temporary internal Flowgate at the request of the SPP Reliability Coordinator.

(2) The Transmission Provider will add an internal Flowgate at the request of SPP Transmission Owners and Transmission Operators.

(3) The Transmission Provider also administers an annual Flowgate assessment using Powerflow models to update the list of active internal Flowgates used for reliability purposes. Except as provided in (1) above, any request to eliminate an internal Flowgate is processed as part of the annual Flowgate assessment.

(a) Powerflow models are selected to cover the 12 month study horizon.

(b) DC and AC analyses are performed on the models to assess NERC Standards and SPP Criteria reliability performance. From these analyses, the Transmission Provider identifies a list of potential new Flowgates to be studied alongside the existing Flowgates.

(c) The new potential Flowgates are compared with existing Flowgates to determine which potential new Flowgates should be considered for addition to the Flowgate list and which existing Flowgates should be eliminated.

(d) The Transmission Owners review the proposed Flowgate changes on their facilities, considering their own operating experience and the results of the Transmission Provider's analyses conducted in accordance with (b) above.

(e) The Transmission Owners approve any additions, eliminations, or changes to the Flowgate list.

2.2.2 Addition or Elimination of an External Flowgate

The Transmission Provider uses the following procedure to add or eliminate an external Flowgate in its AFC Calculations. The Transmission Provider will consider requests to add or eliminate external Flowgates from: (1) reliability coordinators; (2) transmission service providers; (3) transmission owners; and (4) transmission operators. The Transmission Provider will add a requested external Flowgate upon confirming the rating of the facility(ies) involved. Addition or elimination of external Flowgates is governed by NERC Standards, SPP Criteria, and the following seams agreements, as applicable: Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. And Southwest Power Pool, Inc. (Rate Schedule FERC No. 9); Joint Operating Agreement Among and Between Southwest Power Pool, Inc. and Associated Electric Cooperative, Inc. (Rate Schedule FERC No. 10); and United States Department of

Energy Southwestern Power Administration Amendatory Agreement Between United States of America and Southwest Power Pool, Inc. (Attachment AD to this Tariff).

## 3. ATC Calculations

### 3.1 ATC Mathematical Equations.

The following equations are used in calculating ATC:

#### 3.1.1 Firm Existing Transmission Commitments (Firm ETC)*

Operating Horizon

Firm ETC = (Impacts of NRs and DRs serving load within the SPP Balancing Authority Area) + (Σ flows due to Firm Schedules into, out of and through the SPP Balancing Authority Area)

Planning Horizon

Firm ETC = (Impacts of NR serving load within the SPP Balancing Authority Area) + (Σ Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted, and Study)

Study Horizon

Firm ETC = (Impacts of NR serving load within the SPP Balancing Authority Area) + (Σ Positive Impacts > 3% due to Firm OASIS Commitments, Confirmed, Accepted, and Study)

#### 3.1.2 Non-Firm Existing Transmission Commitments (Non-Firm ETC)

Operating Horizon

Non-Firm ETC = (Σ Flows due to Non-Firm Schedules into, out of and through the SPP Balancing Authority Area) + (Σ Positive Impacts > 3% due to Non-Firm OASIS Commitments, Confirmed, Accepted and Study since last AFC calculation)

*Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service. Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

Planning Horizon

Non-Firm ETC = (Σ Positive Impacts due to Non-Firm OASIS Commitments, Confirmed, Accepted, and Study) - (Σ 50% of Counterflows due to Confirmed Firm OASIS Commitments)

Study Horizon

Non-Firm ETC = (Σ Positive Impacts due to Non-Firm OASIS Commitments, Confirmed, Accepted, and Study)

#### 3.1.3 Firm AFC:

• $AFC_F = TFC – ETC_{Fi} – CBM_i – TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$

Where:

**$AFC_F$** is the firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm transmission commitments for the Flowgate during that period.

**$CBM_i$** is the impact of the Capacity Benefit Margin on the Flowgate during that period.

**$TRM_i$** is the impact of the Transmission Reliability Margin on the Flowgate during that period.

**$Postbacks_{Fi}$** are changes to firm AFC due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**$Counterflows_{Fi}$** are adjustments to firm AFC as determined by the Transmission Provider and specified in its Available Transfer Capability Implementation Document.

3.1.4 Non-Firm AFC:

• $AFC_{NF} = TFC – ETC_{Fi} – ETC_{NFi} – CBM_{Si} – TRM_{Ui} + Postbacks_{NFi} + Counterflows$

Where:

**$AFC_{NF}$** is the non-firm Available Flowgate Capability for the Flowgate for that period.

**TFC** is the Total Flowgate Capability of the Flowgate.

**$ETC_{Fi}$** is the sum of the impacts of existing firm transmission commitments for the Flowgate during that period.

**$ETC_{NFi}$** is the sum of the impacts of existing non-firm transmission commitments for the Flowgate during that period.

**$CBM_{Si}$** is the impact of any schedules during that period using Capacity Benefit Margin.

**$TRM_{Ui}$** is the impact on the Flowgate of the Transmission Reliability Margin that has not been released (unreleased) for sale as non-firm capacity by the Transmission Provider during that period.

**Postbacks$_{NF}$** are changes to non-firm Available Flowgate Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

**Counterflows$_{NF}$** are adjustments to non-firm AFC as determined by the Transmission Provider and specified in its Available Transfer Capability Implementation Document.

3.1.5 Converting Flowgate AFCs to ATCs for ATC Paths:

When converting Flowgate AFCs to ATCs for ATC Paths, the Transmission Provider shall convert those values based on the following algorithm:

$$ATC = \min(P)$$

$$P = \{PATC_1, PATC_2, \ldots PATC_n\}$$

$$PATC_n = AFCn / DF_{np}$$

**Where:**

**ATC** is the Available Transfer Capability.

**P** is the set of partial ATCs for all "impacted" Flowgates honored by the Transmission Provider; a Flowgate is considered "impacted" by a path if the Distribution Factor for that path is greater than the percentage threshold used for short-term transmission service used by the Transmission Provider on an OTDF Flowgate or PTDF Flowgate.

**PATC$_n$** is the partial Available Transfer Capability for a path relative to a Flowgate n.

**AFC$_n$** is the Available Flowgate Capability of a Flowgate n.

**DF$_{np}$** is the Distribution Factor for Flowgate n relative to path p.

3.2 AFC Calculation Horizons

AFC and ATC values are calculated for the following periods and frequency:

- Hourly values for at least the next 48 hours are calculated at least once per hour
- Daily values for at least the next 31 calendar days are calculated at least once per day
- Monthly values for at least the next 12 months (months 2-13) are calculated at least once per week

3.3 Transmission Model Update

The transmission models used for AFC calculations are updated for the following periods and frequency:

- Operating Horizon, including all hours of the current day (Day 1), and after 10:00 a.m., all hours of the next day (Day 2). Updated at least once per day.

- Planning Horizon, which extends from the end of the Operating Horizon through the thirty-first day (Day 31). Updated at least once per day.

- Study Horizon, which extends from the end of the Planning Horizon through the twelfth month (month 12). Updated at least once per month.

The actual mathematical algorithms for calculating AFC and ATC are posted on the Transmission Provider's website at: http://www.oatioasis.com/SWPP/SWPPdocs/ATC_Algorithm.doc

# 4. Base Case Models

The AFC process generates a base case model that simulates anticipated system conditions. The base system conditions include projected load, generation dispatch, network topology (based on system configuration and both planned and contingency outages), and base flow transactions.

The impacts on Flowgates due to transactions outside the purpose of representing NR exchange are removed by applying the DFs determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and Counterflows of existing OASIS commitments are applied according to the type of Base Loading (Firm or Non-Firm) under consideration. 50% of Counterflows resulting from firm Confirmed reservations act to reduce the Non-Firm Base Loading. This process establishes the Base Loading expected to serve the Network Load.

The base flows are based on AC power flow calculations performed by RTRFCALC using the following data:

- Network topology
- Hourly load forecast data of the Balancing Authority Areas
- Net interchange of the Balancing Authority Areas
- Unit dispatch data

## 4.1 Operating Horizon

The AFC calculations of the Operating, Planning, and Study Horizons are performed by RTRFCALC in combination with webTrans.

WebTrans receives the following information from RTRFCALC:

- base flows for all Flowgates,
- DFs for all paths, and
- TFC values for all Flowgates.

The base flows are the product of the AC powerflow calculations performed by RTRFCALC using following data:

### 4.1.1 Network Topology

Network topology is established by the network topology model, either from EMS State Estimator or from Eastern Interconnect Interchange Distribution Calculator Model (IDC Model). Network topology models for the Operating Horizon are adjusted with outage data of generators, transmission lines and transformers within the SPP Reliability Coordination Area. This outage data includes both planned outages and contingency outages that are expected to remain in effect for each hour modeled. The Transmission Provider shall also include outage data from neighboring Reliability Coordinators that is available through System Data Exchange (SDX).

#### 4.1.2 Load Forecast

The Transmission Provider utilizes forecast data made available through SDX.

#### 4.1.3 Net Interchange

The net interchange of the Balancing Authority Areas that are part of the State Estimator Model is based on the existing schedules at the time the RTRFCALC application performs its Operating Horizon run at least once per day.

#### 4.1.4 Unit Dispatch

RTRFCALC utilizes forecasted dispatch data for all units within the SPP Balancing Authority Area.

### 4.2 Planning Horizon

The AFC calculations of the Operating, Planning, and Study Horizons are performed by RTRFCALC application in combination with webTrans.

WebTrans receives the following information from RTRFCALC:

- base flows for all Flowgates,
- DFs for all paths, and
- TFC values for all Flowgates.

The base flows are a product of the AC power flow calculations performed by RTRFCALC using following data:

#### 4.2.1 Network Topology

Network topology is established by the State Estimator or IDC Model and adjusted with hour-to-hour outage data of generators, transmission lines and transformers. Such outage data shall be as submitted by Transmission Operators and Generation Operators that are within the SPP Reliability Coordination Area and approved by the Reliability Coordinator. This outage data includes both planned outages and contingency outages that are expected to remain in effect for each time period modeled. The Transmission Provider includes outage data from neighboring Reliability Coordinators that is available through SDX.

#### 4.2.2 Load Forecast

The Transmission Provider utilizes forecast data made available through SDX.

#### 4.2.3 Net Interchange

Initially, the model assumes the net interchange of the Balancing Authority Areas is 0. If a Balancing Authority Area has a confirmed network reservation from a NR outside the Balancing Authority Area boundary, that reservation is incorporated into the net interchange of both Balancing Authority Areas. That particular network reservation will be added to the exclude file to prevent double counting of impacts.

#### 4.2.4 Unit Dispatch

RTRFCALC utilizes forecasted dispatch data for all units within the SPP Balancing Authority Area.

### 4.3 Study Horizon

The AFC calculations of the Operating, Planning, and Study Horizon are performed by RTRFCALC application in combination with webTrans.

WebTrans receives the following information from RTRFCALC:
- Base flows for all Flowgates,
- DFs for all paths, and
- TFC values for all Flowgates.

The base flows are a product of the AC power flow calculations performed by RTRFCALC using the following data:

#### 4.3.1 Network Topology

Network topology is established by the State Estimator or IDC Model and adjusted for outages of generators, transmission lines and transformers. Such outage data shall be as submitted by Transmission Operators and Generation Operators that are within the SPP Reliability Coordination Area and approved by the Reliability Coordinator. This outage data includes both planned outages and contingency outages that are expected to remain in effect for some period within this horizon. The Transmission Provider also includes outage data from neighboring Reliability Coordinators that is available through SDX. The Transmission Provider includes approved planned outages and contingency outages which are active on 15th of the month and last more than 15 days.

#### 4.3.2 Load Forecast

The Transmission Provider utilizes monthly forecast data that is made available through SDX.

#### 4.3.3 Net Interchange

Initially, the model assumes net interchange of the Balancing Authority Areas is 0. If a Balancing Authority Area has a confirmed network reservation from a NR outside the Balancing Authority Area boundary, that reservation is incorporated into the net interchange of both Balancing Authority Areas. That particular network reservation will be added to the exclude file to prevent double counting of impacts.

#### 4.3.4 Unit Dispatch

RTRFCALC utilizes forecasted dispatch data for all units within the SPP Balancing Authority Area.

### 4.4 Exclusion of Reservations in the Calculations of AFC Values

The Transmission Provider shall exclude or limit certain reservations under the following conditions:

- If total sum of reservations (Confirmed, Accepted, Study) impacting a specific corridor exceeds the total capacity of the corridor,

- If total sum of reservations (Confirmed, Accepted, Study) sinking in a Balancing Authority Area exceeds the total load of the Balancing Authority Area,

- If total sum of reservations (Confirmed, Accepted, Study) sourcing from a group of commonly dispatched units exceeds the total available generation capacity of that group of units.

- If the reservation is a network reservation from a NR outside the Balancing Authority Area boundary and that particular reservation is already included in the base flow calculations of the Study Horizon.

### 4.5 Resynchronization of Base Loading Values

The Transmission Provider uses webTrans to evaluate Transmission Service requests that are submitted by Transmission Customers on OASIS. RTRFCALC recalculates the base flows and DF values of the Operating Horizon for every hour at least once per day.

RTRFCALC recalculates the base flows and DF values of the Planning Horizon at least once per day.

The base flows of the Study Horizon are calculated and updated in webTrans at least once per month.

Finally, webTrans recalculates Firm and Non-Firm Base Loading upon each change of status of a reservation that impacts the relevant Base Loading. WebTrans makes adjustments to Firm and Non-Firm Base Loading upon the change of the following inputs:

For Firm ETC

• The transmission capability utilized in serving native load commitments, to include native load growth, load forecast error and losses not otherwise included in TRM or CBM.

• The impact of Firm Network Integration Transmission Service serving Network Load, to
include load forecast error and losses not otherwise included in TRM or CBM.

• The impact of grandfathered firm Transmission Service agreements and bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's OATT or Safe Harbor Tariff accepted by FERC.

• The impact of Firm Point-To-Point Transmission Service into, out of or through the SPP Balancing Authority Area.

• The impact of maintaining roll-over rights for firm Transmission Service contracts, five years or longer in duration, granting Transmission Customers the right of first refusal to take or continue to take Transmission Service from a Transmission Owner when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

• The impact of any Ancillary Services not otherwise included in CBM or TRM.

• Postbacks of redirected or released Firm services.

• The impact of Counterflows not otherwise accounted for in the AFC calculation.

• The impact of any other services, contracts, or agreements not specified above using transmission that serves native load or Firm Network Integration Transmission Service.

• The impact of any relevant third-party firm Transmission Service that has not already been accounted for.

For Non-Firm ETC,

• The impact of Non-Firm Network Integration Transmission Service serving load, to include load forecast error and losses not otherwise included in TRM or CBM.

• The impact of grandfathered non-firm Transmission Service Agreements and
bundled contracts for energy and transmission, where executed prior to the effective date of a Transmission Service Provider's OATT or Safe Harbor Tariff accepted by FERC.

• The impact of Non-Firm Point-To-Point Transmission Service into, out of or through the SPP Balancing Authority Area.

• The impact of Counterflows not otherwise accounted for in the ATC calculation.

• Capacity utilized for TRM that the Transmission Service Provider has elected to be released for as Non-Firm ATC.

• Postbacks due to the reinstating of Firm from a "Firm-to-Non-Firm" redirect.

• The impact of any relevant third-party non-firm Transmission Service that has not already been accounted for.

### 4.6 Changes in TFC

In the event of a change in Network Topology due to actual or anticipated system conditions that impacts one or more TFC values, the Transmission Provider shall adjust the TFC in RTRFCALC for the applicable time periods. The Network Topology from the SPP State Estimator or IDC Model shall be adjusted as described in sections 4.1.1, 4.2.1, and 4.3.1 for the applicable horizons.

## 5. TRM

The Transmission Provider calculates TRM for each Flowgate at least once every 13 months. The TRM calculation for each Flowgate is designed to replicate the outage of the unit that has the largest impact on the Flowgate, assuming that the loss of generation is compensated by other generators that participate in the SPP Operating Reserve Sharing pool according to the reserve sharing rules and the capacity necessary to accommodate that compensation by other generators. The TRM calculations are performed with applicable off- line planning models and the following databases:

BASIC.MON - MUST input file listing definitions of the Flowgates for which TRMs are to be calculated.

SUBSYSTEM.SUB – MUST Input file detailing the SPP Reserve Sharing Group's generators and BAs.

STUDY.ASC - Response file for MUST command line. Instructions for MUST to perform the analysis.

RUNSTUDY.BAT - Batch file that opens MUST and executes study instructions in Study.asc.

UNITS.TXT - List of all units in the Reserve Sharing Group.

UNITS_TEMP.TXT - Data file with filtered results out of Units.txt used in the next IPLAN program.

STUDY OUTPUT.TXT – Output file from MUST with the DF impact for every generator on every Flowgate.

For external Flowgates monitored by the Transmission Provider, it will use appropriate CBM and TRM values provided and justified by the owner of the external Flowgate.

Usage of TRM:

The Transmission Provider decrements firm AFCs by the amount of TRM and thereby withholds TRM in the Planning and Study Horizon from firm sales. TRM is sold as non-firm service in the Operating, Planning, and Study Horizons. The Transmission Provider utilizes TRM to accommodate SPP's Operating Reserve Sharing Program. More specifically, TRM is used to accommodate the flow of replacement energy across one of more SPP Flowgates during a generator contingency requiring the usage of SPP Operating Reserves for the allowable duration of the reserve sharing event. As a result, the Transmission Provider may curtail non-firm service in the operating horizon as necessary to accommodate the loss of the relevant unit and avoid curtailment of firm load and/or curtailment

## 6. CBM

The Transmission Provider does not utilize CBM.

## 7. Coordination with Neighbors

The Transmission Provider shall make the following information available in a manner consistent with the rules as defined by NAESB and NERC. Additional data, that is considered to be proprietary, may be provided on a reciprocal basis.

### 7.1 Transmission Outage Schedules

The Transmission Provider will provide the projected status of transmission outage schedules above 230 kV over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate and complete transmission facility maintenance schedules, including the "outage date" and "return date" of a transmission facility from a scheduled or forced outage. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC/AFC of the neighboring transmission provider, the status of this facility will also be provided.

### 7.2 Transmission Service Requests

(a) The Transmission Provider will make available actual transmission service request information for integration into the neighboring transmission provider's TTC/ATC/AFC determination process.

(b) The Transmission Provider will provide the neighboring transmission provider with the procedures developed and implemented to model requests for transmission service between the transmission providers.

(c) The Transmission provider shall also create, maintain and provide a list of reservations from its OASIS that should not be considered in ATC/AFC calculations. The reasons for these exceptions may include, for example, grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched partial path reservations.

### 7.3 Load Data.

The Transmission Provider shall provide peak load data for each period (*e.g.*, daily, weekly, and monthly). It shall either supply hourly load forecasts or daily peak load forecasts with a load profile for the next seven day horizon. All load forecasts will be provided on a Balancing Authority Area basis, with further granularity provided to reflect load forecasts by company within the Balancing Authority Area, as available.

### 7.4 Calculated Firm and Non-firm Available Flowgate Capability

The Transmission Provider will provide Firm and Non-firm AFC for all relevant Flowgates.

### 7.5 Total Flowgate Capability

The Transmission Provider will provide (seasonal, normal and emergency) TFCs as well as all limiting conditions (thermal, voltage, or stability). It will update this information in a timely manner as required by changes on the transmission system.

### 7.6 Identification of External Flowgates.

The Transmission Provider shall consider in its TTC and ATC/AFC determination process all external Flowgates: (i) that may initiate a TLR event, (ii) that are significantly impacted by the Transmission Provider's transactions, or (iii) as mutually agreed between the Transmission Provider and the neighboring transmission provider.

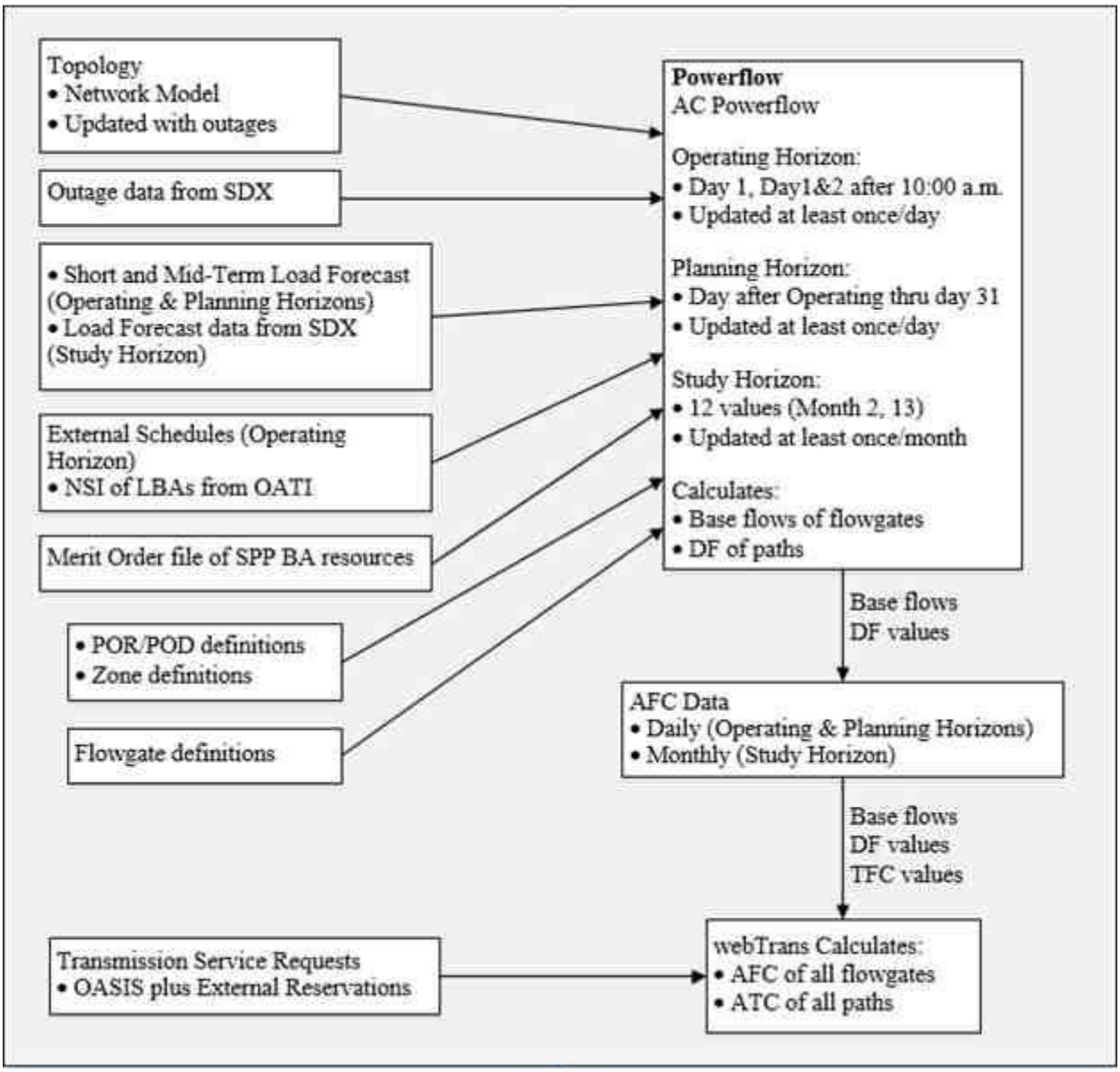
### 7.7 Configuration/Facility Changes (for power system model updates)

(a) The Transmission Provider shall, upon request, work with a neighboring transmission provider to address all significant system changes that need to be incorporated in the Transmission Provider's TTC/ATC/AFC calculation model.

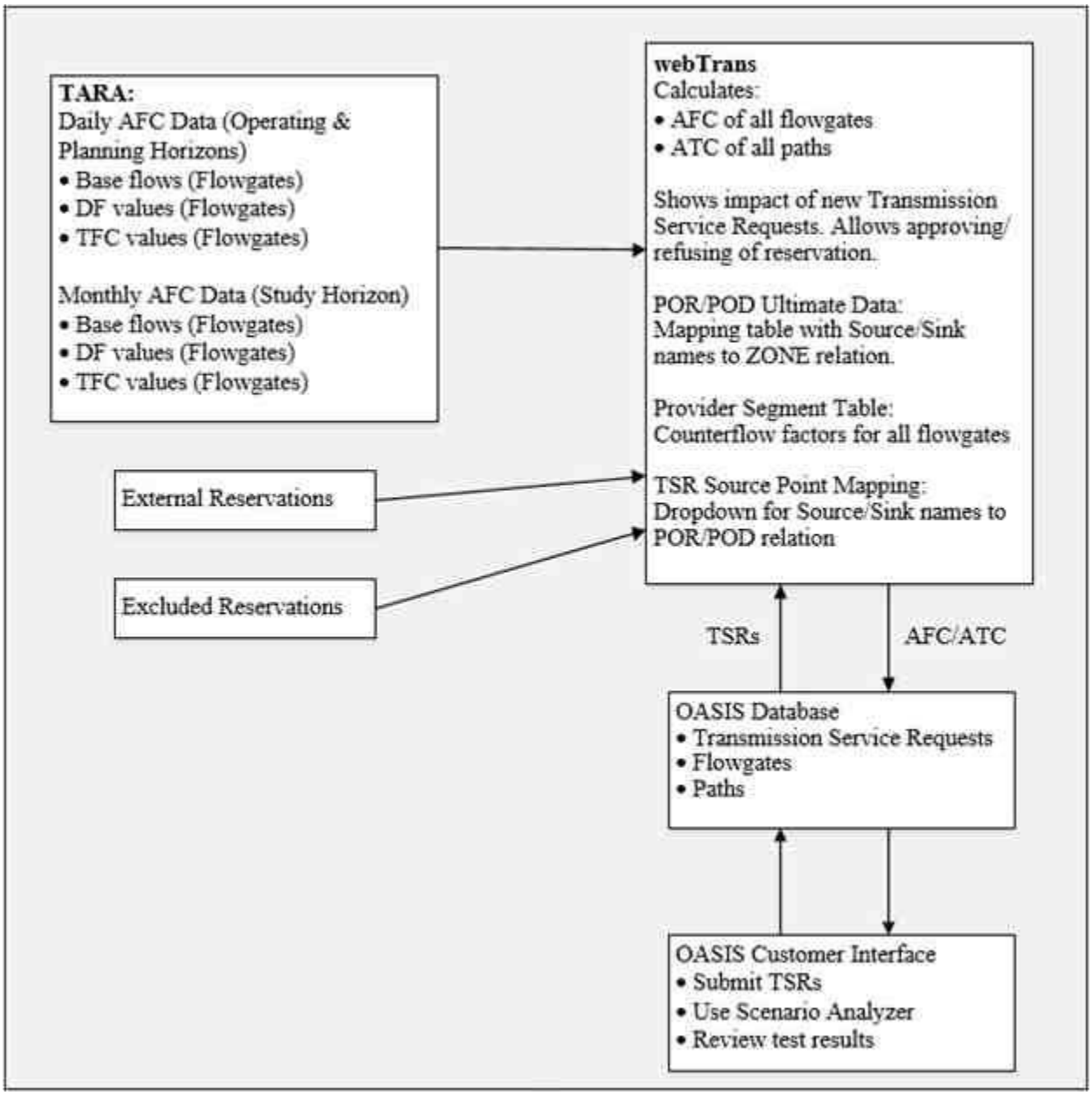
(b) The Transmission Provider shall provide TTC/TFC/ATC/AFC calculation models of its transmission system as soon as mechanisms can be established to facilitate the neighboring transmission provider's request.

## 8. AFC Flowchart

**Process Flow diagram Operating, Planning, and Study Horizons**



## Process Diagram webTrans



# ATTACHMENT D
# METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

Upon receipt of an Eligible Customer's Completed Application for Short-Term Service, the Transmission Provider will evaluate the request in accordance with the provisions of Attachment C of this Tariff to determine whether sufficient transmission capacity exists to satisfy the request. If sufficient transmission capacity exists to support the transaction described in the Eligible Customer's request, as supplemented with necessary details such as the sources and sinks of the power to be scheduled under the request, the Transmission Provider will accept the reservation. If the Transmission Provider determines that existing transmission capacity is insufficient to provide the requested service, the Transmission Provider will initiate the reservation processing methodology pursuant to Section 3 of Attachment AC of this Tariff, and perform a System Impact Study, if requested by the Eligible Customer in accordance with Sections 19 and 32 of this Tariff.

Upon receipt of a completed System Impact Study Agreement, the Transmission Provider will perform a System Impact Study to determine whether the request for transmission service can be accommodated through redispatch. The System Impact Study will provide (i) information about the system constraints that prohibit Transmission Provider's acceptance of the requested service; and (ii) whether redispatch will permit Transmission Provider to accept the reservation. The Transmission Provider shall post the results of the System Impact Study on the OASIS.

System Impact Studies are not performed for Long-Term Service requests. Long-Term Service requests are evaluated through an Aggregate Facilities Study in accordance with the procedures set forth in Attachment Z1 of this Tariff.

# ATTACHMENT E

## Reserved for Future Use

# ATTACHMENT F
# SERVICE AGREEMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE

This Network Integration Transmission Service Agreement ("Service Agreement") is entered into this ____ day of _____, ____, by and between _____ ("Network Customer"), and Southwest Power Pool, Inc. ("Transmission Provider"). The Network Customer and Transmission Provider shall be referred to individually as “Party” and collectively as "Parties."

WHEREAS, the Transmission Provider has determined that the Network Customer has made a valid request for Network Integration Transmission Service in accordance with the Transmission Provider’s Open Access Transmission Tariff ("Tariff") filed with the Federal Energy Regulatory Commission ("Commission") as it may from time to time be amended;

WHEREAS, the Transmission Provider administers Network Integration Transmission Service for Transmission Owners within the SPP Region and acts as agent for the Transmission Owners in providing service under the Tariff;

WHEREAS, the Network Customer has represented that it is an Eligible Customer under the Tariff; and

WHEREAS, the Parties intend that capitalized terms used herein shall have the same meaning as in the Tariff.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein, the Parties agree as follows:

1.0 The Transmission Provider agrees during the term of this Service Agreement, as it may be amended from time to time, to provide Network Integration Transmission Service in accordance with the Tariff to enable delivery of power and energy from the Network Customer's Network Resources that the Network Customer has committed to meet its load.

2.0 The Network Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Parts I, III and V of the Tariff and this Service Agreement with attached specifications.

3.0 The terms and conditions of such Network Integration Transmission Service shall be governed by the Tariff, as in effect at the time this Service Agreement is executed by the Network Customer, or as the Tariff is thereafter amended or by its successor tariff, if any. The Tariff, as it currently exists, or as it is hereafter amended, is incorporated in this Service Agreement by reference. In the case of any conflict between this Service Agreement and the Tariff, the Tariff shall control. The Network Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff. The completed specifications are based on the information provided in the Completed Application and are incorporated herein and made a part hereof as Attachment 1.

4.0 Service under this Service Agreement shall commence on such date as it is permitted to become effective by the Commission. This Service Agreement shall be effective through _____. Upon termination, the Network Customer remains responsible for any outstanding charges including all costs incurred and apportioned or assigned to the Network Customer under this Service Agreement.

5.0 The Transmission Provider and Network Customer have executed a Network Operating Agreement as required by the Tariff.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below. Such representative and address for notices or requests may be changed from time to time by notice by one Party or the other.

Southwest Power Pool, Inc. (Transmission Provider):

_____

201 Worthen Drive

Little Rock, AR 72223-4936

Email Address:

Phone Number:

Network Customer:

_____

_____

_____

Email Address:

Phone Number:

7.0 This Service Agreement shall not be assigned by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld. However, either Party may, without the need for consent from the other, transfer or assign this Service Agreement to any person succeeding to all or substantially all of the assets of such Party. However, the assignee shall be bound by the terms and conditions of this Service Agreement.

8.0 Nothing contained herein shall be construed as affecting in any way the Transmission Provider's or a Transmission Owner's right to unilaterally make application to the Federal Energy Regulatory Commission, or other regulatory agency having jurisdiction, for any change in the Tariff or this Service Agreement under Section 205 of the Federal Power Act, or other applicable statute, and any rules and regulations promulgated thereunder; or the Network Customer's rights under the Federal Power Act and rules and regulations promulgated thereunder.

9.0 By signing below, the Network Customer verifies that all information submitted to the Transmission Provider to provide service under the Tariff is complete, valid and accurate, and the Transmission Provider may rely upon such information to fulfill its responsibilities under the Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

| TRANSMISSION PROVIDER | NETWORK CUSTOMER |
|---|---|
| Signature _____ | Signature _____ |
| Printed Name _____ | Printed Name _____ |
| Title _____ | Title _____ |
| Date _____ | Date _____ |

# ATTACHMENT 1 TO THE NETWORK INTEGRATION TRANSMISSION SERVICE AGREEMENT

## BETWEEN SOUTHWEST POWER POOL AND _____ SPECIFICATIONS FOR NETWORK INTEGRATION TRANSMISSION SERVICE

**1.0 Network Resources**

The Network Resources are listed in Appendix 1.

**2.0 Network Loads**

The Network Load consists of the bundled native load or its equivalent for Network Customer load in the _____ Zone(s) as listed in Appendix 3.

The Network Customer's Network Load shall be measured on an hourly integrated basis, by suitable metering equipment located at each connection and delivery point, and each generating facility. The meter owner shall cause to be provided to the Transmission Provider, Network Customer and applicable Transmission Owner, on a monthly basis such data as required by Transmission Provider for billing. The Network Customer's load shall be adjusted, for settlement purposes, to include applicable Transmission Owner transmission and distribution losses, as applicable, as specified in Sections 8.5 and 8.6, respectively. For a Network Customer providing retail electric service pursuant to a state retail access program, profiled demand data, based upon revenue quality non-IDR meters may be substituted for hourly integrated demand data. Measurements taken and all metering equipment shall be in accordance with the Transmission Provider's standards and practices for similarly determining the Transmission Provider's load. The actual hourly Network Loads, by delivery point, internal generation site and point where power may flow to and from the Network Customer, with separate readings for each direction of flow, shall be provided.

**3.0 Affected Zone(s) and Intervening Systems Providing Transmission Service**

The affected Zone(s) is/are _____. The intervening systems providing transmission service are _____.

**4.0 Electrical Location of Initial Sources**

See Appendix 1.

**5.0 Electrical Location of the Ultimate Loads**

The loads of _____ identified in Section 2.0 hereof as the Network Load are electrically located within the _____ Zone(s).

**6.0 Delivery Points**

The delivery points are the interconnection points of _____ identified in Section 2.0 as the Network Load.

**7.0 Receipt Points**

The Points of Receipt are listed in Appendix 2.

**8.0 Compensation**

Service under this Service Agreement may be subject to some combination of the charges detailed below. The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.

**8.1 Transmission Charge**

Monthly Demand Charge per Section 34 and Part V of the Tariff.

**8.2 System Impact and/or Facility Study Charge**

Studies may be required in the future to assess the need for system reinforcements in light of the ten-year forecast data provided. Future charges, if required, shall be in accordance with Section 32 of the Tariff.

**8.3 Direct Assignment Facilities Charge**

**8.4 Ancillary Service Charges**

**8.4.1** The following Ancillary Services are required under this Service Agreement.

a) Scheduling, System Control and Dispatch Service per Schedule 1 of the Tariff.

b) Tariff Administration Service per Schedule 1-A1 of the Tariff.

c) Reactive Supply and Voltage Control from Generation Sources Service per Schedule 2 of the Tariff.

d) Regulation and Frequency Response Service per Schedule 3 of the Tariff.

e) Energy Imbalance Service per Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service per Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service per Schedule 6 of the Tariff.

The Ancillary Services may be self-supplied by the Network Customer or provided by a third party in accordance with Sections 8.4.2 through 8.4.4, with the exception of the Ancillary Services for Schedules 1, 1-A, and 2, which must be purchased from the Transmission Provider.

**8.4.2** In accordance with the Tariff, when the Network Customer elects to self-supply or have a third party provide Ancillary Services, the Network Customer shall indicate the source for its Ancillary Services to be in effect for the upcoming calendar year in its annual forecasts. If the Network Customer fails to include this information with its annual forecasts, Ancillary Services will be purchased from the Transmission Provider in accordance with the Tariff.

**8.4.3** When the Network Customer elects to self-supply or have third party provide Ancillary Services and is unable to provide its Ancillary Services, the Network Customer will pay the Transmission Provider for such services and associated penalties in accordance with the Tariff as a result of the failure of the Network Customer's alternate sources for required Ancillary Services.

**8.4.4** All costs for the Network Customer to supply its own Ancillary Services shall be the responsibility of the Network Customer.

**8.5 Real Power Losses - Transmission**

The Network Customer shall be responsible for losses in accordance with Attachment M of the Tariff.

**8.6 Real Power Losses - Distribution**

**8.7 Power Factor Correction Charge**

**8.8 Redispatch Charge**

Redispatch charges shall be in accordance with Section 33.3 of the Tariff.

**8.9 Wholesale Distribution Service Charge**

**8.10 Network Upgrade Charges**

**8.11 Meter Data Processing Charge**

**8.12 Other Charges**

**8.13 Candidate Incremental LTCRs**

* Source _____
* Sink _____

* Candidate Incremental LTCR MW _____

* Term (years from in-service date of Network Upgrade) _____

**9.0 Credit for Network Customer-Owned Transmission Facilities**

**10.0 Designation of Parties Subject to Reciprocal Service Obligation**

**11.0 Other Terms and Conditions**

# APPENDIX 1

## Network Resources of

_____

# APPENDIX 1 _____ NETWORK RESOURCES

| Network Resource Name | Service Start Date | Service End Date | Firm Transmission Rights | Comments |
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# Appendix 2

## Receipt Points of

_____

## APPENDIX 2 _____ RECEIPT POINTS

| Tieline / Plant Name | Ownership | Voltage (kV) | |
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# Appendix 3

## Delivery Points of

_____

## APPENDIX 3 _____ DELIVERY POINTS

| Delivery Point Name | Ownership | Voltage (kV) |
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# ATTACHMENT G
# NETWORK OPERATING AGREEMENT

This Network Operating Agreement ("Operating Agreement") is entered into this ____ day of _____, ____, by and between _____ ("Network Customer"), Southwest Power Pool, Inc. ("Transmission Provider") and _____ ("Host Transmission Owner"). The Network Customer, Transmission Provider and Host Transmission Owner shall be referred to individually as a “Party” and collectively as "Parties."

WHEREAS, the Transmission Provider has determined that the Network Customer has made a valid request for Network Integration Transmission Service in accordance with the Transmission Provider’s Open Access Transmission Tariff ("Tariff") filed with the Federal Energy Regulatory Commission ("Commission");

WHEREAS, the Transmission Provider administers Network Integration Transmission Service for Transmission Owners within the SPP Region and acts as an agent for these Transmission Owners in providing service under the Tariff;

WHEREAS, the Host Transmission Owner(s) owns the transmission facilities to which the Network Customer’s Network Load is physically connected;

WHEREAS, the Network Customer has represented that it is an Eligible Customer under the Tariff;

WHEREAS, the Network Customer and Transmission Provider have entered into a Network Integration Transmission Service Agreement (“Service Agreement”) under the Tariff; and

WHEREAS, the Parties intend that capitalized terms used herein shall have the same meaning as in the Tariff, unless otherwise specified herein.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein, the Parties agree as follows:

## 1.0 Network Service

This Operating Agreement sets out the terms and conditions under which the Transmission Provider, Host Transmission Owner, and Network Customer will cooperate and the Host Transmission Owner and Network Customer will operate their respective systems and specifies the equipment that will be installed and operated. The Parties shall operate and maintain their respective systems in a manner that will allow the Host Transmission Owner and the Network Customer to operate their systems and the Transmission Provider to perform its obligations consistent with Good Utility Practice. The Transmission Provider may, on a non-discriminatory basis, waive the requirements of Section 4.1 and Section 8.3 to the extent that such information is unknown at the time of application or where such requirement is not applicable.

## 2.0 Designated Representatives of the Parties

2.1 Each Party shall designate a representative and alternate ("Designated Representative(s)") from their respective company to coordinate and implement, on an ongoing basis, the terms and conditions of this Operating Agreement, including planning, operating, scheduling, redispatching, curtailments, control requirements, technical and operating provisions, integration of equipment, hardware and software, and other operating considerations.

2.2 The Designated Representatives shall represent the Transmission Provider, Host Transmission Owner, and Network Customer in all matters arising under this Operating Agreement and which may be delegated to them by mutual agreement of the Parties hereto.

2.3 The Designated Representatives shall meet or otherwise confer at the request of any Party upon reasonable notice, and each Party may place items on the meeting agenda. All deliberations of the Designated Representatives shall be conducted by taking into account the exercise of Good Utility Practice. If the Designated Representatives are unable to agree on any matter subject to their deliberation, that matter shall be resolved pursuant to Section 12.0 of the Tariff, or otherwise, as mutually agreed by the Parties.

## 3.0 System Operating Principles

3.1 The Network Customer must design, construct, and operate its facilities safely and efficiently in accordance with Good Utility Practice, NERC, SPP, or any successor requirements, industry standards, criteria, and applicable manufacturer's equipment specifications, and within operating physical parameter ranges (voltage schedule, load power factor, and other parameters) required by the Host Transmission Owner and Transmission Provider.

3.2 The Host Transmission Owner and Transmission Provider reserve the right to inspect the facilities and operating records of the Network Customer upon mutually agreeable terms and conditions.

3.3 Electric service, in the form of three phase, approximately sixty hertz alternating current, shall be delivered at designated delivery points and nominal voltage(s) listed in the Service Agreement. When multiple delivery points are provided to a specific Network Load identified in Appendix 3 of the Service Agreement, they shall not be operated in parallel by the Network Customer without the approval of the Host Transmission Owner and Transmission Provider. The Designated Representatives shall establish the procedure for obtaining such approval. The Designated Representatives shall also establish and monitor standards and operating rules and procedures to assure that transmission system integrity and the safety of customers, the public and employees are maintained or enhanced when such parallel operations is permitted either on a continuing basis or for intermittent switching or other service needs. Each Party shall exercise due diligence and reasonable care in maintaining and operating its facilities so as to maintain continuity of service.

3.4 The Host Transmission Owner and Network Customer shall operate their systems and delivery points in continuous synchronism and in accord with applicable NERC Standards, SPP Criteria, and Good Utility Practice.

3.5 If the function of any Party's facilities is impaired or the capacity of any delivery point is reduced, or synchronous operation at any delivery point(s) becomes interrupted, either manually or automatically, as a result of force majeure or maintenance coordinated by the Parties, the Parties will cooperate to remove the

cause of such impairment, interruption or reduction, so as to restore normal operating conditions expeditiously.

3.6 The Transmission Provider and Host Transmission Owner, if applicable, reserve the sole right to take any action necessary during an actual or imminent emergency to preserve the reliability and integrity of the Transmission System, limit or prevent damage, expedite restoration of service, ensure safe and reliable operation, avoid adverse effects on the quality of service, or preserve public safety.

3.7 In an emergency, the reasonable judgment of the Transmission Provider and Host Transmission Owner, if applicable, in accordance with Good Utility Practice, shall be the sole determinant of whether the operation of the Network Customer loads or equipment adversely affects the quality of service or interferes with the safe and reliable operation of the transmission system. The Transmission Provider or Host Transmission Owner, if applicable, may discontinue transmission service to such Network Customer until the power quality or interfering condition has been corrected. Such curtailment of load, redispatching, or load shedding shall be done on a non-discriminatory basis by Load Ratio Share, to the extent practicable. The Transmission Provider or Host Transmission Owner, if applicable, will provide reasonable notice and an opportunity to alleviate the condition by the Network Customer to the extent practicable.

## 4.0 System Planning & Protection

4.1 No later than October 1 of each year, the Network Customer shall provide the Transmission Provider and Host Transmission Owner the following information:

a) A ten (10) year projection of summer and winter peak demands with the corresponding power factors and annual energy requirements on an aggregate basis for each delivery point. If there is more than one delivery point, the Network Customer shall provide the summer and winter peak demands and energy requirements at each delivery point for the normal operating configuration;

b) A ten (10) year projection by summer and winter peak of planned generating capabilities and committed transactions with third parties which resources are expected to be used by the Network Customer to supply the peak demand and energy requirements provided in (a);

c) A ten (10) year projection by summer and winter peak of the estimated maximum demand in kilowatts that the Network Customer plans to acquire from the generation resources owned by the Network Customer, and generation resources purchased from others; and

d) A projection for each of the next ten (10) years of transmission facility additions to be owned and/or constructed by the Network Customer which facilities are expected to affect the planning and operation of the transmission system within the Host Transmission Owner's Zone.

This information is to be delivered to the Transmission Provider's and Host Transmission Owner's Designated Representatives pursuant to Section 2.0.

4.2 Information exchanged by the Parties under this article will be used for system planning and protection only, and will not be disclosed to third parties absent mutual consent or order of a court or regulatory agency.

4.3 The Host Transmission Owner, and Transmission Provider, if applicable, will incorporate this information in its system load flow analyses performed during the first half of each year. Following completion of these analyses, the Transmission Provider or Host Transmission Owner will provide the following to the Network Customer:

a) A statement regarding the ability of the Host Transmission Owner's transmission system to meet the forecasted deliveries at each of the delivery points;

b) A detailed description of any constraints on the Host Transmission Owner's system within the five (5) year horizon that will restrict forecasted deliveries; and

c) In the event that studies reveal a potential limitation of the Transmission Provider's ability to deliver power and energy to any of the delivery points, a Designated Representative of the Transmission Provider will coordinate with the Designated Representatives of the Host Transmission Owner and the Network Customer to identify appropriate remedies for such constraints including but not limited to: construction of new transmission facilities, upgrade or other improvements to existing transmission facilities or temporary modification to operating procedures designed to relieve identified constraints. Any constraints within the Transmission System will be remedied pursuant to the procedures of Attachment O of the Tariff.

For all other constraints the Host Transmission Owner, upon agreement with the Network Customer and consistent with Good Utility Practice, will endeavor to construct and place into service sufficient capacity to maintain reliable service to the Network Customer.

An appropriate sharing of the costs to relieve such constraints will be determined by the Parties, consistent with the Tariff and with the Commission's rules, regulations, policies, and precedents then in effect. If the Parties are unable to agree upon an appropriate remedy or sharing of the costs, the Transmission Provider shall submit its proposal for the remedy or sharing of such costs to the Commission for approval consistent with the Tariff.

4.4 The Host Transmission Owner and the Network Customer shall coordinate with the Transmission Provider: (1) all scheduled outages of generating resources and transmission facilities consistent with the reliability of service to the customers of

each Party, and (2) additions or changes in facilities which could affect another Party's system. Where coordination cannot be achieved, the Designated Representatives shall intervene for resolution.

4.5 The Network Customer shall coordinate with the Host Transmission Owner regarding the technical and engineering arrangements for the delivery points, including one line diagrams depicting the electrical facilities configuration and parallel generation, and shall design and build the facilities to avoid interruptions on the Host Transmission Owner's transmission system.

4.6 The Network Customer shall provide for automatic and underfrequency load shedding of the Network Customer Network Load in accordance with the SPP Criteria related to emergency operations.

## 5.0 Maintenance of Facilities

5.1 The Network Customer shall maintain its facilities necessary to reliably receive capacity and energy from the Host Transmission Owner's transmission system consistent with Good Utility Practice. The Transmission Provider or Host Transmission Owner, as appropriate, may curtail service under this Operating Agreement to limit or prevent damage to generating or transmission facilities caused by the Network Customer's failure to maintain its facilities in accordance with Good Utility Practice, and the Transmission Provider or Host Transmission Owner may seek as a result any appropriate relief from the Commission.

5.2 The Designated Representatives shall establish procedures to coordinate the maintenance schedules, and return to service, of the generating resources and transmission and substation facilities, to the greatest extent practical, to ensure sufficient transmission resources are available to maintain system reliability and reliability of service.

5.3 The Network Customer shall obtain: (1) concurrence from the Transmission Provider before beginning any scheduled maintenance of facilities which could impact the operation of the Transmission System over which transmission service is administered by Transmission Provider; and (2) clearance from the Transmission Provider when the Network Customer is ready to begin maintenance on a transmission line or substation. The Transmission Provider shall coordinate clearances with the Host Transmission Owner. The Network Customer shall notify the Transmission Provider and the Host Transmission Owner as soon as practical at the time when any unscheduled or forced outages occur and again when such unscheduled or forced outages end.

## 6.0 Scheduling Procedures

6.1 The Network Customer is responsible for providing its Resource and load information to the Transmission Provider in accordance with Attachment AE.

6.2 For Interchange Transactions the Network Customer shall submit, or arrange to have submitted, the schedule of Energy to or from the Transmission Provider and a transaction identification E-Tag for each such schedule where required by NERC Standard INT-001.

## 7.0 Ancillary Services

7.1 The Network Customer must make arrangements in appropriate amounts for all of the required Ancillary Services described in the Tariff. The Network Customer must obtain these services from the Transmission Provider or, where applicable, self-supply or obtain these services from a third party.

7.2 Where the Network Customer elects to self-supply or have a third party provide Ancillary Services, the Network Customer must demonstrate to the Transmission Provider that it has either acquired the Ancillary Services from another source or is capable of self-supplying the services.

7.3 The Network Customer must designate the supplier of Ancillary Services.

## 8.0 Metering

8.1 The Network Customer shall provide for the installation of meters, associated metering equipment and telemetering equipment. The Network Customer shall permit (or provide for, if the Network Customer is not the meter owner) the Transmission Provider's and Host Transmission Owner's representative to have access to the equipment at all reasonable hours and for any reasonable purpose, and shall not permit unauthorized persons to have access to the space housing the equipment. Network Customer shall provide to (or provide for, if the Network Customer is not the meter owner) the Host Transmission Owner access to load data and other data available from any delivery point meter. If the Network Customer does not own the meter, the Host Transmission Owner shall make available, upon request, all load data and other data obtained by the Host Transmission Owner from the relevant delivery point meter, if available utilizing existing equipment. The Network Customer will cooperate on the installation of advanced technology metering in place of the standard metering equipment at a delivery point at the expense of the requestor; provided, however, that meter owner shall not be obligated to install, operate or maintain any meter or related equipment that is not approved for use by the meter owner and/or Host Transmission Owner, and provided that such equipment addition can be accomplished in a manner that does not interfere with the operation of the meter owner's equipment or any Party's fulfillment of any statutory or contractual obligation.

8.2 The Network Customer shall provide for the testing of the metering equipment at suitable intervals and its accuracy of registration shall be maintained in accordance with standards acceptable to the Transmission Provider and consistent with Good Utility Practice. At the request of the Transmission Provider or Host Transmission Owner, a special test shall be made, but if less than two percent inaccuracy is found, the requesting Party shall pay for the test. Representatives of the Parties may be present at all routine or special tests and whenever any readings for purposes of settlement are taken from meters not having an automated record. If any test of metering equipment discloses an inaccuracy

exceeding two percent, the accounts of the Parties shall be adjusted. Such adjustment shall apply to the period over which the meter error is shown to have been in effect or, where such period is indeterminable, for one-half the period since the prior meter test. Should any metering equipment fail to register, the amounts of energy delivered shall be estimated from the best available data.

8.3 If the Network Customer is supplying energy to retail load that has a choice in its supplier, the Network Customer shall be responsible for providing all information required by the Transmission Provider for billing purposes. Metering information shall be available to the Transmission Provider either by individual retail customer or aggregated retail energy information for that load the Network Customer has under contract during the billing month. For the retail load that has interval demand metering, the actual energy used by interval must be supplied. For the retail load using standard kWh metering, the total energy consumed by meter cycle, along with the estimated demand profile must be supplied. All rights and limitations between Parties granted in Sections 8.1, and 8.2 are applicable in regards to retail metering used as the basis for billing the Network Customer.

## 9.0 Connected Generation Resources

9.1 The Network Customer's connected generation resources that have automatic generation control and automatic voltage regulation shall be operated and maintained consistent with regional operating standards, and the Network Customer or the operator shall operate, or cause to be operated, such resources to avoid adverse disturbances or interference with the safe and reliable operation of the transmission system as instructed by the Transmission Provider.

9.2 For all Network Resources of the Network Customer, the following generation telemetry readings shall be submitted to the Transmission Provider and Host Transmission Owner:

1) Analog MW;
2) Integrated MWHRS/HR;
3) Analog MVARS; and
4) Integrated MVARHRS/HR.

## 10.0 Redispatching, Curtailment and Load Shedding

10.1 In accordance with Section 33 of the Tariff, the Transmission Provider may require redispatching of Resources to relieve existing or potential transmission system constraints. The Transmission Provider shall redispatch Resources in accordance with the Energy and Operating Reserve Markets operations specified in Attachment AE. The Network Customer shall respond immediately to requests for redispatch from the Transmission Provider. The Transmission Provider will bill or credit the Network Customer as appropriate using the settlement procedures specified in Attachment AE.

10.2 The Parties shall implement load-shedding procedures to maintain the reliability and integrity for the Transmission System as provided in Section 33.1 of the Tariff and in accordance with applicable NERC and SPP requirements and Good Utility Practice. Load shedding may include (1) automatic load shedding, (2) manual load shedding, and (3) rotating interruption of customer load. When manual load shedding or rotating interruptions are necessary, the Host Transmission Owner shall notify the Network Customer's dispatcher or schedulers of the required action and the Network Customer shall comply immediately.

10.3 The Network Customer will coordinate with the Host Transmission Owner to ensure sufficient load shedding equipment is in place on their respective systems to meet SPP requirements. The Network Customer and the Host Transmission Owner shall develop a plan for load shedding which may include manual load shedding by the Network Customer.

## 11.0 Communications

11.1 The Network Customer shall, at its own expense, install and maintain communication link(s) for scheduling. The communication link(s) shall be used for data transfer and for voice communication.

11.2 A Network Customer self-supplying Ancillary Services or securing Ancillary Services from a third-party shall, at its own expense, install and maintain telemetry equipment communicating between the generating resource(s) providing such Ancillary Services and the Host Transmission Owner's Zone.

## 12.0 Cost Responsibility

12.1 The Network Customer shall be responsible for all costs incurred by the Network Customer, Host Transmission Owner, and Transmission Provider to implement the provisions of this Operating Agreement including, but not limited to, engineering, administrative and general expenses, material and labor expenses associated with the specification, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, upgrading, calibration, removal, and relocation of equipment or software, so long as the direct assignment of such costs is consistent with Commission policy.

12.2 The Network Customer shall be responsible for all costs incurred by Network Customer, Host Transmission Owner, and Transmission Provider for on-going operation and maintenance of the facilities required to implement the provisions of this Operating Agreement so long as the direct assignment of such costs is consistent with Commission policy. Such work shall include, but is not limited to, normal and extraordinary engineering, administrative and general expenses, material and labor expenses associated with the specifications, design, review, approval, purchase, installation, maintenance, modification, repair, operation, replacement, checkouts, testing, calibration, removal, or relocation of equipment required to accommodate service provided under this Operating Agreement.

## 13.0 Billing and Payments

Billing and Payments shall be in accordance with Attachment AE and Section 7 of the Tariff.

## 14.0 Dispute Resolution

Any dispute among the Parties regarding this Operating Agreement shall be resolved pursuant to Section 12 of the Tariff, or otherwise, as mutually agreed by the Parties.

## 15.0 Assignment

This Operating Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by any Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the other Parties. Such written consent shall not be unreasonably withheld.

## 16.0 Choice of Law

The interpretation, enforcement, and performance of this Operating Agreement shall be governed by the laws of the State of Arkansas, except laws and precedent of such jurisdiction concerning choice of law shall not be applied, except to the extent governed by the laws of the United States of America.

## 17.0 Entire Agreement

The Tariff and Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof. To the extent that a conflict exists between the terms of this Operating Agreement and the terms of the Tariff, the Tariff shall control.

## 18.0 Unilateral Changes and Modifications

Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way the right of the Transmission Provider or a Transmission Owner unilaterally to file with the Commission, or make application to the Commission for, changes in rates, charges, classification of service, or any rule, regulation, or agreement related thereto, under section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder, or under other applicable statutes or regulations.

Nothing contained in this Operating Agreement or any associated Service Agreement shall be construed as affecting in any way the ability of any Network Customer receiving Network Integration Transmission Service under the Tariff to exercise any right under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder; provided, however, that it is expressly recognized that this Operating Agreement is necessary for the implementation of the Tariff and Service Agreement. Therefore, no Party shall propose a change to this Operating Agreement that is inconsistent with the rates, terms and conditions of the Tariff and/or Service Agreement.

## 19.0 Term

This Operating Agreement shall become effective on the date assigned by the Commission ("Effective Date"), and shall continue in effect until the Tariff or the Network Customer's Service Agreement is terminated, whichever shall occur first.

## 20.0 Notice

20.1 Any notice that may be given to or made upon any Party by any other Party under any of the provisions of this Operating Agreement shall be in writing, unless otherwise specifically provided herein, and shall be considered delivered when the notice is personally delivered or deposited in the United States mail, certified or registered postage prepaid, to the following:

[Transmission Provider]
[name]
[title]
[address]
[phone]
[fax]
[email address]

[Host Transmission Owner]
[name]
[title]
[address]
[phone]
[fax]
[email address]

[Network Customer]
[name]
[title]
[address]
[phone]
[fax]
[email address]

Any Party may change its notice address by written notice to the other Parties in accordance with this Article 20.

20.2 Any notice, request, or demand pertaining to operating matters may be delivered in writing, in person or by first class mail, e-mail, messenger, or facsimile transmission as may be appropriate and shall be confirmed in writing as soon as reasonably practical thereafter, if any Party so requests in any particular instance.

## 21.0 Execution in Counterparts

This Operating Agreement may be executed in any number of counterparts with the same effect as if all Parties executed the same document. All such counterparts shall be construed together and shall constitute one instrument.

IN WITNESS WHEREOF, the Parties have caused this Operating Agreement to be executed by their respective authorized officials, and copies delivered to each Party, to become effective as of the Effective Date.

TRANSMISSION PROVIDER

_____
Signature

_____
Printed Name

_____
Title

_____
Date

HOST TRANSMISSION OWNER

_____
Signature

_____
Printed Name

_____
Title

_____
Date

NETWORK CUSTOMER

_____
Signature

_____
Printed Name

_____
Title

_____
Date

# ATTACHMENT H
# ANNUAL TRANSMISSION REVENUE REQUIREMENT FOR NETWORK INTEGRATION TRANSMISSION SERVICE

## SECTION I: General Requirements

1. The Zonal Annual Transmission Revenue Requirement ("Zonal ATRR") for each Transmission Owner for purposes of determining the charges under Schedule 9, Network Integration Transmission Service, is specified in Column (3) Section I, of Table 1. The Base Plan Zonal Annual Transmission Revenue Requirement ("Base Plan Zonal ATRR") used to determine the zonal charges under Schedule 11 for Base Plan Upgrades issued a Notification to Construct ("NTC") prior to June 19, 2010 is specified in Column (4) Section I, of Table 1. The Base Plan Zonal ATRR used to determine the zonal charges under Schedule 11 for Base Plan Upgrades issued an NTC on or after June 19, 2010 is specified in Column (5) of Section I, Table 1. The amount of Zonal ATRR and Base Plan Zonal ATRR that is included in Columns (3), (4), (5), and (7) and reallocated to the Region-wide Annual Transmission Revenue Requirement ("Region-wide ATRR"), in accordance with Attachment J, is specified in Column (6) of Section I, Table 1. The Base Plan Zonal ATRR to pay Upgrade Sponsors in accordance with Attachment Z2 is specified in Column (7) of Section I, Table 1.

Table 1

(See Note A below)

| (1) Zone | (2) | (3) Zonal ATRR | (4) Base Plan Zonal ATRR | (5) Base Plan Zonal ATRR after June 19, 2010 | (6) ATRR Reallocated to Balanced Portfolio Region-wide ATRR | (7) Base Plan Zonal ATRR to pay Upgrade Sponsors |
|---|---|---|---|---|---|---|
| 1 | American Electric Power –West (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

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|---|---|---|---|---|---|---|
| 1a | American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.2 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | | | |
| 1b | East Texas Electric Cooperative, Inc. | $14,567,983 | | | | |
| 1c | Reserved for Future Use | | | | | |
| 1d | Deep East Texas Electric Cooperative, Inc. | $2,576,698 | | | | |
| 1e | Oklahoma Municipal Power Authority | $768,624 | | | | |
| 1f | AEP West Transmission Companies (AEP Oklahoma Transmission Company, Inc and AEP Southwestern Transmission Company, Inc) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 1g | Coffeyville Municipal Light and Power (CMLP) | $391,790 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 1h | Arkansas Electric Cooperative Corporation (AECC) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 1i | Transource Oklahoma, LLC | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 2 | Kansas City Board of Public Utilities | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

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| 3 | City Utilities of Springfield, Missouri | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 4 | Empire District Electric Company | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 5 | Grand River Dam Authority | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 6 | Evergy Metro, Inc. (TOTAL) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 6a | Evergy Metro, Inc. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 6b | City of Independence, Missouri | $7,043,930 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 7 | Oklahoma Gas and Electric (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 7a | Oklahoma Gas and Electric | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 7b | Oklahoma Municipal Power Authority | $368,501 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 7c | Arkansas Electric Cooperative Corporation | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 7d | People’s Electric Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 8 | Midwest Energy, Inc. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 9 | Evergy Missouri West, Inc. (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 9a | Evergy Missouri West, Inc. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

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| 9b | Transource Missouri, LLC | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 10 | Southwestern Power Administration (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 10a | Southwestern Power Administration Zonal ATRR (Non-Federal Transmission Service ATRR) | $15,533,800 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 10a(i) | NITS ATRR | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 10b | South Central MCN LLC | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 10c | Missouri Joint Municipal Electric Utility Commission | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 10d | People's Electric Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 11 | Southwestern Public Service Company (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 11a | Southwestern Public Service Company | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 11b | *Reserved for Future Use* | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 11c | Lea County Electric Cooperative, Inc. | $388,000 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 12 | Sunflower Electric Power Corporation (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 12a | Sunflower Electric Power Corporation | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

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| 12b | ITC Great Plains, LLC | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 12c | Prairie Wind Transmission, LLC | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 13 | Western Farmers Electric Cooperative (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 13a | Western Farmers Electric Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 13b | People's Electric Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 14 | Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc.) (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 14a | Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc.) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 14b | Prairie Wind Transmission, LLC. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 14c | Kansas Power Pool | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 14d | South Central MCN LLC | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 15 | Reserved for Future Use | | | | | |
| 16 | Lincoln Electric System | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

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| 17 | Nebraska Public Power District (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 17a | Nebraska Public Power District | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 17b | Central Nebraska Public Power and Irrigation District | $327,891 | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 17c | Tri-State G&T Association | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 18 | Omaha Public Power District | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19 | Upper Missouri Zone – Total | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19a | Western-UGP | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19b | Basin Electric Power Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19c | Heartland Consumers Power District | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d | Missouri River Energy Services (Total) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (i) | Missouri River Energy Services | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (ii) | Moorhead Public Service | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (iii) | Orange City Municipal Utilities | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (iv) | City of Pierre, South Dakota | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

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| 19d (v) | City of Sioux Center, Iowa | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (vi) | Watertown Municipal Utility Department | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (vii) | Denison Municipal Utilities | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19d (viii) | Vermillion Light & Power | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19e | East River Electric Power Cooperative, Inc. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19f | Corn Belt Power Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19g | NorthWestern Corporation (South Dakota) | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19h | Northwest Iowa Power Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19i | Harlan Municipal Utilities | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19j | Central Power Electric Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19k | Mountrail-Williams Electric Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19l | Mor-Gran-Sou Electric Cooperative, Inc. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19m | Roughrider Electric Cooperative, Inc. | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |
| 19n | L and O Power Cooperative | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

| | | | | | | |
|---|---|---|---|---|---|---|
| 20 | Total | | | | See Att. H tab, posted RRR File | See Att. H tab, posted RRR File |

Note A: The Annual Transmission Revenue Requirements ("ATRR") for each Zone are set forth in the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

2. Table 2-A specifies the Region-wide ATRR for Network Upgrades needed prior to October 1, 2015 and Table 2-B specifies the Region-wide ATRR for Network Upgrades needed on or after October 1, 2015. The Region-wide ATRR, shown in Line 8 of Section I, Table 2-A, shall be the sum of (i) the Base Plan Region-wide Annual Transmission Revenue Requirements ("Base Plan Region-wide ATRR") (reflected in Line 1 and Line 2), (ii) the total Balanced Portfolio Region-wide Annual Transmission Revenue Requirements ("Balanced Portfolio Region-wide ATRR") (reflected in Line 3 and Line 4), (iii) for transmission service beginning prior to October 1, 2015, the Base Plan Region-wide ATRR to pay Upgrade Sponsors as determined in accordance with Attachment Z2 of this Tariff (reflected in Line 5), and (iv) the Interregional Planning Region Annual Transmission Revenue Requirements ("Interregional Planning Region ATRR") allocable to customers receiving transmission service under this Tariff for any Interregional Project(s) constructed within the SPP Region (Line 6) and/or within other Interregional Planning Regions (Line 7).

The Region-wide ATRR shown in Line 8 of Section I, Table 2-B, shall be the sum of (i) the Base Plan Region-wide ATRR (reflected in Line 1 and Line 2), (ii) the total Balanced Portfolio Region-wide ATRR (reflected in Line 3 and Line 4) and (iii) for transmission service beginning on or after October 1, 2015, the Base Plan Region-wide ATRR to pay Upgrade Sponsors as determined in accordance with Attachment Z2 of this Tariff (reflected in Line 5), (iv) the Interregional Planning Region Annual Transmission Revenue Requirements ("Interregional Planning Region ATRR") allocable to customers receiving transmission service under this Tariff for any Interregional Project(s) constructed within the SPP Region (Line 6) and/or within other Interregional Planning Regions (Line 7a), and (v) the Annual Transmission Revenue Requirements approved for

inclusion in the Region-wide ATRR (Line 7b) and associated with any transmission upgrade approved pursuant to the coordination agreements listed in Addendum 1 to Attachment O.

As described in Schedule 11, the Region-wide Charges for Zones 1 through 18 shall be based upon Line 8 of Table 2-A and Line 8 of Table 2-B. The Region-wide Charges for Zone 19 shall be based upon Line 8 of Table 2-B.

Table 2-A

(See Note B below)

| | | |
|---|---|---|
| 1 | Base Plan Region-wide ATRR (NTC prior to June 19, 2010) | See Att. H tab, posted RRR File |
| 2 | Base Plan Region-wide ATRR (NTC on or after June 19, 2010) | See Att. H tab, posted RRR File |
| 3 | Total ATRR reallocated to Balanced Portfolio Region-wide ATRR from Column (6), Section I, Table 1 | See Att. H tab, posted RRR File |
| 4 | Balanced Portfolio Region-wide ATRR | See Att. H tab, posted RRR File |
| 5 | Base Plan Region-wide ATRR to pay Upgrade Sponsors | See Att. H tab, posted RRR File |
| 6 | SPP Interregional Planning Region ATRR | See Att. H tab, posted RRR File |
| 7 | Other Interregional Planning Region ATRR | See Att. H tab, posted RRR File |
| 8 | Region-wide ATRR (Sum of Lines 1 through 7) | See Att. H tab, posted RRR File |

Table 2-B

(See Notes B and C below)

| | | |
|---|---|---|
| 1 | Base Plan Region-wide ATRR (NTC prior to June 19, 2010) | See Att. H tab, posted RRR File |
| 2 | Base Plan Region-wide ATRR (NTC on or after June 19, 2010) | See Att. H tab, posted RRR File |
| 3 | Total ATRR reallocated to Balanced Portfolio Region-wide ATRR from Column (6), Section I, Table 1 | See Att. H tab, posted RRR File |
| 4 | Balanced Portfolio Region-wide ATRR | See Att. H tab, posted RRR File |
| 5 | Base Plan Region-wide ATRR to pay Upgrade Sponsors | See Att. H tab, posted RRR File |

| | | |
|---|---|---|
| 6 | SPP Interregional Planning Region ATRR | See Att. H tab, posted RRR File |
| 7a | Other Interregional Planning Region ATRR | See Att. H tab, posted RRR File |
| 7b | Other transmission provider ATRR | See Att. H tab, posted RRR File |
| 8 | Region-wide ATRR (Sum of Lines 1 through 7) | See Att. H tab, posted RRR File |

Note B: The Region-wide ATRRs are set forth in the RRR File posted on the SPP website.

Note C: The Region-wide ATRR provided in Line 7b of Table 2-B includes the revenue requirements for the Morgan Transformer Project, as set forth in the Cost Sharing and Usage Agreement Between Southwest Power Pool, Inc. and Associated Electric Cooperative, Inc.; and for the Blackberry Substation Upgrade, as set forth in the Cost and Usage Agreement Between Southwest Power Pool, Inc. and Associated Electric Cooperative, Inc. Such revenue requirements are posted in the RRR File on the SPP website.

3. A Transmission Owner's revenue requirement referenced or stated in this Attachment H shall not be changed absent a filing with the Commission, accompanied by all necessary cost support, unless such Transmission Owner utilizes Commission-approved formula rate processes contained in this Tariff to determine its revenue requirements.
4. A new or amended revenue requirement referenced or stated in this Attachment H shall not be filed with the Commission by the Transmission Provider unless such revenue requirements have been provided by or for a Transmission Owner. Such revenue requirements shall have been accepted or approved by the applicable regulatory or governing authority except in the event of a simultaneous filing with the Commission by the Transmission Owner and Transmission Provider.
5. If a Transmission Owner has a Commission-approved formula rate, the successful completion of its approved annual formula rate update procedures shall constitute regulatory acceptance sufficient to authorize the Transmission Provider to update that Transmission Owner's revenue requirements posted on the SPP website. Such update by the Transmission Provider shall not require a filing with the Commission, provided that the Transmission Owner posts the populated formula rate for public review and comment

as required under the applicable protocols and/or procedures contained in this Attachment H. The Transmission Provider shall follow any special procedures related to updating a Transmission Owner's revenue requirements as outlined in Section II of this Attachment.

6. The Transmission Provider shall allocate the accepted or approved revenue requirement associated with a Base Plan Upgrade, in accordance with Attachment J to this Tariff, to the Base Plan Region-wide ATRRs in Section I, Table 2-A and Table 2-B above and to the appropriate Base Plan Zonal ATRR in Column (4) or (5) in Section I, Table 1.

7. For each Transmission Owner not using a formula rate, the amount of (i) Schedule 7 and 8 revenue received under this Tariff and (ii) revenue distributed to the Transmission Owner under Section IV of Attachment AU and allocated in proportion to Schedule 7 and 8 revenues under Section V of Attachment AU, that is credited in the determination of the Transmission Owner's Commission approved Zonal Annual Transmission Revenue Requirement is specified in Column (3) of Table 3. For each Transmission Owner not using a formula rate, the amount of (i) Point-To-Point Transmission Service Schedule 11 revenue received under this Tariff and (ii) revenue distributed to the Transmission Owner under Section IV of Attachment AU and allocated in proportion to Point-To-Point Transmission Service Schedule 11 revenue under Section V of Attachment AU, that is credited in the determination of the Transmission Owner's Commission approved annual transmission revenue requirement for upgrades eligible for cost recovery under Schedule 11 is specified in Column (4) of Table 3. For a Transmission Owner using a formula rate that does not annually update the amount of point-to-point revenues received under this Tariff and revenues distributed and allocated under Attachment AU, Column (3) and Column (4) of Table 3 shall reflect any amount of such revenue embedded in its formula rate. For a Transmission Owner using a formula rate and where Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU are credited and annually updated to adjust the Transmission Owner's Commission approved Zonal Annual Transmission Revenue Requirement, the entry in Column (3) of Table 3 shall be Not Applicable (N/A). For a Transmission Owner using a formula rate and where Point-To-Point Transmission Service Schedule 11 revenue received under this Tariff and revenue distributed and allocated under Attachment AU are credited and annually updated to adjust the Transmission Owner's Commission approved annual revenue

requirement for upgrades eligible for cost recovery under Schedule 11, the entry in Column (4) of Table 3 shall be Not Applicable (N/A).

Table 3

| (1) Zone | (2) Zone Name / Transmission Owner | (3) Zonal ATRR Credit Included | (4) Schedule 11 Credit Included |
|---|---|---|---|
| 1 | American Electric Power –West | | |
| 1a | American Electric Power (Public Service Company of Oklahoma and Southwestern Electric Power Company) See Section II.3 | N/A | N/A |
| 1b | East Texas Electric Cooperative, Inc. | $0 | $0 |
| 1c | Reserved for Future Use | | |
| 1d | Deep East Texas Electric Cooperative, Inc. | $0 | $0 |
| 1e | Oklahoma Municipal Power Authority | $0 | $0 |
| 1f | AEP West Transmission Companies (AEP Oklahoma Transmission Company, Inc. and AEP Southwestern Transmission Company, Inc.) | N/A | N/A |
| 1g | Coffeyville Municipal Light and Power (CMLP) | $0 | $0 |
| 1h | Arkansas Electric Cooperative Corporation (AECC) | N/A | N/A |
| 1i | Transource Oklahoma, LLC | N/A | N/A |
| 2 | Kansas City Board of Public Utilities | N/A | N/A |
| 3 | City Utilities of Springfield, Missouri | N/A | N/A |
| 4 | Empire District Electric Company | N/A | $0 |
| 5 | Grand River Dam Authority | N/A | N/A |
| 6 | Evergy Metro, Inc. | | |
| 6a | Evergy Metro, Inc. | N/A | N/A |
| 6b | City of Independence, Missouri | $0 | $0 |
| 7 | Oklahoma Gas and Electric | | |
| 7a | Oklahoma Gas and Electric | N/A | N/A |
| 7b | Oklahoma Municipal Power Authority | $0 | $0 |
| 7c | Arkansas Electric Cooperative | N/A | N/A |

| | | | |
|---|---|---|---|
| | Corporation | | |
| 7d | People's Electric Cooperative | N/A | N/A |
| 8 | Midwest Energy, Inc. | N/A | N/A |
| 9 | Evergy Missouri West, Inc. | | |
| 9a | Evergy Missouri West, Inc. | N/A | N/A |
| 9b | Transource Missouri, LLC | N/A | $0 |
| 10 | Southwestern Power Administration | $0 | $0 |
| 10a | Southwestern Power Administration | $0 | $0 |
| 10a (i) | NITS ATRR | $0 | $0 |
| 10b | South Central MCN LLC | N/A | N/A |
| 10c | Missouri Joint Municipal Electric Utility Commission | N/A | N/A |
| 10d | People's Electric Cooperative | N/A | N/A |
| 11 | Southwestern Public Service Company | | |
| 11a | Southwestern Public Service Company | N/A | N/A |
| 11b | *Reserved for Future Use* | N/A | N/A |
| 11c | Lea County Electric Cooperative, Inc. | $0 | $0 |
| 12 | Sunflower Electric Power Corporation | | |
| 12a | Sunflower Electric Power Corporation | N/A | N/A |
| 12b | ITC Great Plains, LLC | N/A | N/A |
| 12c | Prairie Wind Transmission, LLC | N/A | N/A |
| 13 | Western Farmers Electric Cooperative | | |
| 13a | Western Farmers Electric Cooperative | N/A | N/A |
| 13b | People's Electric Cooperative | N/A | N/A |
| 14 | Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc.) | | |
| 14a | Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc.) | N/A | N/A |
| 14b | Prairie Wind Transmission, LLC | N/A | N/A |
| 14c | Kansas Power Pool | N/A | N/A |
| 14d | South Central MCN LLC | N/A | N/A |
| 15 | Reserved for Future Use | | |
| 16 | Lincoln Electric System | N/A | N/A |
| 17 | Nebraska Public Power District | | |
| 17a | Nebraska Public Power District | N/A | N/A |
| 17b | Central Nebraska Public Power and Irrigation District | $0 | $0 |
| 17c | Tri-State G&T Association | N/A | N/A |
| 18 | Omaha Public Power District | N/A | N/A |
| 19 | Upper Missouri Zone | | |
| 19a | Western-UGP | N/A | N/A |
| 19b | Basin Electric Power Cooperative | $0 | $0 |

| | | | |
|---|---|---|---|
| 19c | Heartland Consumers Power District | N/A | N/A |
| 19d | Missouri River Energy Services (Total) | | |
| 19d (i) | Missouri River Energy Services | N/A | N/A |
| 19d (ii) | Moorhead Public Service | N/A | N/A |
| 19d (iii) | Orange City Municipal Utilities | N/A | N/A |
| 19d (iv) | City of Pierre, South Dakota | N/A | N/A |
| 19d (v) | City of Sioux Center, Iowa | N/A | N/A |
| 19d (vi) | Watertown Municipal Utility Department | N/A | N/A |
| 19d (vii) | Denison Municipal Utilities | N/A | N/A |
| 19d (viii) | Vermillion Light & Power | N/A | N/A |
| 19e | East River Electric Power Cooperative, Inc. | N/A | N/A |
| 19f | Corn Belt Power Cooperative | N/A | N/A |
| 19g | NorthWestern Corporation (South Dakota) | N/A | $0 |
| 19h | Northwest Iowa Power Cooperative | N/A | N/A |
| 19i | Harlan Municipal Utilities | N/A | N/A |
| 19j | Central Power Electric Cooperative | N/A | N/A |
| 19k | Mountrail-Williams Electric Cooperative | N/A | N/A |
| 19l | Mor-Gran-Sou Electric Cooperative, Inc. | N/A | N/A |
| 19m | Roughrider Electric Cooperative, Inc. | N/A | N/A |
| 19n | L and O Power Cooperative | N/A | N/A |

**SECTION II: Transmission Owner-Specific Requirements**

**1. Southwestern Public Service Company**

For Southwestern Public Service Company ("SPS"), the Existing Zonal ATRR for Zone 11 in Column (3), of Section I, Table 1 of this Attachment H shall be calculated using: (1) the formula rate as specified in Attachment O – SPS of the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("Xcel Energy OATT"), (2) will be equal to the Current Year Revenue Requirement with True Up as specified on line 6, page 1 of Attachment O – SPS of the Xcel Energy OATT, (3) and subject to the Implementation Procedures in Appendix 1 of Attachment O – SPS of the Xcel Energy OATT. The results of the formula calculation shall be posted on the SPP website and in

an accessible location on SPS's OASIS website by October 1 of each calendar year and shall be effective on January 1 of the following year. The Existing Zonal ATRR for Zone 11, in Column (3), Section I, Table 1 of this Attachment H shall not be subject to adjustment pursuant to section 34.1 for the previous calendar year's total firm Point-to-Point transmission revenue allocated to SPS under Attachment L when determining the monthly zonal Demand Charge for Zone 11.

**2. American Electric Power**

The American Electric Power ATRR for purposes of the Network Integrated Transmission Service shall be (i) calculated using the formula rate set forth in Addendum 1 to this Attachment H, (ii) posted on the SPP website by October 31 of each calendar year, and (iii) effective on January 1 of the following calendar year.

In accordance with Section VIII of Attachment J, commencing April 1, 2018, the American Electric Power ATRR shall include $3,264,402.55, which consists of $3,068,489.38 associated with the canceled Multi - Shipe Road - East Rogers - Kings River 345 kV project (Network Upgrades 10656, 10659, and 10660) and $195,913.17 associated with the canceled Line - Georgia Pacific - Keatchie 138 kV Ckt 1 project (Network Upgrade 10616). This amount, which shall be recovered over the following twelve-month period in equal monthly installments with interest for the twelve-month recovery period calculated at the interest rate set forth in the Commission's regulations (18 C.F.R. § 35.19a(a)(2)(iii)), shall be allocated pursuant to Attachment J and recovered pursuant to Schedule 11. Upon full recovery following the end of the twelve-month period, the American Electric Power ATRR shall no longer include the $3,264,402.55 associated with these canceled projects. The $3,264,402.55 shall be reflected in the RRR File until it is fully recovered, at which time it will be replaced with $0 in the RRR File and SPP and AEP shall make a joint informational filing notifying the Commission of the final total amount that AEP has recovered, including the costs incurred associated with the canceled Multi - Shipe Road - East Rogers - Kings River 345 kV project (Network Upgrades 10656, 10659, and 10660) and the canceled Line - Georgia Pacific - Keatchie 138 kV Ckt 1 project (Network Upgrade 10616), plus all interest recovered. In the event

that property, the costs of which are included in the American Electric Power ATRR pursuant to this paragraph, is sold or otherwise disposed of during the twelve-month recovery period or thereafter, the revenues associated with such sale or disposition shall be credited against the American Electric Power ATRR. Such a credit shall be reflected in the RRR File and SPP and AEP shall make a joint informational filing notifying the Commission of the sale or distribution of the property and the amount that the American Electric Power ATRR will be credited due to such sale or disposition.

In accordance with Section VIII of Attachment J, commencing March 1, 2019, the American Electric Power ATRR shall include $414,465, which consists of the costs associated with the canceled Line – Chapel Hill REC – Welsh Reserve 138 kV Ckt 1 (Network Upgrade 50697) project and Line – Welsh Reserve - Wilkes 138 kV Ckt 1 (Network Upgrade 11423) project. This amount, which shall be recovered over the following twelve-month period in equal monthly installments, shall be allocated pursuant to Attachment J and recovered pursuant to Schedule 11. Upon full recovery following the end of the twelve-month period, the American Electric Power ATRR shall no longer include the $414,465 associated with these canceled projects. The $414,465 shall be reflected in the RRR File until it is fully recovered, at which time it will be replaced with $0 in the RRR File and SPP and AEP shall make a joint informational filing notifying the Commission of the final total amount that AEP has recovered, including the costs incurred associated with the canceled Line – Chapel Hill REC – Welsh Reserve 138 kV Ckt 1 (Network Upgrade 50697) project and Line – Welsh Reserve - Wilkes 138 kV Ckt 1 (Network Upgrade 11423) project, plus all interest recovered. In the event that property, the costs of which are included in the American Electric Power ATRR pursuant to this paragraph, is sold or otherwise disposed of during the twelve-month recovery period or thereafter, the revenues associated with such sale or disposition shall be credited against the American Electric Power ATRR. Such a credit shall be reflected in the RRR File and SPP and AEP shall make a joint informational filing notifying the Commission of the sale or distribution of the property and the amount that the American Electric Power ATRR will be credited due to such sale or disposition.

### *3.* Sunflower Electric Power Corporation

No changes to the ratios used to establish rates pursuant to Addendum 20 of this Attachment H will take effect unless accepted for approval by the FERC pursuant to the Federal Power Act.

### *4.* Southwestern Power Administration

The NITS ATRR component shown in 10a(i) of Column (3) in Table 1 of Attachment H associated with the Southwestern Power Administration Zonal ATRR stated in 10a of Column (3) of Table 1 of Attachment H shall be calculated as follows:

A. Southwestern Power Administration shall determine the ratio of: (i) the capacity on Southwestern Power Administration's transmission system utilized for Network Integration Transmission Service which shall be based on Southwestern Power Administration's Power Repayment Study filed before the Commission and employed in the Commission's final confirmation of Southwestern Power Administration's Zonal ATRR to (ii) the total capacity on the transmission system of Southwestern Power Administration available for Network Integration Transmission Service which is as stated in Section 2.3.3 of Southwestern Power Administration's Rate Schedule NFTS-13A and is 872,000 kilowatts.

B. Southwestern Power Administration shall apply this ratio to Southwestern Power Administration's Zonal ATRR stated in 10a of Column (3) of Table 1 of this Attachment H.

Southwestern Power Administration shall provide the Transmission Provider with supporting documentation when the calculation of the NITS ATRR is revised pursuant to this section, which shall be posted on the SPP website. Southwestern Power Administration will provide electronic notice of the revised NITS ATRR to all interested parties through the Formula Rate Posting Information Notification List. As used in this section "Formula Rate Posting Information Notification List" means the email exploder maintained by the Transmission Provider of interested parties, provided that such interested parties request to be added to the Formula Rate Posting Information

Notification List through the "Exploder List" link on the SPP website. As of April 2017, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/.

## SECTION III: Network Customer Transmission Credits for Transmission Facilities under Section 30.9

### A. General Terms of Applicability

In accordance with Section 30.9 of this Tariff, Network Customers are eligible to receive Network Customer Transmission Credits for Network Customer's transmission facilities if such transmission facilities are integrated into the operations of the Transmission System in such a manner that the transmission facilities, if owned by a Transmission Owner, would be included in Transmission Owner's Annual Transmission Revenue Requirement under Section I. of this Attachment H. This provision does not apply to Network Customer transmission facilities that are otherwise reflected in the rates for service under this Tariff. The revenue requirements associated with such Network Customer Transmission Credits, methods of calculation, and application of Network Customer Transmission Credits to Network Customer's transmission service charges are specified in Table 4 below.

### B. Revenue Requirements for Network Customer Transmission Credits

The following Network Customers have been determined to be eligible to receive Network Customer Transmission Credits pursuant to Section 30.9 of this Tariff for SPP's use of certain Network Customer-owned transmission facilities.

Table 4

| Network Customer | Revenue requirements for Network Customers eligible for Network Customer Transmission Credits | Application of Network Customer Transmission Credits |
|---|---|---|
| Montana-Dakota Utilities ("MDU") | See *Joint Offer of Partial Settlement* in Docket Nos. ER14-2850-006 and ER14-2851-006 (consolidated) accepted by the Commission | (a) MDU shall receive Network Customer Transmission Credits applied against MDU's transmission charges for transmission service taken in pricing Zone 19 under |

| | | |
|---|---|---|
| | on May 19, 2016, as amended in Docket No. ER21-169-000.<br><br>Revenue requirements for Network Customer Transmission Credits for MDU shall be recovered from Transmission Customers in the pricing Zone 19. | Schedule 9 and, if any Network Customer Transmission Credits remain thereafter, to its Schedule 11 monthly Base Plan Zonal Charge.<br><br>(b) The Transmission Provider shall apply MDU Network Customer Transmission Credits in the following manner:<br><br>Schedule 9 - MDU shall be responsible for its monthly demand charge less any Network Customer Transmission Credits, and for all other applicable charges under this Tariff.<br><br>Schedule 11 - MDU shall be responsible for all its Schedule 11 Base Plan Zonal Charges less any remaining Network Customer Transmission Credits, if any. |
| Otter Tail Power Company ("OTP") | See Tariff revision filed in Docket No. ER19-457-000 and Network Integration Transmission Service Agreement filed in Docket No. ER19-450-000.<br><br>Revenue requirements for Network Customer Transmission Credits for OTP shall be recovered from Transmission Customers in pricing Zone 19. | (a) OTP shall receive Network Customer Transmission Credits applied against OTP's transmission charges for transmission service taken in pricing Zone 19 under Schedule 9.<br><br>(b) The Transmission Provider shall apply OTP Network Customer Transmission Credits in the following manner:<br><br>Schedule 9 - OTP shall be responsible for its monthly demand charge under this schedule less one-twelfth of the annual amount of any Network Customer Transmission Credits. The amount of credit applied in each month shall not exceed the Schedule 9 demand charge applicable to that operating month ("Demand Charge Credit Limit"). The Demand Charge Credit Limit shall not include any billing correction of demand |

| | | |
|---|---|---|
| | | charges for other operating months.<br><br>OTP shall be responsible for all other applicable charges under this Tariff. |

## Addendum 1 To Attachment H

### Monthly Demand Charge Calculation For Zone 1
### Network Integration Transmission Service

This Addendum to Attachment H sets forth the component of the monthly Demand Charge for AEP's revenue requirement, which is applicable in Zone 1 for Network Customers taking Network Integration Transmission Service ("NITS") under Schedule 9 to this Tariff.

### Charges for Compensation to AEP

The monthly NITS charge to Network Customers for compensation to AEP shall be determined by multiplying the Network Customer's monthly Network Load, determined in accordance with the provisions of Section 34.4, expressed in MW, by the rate for NITS then in effect pursuant to the Formula Rate as set out in this Addendum 1 to Attachment H. The Network Load used in the divisor of the calculation of the rate for NITS shall be the sum of the twelve highest monthly AEP Zone Network Loads, and shall include all the load connected to the AEP transmission system within the AEP zonal boundary, e.g., load taking Network Service and any other zonal load served under concurrent exchange grandfathered agreements or network and long term firm point-to-point service grandfathered agreements. The cost-of-service included in the numerator of the NITS Rate (as that term is defined in Section I.1 below) calculation will include credits for revenues received from other transmission customers, and any direct assignment charges paid by customers for transmission facilities associated with service to load that is included in the divisor, unless the cost of the direct assignment facilities is excluded from the cost of service.

**Addendum 2-A Part 1 to Attachment H**

Attachment H Addendum 2-A

**Rate Formula Template**
**Utilizing FERC Form 1 for the 12 months ended** mm/dd/yyyy
(Enter whether "Projected Data" or "Actual Data")

**Oklahoma Gas and Electric Company**

**Index of Worksheets**


| | Worksheet | Description |
|---|---|---|
| 2 | Attachment H - Addendum 2-A | Rate Formula Template Utilizing FERC Form 1 for the 12 months ended mm/dd/yyyy and " Data" |
| 3 | Worksheet A | Account 454, Rent from Electric Property |
| 4 | | Account 456, Other Electric Revenues |
| 5 | | Account 456.1, Revenues from Transmission of Electricity of Others, Current Year Less Credits |
| 6 | | Revenue from Grandfathered Interzonal Transactions and amounts received from SPP for PTP service |
| 7 | Worksheet B | Transmission Network Load (MW) |
| 8 | Worksheet C | Account 281, Accumulated Deferred Income Taxes (“ADIT”) - Accelerated Amortization Property |
| 9 | | Account 282, Accumulated Deferred Income Taxes (“ADIT”) - Other Property |
| 10 | | Account 283, Accumulated Deferred Income Taxes (“ADIT”) - Other |
| 11 | | Account 190, Accumulated Deferred Income Taxes (“ADIT”) |
| 12 | | Account 255, Accumulated Deferred Investment Tax Credits |
| 13 | | Account 254, Excess Accumulated Deferred Income Taxes ("ADIT") – Liabilities |
| 14 | | Account 182.3, Excess Accumulated Deferred Income Taxes ("ADIT") - Assets |
| 15 | Worksheet C.1 | Average ADIT Balances |
| 16 | Worksheet C.2 | ADIT Proration Adjustment |
| 17 | Worksheet C.3 | Excess / Deficient ADIT Amortization |
| 18 | Worksheet D | Account 928, Regulatory Commission Expense Allocations |
| 19 | | Account 930.1, General Advertising Allocations (safety related only to trans.) |
| 20 | | Transmission Lease Payments |
| 21 | | Account 930.2, Miscellaneous General Expenses |
| 22 | Worksheet E | Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility |
| 23 | Worksheet F | Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase |
| 24 | | Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase |
| 25 | | Calculation of Composite Depreciation Rate |

| | | |
|---|---|---|
| 26 | | Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives |
| 27 | Worksheet G | Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities |
| 28 | Worksheet H | Transmission Plant Adjustments |
| 29 | Worksheet I | Plant Held for Future Use |
| 30 | Worksheet J | Development of Composite State Income Tax Rates |
| 31 | Worksheet K | 13 Month Balances for Plant & Accumulated Depreciation, Material & Supplies and Debt & Equity |
| 32 | | Account 165, Prepayments Calculation |
| 33 | | Long Term Debt Cost Calculation |
| 34 | Worksheet L | True-Up Adjustment with Interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation |
| 35 | Worksheet M | Depreciation Rates |
| 36 | Worksheet N | Unfunded Reserves Calculation |
| 37 | Worksheet O | Amortizations for Extraordinary O&M and Storm Costs |
| 38 | Worksheet P | Construction Work in Progress and Abandoned Plant Balances |

**Attachment H**
**Addendum 2-A**

**Page 1 of 7**

**Rate Formula Template**
**Utilizing FERC Form 1 for the 12 months ended** mm/dd/yyyy
**(Enter whether "Projected Data" or "Actual Data")**

**OKLAHOMA GAS AND ELECTRIC COMPANY**

For rates effective mmm dd, yyyy

| Line No. | | | | Transmission Amount |
|---|---|---|---|---|
| 1 | NET SPP OATT RELATED UPGRADE REV. REQ. | (Addendum 2-A, ln 17 + ln 18 ) | | $ - |
| 2 | OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3 | (Addendum 2-A, ln 21) | | - |
| 3 | DIVISOR | | | |
| 4 | TO's Transmission Network Load | (Worksheet B, ln 14) | | - |
| 5 | RATES | | | |
| 6 | Annual Cost ($/kW/Yr) | (ln 2 / ln 4) | - | |
| 7 | P-to-P Rate ($/kW/Mo) | (ln 6 / 12) | - | |

| | | | Peak | | Off-Peak |
|---|---|---|---|---|---|
| 8 | Weekly P-To-P Rate ($/kW/Wk) | (ln 6 / 52; ln 6 / 52) | - | | - |
| 9 | Daily P-To-P Rate ($/kW/Day) | (ln 8 / 5; ln 8 / 7) | - | Capped at weekly rate | - |
| 10 | Hourly P-To-P Rate ($/MWh) | (ln 9 / 16; ln 9 / 24 both x 1,000) | - | Capped at weekly & daily rate | - |

**Attachment H**
**Addendum 2-A**

**Rate Formula Template**
**Utilizing FERC Form 1 for the 12 months Ended** **mm/dd/yyyy**
(Enter whether "Projected Data" or "Actual Data")



**OKLAHOMA GAS AND ELECTRIC COMPANY**

| Line No. | | | Total | Allocator | Transmission Amount |
|---|---|---|---|---|---|
| 11 | REVENUE REQUIREMENT (w/o incentives) | (ln 117) | | | $ - |
| 12 | REVENUE CREDITS | (Note A) | | | |
| 13 | | | | | $ - |
| 14 | Other Transmission Revenue | (Worksheet A) | - | DA 1.00000 | $ - |
| 15 | Total Revenue Credits | | - | | $ - |
| 16 | NET REVENUE REQUIREMENT (w/o incentives) | (ln 11 less ln 15) | | | $ - |
| 17 | SPP OATT RELATED UPGRADES REVENUE REQUIREMENT (Worksheet G) (Note X) | | | | $ - |
| 18 | SPP OATT RELATED UPGRADES REV. REQ. TRUE-UP (Worksheet L) | | | | $ - |
| 19 | PRIOR YEAR TRUE-UP ADJUSTMENT w/INTEREST | (Worksheet L) | | | $ - |
| 20 | ADDITIONAL REVENUE REQUIREMENT (w/ incentives) (Note C) & (Worksheet F, ln 61) | | | | $ - |
| 21 | OG&E ZONAL REVENUE REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3 | (ln 16 - ln 17 - ln 18 - ln 19 + ln 20) | | | $ - |
| 22 | NET PLANT CARRYING CHARGE (w/o incentives) | (Note B) | | | |
| 23 | Annual Rate | ( (ln 16 / ln 46) x 100) | | | 0.00% |
| 24 | Monthly Rate | (ln 23 / 12) | | | 0.00% |
| 25 | NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B) | | | | |
| 26 | Annual Rate | ( ( (ln 16 - ln 92) / ln 46) x 100) | | | 0.00% |

| | | | |
|---|---|---|---|
| 27 | NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B) | | |
| 28 | Annual Rate | ( ( (ln 16 - lns 92 - ln 115 - ln 116) / lns 46) x 100) | 0.00% |

**Rate Formula Template**

**Attachment H Addendum 2-A**

**Utilizing FERC Form 1 for the 12 months Ended** **mm/dd/yyyy**
**(Enter whether "Projected Data" or "Actual Data")** **0**

**Page 3 of 7**

**OKLAHOMA GAS AND ELECTRIC COMPANY**

| Line No. | (1) **RATE BASE CALCULATION** | (2) **Data Sources (See "General Notes")** | (3) **TO Total** | (4) **Allocator** | | (5) **Total Transmission** |
|---|---|---|---|---|---|---|
| 29 | GROSS PLANT IN SERVICE | | | | | |
| 30 | Production | (Worksheet K) | - | NA | | |
| 31 | Transmission | (Worksheet K) | - | TP | 0.00000 | - |
| 32 | Distribution | (Worksheet K) | - | NA | | |
| 33 | General Plant | (Worksheet K) (Note J) | - | W/S | 0.00000 | - |
| 34 | Intangible Plant | (Worksheet K) (Note V) | - | W/S | 0.00000 | - |
| 35 | TOTAL GROSS PLANT | (sum lns 30 to 34) | - | | | - |
| 36 | GROSS PLANT ALLOCATOR | (ln 35 - Col. 5 / Col. 3) | | **GP=** | **0.000000** | |
| 37 | ACCUMULATED DEPRECIATION | | | | | |
| 38 | Production | (Worksheet K) | - | NA | | |
| 39 | Transmission | (Worksheet K) | - | TP | 0.00000 | - |
| 40 | Distribution | (Worksheet K) | - | NA | | |
| 41 | General Plant | (Worksheet K) (Note J) | - | W/S | 0.00000 | - |
| 42 | Intangible Plant | (Worksheet K) (Note V) | - | W/S | 0.00000 | - |
| 43 | TOTAL ACCUMULATED DEPRECIATION | (sum lns 38 to 42) | - | | | - |
| 44 | NET PLANT IN SERVICE | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 45 | Production | (ln 30 - ln 38) | | - | NA | | |
| 46 | Transmission | (ln 31 - ln 39) | | - | | | - |
| 47 | Distribution | (ln 32 - ln 40) | | - | NA | | |
| 48 | General Plant | (ln 33 - ln 41) | | - | | | - |
| 49 | Intangible Plant | (ln 34 - ln 42) | | - | | | - |
| 50 | TOTAL NET PLANT IN SERVICE | (sum lns 45 to 49) | | - | | | - |
| 51 | NET PLANT ALLOCATOR | (ln 50 - Col. 5 / Col. 3) | | | **NP=** | **0.000000** | |
| 52 | ADJUSTMENTS TO RATE BASE | (Note D) | | | | | |
| 53 | Account No. 281 | (Worksheet C) | | - | | | - |
| 54 | Account No. 282 | (Worksheet C) | | - | | | - |
| 55 | Account No. 283 | (Worksheet C) | | - | | | - |
| 56 | Account No. 190 | (Worksheet C) | | - | | | - |
| 57 | Account No. 255 | (Worksheet C) | | - | | | - |
| 57a | Account No. 254 | (Worksheet C) | | | | | |
| 57b | Account No. 182.3 | (Worksheet C) | | | | | |
| 58 | Unfunded Reserves | (Worksheet N) | | - | DA | 1.00000 | - |
| 59 | TOTAL ADJUSTMENTS | (sum lns 53 to 58) | | - | | | - |
| 60 | UNAMORTIZED ABANDONED PLANT | (Worksheet P) (Note R) | 0 | | DA | 1.00000 | 0 |
| 60a | Construction Work in Progress (CWIP) | (Worksheet P) (Note Z) | 0 | | DA | 0.00000 | 0 |
| 61 | LAND HELD FOR FUTURE USE | (Worksheet I) (Note F) | | - | TP | 0.00000 | - |
| 62 | WORKING CAPITAL | (Note G) | | | | | |
| 63 | CWC | (1/8 * ln 90) | | - | | | - |
| 64 | Materials & Supplies -- Transmission Related | (Worksheet K) (Note S) | | - | TP | 0.00000 | - |
| 65 | Prepayments (Account 165) | (Worksheet K) | | - | GP | 0.00000 | - |
| 66 | TOTAL WORKING CAPITAL | (sum lns 63 to 65) | | - | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 67 | RATE BASE | (sum lns 50, 59, 60,60a, 61, 66) | - | | | - |

**Rate Formula Template**

**Utilizing FERC Form 1 for the 12 months Ended** **mm/dd/yyyy**
**(Enter whether "Projected Data" or "Actual Data")** **0**

**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Attachment H Addendum 2-A**

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| Line No. | (1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION | (2) Data Sources (See "General Notes") | (3) TO Total | (4) Allocator | | (5) Total Transmission |
|---|---|---|---|---|---|---|
| | OPERATION & MAINTENANCE EXPENSE | | | | | |
| 68 | Transmission | 321.112.b | | | | |
| 68a | Less Extraordinary & Storm Cost Amortization | (Worksheet O) (Note Y) | - | | | |
| 69 | Less expenses for LSE cost responsibility | (Worksheet E, ln 14) | | | | |
| 70 | Less Account 561 (Load Dispatching) | 321.84-92.b (Note P & U) | | | | |
| 71 | Less Account 565 | 321.96.b (Note I) | | | | |
| 72 | Plus Acct 565 native load, zonal or pool | (Note I ) | | | | |
| 73 | Transmission Subtotal | (ln 68-ln68a- ln 69-ln 70-ln 71+ln 72) | - | TP | 0.00000 | - |
| 74 | Administrative and General | 323.197.b (Note J) | | NA | | |
| 75 | Less: Acct. 924, Property Insurance | 323.185.b | | NA | | |
| 76 | Less: Acct. 928, Reg. Com. Exp. | 323.189.b | | NA | | |
| 77 | Less: Acct. 930.1, Gen. Advert. Exp. | 323.191.b | | NA | | |
| 78 | Less: Acct. 930.2, Misc. General Exp. | 323.192.b | | | | |
| 79 | Less: PBOP amount included in Line 74 | (Note T) | | | | |
| 80 | Balance of A & G | (ln 74 - sum ln 75 to ln 79) | - | W/S | 0.00000 | - |
| 81 | Plus: Acct. 924 | (ln 75) | - | GP | 0.00000 | - |
| 82 | Plus: Acct. 928 - Transmission Direct | (Note K) (Worksheet D) | - | DA | 1.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Assigned | | | | | |
| 83 | Plus: Acct. 928 - Transmission Allocated | (Note K) (Worksheet D) | - | DA | 1.00000 | - |
| 84 | Plus: Acct. 930.1 - Transmission Direct Assigned | (Note K) (Worksheet D) | - | DA | 1.00000 | - |
| 85 | Plus: Acct. 930.1 - Transmission Allocated | (Note K) (Worksheet D) | - | DA | 1.00000 | - |
| 86 | Plus: Acct. 930.2 - Adj. Misc. General Expenses | (Worksheet D) | - | W/S | 0.00000 | - |
| 87 | Plus: PBOP Amount | (Note T) | - | W/S | 0.00000 | - |
| 88 | A & G Subtotal | (sum lns 80 to 87) | - | | | - |
| 89 | Transmission Lease Payments | (Worksheet D) | - | DA | 1.00000 | - |
| 90 | TOTAL O & M EXPENSE | (ln 73 + ln 88 + ln 89) | - | | | - |
| 91 | DEPRECIATION AND AMORTIZATION EXPENSE | | | | | |
| 92 | Transmission | 336.7.b | | TP | 0.00000 | - |
| 93 | Plus: Extraordinary & Storm Cost O&M Amortization | (Worksheet O) (Note W) | - | TP | 0.00000 | - |
| 94 | Plus: Recovery of Abandoned Incentive Plant | (Worksheet P ) (Note R) | 0 | DA | 1.00000 | 0 |
| 95 | General | 336.10.b | | W/S | 0.00000 | - |
| 96 | Intangible | 336.1.f | | W/S | 0.00000 | - |
| 97 | TOTAL DEPRECIATION AND AMORTIZATION | (sum lns 92 to 96) | - | | | - |
| 98 | TAXES OTHER THAN INCOME | (Note L) | | | | |
| 99 | Labor Related | | | | | |
| 100 | Payroll | 263.i | | W/S | 0.00000 | - |
| 101 | Plant Related | | | | | |
| 102 | Property | 263.i | | GP | 0.00000 | - |
| 103 | Gross Receipts | 263.i | | | | |
| 104 | Other | 263.i | | GP | 0.00000 | - |
| 105 | TOTAL OTHER TAXES | ln 100 + (sum lns 102 to 104) | - | | | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 106 | INCOME TAXES | (Note M) | | | | | |
| 107 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | | |
| 108 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.00% | | | | |
| 109 | where WCLTD=(ln 137) and R= (ln 140) | | | | | | |
| 110 | and FIT, SIT & p are as given in Note M. | | | | | | |
| 111 | 1 / (1 - T) = (from ln 107) | | | - | | | |
| 112 | Amortized Investment Tax Credit | 266.8.f (enter negative) | | | | | |
| 112a | (Excess)/Deficient ADIT Amortization – Protected | (Worksheet C.3) (Note AA) | | | | | |
| 112b | (Excess)/Deficient ADIT Amortization – Unprotected | (Worksheet C.3) (Note AA) | | | | | |
| 113 | Income Tax Calculation | (ln 108 * ln 116) | | - | NA | | - |
| 114 | ITC adjustment | (ln 111 * ln 112) | | - | NP | - | - |
| 114a | (Excess)/Deficient ADIT Amortization – Protected | (ln 111 * ln 112a) | | | DA | | |
| 114b | (Excess)/Deficient ADIT Amortization – Unprotected | (ln 111 * ln 112b) | | | DA | | |
| 115 | TOTAL INCOME TAXES | (sum lns 113 to 114) | | - | | | - |
| 116 | RETURN (Rate Base * Rate of Return) | (ln 67 * ln 140) | | - | NA | | - |
| 117 | REVENUE REQUIREMENT (sum lns 90, 97, 105, 115, 116) | | | - | | | - |

**Rate Formula Template**
**Utilizing FERC Form 1 for the 12 months Ended** **mm/dd/yyyy**
**(Enter whether "Projected Data" or "Actual Data")** **$0.00**

**Attachment H**
**Addendum 2-A**

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**OKLAHOMA GAS AND ELECTRIC COMPANY**

**SUPPORTING CALCULATIONS**

| ln No. | (1) | (2) | (3) | (4) | | | (5) |
|---|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN SPP TARIFF | | | | | | |
| 118 | Total transmission plant | (ln 31) | | | | | - |
| 119 | Less transmission plant excluded from SPP Tariff | (Worksheet H) (Note N) | | | | | - |
| 120 | Less Production Related Transmission Facilities | (Worksheet H) (Note O) | | | | | - |
| 121 | Transmission plant included in SPP Tariff | (ln 118 - ln 119 - ln 120) | | | | | - |
| 122 | Percent of transmission plant in SPP Tariff | (ln 121 / ln 118) | | | | **TP=** | **0.00000** |
| 123 | WAGES & SALARY ALLOCATOR (W/S) | | | | | | |
| 124 | Production | 354.20.b | | NA | | | - |
| 125 | Transmission | 354.21.b | | TP | 0.00000 | | - |
| 126 | Distribution | 354.23.b | | NA | | | - |
| 127 | Other (Excludes A&G) | 354.24,25,26.b | | NA | | | - |
| 128 | Total | (sum lns 124 to 127) | 0 | | | | - |
| 129 | Transmission related amount | (ln 128 - Col. 5 / Col. 3) | | | | **W/S =** | **0.00000** |
| 130 | RETURN (R) | | | | | | |
| 131 | Preferred Dividends | (118.29.c) (positive number) | | | | | - |
| 132 | Development of Common Stock: | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 133 | Long Term Debt | (Worksheet K) (Note Q) | | | 0.00 % | | - |
| 134 | Preferred Stock | (Worksheet K) (Note Q) | | | 0.00 % | | - |
| 135 | Common Stock | (Worksheet K) (Note Q) | | | 0.00 % | | - |
| 136 | Total | (sum lns 133 to 135) | | | | | - |

| | | | $ | % | Cost (Note Q) | | Weighted |
|---|---|---|---|---|---|---|---|
| 137 | Long Term Debt | | - | 0.00% | 0.0000 | | 0.0000 |
| 138 | Preferred Stock | 112.3.c | - | 0.00% | 0.0000 | | 0.0000 |
| 139 | Common Stock | | - | 0.00% | 0.0000 | | 0.0000 |
| 140 | Total | (sum lns 137 to 139) | - | | | **R** | **0.0000** |

**Rate Formula Template**

**Attachment H Addendum 2-A**

**Utilizing FERC Form 1 for the 12 months Ended** mm/dd/yyyy
**(Enter whether "Projected Data" or "Actual Data")** 0



**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Notes**

General Notes: a) References to data from Form 1 are indicated as: page#.line#.col.#
b) If transmission owner ("TO") functionalizes its costs to transmission on its books, those costs are shown above and on any supporting workpapers rather than using the allocations above.

| Note Letter | |
|---|---|
| A | The revenues credited shall include a) amounts received directly from the SPP for service under this tariff reflecting the TO's integrated transmission facilities and b) amounts from customers taking service under grandfathered agreements. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the definition of transmission facilities under this tariff shall not be included as revenue credits. Revenues from coincident peak loads included in the DIVISOR are also not included as revenue credits unless this revenue is offset by a corresponding expense. See Worksheet A for details. |
| B | The annual and monthly net plant carrying charges on page 2 are to be used to compute the revenue requirement for directly assigned transmission facilities, Base Plan Upgrades, Transmission Service Upgrades, Sponsored, Economic Portfolio Upgrades and Generator Interconnection Facilities, etc. whose revenue requirement is calculated in Worksheet G and recovered pursuant to Attachments J and Z, or successor attachments, of the SPP OATT. |
| C | This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet F shows the calculation of the additional revenue requirements for each project receiving incentive rate treatment, as accepted by FERC. These individual additional revenue requirements shall be summed, for the relevant year, and included here. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year being projected. |
| D | Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190 and 255 as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M. Transmission allocations shall be shown on Worksheet C, including amounts excluded through direct assignment to incentive plant, as shown on separate workpapers. |
| E | Reserved for future use. |
| F | Identified as being only transmission related or functionally booked to transmission. |
| G | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 90. Prepayments are limited to electric related items. |
| H | Reserved for future use |
| I | Only include transmission costs paid to others by the TO for which the transmission customer under the tariff receives a benefit (such as the payment of Base Plan Charges allocated to the TO's zone and not otherwise recovered by SPP from customers). Charges related to Base Plan Upgrades under Attachment J, Future Roll-Ins under Attachment Z and replacement of Existing Facilities are to be included. Direct Assignment Facilities, Economic Upgrades, Requested Upgrades and generator related to Network Upgrades (as defined in Attachment J) are to be excluded. |

J General Plant and Administrative and General expenses will be functionalized based on the indicated allocator on each line.

K Includes all Regulatory Commission expense itemized in FERC Form 1 at 351.h. Show in Worksheet D how these expense items are allocated to transmission. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Account 930.1 shall Include only safety-related advertising cost booked to the account.

L Includes only FICA, unemployment, highway, property and other assessments charged in the relevant year. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year being projected. Gross receipts tax and taxes related to income are excluded.

M The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 112) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

FIT = 0.00%

Inputs Required:

SIT= 0.00% (State Income Tax Rate or Composite SIT - Worksheet J)

p = 0.00% (percent of federal income tax deductible for state purposes)

N Removes the dollars of plant booked to transmission plant that is excluded from the Tariff because it does not meet the Tariff's definition of Transmission Facilities or is otherwise not eligible to be recovered under this Tariff.

O Removes the dollars of plant booked to transmission (e.g. step-up transformers) that are included in the development of OATT ancillary services rates and not already removed in Note N above.

P Removes the dollars of expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.

Q Long Term Debt cost rate calculated in Section V of Worksheet K. Preferred Stock cost rate = preferred dividends (ln 131) / preferred outstanding (ln 138). Common Stock cost rate (ROE) = 10.50%. It includes an additional 50 basis points for the TO remaining a member of the SPP RTO. This rate shall not change until a new rate is accepted by FERC in a subsequent filing under the FPA, including Sections 205 and 206. The percentage of equity used in determining the weighted cost of equity for OG&E for purposes of the Formula Rate shall not exceed 56% ("Equity Cap") as accepted by FERC in Docket No. ER08-281 regardless of OG&E's actual percentage of equity. To the extent OG&E's actual percentage of equity exceeds the Equity Cap, such amount in excess of the Equity Cap shall be treated as Long-Term Debt for purposes of the Formula Rate. The Equity Cap shall not change until a new Equity Cap is accepted by FERC in a subsequent filing under the FPA, including Sections 205 and 206. Include in the interest on Debt from Associated Companies only the interest on Long-Term Debt.

R OG&E must make the appropriate filing at FERC before inputting or changing amounts on lines 60 & 94 (abandoned plant).

S The Formula Rate will functionalize Material and Supplies for Construction on the basis of a single-year usage ratio in accordance with the most recent FERC Form 1, and will true-up these costs based on the trued-up year's Form 1. M&S for Construction will utilize 13 month average balances as reflected in Worksheet K, Section II and exclude any M&S booked in Account 107.

T PBOP base amount, initially set at $12,400,000, shall not be changed absent a separate filing made with the FERC.

U Transmission Service Study and Generation Interconnection Study costs shall be recorded in FERC Accounts 561.6 and 561.7, respectively. Costs of studies performed by SPP on behalf of OG&E, costs of studies performed by OG&E at SPP's request, reimbursement of study costs from SPP for studies performed by OG&E at SPP's request and studies for OG&E's retail load shall be recorded in FERC Accounts 561.6 & 561.7. FERC Accounts 561.6 and 561.7 are excluded from the Formula Rate.

V Accumulated Amortization for Intangible Plant shall be reflected as a Rate Base Adjustment under "Accumulated Depreciation".

W OG&E may only include the amortization of transmission-related extraordinary property losses if; (1) OG&E makes a filing with the Oklahoma Corporation

Commission requesting approval for the new amount to be recovered and the amortization period and (2) OG&E makes a single issue FPA Section 205 filing that requests the same recovery treatment from the FERC. OG&E shall be obligated to make such a single issue FPA Section 205 filing whenever it requests amortized extraordinary property loss costs recovery from the Oklahoma Corporation Commission.

X SPP OATT Related Upgrades include Base Plan Upgrades, Sponsored, Economic Portfolio Upgrades, Transmission Service Upgrades and Generator Interconnection Facilities, etc. whose individual Revenue Requirements are calculated and summarized in Worksheet G. Also included are the individual Revenue Requirements of facilities receiving Construction Work in Progress and Abandoned Plant incentives, as calculated and summarized in Worksheet P. The sum of the individual Revenue Requirements is credited to zonal network customers on line 17 above.

Y Exclude annualized amortization amounts booked back into O&M accounts that costs would have been booked had not a Regulatory Asset and amortization period been approved by the Oklahoma Corporation Commission and the FERC. This amount should equal amount reflected on line 93.

Z OG&E may only recover CWIP on projects that the FERC has specifically authorized the incentive.

AA Includes the amortization of any excess/deficient Accumulated Deferred Income Taxes ("ADIT") resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess / deficient ADIT will reduce or increase tax expense by the amount of the excess or deficient multiplied by ln 111.

**List of Allocators:**

| | | |
|---|---|---|
| Direct Assigned | DA | 1.000000 |
| Gross Plant | GP | 0.000000 |
| Net Plant | NP | 0.000000 |
| Trans. Plant in SPP | TP | 0.000000 |
| Wages & Salaries | W/S | 0.000000 |
| No Allocator | NA | |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet A**

**I. Account 454, Rent from Electric Property - Relevant Year =** (Note 1)

( Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and explanations in Section V, Notes below )

| Line No. | | Data Sources | 0 YE Balance | GP Allocator | Allocated to Transmission |
|---|---|---|---|---|---|
| 1 | Rent from Electric Property | 300.19.b | | 0.0000% | $0 |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | **Net Account 454 - Credited as transmission pole rentals =** | **$0** |

**II. Account 456, Other Electric Revenue - Relevant Year =** **0** (Notes 1 & 2)

( Other electric revenues including miscellaneous transmission revenues. Provide data sources and explanations in Section V, Notes below)

| | | | (A)<br>0<br>YE Balance | (B)<br>Power<br>Production | (C)<br>Distribution | (D)<br>Utility<br>Commercial | (E)<br>Utility A & G | (F)<br>Miscellaneous | (G)<br>Transmission<br>(Load in Divisor) | (H)<br>Other<br>Transmission |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | 300.22.b | | | | | | | | |
| 6 | Miscellaneous - McClain Adder | | | | | | | | | |
| 7 | Miscellaneous - Scrap Sales | | | | | | | | | |
| 8 | Miscellaneous | | | | | | | | | |
| 9 | Miscellaneous - Honeywell Energy Management | | | | | | | | | |
| 10 | Miscellaneous - Sale of Residual Oil | | | | | | | | | |
| 11 | Reimbursed Payroll Costs | | | | | | | | | |
| 12 | Remuneration Sales Taxes Collection - Oklahoma | | | | | | | | | |
| 13 | Franchise & Privilege Tax Adjustment | | | | | | | | | |
| 14 | Oil Lease & Royalties | | | | | | | | | |
| 15 | Pace Payments | | | | | | | | | |
| 16 | Transmission Service Revenues - from OG&E LSE | | | | | | | | | |
| 17 | Transmission Service Revenues - Unbundled OK & AR | | | | | | | | | |
| 18 | Transmission Service Revenues - Direct Assigned Facilities | | | | | | | | | |
| 19 | Salvage Clearing | | | | | | | | | |
| 20 | Off-System Sales Credit - Oklahoma | | | | | | | | | |
| 21 | Renewable Energy Certificate Sales - OK & AR | | | | | | | | | |
| 22 | | | | | | | | | | |
| 23 | | | | | | | | | | |
| 24 | | | | | | | | | | |
| 25 | | | | | | | | | | |
| 26 | TOTALS (Sum lns 6 - 25) | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 27 | | | | **Net Account 454 - Credited as Transmission Revenues** | | | | [(A)-(B)-(C)-(D)-(E)-(F)-(G)] = | | **$0** |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet A**

**III. Account 456.1, Revenues from Transmission of Electricity of Others - Relevant Year =** **0** (Notes 1 & 3) 328-330.Total.n

( Provide data sources and any detailed explanations necessary in Section V, Notes below )

**Transmission (Load in Divisor)**

**Less:**

28 TO's LSE Direct Assignment Revenue Credits
29 TO's LSE Sponsored (Requested or Economic) Upgrade Revenue Credits
30 TO's LSE Network Upgrades for Generation Interconnection - Credits
31 TO's Point-To-Point Revenue for GFA's Associated with Load Included in the Divisor
32 Network Service Revenue (Schedule 9) Associated With Load Included in the Divisor
33 TO's Revenue Associated with Transmission Plant Excluded From SPP Tariff
34 Wholesale Distribution charges
35 TO's LSE Revenue from Ancillary Services Provided
36 Network Service Ancillary Revenues (Schedule 1) Associated With Load Included in the Divisor
37
38
39

40 **Total Revenues Adjusted from Account 456.1 (Revenues retained by OG&E for load included in the divisor ) =** (Sum lns 28 thru 39) $ 0

41 **Net Account 456.1 Included in Template (PTP revenues to be credited) =** [(328-330.Total.n) - ln 40] **$ 0**

**IV. Revenue from Grandfathered Interzonal Transactions - Relevant Year =** **0** (Note 3)

( Provide data sources and any detailed explanations necessary in Section V, Notes below )

42 Revenues from Grandfathered Interzonal Transactions 0
43
44 Revenues received from SPP for PTP service 0
45

46 **Sum of Parts I, II & III** (Addendum 2-A, ln 14) **$ 0**

**V. Notes** ( Provide data sources for Sections I, II, III and IV along with any detailed explanations necessary.)

47 1. When calculating the Baseline ATRR, the " Relevant t Year" is the year being trued-up. When calculating the Projected ATRR, the " Relevant Year" is the year of the most recent FERC Form 1.
48 2. Section II, Other Electric Revenues reflects revenues received from SPP for Directly Assigned Upgrades and Other Transmission Revenues to be credited to customers. of this Attachment H - Addendum 2-A.
49 3. Section III, Net Account 456.1 reflects SPP Point-to-Point revenues to be credited to customers.

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet B**

**I. Transmission Network Load (MW)**

| Line No. | Month, Day and Year[1] | Hour Ending[1] | OG&E Peak Load | WFEC Peak Load | OMPA Peak Load | AECI/KAMO Peak Load | | | | TO's Transmission Peak Load[1] |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | 0 |
| 2 | | | | | | | | | | 0 |
| 3 | | | | | | | | | | 0 |
| 4 | | | | | | | | | | 0 |
| 5 | | | | | | | | | | 0 |
| 6 | | | | | | | | | | 0 |
| 7 | | | | | | | | | | 0 |
| 8 | | | | | | | | | | 0 |
| 9 | | | | | | | | | | 0 |
| 10 | | | | | | | | | | 0 |
| 11 | | | | | | | | | | 0 |
| 12 | | | | | | | | | | 0 |
| 13 | Total | | 0 | 0 | 0 | 0 | | | | 0 |
| 14 | 12-CP | | 0 | 0 | 0 | 0 | | | | 0 |

**II. Notes**

1 These are the dates, hour ending and loads at the time of the TO's transmission peak, as reported in FERC Form 1, page 400. Peak Load for Point-to-Point services sold under the SPP Tariff are not reflected in the totals above. Revenues from Point-to-Point services are shared according to Attachment L of the SPP OATT and revenues received provide revenue credits to network customers.

2 "GFA PTP Scheduled Load" is the firm load in kW scheduled by Grandfathered Agreements' (GFA) customers taking firm point-to-point (PTP) service at the time of TO's monthly transmission peak load. Details are as follows:

| Ln No. | Month, Day and Year | Hour ending | | | | | | | | GFA PTP Scheduled Load |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| 15 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 16 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 17 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 18 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 19 | 00-Jan-00 | 0 | | | | | | | | 0 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 20 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 21 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 22 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 23 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 24 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 25 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 26 | 00-Jan-00 | 0 | | | | | | | | 0 |

3 "GFA PTP Contract Demand" is the contract demand in kW for GFA customers taking firm PTP service at the time of TO's monthly peak load. Details are as follows:

| Ln No. | **Month, Day and Year** | **Hour ending** | | | | | | | | **GFA PTP Contract Demand** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| 27 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 28 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 29 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 30 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 31 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 32 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 33 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 34 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 35 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 36 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 37 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 38 | 00-Jan-00 | 0 | | | | | | | | 0 |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet B**

**II. Notes (cont.)**

4 "Non-Firm Sales in TO's Zone" are non-firm loads in kW at the time of, and included in, TO's monthly transmission system peak load associated with sales to customers in TO's zone. Details are as follows:

| Line No. | **Month, Day and Year** | **Hour ending** | | | | | | | | **Non-Firm Sales in TO's Zone** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| 39 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 40 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 41 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 42 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 43 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 44 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 45 | 00-Jan-00 | 0 | | | | | | | | 0 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 46 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 47 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 48 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 49 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 50 | 00-Jan-00 | 0 | | | | | | | | 0 |

5 "Non-TO Generation" in kW is load served by non-TO generators operating synchronously with the TO's transmission system. Details are as follows:

| Line No. | **Month, Day and Year** | **Hour ending** | | | | | | | | **Non-TO Generation in TO's Zone** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| 51 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 52 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 53 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 54 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 55 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 56 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 57 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 58 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 59 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 60 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 61 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 62 | 00-Jan-00 | 0 | | | | | | | | 0 |

6 "Non-TO Load in TO's Zone" is load in kW for firm-service customers in TO's zone that is electronically transferred to other TO zones. Details are as follows:

| Line No. | **Month, Day and Year** | **Hour ending** | | | | | | | | **Non-TO Load in TO's Zone** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | |
| 63 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 64 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 65 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 66 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 67 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 68 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 69 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 70 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 71 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 72 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 73 | 00-Jan-00 | 0 | | | | | | | | 0 |
| 74 | 00-Jan-00 | 0 | | | | | | | | 0 |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C**

**I. Account 281 - ADIT - Accelerated Amortization Property** **Relevant Year =** (Note 2)

| Line No. | (A) Identification | (B) Relevant Year Avg. Balance Worksheet C.1 | (C) 100% Non-Transmission Related | (D) 100% Related to facilities excluded in Worksheet H | (E) 100% Transmission Related | (F) Plant Related | (G) Labor Related | (H) Total Included in Ratebase (E)+(F)+(G) | (I) Description / Justification |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | |
| 2 | | - | - | - | - | - | - | | |
| 3 | | - | - | - | - | - | - | | |
| 4 | | - | - | - | - | - | - | | |
| 5 | | - | - | - | - | - | - | | |
| 6 | | - | - | - | - | - | - | | |
| 7 | | - | - | - | - | - | - | | |
| 8 | | - | - | - | - | - | - | | |
| 9 | | - | - | - | - | - | - | | |
| 10 | | - | - | - | - | - | - | | |
| 11 | | - | - | - | - | - | - | | |
| 12 | | - | - | - | - | - | - | | |
| 13 | | - | - | - | - | - | - | | |
| 14 | | - | - | - | - | - | - | | |
| 15 | | - | - | - | - | - | - | | |
| 16 | | - | - | - | - | - | - | | |
| 17 | | - | - | - | - | - | - | | |
| 18 | | - | - | - | - | - | - | | |
| 19 | | - | - | - | - | - | - | | |
| 20 | | - | - | - | - | - | - | | |
| 21 | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - | | |
| 22 | | | | | | | | | |
| | | - | - | - | - | - | - | | |
| 23 | | | | | | | | | |
| 24 | **Subtotal - Form 1, p273** | | | | | | | | |
| | | - | - | - | - | - | - | | |
| 25 | **Less FASB 109 Above if not separately removed** | - | - | - | - | - | - | | |
| 26 | **Less FASB 106 Above if not separately removed** | - | - | - | - | - | - | | |
| 27 | **Proration Adjustment - (from Worksheet C.2)** | - | - | - | - | - | - | | |
| 28 | **Total (ln 24 - ln 25 - ln 26 + ln 27)** | | | | | | | | |
| 29 | **Transmission Allocator [ GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000% | 0.0000 % | 0.0000 % | | |
| 30 | **Total (ln 27 * ln 28)** | | 0 | 0 | 0 | 0 | 0 | 0 | |

**II. Account 282 - ADIT - Other Property** **Relevant Year = 0** (Note 2)

| Line No. | (A) **Identification** | (B) **Relevant Year Avg. Balance Worksheet C.1** | (C) **100% Non-Transmission Related** | (D) **100% Related to facilities excluded in Worksheet H** | (E) **100% Transmission Related** | (F) **Plant Related** | (G) **Labor Related** | (H) **Total Included in Ratebase (E)+(F)+(G)** | (I) **Description / Justification** |
|---|---|---|---|---|---|---|---|---|---|
| 31 | | | | | | | | | |
| 32 | | | | | - | | | - | |
| | | | - | - | | - | - | | |
| 33 | | | | | - | | | - | |
| | | | - | - | | - | - | | |
| 34 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 35 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 36 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 37 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 38 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 39 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 40 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 41 | | | | | | | | | |
| | | | - | - | - | - | - | | |
| 42 | | | | | | | | | |
| | | | - | - | - | - | - | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 43 | | | - | - | - | - | - | |
| 44 | | | - | - | - | - | - | |
| 45 | | | - | - | - | - | - | |
| 46 | | | - | - | - | - | - | |
| 47 | | | - | | - | - | - | |
| 48 | | | - | - | - | - | - | |
| 49 | | | - | - | - | - | - | |
| 50 | | | - | - | - | - | - | |
| 51 | | | | | | | | |
| 52 | **Subtotal - Form 1, p275** | - | - | - | - | - | - | |
| 53 | **Less FASB 109 Above if not separately removed** | - | - | - | - | - | - | |
| 54 | **Less FASB 106 Above if not separately removed** | - | - | - | - | - | - | |
| 55 | **Proration Adjustment - (from Worksheet C.2)** | - | - | - | - | - | - | |
| 56 | **Total (ln 52 - ln 53 - ln 54 + ln 55)** | | | | | | | |
| 57 | **Transmission Allocator [ GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000% | 0.0000 % | 0.0000 % | |
| 58 | **Total (ln 54 * ln 55)** | | 0 | 0 | 0 | 0 | 0 | 0 |

**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Worksheet C**

**III. Account 283 - ADIT - Other** **Relevant Year = 0** (Note 2) 

| (A) | (B) Relevant Year Avg. Balance | (C) 100% Non- | (D) 100% Related to facilities | (E) 100% Transmissio | (F) Plant | (G) Labor | (H) Total Included in Ratebase | (I) |
|---|---|---|---|---|---|---|---|---|

| Line No. | Identification | Worksheet C.1 | Transmission Related | excluded in Worksheet H | n Related | Related | Related | (E)+(F)+(G) | Description / Justification |
|---|---|---|---|---|---|---|---|---|---|
| 59 | **Accumulated Deferred Income Tax:** | | | | | | | | |
| 60 | | | - | - | - | - | - | - | |
| 61 | | | - | - | - | - | - | - | |
| 62 | | | - | - | - | - | - | - | |
| 63 | | | - | - | - | - | - | - | |
| 64 | | | - | - | - | - | - | - | |
| 65 | | | - | - | - | - | - | - | |
| 66 | | | - | - | - | - | - | - | |
| 67 | | | - | - | - | - | - | - | |
| 68 | | | - | - | - | - | - | - | |
| 69 | | | - | - | - | - | - | - | |
| 70 | | | - | - | - | - | - | - | |
| 71 | | | - | - | - | - | - | - | |
| 72 | | | - | - | - | - | - | - | |
| 73 | | | - | - | - | - | - | - | |
| 74 | | | - | - | - | - | - | - | |
| 75 | | | - | - | - | - | - | - | |
| 76 | | | - | - | - | - | - | - | |
| 77 | | | - | - | - | - | - | - | |
| 78 | | | - | - | - | - | - | - | |
| 79 | | | - | - | - | - | - | - | |
| 80 | | | - | - | - | - | - | - | |
| 81 | | | - | - | - | - | - | - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 82 | - | - | - | - | - | - |
| 83 | - | - | - | - | - | - |
| 84 | - | - | - | - | - | - |
| 85 | - | - | - | - | - | - |
| 86 | - | - | - | - | - | - |
| 87 | - | - | - | - | - | - |
| 88 | - | - | - | - | - | - |
| 89 | - | - | - | - | - | - |
| 90 | - | - | - | - | - | - |
| 91 | - | - | - | - | - | - |
| 92 | - | - | - | - | - | - |
| 93 | - | - | - | - | - | - |
| 94 | - | - | - | - | - | - |
| 95 | - | - | - | - | - | - |
| 96 | - | - | - | - | - | - |
| 97 | - | - | - | - | - | - |
| 98 | - | - | - | - | - | - |
| 99 | - | - | - | - | - | - |
| 100 | - | - | - | - | - | - |
| 101 | - | - | - | - | - | - |
| 102 | - | - | - | - | - | - |
| 103 | - | - | - | - | - | - |
| 104 | - | - | - | - | - | - |
| 105 | - | - | - | - | - | - |
| 106 | - | - | - | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 107 | | | | | | | | | - |
| | | | - | - | - | - | - | | |
| 108 | | | | | | | | | - |
| | | | - | - | - | - | - | | |
| 109 | | | | | | | | | - |
| | | | - | - | - | - | - | | |
| 110 | | | | | | | | | |
| 111 | **Subtotal - Form 1, p277.9.k** | | | | | | | | |
| | | - | - | - | - | - | - | | |
| 112 | **Less FASB 109 Above if not separately removed** | - | - | - | - | - | - | | |
| 113 | **Less FASB 106 Above if not separately removed** | - | - | - | - | - | - | | |
| 114 | **Proration Adjustment - (from Worksheet C.2)** | - | - | - | - | - | - | | |
| 115 | **Total (ln 111 - ln 112 - ln 113 + 114)** | | | | | | | | |
| 116 | **Transmission Allocator [ GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000% | 0.0000 % | 0.0000 % | | |
| 117 | **Total (ln 115 * ln 116)** | | 0 | 0 | 0 | 0 | 0 | 0 | |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C**

**IV. Account 190 - ADIT** **Relevant Year = 0** (Note 2)

| Line No. | (A) Identification | (B) Relevant Year Avg. Balance Worksheet C.1 | (C) 100% Non-Transmission Related | (D) 100% Related to facilities excluded in Worksheet H | (E) 100% Transmission Related | (F) Plant Related | (G) Labor Related | (H) Total Included in Ratebase (E)+(F)+(G) | (I) Description / Justification |
|---|---|---|---|---|---|---|---|---|---|
| 118 | | | | | | | | | - |
| | | | - | - | - | - | - | | |
| 119 | | | | | | | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | - | - | - | - | - | |
| 120 | | | | | | - |
| | - | - | - | - | - | |
| 121 | | | | | | - |
| | - | - | - | - | - | |
| 122 | | | | | | - |
| | - | - | - | - | - | |
| 123 | | | | | | - |
| | - | - | - | - | - | |
| 124 | | | | | | - |
| | - | - | - | - | - | |
| 125 | | | | | | - |
| | - | - | - | | - | |
| 126 | | | | | | - |
| | - | - | - | - | - | |
| 127 | | | | | | - |
| | - | - | - | - | - | |
| 128 | | | | | | |
| | - | | | | | |
| 129 | | | | | | |
| | - | | | | | |
| 130 | | | | | | - |
| | - | - | - | - | - | |
| 131 | | | | | | - |
| | - | - | - | - | - | |
| 132 | | | | | | - |
| | - | - | - | - | - | |
| 133 | | | | | | - |
| | - | - | - | - | - | |
| 134 | | | | | | - |
| | - | - | - | - | - | |
| 135 | | | | | | - |
| | - | - | - | - | - | |
| 136 | | | | | | |
| 137 | | | | | | |
| 138 | | | | | | - |
| | | | | | - | |
| 139 | | | | | | |
| 140 | | | | | | |
| 141 | | | | | | - |
| | | - | - | - | - | |
| 142 | | | | | | |
| 143 | | | | | | |
| 144 | | | | | | |
| 145 | | | | | | |
| 146 | | | | | | - |
| | | - | - | - | - | |
| 147 | | | | | | - |
| | - | - | - | - | - | |
| 148 | | | | | | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | - | |
| 149 | | | | | | | | - |
| | | | - | - | - | - | - | |
| 150 | | | | | | | | - |
| | | | - | - | - | - | - | |
| 151 | | | | | | | | - |
| | | | - | - | - | - | - | |
| 152 | | | | | | | | - |
| | | | - | - | - | - | - | |
| 153 | | | | | | | | |
| 154 | **Subtotal - Form 1, p234.8.c** | | | | | | | |
| | | - | - | - | - | - | - | |
| 155 | **Less FASB 109 Above if not separately removed** | - | - | - | - | - | - | |
| 156 | **Less FASB 106 Above if not separately removed** | - | - | - | - | - | - | |
| 157 | **Proration Adjustment (from Worksheet C.2)** | | | | | | | |
| 158 | **Total (ln 154 - ln 155 - ln 156 + 157)** | | | | | | | |
| | | - | - | - | - | - | - | |
| 159 | **Transmission Allocator [ GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000% | 0.0000 % | 0.0000 % | |
| 160 | **Total (ln 158 * ln 159)** | | 0 | 0 | 0 | 0 | 0 | 0 |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C**

**V. Account 255 - Accumulated Deferred Investment Tax Credits** **Relevant Year =** **0** (Note 2)

| Line | (A) **Identification** | (B) **Relevant Year Avg. Balance Worksheet C.1** | (C) **100% Non-Transmission Related** | (D) **100% Related to facilities excluded in Worksheet H** | (E) **100% Transmission Related** | (F) **Plant Related** | (G) **Labor Related** | (H) **Total Included in Ratebase (E)+(F)+(G)** |
|---|---|---|---|---|---|---|---|---|

| No. | | | | | | | |
|---|---|---|---|---|---|---|---|
| 161 | | | - | - | - | - | - |
| 162 | | | - | - | - | - | - |
| 163 | | | - | - | - | - | - |
| 164 | | | - | - | - | - | - |
| 165 | | | - | - | - | - | - |
| 166 | | | - | - | - | - | - |
| 167 | | | - | - | - | - | - |
| 168 | | | - | - | - | - | - |
| 169 | | | - | - | - | - | - |
| 170 | | | - | - | - | - | - |
| 171 | | | - | - | - | - | - |
| 172 | | | - | - | - | - | - |
| 173 | | | - | - | - | - | - |
| 174 | | | - | - | - | - | - |
| 175 | | | - | - | - | - | - |
| 176 | | | - | - | - | - | - |
| 177 | | | - | - | - | - | - |
| 178 | | | - | - | - | - | - |
| 179 | | | | | | | |
| 180 | **Subtotal - Form 1, p267.8.h** | - | - | - | - | - | - |
| 181 | **Less FASB 109 Above if not separately removed** | - | - | - | - | - | - |
| 182 | **Less FASB 106 Above if not separately removed** | | | | | | |
| 183 | **Less Post 1971 ITC Property Under F2 Option** | - | - | - | - | - | - |
| 184 | **Total (ln 180 - ln 181 - ln 182 - ln 183)** | - | - | - | - | - | - |
| 185 | **Transmission Allocator [ GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000% | 0.0000 % | 0.0000 % |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 186 | **Total (ln 184 * ln 185)** | | 0 | 0 | 0 | 0 | 0 | 0 | |
| | VI. Account 254 - Excess ADIT Liabilities | | | Relevant Year = | 0 | (Note 2) | | | |
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
| Line No. | Identification | Relevant Year Avg. Balance Worksheet C.1 | 100% Non-Transmission Related | 100% Related to facilities excluded in Worksheet H | 100% Transmission Related | Plant Related | Labor Related | Total Included in Ratebase (E)+(F)+(G) | Description / Justification |
| 187 | | | - | - | - | - | - | - | |
| 188 | | | - | - | - | - | - | - | |
| 189 | | | - | - | - | - | - | - | |
| 190 | | | - | - | - | - | - | - | |
| 191 | | | - | - | - | - | - | - | |
| 192 | | | - | - | - | - | - | - | |
| 193 | | | - | - | - | - | - | - | |
| 194 | | | - | - | - | - | - | - | |
| 195 | | | - | - | - | - | - | - | |
| 196 | | | | | | | | | |
| 197 | | | | | | | | | |
| 198 | | | | | | | | | |
| 199 | | | | | | | | | |
| 200 | | | | | | | | | |
| 201 | | | | | | | | | |
| 202 | | | | | | | | | |
| 203 | | | | | | | | | |
| 204 | | | - | - | - | - | - | - | |
| 205 | | | - | - | - | - | - | - | |
| 206 | Excess ADIT Liabilities Subject to Proration | | - | - | - | - | - | - | |
| 207 | | | - | - | - | - | - | - | |
| 208 | | | - | - | - | - | - | - | |
| 209 | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | - | - | |
| 210 | | | | | | | | | |
| | | | - | - | - | - | - | - | |
| 211 | | | | | | | | | |
| | | | - | - | - | - | - | - | |
| 212 | | | | | | | | | |
| | | | - | - | - | - | - | - | |
| 213 | | | | | | | | | |
| 214 | Subtotal - Form 1, p278 | | | | | | | | |
| | | - | - | - | - | - | - | | |
| 215 | Proration Adjustment - (from Worksheet C.2) | - | - | - | - | - | - | | |
| 216 | Total (ln 214 + ln 215 ) | | | | | | | | |
| | | - | - | - | - | - | - | | |
| 217 | Transmission Allocator [ GP or W/S ] | | 0.0000% | 0.0000% | 100.0000% | #DIV/0! | #DIV/0! | | |
| 218 | Total (ln 216 * ln 217) | | 0 | 0 | 0 | 0 | 0 | 0 | |

OKLAHOMA GAS AND ELECTRIC COMPANY



Worksheet C

VII. Account 182.3 - Excess ADIT Assets

Relevant Year = 0 (Note 2)

| Line No. | (A) Identification | (B) Relevant Year Avg. Balance Worksheet C.1 | (C) 100% Non-Transmission Related | (D) 100% Related to facilities excluded in Worksheet H | (E) 100% Transmission Related | (F) Plant Related | (G) Labor Related | (H) Total Included in Ratebase (E)+(F)+(G) | (I) Description / Justification |
|---|---|---|---|---|---|---|---|---|---|
| 219 | | | - | - | - | - | - | - | |
| 220 | | | - | - | - | - | - | - | |
| 221 | | | - | - | - | - | - | - | |
| 222 | | | - | - | - | - | - | - | |
| 223 | | | - | - | - | - | - | - | |
| 224 | | | - | - | - | - | - | - | |
| 225 | | | - | - | - | - | - | - | |
| 226 | | | - | - | - | - | - | - | |
| 227 | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | - | - |
| 228 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 229 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 230 | | | | | | | | |
| 231 | | | | | | | | |
| 232 | | | | | | | | |
| 233 | | | | | | | | |
| 234 | | | | | | | | |
| 235 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 236 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 237 | Excess ADIT Assets Subject to Proration | | | | | | | |
| | | | - | - | - | - | - | - |
| 238 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 239 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 240 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 241 | | | | | | | | |
| | | | - | - | - | - | - | - |
| 242 | | | | | | | | |
| 243 | Subtotal - Form 1, p232 | | | | | | | |
| | | - | - | - | - | - | - | |
| 244 | Proration Adjustment - Transmission NOL (Worksheet C.2) | - | - | - | - | - | - | |
| 245 | Proration Adjustment - General NOL (Worksheet C.2) | - | - | | | | | |
| 246 | Total (ln 243 + ln 244 + ln 245) | | | | | | | |
| | | - | - | - | - | - | - | |
| 247 | Transmission Allocator [ GP or W/S ] | | 0.0000% | 0.0000% | 100.0000% | #DIV/0! | #DIV/0! | |
| 248 | Total (ln 246 * ln 247) | | 0 | 0 | 0 | 0 | 0 | 0 |

NOTE:
1. A worksheet will be provided to support the average of beginning and ending balances for items in ADIT Accounts 281, 282, 283, 190, 255, 254 & 182.3.
2. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form 1.

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.1 - Average Balance Calculation (YYYY & XXXX)**

| Line No. | **(YYYY)** | Dr. (Cr.) | **XXXX** | AVG Bal |
|---|---|---|---|---|

| | | (a) | | (b) | to Worksheet C |
|---|---|---|---|---|---|
| 1 | **Acct 282** | | | | |
| 2 | | | | | #DIV/0! |
| 3 | | | | | #DIV/0! |
| 4 | | | | | #DIV/0! |
| 5 | | | | | #DIV/0! |
| 6 | | | | | |
| 7 | | - | | - | - |
| 8 | FAS 109 Taxes - Debt AFUDC included in balance above | - | FAS 109 Taxes - Debt AFUDC included in balance above | - | - |
| 9 | **Acct 283** | | | | |
| 10 | | | | | #DIV/0! |
| 11 | | | | | #DIV/0! |
| 12 | | | | | #DIV/0! |
| 13 | | | | | #DIV/0! |
| 14 | | | | | |
| 15 | | | | | |
| 16 | | | | | |
| 17 | | | | | |
| 18 | | | | | |
| 19 | | | | | |
| 20 | | | | | #DIV/0! |
| 21 | | | | | #DIV/0! |
| 22 | | | | | #DIV/0! |
| 23 | | | | | #DIV/0! |
| 24 | | | | | #DIV/0! |
| 25 | | | | | #DIV/0! |
| 26 | | | | | #DIV/0! |
| 27 | | | | | #DIV/0! |
| 28 | | | | | #DIV/0! |
| 29 | | | | | #DIV/0! |
| 30 | | - | | - | - |
| 31 | **Acct 190** | | | | |
| 32 | | | | | #DIV/0! |
| 33 | | | | | #DIV/0! |
| 34 | | | | | #DIV/0! |
| 35 | | | | | #DIV/0! |
| 36 | | | | | #DIV/0! |
| 37 | | | | | #DIV/0! |
| 38 | | | | | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 39 | | | | | | #DIV/0! |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | | | | | | #DIV/0! |
| 45 | | | | | | #DIV/0! |
| 46 | | | | | | #DIV/0! |
| 47 | | | | | | #DIV/0! |
| 48 | | | | | | #DIV/0! |
| 49 | | | | | | |
| | | - | | | - | - |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C - Average Balance Calculation (YYYY & XXXX)**

| No. | Line **(YYYY)** | | Dr. (Cr.) | **XXXX** | | AVG Bal to Worksheet C |
|---|---|---|---|---|---|---|
| 50 | **Acct 255** | (a) | | | (b) | |
| 51 | Accumulated Deferred Investment Tax Credits | | | Accumulated Deferred Investment Tax Credits | | #DIV/0! |
| 52 | **Acct 254** | | | | | |
| | | | | | | #DIV/0! |
| 53 | | | | | | #DIV/0! |
| 54 | | | | | | #DIV/0! |
| 55 | | | | | | #DIV/0! |
| 56 | | | | | | #DIV/0! |
| 57 | | | | | | #DIV/0! |
| 58 | | | | | | #DIV/0! |
| 59 | | | | | | #DIV/0! |
| 60 | | | | | | #DIV/0! |
| 61 | | | | | | #DIV/0! |
| 62 | | | | | | #DIV/0! |
| 63 | | | | | | #DIV/0! |
| 64 | | | | | | #DIV/0! |
| 65 | **Excess ADIT Liabilities Subject to Proration** | | | **Excess ADIT Liabilities Subject to Proration** | | #DIV/0! |
| 66 | | | | | | #DIV/0! |
| 67 | | | | | | #DIV/0! |
| 68 | | | | | | #DIV/0! |
| 69 | | | | | | #DIV/0! |
| 70 | | | | | | #DIV/0! |
| 71 | | 0 | | | 0 | - |
| 72 | Acct 254 Gross Up | | | | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 73 | Total Acct 254 Grossed Up | 0 | | 0 | - |
| 74 | **Acct 182.3** | | | | |
| 75 | | | | | #DIV/0! |
| 76 | | | | | #DIV/0! |
| 77 | | | | | #DIV/0! |
| 78 | | | | | #DIV/0! |
| 79 | | | | | #DIV/0! |
| 80 | | | | | #DIV/0! |
| 81 | | | | | #DIV/0! |
| 82 | | | | | #DIV/0! |
| 83 | | | | | #DIV/0! |
| 84 | | | | | #DIV/0! |
| 85 | **Excess ADIT Assets Subject to Proration** | | **Excess ADIT Assets Subject to Proration** | | #DIV/0! |
| 86 | | | | | #DIV/0! |
| 87 | | | | | #DIV/0! |
| 88 | | | | | #DIV/0! |
| 89 | | | | | #DIV/0! |
| 90 | | 0 | | 0 | - |
| 91 | Acct 182.3 Gross Up | | | | #DIV/0! |
| 92 | Total Acct 182.3 Grossed Up | 0 | | 0 | - |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.2 - ADIT Proration Adjustment**

**Account 282 - Liberalized Depreciation - Transmission**

**Relevant Year =** 0

| Line No. | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Days in Period** | | | | | **Averaging with Proration** | | | |
| 2 | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | |

| 3 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
|---|---|---|---|---|---|---|---|---|
| 4 | | | | | | | | |
| 5 | December 31st balance Prorated Items | | | | | | | |
| 6 | January | 31 | 335 | 365 | 91.78% | | - | - |
| 7 | February | 28 | 307 | 365 | 84.11% | | - | - |
| 8 | March | 31 | 276 | 365 | 75.62% | | - | - |
| 9 | April | 30 | 246 | 365 | 67.40% | | - | - |
| 10 | May | 31 | 215 | 365 | 58.90% | | - | - |
| 11 | June | 30 | 185 | 365 | 50.68% | | - | - |
| 12 | July | 31 | 154 | 365 | 42.19% | | - | - |
| 13 | August | 31 | 123 | 365 | 33.70% | | - | - |
| 14 | September | 30 | 93 | 365 | 25.48% | | - | - |
| 15 | October | 31 | 62 | 365 | 16.99% | | - | - |
| 16 | November | 30 | 32 | 365 | 8.77% | | - | - |
| 17 | December | 31 | 1 | 365 | 0.27% | | - | - |
| 18 | Total | 365 | 2,029 | 4,380 | | - | - | |

| | | | | |
|---|---|---|---|---|
| 19 | Ending Balance of Prorated items | (Line 17, & Col H) | | - |
| 20 | Non-prorated Average Balance | | | |
| 21 | Proration Adjustment | (Line 19 minus Line 20) | | - |

**Account 282 - Liberalized Depreciation - General Plant**

**Relevant Year =** 0

| Line No. | | Days in Period | | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|---|
| 22 | | | | | | | | | |
| 23 | | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** |
| 24 | | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
| 25 | | | | | | | | | |
| 26 | | December 31st balance Prorated Items | | | | | | | |
| 27 | | January | 31 | 335 | 365 | 91.78% | | - | - |
| 28 | | February | 28 | 307 | 365 | 84.11% | | - | - |
| 29 | | March | 31 | 276 | 365 | 75.62% | | - | - |
| 30 | | April | 30 | 246 | 365 | 67.40% | | - | - |
| 31 | | May | 31 | 215 | 365 | 58.90% | | - | - |
| 32 | | June | 30 | 185 | 365 | 50.68% | | - | - |
| 33 | | July | 31 | 154 | 365 | 42.19% | | - | - |
| 34 | | August | 31 | 123 | 365 | 33.70% | | - | - |
| 35 | | September | 30 | 93 | 365 | 25.48% | | - | - |
| 36 | | October | 31 | 62 | 365 | 16.99% | | - | - |
| 37 | | November | 30 | 32 | 365 | 8.77% | | - | - |
| 38 | | December | 31 | 1 | 365 | 0.27% | | - | - |
| 39 | | Total | 365 | 2,029 | 4,380 | | - | - | |

| | | | |
|---|---|---|---|
| 40 | Ending Balance of Prorated items | (Line 38, & Col H) | - |
| 41 | Non-prorated Average Balance | | |
| 42 | Proration Adjustment | (Line 40 minus Line 41) | - |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.2 - ADIT Proration Adjustment**

**Account 282 - Liberalized Depreciation - Intangible Plant** **Relevant Year =** 0

| Line No. | | Days in Period | | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|---|
| | | A | B | C | D | E | F | G | H |
| | | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
| 46 | | | | | | | | | |
| 47 | December 31st balance Prorated Items | | | | | | | | |
| 48 | January | | 31 | 335 | 365 | 91.78% | | - | - |
| 49 | February | | 28 | 307 | 365 | 84.11% | | - | - |
| 50 | March | | 31 | 276 | 365 | 75.62% | | - | - |
| 51 | April | | 30 | 246 | 365 | 67.40% | | - | - |
| 52 | May | | 31 | 215 | 365 | 58.90% | | - | - |
| 53 | June | | 30 | 185 | 365 | 50.68% | | - | - |
| 54 | July | | 31 | 154 | 365 | 42.19% | | - | - |
| 55 | August | | 31 | 123 | 365 | 33.70% | | - | - |
| 56 | September | | 30 | 93 | 365 | 25.48% | | - | - |
| 57 | October | | | | | 16.99 | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 31 | 62 | 365 | 9% | | - | - |
| 58 | November | | | | 8.77 | | | |
| | | 30 | 32 | 365 | % | | - | - |
| 59 | December | | | | 0.27 | | | |
| | | 31 | 1 | 365 | % | | - | - |
| 60 | Total | | | | | | | |
| | | 365 | 2,029 | 4,380 | | - | - | |

| | | | | |
|---|---|---|---|---|
| 61 | Ending Balance of Prorated items | (Line 59, & Col H) | | - |
| 62 | Non-prorated Average Balance | | | |
| 63 | Proration Adjustment | (Line 61 minus Line 62) | | - |
| 64 | **Account 282 - TOTAL Proration Adjustment** | (ln 21 + ln 42 + ln 63) | | - |

**Account 283 - Liberalized Depreciation** **Relevant Year =** 0

| Line No. | Days in Period | | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|
| 65 | | | | | | | | |
| 66 | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** |
| 67 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
| 68 | | | | | | | | |
| 69 | December 31st balance Prorated Items | | | | | | | |
| 70 | January | | | | 91.7 | | | |
| | | 31 | 335 | 365 | 8% | | - | - |
| 71 | February | | | | 84.1 | | | |
| | | 28 | 307 | 365 | 1% | | - | - |
| 72 | March | | | | 75.6 | | | |
| | | 31 | 276 | 365 | 2% | | - | - |
| 73 | April | | | | 67.4 | | | |
| | | 30 | 246 | 365 | 0% | | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 74 | May | 31 | 215 | 365 | 58.9 0% | | - | - |
| 75 | June | 30 | 185 | 365 | 50.6 8% | | - | - |
| 76 | July | 31 | 154 | 365 | 42.1 9% | | - | - |
| 77 | August | 31 | 123 | 365 | 33.7 0% | | - | - |
| 78 | September | 30 | 93 | 365 | 25.4 8% | | - | - |
| 79 | October | 31 | 62 | 365 | 16.9 9% | | - | - |
| 80 | November | 30 | 32 | 365 | 8.77 % | | - | - |
| 81 | December | 31 | 1 | 365 | 0.27 % | | - | - |
| 82 | Total | 365 | 2,029 | 4,380 | | - | - | |

| | | | | |
|---|---|---|---|---|
| 83 | Ending Balance of Prorated items | (Line 81, & Col H) | | - |
| 84 | Non-prorated Average Balance | | | |
| 85 | Proration Adjustment | (Line 83 minus Line 84) | | - |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.2 - ADIT Proration Adjustment**

**Account 190 - Basis Difference**

**Relevant Year =** 0

| Line No. | Days in Period | | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|
| 86 | | | | | | | | |
| 87 | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** |
| 88 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferre | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |

| | | | d Taxes | | | | | |
|---|---|---|---|---|---|---|---|---|
| 89 | | | | | | | | |
| 90 | December 31st balance Prorated Items | | | | | | | |
| 91 | January | | | | 91.7 | | | |
| | | 31 | 335 | 365 | 8% | | - | - |
| 92 | February | | | | 84.1 | | | |
| | | 28 | 307 | 365 | 1% | | - | - |
| 93 | March | | | | 75.6 | | | |
| | | 31 | 276 | 365 | 2% | | - | - |
| 94 | April | | | | 67.4 | | | |
| | | 30 | 246 | 365 | 0% | | - | - |
| 95 | May | | | | 58.9 | | | |
| | | 31 | 215 | 365 | 0% | | - | - |
| 96 | June | | | | 50.6 | | | |
| | | 30 | 185 | 365 | 8% | | - | - |
| 97 | July | | | | 42.1 | | | |
| | | 31 | 154 | 365 | 9% | | - | - |
| 98 | August | | | | 33.7 | | | |
| | | 31 | 123 | 365 | 0% | | - | - |
| 99 | September | | | | 25.4 | | | |
| | | 30 | 93 | 365 | 8% | | - | - |
| 100 | October | | | | 16.9 | | | |
| | | 31 | 62 | 365 | 9% | | - | - |
| 101 | November | | | | 8.77 | | | |
| | | 30 | 32 | 365 | % | | - | - |
| 102 | December | | | | 0.27 | | | |
| | | 31 | 1 | 365 | % | | - | - |
| 103 | Total | | | | | | | |
| | | 365 | 2,029 | 4,380 | | | - | - |

| | | | |
|---|---|---|---|
| 104 | Ending Balance of Prorated items | (Line 102, & Col H) | - |
| 105 | Non-prorated Average Balance | | |
| 106 | Proration Adjustment | (Line 104 minus Line 105) | - |

**Account 281 - Liberalized Depreciation**

**Relevant Year =** 0

Line

| No. | | Days in Period | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|
| 107 | | | | | | | | |
| 108 | | A | B | C | D | E | F | G | H |
| 109 | | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
| 110 | | | | | | | | | |
| 111 | | December 31st balance Prorated Items | | | | | | | |
| 112 | | January | 31 | 335 | 365 | 91.78% | | - | - |
| 113 | | February | 28 | 307 | 365 | 84.11% | | - | - |
| 114 | | March | 31 | 276 | 365 | 75.62% | | - | - |
| 115 | | April | 30 | 246 | 365 | 67.40% | | - | - |
| 116 | | May | 31 | 215 | 365 | 58.90% | | - | - |
| 117 | | June | 30 | 185 | 365 | 50.68% | | - | - |
| 118 | | July | 31 | 154 | 365 | 42.19% | | - | - |
| 119 | | August | 31 | 123 | 365 | 33.70% | | - | - |
| 120 | | September | 30 | 93 | 365 | 25.48% | | - | - |
| 121 | | October | 31 | 62 | 365 | 16.99% | | - | - |
| 122 | | November | 30 | 32 | 365 | 8.77% | | - | - |
| 123 | | December | 31 | 1 | 365 | 0.27% | | - | - |
| 124 | | Total | 365 | 2,029 | 4,380 | | - | - | |

| | | | |
|---|---|---|---|
| 125 | Ending Balance of Prorated items | (Line 123, & Col H) | - |
| 126 | Non-prorated Average Balance | | |
| 127 | Proration Adjustment | (Line 125 minus Line 126) | |

-

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.2 - ADIT Proration Adjustment**

**Account 182.3 - Excess ADIT - Federal Only NOL** **Relevant Year =** 0

| Line No. | | Days in Period | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|
| 128 | | | | | | | | |
| 129 | | A | B | C | D | E | F | G | H |
| 130 | | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
| 131 | | | | | | | | | |
| 132 | | December 31st balance Prorated Items | | | | | | | |
| 133 | | January | 31 | 335 | 365 | 91.78% | | - | - |
| 134 | | February | 28 | 307 | 365 | 84.11% | | - | - |
| 135 | | March | 31 | 276 | 365 | 75.62% | | - | - |
| 136 | | April | 30 | 246 | 365 | 67.40% | | - | - |
| 137 | | May | 31 | 215 | 365 | 58.90% | | - | - |
| 138 | | June | 30 | 185 | 365 | 50.68% | | - | - |
| 139 | | July | 31 | 154 | 365 | 42.19% | | - | - |
| 140 | | August | 31 | 123 | 365 | 33.70% | | - | - |
| 141 | | September | 30 | 93 | 365 | 25.48% | | - | - |
| 142 | | October | 31 | 62 | 365 | 16.99% | | - | - |
| 143 | | November | 30 | 32 | 365 | 8.77% | | - | - |
| 144 | | December | | | | 0.27 | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 31 | 1 | 365 | % | | - | - |
| 145 | Total | 365 | 2,029 | 4,380 | | - | - | |

| | | | |
|---|---|---|---|
| 146 | Ending Balance of Prorated items | (Line 144, & Col H) | - |
| 147 | Non-prorated Average Balance | | |
| 148 | Proration Adjustment | (Line 146 minus Line 147) | - |

**Account 182.3 - Excess ADIT - General NOL** **Relevant Year =** 0

| Line No. | Days in Period | | | | | Averaging with Proration - Projected | | |
|---|---|---|---|---|---|---|---|---|
| 149 | | | | | | | | |
| 150 | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** |
| 151 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) |
| 152 | | | | | | | | |
| 153 | December 31st balance Prorated Items | | | | | | | |
| 154 | January | 31 | 335 | 365 | 91.78% | | - | - |
| 155 | February | 28 | 307 | 365 | 84.11% | | - | - |
| 156 | March | 31 | 276 | 365 | 75.62% | | - | - |
| 157 | April | 30 | 246 | 365 | 67.40% | | - | - |
| 158 | May | 31 | 215 | 365 | 58.90% | | - | - |
| 159 | June | 30 | 185 | 365 | 50.68% | | - | - |
| 160 | July | 31 | 154 | 365 | 42.19% | | - | - |
| 161 | August | 31 | 123 | 365 | 33.70% | | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 162 | September | 30 | 93 | 365 | 25.48% | | - | - |
| 163 | October | 31 | 62 | 365 | 16.99% | | - | - |
| 164 | November | 30 | 32 | 365 | 8.77% | | - | - |
| 165 | December | 31 | 1 | 365 | 0.27% | | - | - |
| 166 | Total | 365 | 2,029 | 4,380 | | - | - | |

| | | | |
|---|---|---|---|
| 167 | Ending Balance of Prorated items | (Line 165, & Col H) | - |
| 168 | Non-prorated Average Balance | | |
| 169 | Proration Adjustment | (Line 167 minus Line 168) | - |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.3 - (Excess)/Deficient ADIT Amortization (Note 1)**

**Protected - (Excess) / Deficient ADIT Amortization (Note 2)** **Relevant Year =** 2018

| Line No. | (a) **Identification** | (b) **Total (Note 1)** | (c) **100% Non-Transmission Related** | (d) **100% Related to facilities excluded in Worksheet H** | (e) **100% Transmission Related** | (f) **Plant Related** | (g) **Labor Related** | (h) **Total Included in Income Tax Expense (e)+(f)+(g)** | (i) **Remaining Amortization Period (Note 2)** |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | ARAM |
| 2 | | | | | | | | | ARAM |
| 3 | | | | | | | | | ARAM |
| 4 | | | | | | | | | ARAM |
| 5 | | | | | | | | | ARAM |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 11 | | | | | | | | | |
| 12 | **Subtotal** | - | - | - | | - | - | | |
| 13 | **Transmission Allocator [GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000 % | #DIV/0! | #DIV/0! | | |
| 14 | **Total (ln 12 * ln 13)** | | 0 | 0 | 0 | #DIV/0! | #DIV/0! | #DIV/0! | |

**Unprotected - (Excess) / Deficient ADIT Amortization (Note 3)** **Relevant Year =** 2018

| No. | (a) Line Identification | (b) Total (Note 1) | (c) 100% Non-Transmission Related | (d) 100% Related to facilities excluded in Worksheet H | (e) 100% Transmission Related | (f) Plant Related | (g) Labor Related | (h) Total Included in Income Tax Expense (e)+(f)+(g) | (i) Remaining Amortization Period (Note 2) |
|---|---|---|---|---|---|---|---|---|---|
| 15 | | | | | | | | | |
| 16 | | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | | | | | | | | | |
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| 23 | | | | | | | | | |
| 24 | | | | | | | | | |
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| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
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| 39 | | | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 42 | | | | | | | | | |
| 43 | | | | | | | | | |
| 44 | **Subtotal** | - | - | - | | - | - | | |
| 45 | **Transmission Allocator [GP or W/S ]** | | 0.0000% | 0.0000% | 100.0000 % | #DIV/0! | #DIV/0! | | |
| 46 | **Total (ln 44 * ln 45)** | | 0 | 0 | | #DIV/0! | #DIV/0! | #DIV/0! | |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet C.3 - Excess Deferred Taxes (2017 TCJA Rate Change) - Calculated End of Year Balance**

| | (a) | (b) | (c) | (d) | (e) |
|---|---|---|---|---|---|
| Line No. | **Total Company Regulatory Liability Balances** | **Beginning of Year Balances** | **Return to Provision Adjustment** | **Current Year EDIT Amortization** | **End of Year Balance** |
| 47 | **Protected Plant, before Gross-up (Note 4)** | | | | - |
| 48 | **Protected Plant, Gross-up Adj** | | | | - |
| 49 | **Unprotected, before Gross-up (Note 5)** | | | | - |
| 50 | **Unprotected, Gross-up Adj** | | | | - |
| 51 | **Total (sum lns 47 to 50)** | - | - | - | - |

Note 1: Worksheet C.3 presents total company amortization for excess / deficient ADIT amounts. This worksheet does not attempt to present jurisdictional balances.
Note 2: The amortization of Tax Cuts and Jobs Act ("TCJA") related Excess and Deficient Protected ADIT balances starts January 1, 2018 over the remaining life of OG&E's assets consistent the "Average Rate Assumption Method" ("ARAM").

Note 3: This amortization of TCJA-related Excess and Deficient Unprotected ADIT balances starts January 1, 2019 using a straight-line amortization period of five (5) years. Unprotected amortization is not generally booked or
or tracked by item. Excess unprotected amortization primarily relates to the following deferred tax items: Prepaid Pension, Regulatory Assets & Liabilities, Bond Redemptions, Oklahoma Tax Credits carryovers
& Oklahoma NOL carryovers. Deficient unprotected amortization primarily relates to the following deferred tax items: ARO Liability, Post-Retirement Benefits, and Accrued Employee Benefits. This page 2 of Worksheet C.3
(i) will be used to calculate rates for service provided in the 2019 Rate Year and thereafter, and (ii) will not be used to calculate rates for service provided in the 2018 Rate Year.
Note 4: The amortization of TCJA-related Excess and Deficient Protected ADIT balances starts January 1, 2018.
Note 5: The amortization of TCJA-related Excess and Deficient Unprotected ADIT balances starts January 1, 2019.

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet D**

**I. Account 928 - Regulatory Comm. Expenses** **Relevant Year =**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|
| **Item No.** | **Description** | **Expense** | **Non-Transmission** | **Transmission Allocation** | **Transmission Direct Assigned** | **Explanation** |
| | **Regulatory Commission Expenses:** | | | | | |
| 1 | FERC Assessment - SPP Schedule 12 | | - | | - | |
| 2 | Arkansas Public Service Commission for Annual Charges | | - | - | - | |
| 3 | Oklahoma Corporation Commission for Annual Charges | | - | - | - | |
| 4 | | | - | - | - | |
| 5 | | | - | - | - | |
| 6 | | | - | - | - | |
| 7 | | | - | - | - | |
| 8 | | | - | - | - | |
| 9 | | | - | - | - | |
| 10 | | | - | - | - | |
| 11 | | | - | - | - | |
| 12 | | | - | - | - | |
| 13 | | | - | - | - | |
| 14 | Minor Items | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| NOTE: | FERC Assessments are to be included in Column (D) | | - | - | - | |
| | **Total - Form I, pg 351.46.h+k** | - | - | - | - | |

**II. Account 930.1 - General Advertising Expense** **Relevant Year =**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|
| **Item No.** | **Description** | **Expense** | **Non-Transmission** | **Transmission Allocation** | **Transmission Direct Assigned** | **Explanation** |
| 1 | General Advertising Expense | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | | | - | - | - | |
| | **Total - Form I, pg 323.191.b** | - | - | - | - | |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet D**

**III. Transmission Lease Payments** **Relevant Year =**

| (A) | (B) | (C) |
|---|---|---|
| **Item No.** | **Description** | **Expense** |

**Total Transmission Lease Payments**

**IV. Account 930.2 - Misc. General Expenses** **Relevant Year =**

| Item No. | Description | Date Sources | TO Total | Explanation |
|---|---|---|---|---|
| 1 | Miscellaneous General Expenses | 323.192.b | | |
| 2 | Less: Industry Association Dues | 335.1.b | | |
| 3 | Plus: EEI Dues | | | |
| 4 | Plus: SPP Dues | | | |
| 5 | Adjusted Miscellaneous General Expenses | (ln 1-ln 2+ln 3+ln 4) | 0 | |

NOTE:
1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form 1.
2. All Industry Assn. Dues shall be removed from Acct. 930.2 and the Formula Rate except for EEI and SPP.
3. In sections I and II, the explanation will include why the cost is related to transmission service as the basis for the allocation

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet E**

**Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility**

| | | | Relevant Year |
|---|---|---|---|
| 1 | Other Expenses: | | |
| 2 | Direct Assignment Charge | | |
| 3 | Sponsored (Requested or Economic) Upgrades Charge | | |
| 4 | Firm and Non-Firm Point-To-Point Charges | | |
| 5 | Base Plan Charges | | |
| 6 | Schedule 9 Charges | | |
| 7 | SPP Schedule 1-A | | |
| 8 | SPP Annual Assessment | | |
| 9 | NERC Assessment | | |
| 10 | Ancillary Services Expenses | | |
| 11 | Other | | |
| 12 | Other | | |
| 13 | Other | | |
| 14 | Total | (Sum of lns 2 through 13 ) | $ - |

*Notes: 1. When calculating the Baseline ATRR, the "Relevant Year" is the year being true-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the recent FERC Form No. 1. 2. Adjustment to charges that are booked to transmission accounts that are the responsibility of the TO's LSE.* **OKLAHOMA GAS AND ELECTRIC COMPANY**

**Worksheet F**

**I. Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase.**

**A. Determine "R" with hypothetical 100 basis point increase in ROE.**

| Line No. | | | | |
|---|---|---|---|---|
| 1 | ROE w/o incentives (Addendum 2-A, ln 139) | | | 0.00% |
| 2 | ROE with additional 100 basis point incentive | | | 1.00% |
| 3 | Determine R (cost of long term debt, cost of preferred stock and percent is from Addendum 2-A, lns 137 through139) | | | |
| 4 | | % | Cost | Weighted cost |
| 5 | Long Term Debt | 0.00% | 0.0000 | 0.0000 |
| 6 | Preferred Stock | 0.00% | 0.0000 | 0.0000 |
| 7 | Common Stock | 0.00% | 0.0100 | 0.0000 |
| | | | R = | 0.0000 |

**B. Determine Return using "R" with hypothetical 100 basis point ROE increase.**

| | | | |
|---|---|---|---|
| 8 | Rate Base (Addendum 2-A, ln 67) | | - |
| 9 | R (from A. above) | - | |
| 10 | Return (Rate Base x R) | | - |

**C. Determine Income Taxes using Return with hypothetical 100 basis point ROE increase.**

| | | | |
|---|---|---|---|
| 11 | Return (from B. above) | | - |

| | | | | | |
|---|---|---|---|---|---|
| 12 | CIT (Addendum 2-A, ln 108) | 0.00% | | | |
| 13 | Income Tax Calculation (Return x CIT) | | - | | |
| 14 | ITC Adjustment (Addendum 2-A, ln 114) | | - | | |
| 15 | Income Taxes | | - | | |

**II. <u>Calculate Net Plant Carrying Charge Rate (NPCC) with hypothetical 100 basis point ROE increase.</u>**

**A. Determine Net Revenue Requirement less Return and Income Taxes.**

| | | | | |
|---|---|---|---|---|
| 16 | Net Revenue Requirement (Addendum 2-A, ln 16) | | - | |
| 17 | Return (Addendum 2-A, ln 116) | | - | |
| 18 | Income Taxes (Addendum 2-A, ln 115) | | - | |
| 19 | Net Revenue Requirement, Less Return and Taxes | | - | |

**B. Determine Net Revenue Requirement with hypothetical 100 basis point increase in ROE.**

| | | | | |
|---|---|---|---|---|
| 20 | Net Revenue Requirement, Less Return and Taxes | | - | |
| 21 | Return (from I.B. above) | | - | |
| 22 | Income Taxes (from I.C. above) | | - | |
| 23 | Net Revenue Requirement, with 100 Basis Point ROE increase | | - | |
| 24 | Transmission Plant Depreciation Expense (Addendum 2-A, lns 92) | | - | |
| 25 | Net Rev. Req, w/100 Basis Point ROE increase, less Depreciation | | - | |

**C. Determine NPCC with hypothetical 100 basis point ROE increase.**

| | | | | |
|---|---|---|---|---|
| 26 | Net Transmission Plant (Addendum 2-A, lns 46) | | - | |
| 27 | Net Revenue Requirement, with 100 Basis Point ROE increase | | - | |
| 28 | NPCC with 100 Basis Point increase in ROE | 0.00% | | |
| 29 | | | | |
| 30 | Net Rev. Req, w/100 Basis Point ROE increase, less Dep. | | - | |
| 31 | NPCC with 100 Basis Point ROE increase, less Depreciation | 0.00% | | (use when no CIAC is associated with facilities receiving incentives) |
| 32 | NPCC w/o 100 Basis Point ROE increase, less Depreciation | 0.00% | | (Addendum 2-A, ln 26) |
| 33 | NPCC w/o Return, income taxes and Depreciation | 0.00% | | (use when CIAC is associated with facilities receiving incentives) |
| 34 | 100 basis point ROE increase (line 31 - 32) | 0.00% | | |

**III. <u>Calculation of Composite Depreciation Rate.</u>**

| | | |
|---|---|---|
| 35 | Transmission Plant @ Beginning of Period (p.206, ln 58, col. b) | |
| 36 | Transmission Plant @ End of Period (p.207, ln 58, col. g) | |

| | | | |
|---|---|---|---|
| 37 | | | - |
| 38 | Average Balance of Transmission Investment | | - |
| 39 | Annual Depreciation (p.336, ln 7, col. f) | | |
| 40 | Composite Depreciation Rate | 0.00% | |
| 41 | Depreciable Life for Composite Depreciation Rate | | - |
| 42 | Depreciable Life Rounded to Nearest Whole Year | | |

NOTE:
Incentives shall not be included in the revenue requirement calculation unless approved by the FERC in a separate single issue filing.

**OKLAHOMA GAS AND ELECTRIC COMPANY** Page 2 of 3

**Worksheet F**

**IV. Summary of Additional Revenue Requirements Detailed in Section V below.**

| Line No. | SUMMARY OF ADDITIONAL REVENUE REQUIREMENT FOR FACILITIES RECEIVING INCENTIVES | | | | |
|---|---|---|---|---|---|
| | Proj. No. | **Project Description Summary** | **In-Service** | **Investment** | **Additional Rev. Requirement** |
| 43 | 1 | | | | $ - |
| 44 | 2 | | | | |
| 45 | 3 | | | | |
| 46 | 4 | | | | |
| 47 | 5 | | | | |
| 48 | 6 | | | | |
| 49 | 7 | | | | |
| 50 | 8 | | | | |
| 51 | 9 | | | | |
| 52 | 10 | | | | |
| 53 | 11 | | | | |
| 54 | 12 | | | | |
| 55 | 13 | | | | |
| 56 | 14 | | | | |
| 57 | 15 | | | | |
| 58 | 16 | | | | |
| 59 | | | | | |
| 60 | | | | | |
| 61 | **TOTALS** | | | **$ -** | **$ -** |

**OKLAHOMA GAS AND ELECTRIC COMPANY** Page 3 of 3

**Worksheet F**

**V. Determine the Additional Revenue Requirement for facilities receiving incentives.**
**A. Facilities receiving incentives**

**Project** Approved by FERC in Docket No. (e.g. ER05-925-000)

**1.**

Each individual facilities receiving incentives will have a separate sheet in this section.

| Line No. | | Details | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 62 | | Investment | | - | Current Year | | | | | |
| 63 | | Service Year (yyyy) | | | ROE increase accepted by FERC (Basis Points) | | | | | |
| 64 | | Service Month (1-12) | | - | NPCC w/o incentives, less depreciation | | | | 0.00% | |
| 65 | | Useful Life | | - | NPCC w/incentives approved for these facilities, less dep. | | | | 0.00% | |
| 66 | | CIAC (Yes or No) | | | Annual Depreciation Expense | | (Investment / Useful Life) | | | - |
| 67 | | **Investment** | **Beginning** | | | **Ending** | **Revenue** | | **Additional Rev.** | |
| 68 | | **Year** | **Balance** | | **Depreciation Expense** | **Balance** | **Requirement** | | **Requirement** | |
| 69 | w/o incentives | - | | - | - | | $ | - | | |
| 70 | w/incentives | - | | - | - | - | $ | - | $ | - |
| 71 | w/o incentives | - | | - | - | | | - | | |
| 72 | w/incentives | - | | - | - | - | | - | $ | - |
| 73 | w/o incentives | - | | - | - | | | - | | |
| 74 | w/incentives | - | | - | - | - | | - | $ | - |
| 75 | w/o incentives | - | | - | - | | | - | | |
| 76 | w/incentives | - | | - | - | - | | - | $ | - |
| 77 | w/o incentives | - | | - | - | | | - | | |
| 78 | w/incentives | - | | - | - | - | | - | $ | - |
| 79 | w/o incentives | - | | - | - | | | - | | |
| 80 | w/incentives | - | | - | - | - | | - | $ | - |
| 81 | w/o incentives | - | | - | - | | | - | | |
| 82 | w/incentives | - | | - | - | - | | - | $ | - |
| 83 | w/o incentives | - | | - | - | | | - | | |
| 84 | w/incentives | - | | - | - | - | | - | $ | - |
| 85 | w/o incentives | - | | - | - | | | - | | |
| 86 | w/incentives | - | | - | - | | | - | $ | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | - | | | |
| 87 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 88 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 89 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 90 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 91 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 92 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 93 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 94 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 95 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 96 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 97 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 98 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 99 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 100 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 101 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 102 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 103 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 104 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 105 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 106 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 107 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 108 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 109 | w/o incentives | - | - | - | | - | | |
| | | | | | - | | | |
| 110 | w/incentives | - | - | - | | - | $ | - |
| | | | | | - | | | |
| 111 | w/o | - | - | - | | - | | |

| | | |

## Addendum 2-A Part 2 to Attachment H

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet G**

**I. Project Summary**

| Proj. No. | A. BASE PLAN UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY | | | |
|---|---|---|---|---|
| | **Project Description Summary** | **In-Service** | **Investment** | **ATRR** |
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | | | | |

| | | |
|---|---|---|
| **BASE PLAN UPGRADE TOTALS** | **$ -** | **$ -** |

| Proj. No. | B. TRANSMISSION SERVICE UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY | | | |
|---|---|---|---|---|
| | **Project Description Summary** | **In-Service** | **Investment** | **ATRR** |
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| | **TRANSMISSION SERVICE UPGRADE TOTALS** | | | |

| Proj. No. | C. SPONSORED OR ECONOMIC PORTFOLIO UPGRADE ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY | | | |
|---|---|---|---|---|
| | **Project Description Summary** | **In-Service** | **Investment** | **ATRR** |
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| | **SPONSORED OR ECONOMIC PORTFOLIO UPGRADE TOTALS** | | | |

| Proj. No. | D. GENERATOR INTERCONNECTION FACILITIES ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY | | | |
|---|---|---|---|---|
| | **Project Description Summary** | **In-Service** | **Investment** | **ATRR** |
| 1 | | | | |
| 2 | | | | |

| | | | | |
|---|---|---|---|---|
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| | **GENERATOR INTERCONNECTION FACILITIES TOTALS** | | | |

| | | |
|---|---|---|
| **TOTAL SPP OATT RELATED UPGRADES REVENUE REQUIREMENT** | (Sum of Parts A, B, C & D above) | **$ -** |

*Notes:*

1. *Base Plan Upgrades and Economic Portfolio revenue requirement are estimates and will be trued-up to actual amounts in the True-up Adjustment.*
2. *Base Plan and Economic Portfolio revenue requirements in the Summaries will be provided to SPP for their Cost Allocation calculations.*
3. Refund or Surcharge amounts for each project are reflected on Worksheet L. Section III.

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet G**

**II. Determine the Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades, Sponsored or Economic Portfolio Upgrades and Generator Interconnection Facilities.**

**A. Base Plan facilities.**

**Project 1:** Each individual Base Plan project will have a separate sheet in this section.

**The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year**

**matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated.**

**These changes will not result in a refund or additional charge related to years prior to Current Year.**

| Line No. | Details | | | | | |
|---|---|---|---|---|---|---|
| 1 | Investment | $ - | Current Year | | | |
| 2 | Service Year (yyyy) | | NPCC w/o incentives, less depreciation | | | 0.00% |
| 3 | Service Month (1-12) | - | | | | |
| 4 | Useful Life | | Annual Depreciation Expense | (Investment / Useful Life) | $ | - |
| 5 | CIAC (Yes or No) | | | | | |

| 6 | Investment | Beginning | Depreciation | Ending | Revenue | Rev. Req. for |
|---|---|---|---|---|---|---|
| 7 | Year | Balance | Expense | Balance | Requirement | SPP Allocation |
| 8 | - | $ - | $ - | $ - | $ - | $ - |
| 9 | - | $ - | $ - | $ - | $ - | $ - |
| 10 | - | $ - | $ - | $ - | $ - | $ - |
| 11 | - | $ - | $ - | $ - | $ - | $ - |
| 12 | - | $ - | $ - | $ - | $ - | $ - |
| 13 | - | $ - | $ - | $ - | $ - | $ - |
| 14 | - | $ - | $ - | $ - | $ - | $ - |
| 15 | - | $ - | $ - | $ - | $ - | $ - |
| 16 | - | $ - | $ - | $ - | $ - | $ - |
| 17 | - | $ - | $ - | $ - | $ - | $ - |
| 18 | - | $ - | $ - | $ - | $ - | $ - |
| 19 | - | $ - | $ - | $ - | $ - | $ - |
| 20 | - | $ - | $ - | $ - | $ - | $ - |
| 21 | - | $ - | $ - | $ - | $ - | $ - |
| 22 | - | $ - | $ - | $ - | $ - | $ - |
| 23 | - | $ - | $ - | $ - | $ - | $ - |
| 24 | - | $ - | $ - | $ - | $ - | $ |

| | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | - |
| 50 | - | $ | - | $ | - | $ | - | $ | - | $ | - | $ - |
| 51 | - | $ | - | $ | - | $ | - | $ | - | $ | - | $ - |
| 52 | - | $ | - | $ | - | $ | - | $ | - | $ | - | $ - |
| 53 | | | | | | | | | | | | |
| 54 | Project Totals | | | | | | | $ | - | $ | - | |

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet G**

**B. Transmission Service Upgrades.**

**Project 1:** Each individual Transmission Service Upgrade will have a separate sheet in this section.

**The calculated Rev. Req. from Customers and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.**

| Line No. | Details | | | |
|---|---|---|---|---|
| 55 | Investment | - | Current Year | |
| 56 | Service Year (yyyy) | | NPCC w/o incentives, less depreciation | 0.00% |
| 57 | Service Month (1-12) | - | Rev. Req. allocated to TO's Identified Customers | 100.00% |
| 58 | Useful Life | 0 | Annual Depreciation Expense (Investment / Useful Life) | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 59 | CIAC (Yes or No) | | | | | |
| 60 | **Investment** | **Beginning** | **Depreciation** | **Ending** | **Revenue** | **Rev. Req. for** |
| 61 | **Year** | **Balance** | **Expense** | **Balance** | **Requirement** | **SPP Allocation** |
| 62 | - | - | - | - | $ - | $ - |
| 63 | - | - | - | - | - | $ - |
| 64 | - | - | - | - | - | $ - |
| 65 | - | - | - | - | - | $ - |
| 66 | - | - | - | - | - | $ - |
| 67 | - | - | - | - | - | $ - |
| 68 | - | - | - | - | - | $ - |
| 69 | - | - | - | - | - | $ - |
| 70 | - | - | - | - | - | $ - |
| 71 | - | - | - | - | - | $ - |
| 72 | - | - | - | - | - | $ - |
| 73 | - | - | - | - | - | $ - |
| 74 | - | - | - | - | - | $ - |
| 75 | - | - | - | - | - | $ - |
| 76 | - | - | - | - | - | $ - |
| 77 | - | - | - | - | - | $ - |
| 78 | - | - | - | - | - | $ - |
| 79 | - | - | - | - | - | $ - |
| 80 | - | - | - | - | - | $ - |
| 81 | - | - | - | - | - | $ - |
| 82 | - | - | - | - | - | $ - |
| 83 | - | - | - | - | - | $ - |
| 84 | - | - | - | - | - | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 85 | - | - | - | - | - | $ - |
| 86 | - | - | - | - | - | $ - |
| 87 | - | - | - | - | - | $ - |
| 88 | - | - | - | - | - | $ - |
| 89 | - | - | - | - | - | $ - |
| 90 | - | - | - | - | - | $ - |
| 91 | - | - | - | - | - | $ - |
| 92 | - | - | - | - | - | $ - |
| 93 | - | - | - | - | - | $ - |
| 94 | - | - | - | - | - | $ - |
| 95 | - | - | - | - | - | $ - |
| 96 | - | - | - | - | - | $ - |
| 97 | - | - | - | - | - | $ - |
| 98 | - | - | - | - | - | $ - |
| 99 | - | - | - | - | - | $ - |
| 100 | - | - | - | - | - | $ - |
| 101 | - | - | - | - | - | $ - |
| 102 | - | - | - | - | - | $ - |
| 103 | - | - | - | - | - | $ - |
| 104 | - | - | - | - | - | $ - |
| 105 | - | - | - | - | - | $ - |
| 106 | - | - | - | - | - | $ - |
| 107 | - | - | - | - | - | $ - |
| 108 | - | - | - | - | - | $ - |
| 109 | - | - | - | - | - | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 110 | - | - | - | - | - | $ - |
| 111 | - | - | - | - | - | $ - |
| 112 | - | - | - | - | - | $ - |
| 113 | .... | .... | ..... | ..... | .... | .... |
| 114 | | | | | | |

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet G**

**C. Sponsored or Economic Portfolio Upgrades.**

**Project 1:** Each individual Sponsored Upgrade or Economic Portfolio Upgrade will have a separate sheet in this section.

**The calculated Rev. Req. from Sponsor and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.**

| Line No. | Details | | | | |
|---|---|---|---|---|---|
| 115 | Investment | - | Current Year | | |
| 116 | Service Year (yyyy) | | NPCC w/o incentives, less depreciation | | 0.00% |
| 117 | Service Month (1-12) | - | Rev. Req. allocated to Sponsoring Entity | | 100.00% |
| 118 | Useful Life | | Annual Depreciation Expense (Investment / Useful Life) | | - |
| 119 | CIAC (Yes or No) | | | | |

| | Investment Year | Beginning Balance | Depreciation Expense | Ending Balance | Revenue Requirement | Rev. Req. for SPP Allocation |
|---|---|---|---|---|---|---|
| 120 | | | | | | |
| 121 | | | | | | |
| 122 | - | - | - | - | $ - | $ - |
| 123 | - | - | - | - | - | $ - |
| 124 | - | - | - | - | - | $ - |
| 125 | - | - | - | - | - | $ - |
| 126 | - | - | - | - | - | $ - |
| 127 | - | - | - | - | - | $ - |
| 128 | - | - | - | - | - | $ - |
| 129 | - | - | - | - | - | $ - |
| 130 | - | - | - | - | - | $ - |
| 131 | - | - | - | - | - | $ - |
| 132 | - | - | - | - | - | $ - |
| 133 | - | - | - | - | - | $ - |
| 134 | - | - | - | - | - | $ - |
| 135 | - | - | - | - | - | $ - |
| 136 | - | - | - | - | - | $ - |
| 137 | - | - | - | - | - | $ - |
| 138 | - | - | - | - | - | $ - |
| 139 | - | - | - | - | - | $ - |
| 140 | - | - | - | - | - | $ - |
| 141 | - | - | - | - | - | $ - |
| 142 | - | - | - | - | - | $ - |
| 143 | - | - | - | - | - | $ - |
| 144 | - | - | - | - | - | $ - |
| 145 | - | - | - | - | - | $ |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | - |
| 146 | - | - | - | - | - | $ - |
| 147 | - | - | - | - | - | $ - |
| 148 | - | - | - | - | - | $ - |
| 149 | - | - | - | - | - | $ - |
| 150 | - | - | - | - | - | $ - |
| 151 | - | - | - | - | - | $ - |
| 152 | - | - | - | - | - | $ - |
| 153 | - | - | - | - | - | $ - |
| 154 | - | - | - | - | - | $ - |
| 155 | - | - | - | - | - | $ - |
| 156 | - | - | - | - | - | $ - |
| 157 | - | - | - | - | - | $ - |
| 158 | - | - | - | - | - | $ - |
| 159 | - | - | - | - | - | $ - |
| 160 | - | - | - | - | - | $ - |
| 161 | - | - | - | - | - | $ - |
| 162 | - | - | - | - | - | $ - |
| 163 | - | - | - | - | - | $ - |
| 164 | - | - | - | - | - | $ - |
| 165 | - | - | - | - | - | $ - |
| 166 | - | - | - | - | - | $ - |
| 167 | - | - | - | - | - | $ - |
| 168 | - | - | - | - | - | $ - |
| 169 | - | - | - | - | - | $ - |
| 170 | - | - | - | - | - | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | - |
| 171 | - | - | - | - | - | $ | - |
| 172 | - | - | - | - | - | $ | - |
| 173 | .... | .... | ..... | ..... | .... | | .... |
| 174 | | | | | | | |

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet G**

**D. Generator Interconnect Upgrades.**

**Project 1:** Each individual project will have a separate sheet in this section.

**The calculated Rev. Req. from Generator and Credit shown below are only valid for Investment Year matching Current Year. Values prior and subsequent to Current Year will change as Attachment H-1 is updated. These changes will not result in a refund or additional charge related to years prior to Current Year.**

| Line No. | Details | | | | | |
|---|---|---|---|---|---|---|
| 175 | Investment | - | Current Year | | | |
| 176 | Service Year (yyyy) | | NPCC w/o incentives, less depreciation | | | 0.00% |
| 177 | Service Month (1-12) | - | Rev. Req. allocated to TO's Zone | | | 100.00% |
| 178 | Useful Life | | Annual Depreciation Expense | (Investment / Useful Life) | | - |
| 179 | CIAC (Yes or No) | | | | | |

| 180 | Investment | Beginning | Depreciation | Ending | | Revenue | Rev. Req. for SPP |
|---|---|---|---|---|---|---|---|
| 181 | Year | Balance | Expense | Balance | | Requirement | Allocation |
| 182 | - | - | - | - | $ | - | $ - |
| 183 | - | - | - | - | | - | $ - |
| 184 | - | - | - | - | | - | $ - |
| 185 | - | - | - | - | | - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 186 | - | - | - | - | - | $ | - |
| 187 | - | - | - | - | - | $ | - |
| 188 | - | - | - | - | - | $ | - |
| 189 | - | - | - | - | - | $ | - |
| 190 | - | - | - | - | - | $ | - |
| 191 | - | - | - | - | - | $ | - |
| 192 | - | - | - | - | - | $ | - |
| 193 | - | - | - | - | - | $ | - |
| 194 | - | - | - | - | - | $ | - |
| 195 | - | - | - | - | - | $ | - |
| 196 | - | - | - | - | - | $ | - |
| 197 | - | - | - | - | - | $ | - |
| 198 | - | - | - | - | - | $ | - |
| 199 | - | - | - | - | - | $ | - |
| 200 | - | - | - | - | - | $ | - |
| 201 | - | - | - | - | - | $ | - |
| 202 | - | - | - | - | - | $ | - |
| 203 | - | - | - | - | - | $ | - |
| 204 | - | - | - | - | - | $ | - |
| 205 | - | - | - | - | - | $ | - |
| 206 | - | - | - | - | - | $ | - |
| 207 | - | - | - | - | - | $ | - |
| 208 | - | - | - | - | - | $ | - |
| 209 | - | - | - | - | - | $ | - |
| 210 | - | - | - | - | - | $ | - |
| 211 | - | - | - | - | - | $ | - |
| 212 | - | - | - | - | - | $ | - |
| 213 | - | - | - | - | - | $ | - |
| 214 | - | - | - | - | - | $ | - |
| 215 | - | - | - | - | - | $ | - |
| 216 | - | - | - | - | - | $ | - |
| 217 | - | - | - | - | - | $ | - |
| 218 | - | - | - | - | - | $ | - |
| 219 | - | - | - | - | - | $ | - |
| 220 | - | - | - | - | - | $ | - |
| 221 | - | - | - | - | - | $ | - |

| | | |

| e<br>No<br>. | | | | |
|---|---|---|---|---|
| 1 | Radial Lines | | | |
| 2 | | | | |
| 3 | Other Adjustments -<br>Transfers: | | | |
| 4 | Distribution Assets Reclassified as Transmission Assets | | | |
| 5 | Transmission Assets Reclassified as Distribution Assets | | | |
| 6 | | | | |
| 7 | Plant Transfers Excluded from SPP Tariff | (line 119) | **$** | **-** |
| 8 | | | | |
| 9 | | | | |

**II. Production Related Transmission Facilities**

| | (A) | | (B) |
|---|---|---|---|
| Line No. | **Plant Description** | | **Amount** |
| 10 | Generation Radial Ties (Centennial) | | |
| 11 | Generation Step Up Transformers (GSU's) and Related Equipment | | |
| 12 | | | |
| 13 | Total | (line 120) | **$** - |

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet I - Account 105 - Electric Plant Held for Use**

Form I - Page 214 Detail

**I. Non-Transmission**

| Line No. | LOC CODE &/OR REG | PLANT NAME | ACQUISITION DATE | ACQUISITION VALUE | ACCUM DEPR | AVG BOY and EOY | EST. YEAR IN SERVICE | COMMENT |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | |
| 2 | | | | | | | | |
| 3 | | | | | | | | |
| 4 | | | | | | | | |
| 5 | | | | | | | | |
| 6 | | | | | | | | |
| 7 | | | | | | | | |
| 8 | | | | | | | | |
| 9 | | | | | | | | |
| 10 | | | | | | | | |
| 11 | | | | | | | | |
| 12 | | | | | | | | |
| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| 17 | | | | | | | | |
| 18 | | | | | | | | |
| 19 | | | | | | | | |
| 20 | | | | | | | | |
| 21 | | | | | | | | |
| 22 | | | | | | | | |
| 23 | | | | | | | | |
| 24 | | | | | | | | |
| 25 | | | | | | | | |
| 26 | | | | | | | | |
| 27 | | | | | | | | |
| 28 | | | | | | | | |
| 29 | | | | | | | | |
| 30 | | | | | | | | |
| 31 | | | | | | | | |
| 32 | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 33 | | | | | | | | |
| 34 | | | | | | | | |
| 35 | | | | | | | | |
| 36 | | | | | | | | |
| 37 | | | | | | | | |
| 38 | | | | | | | | |
| 39 | | | | | | | | |
| 40 | | **TOTAL ARKANSAS** | | 0 | | 0 | | |
| 41 | | **TOTAL OKLAHOMA** | | 0 | | 0 | | |
| 42 | | **TOTAL ALL** | | 0 | | 0 | | |
| 43 | | | | | | | | |
| 44 | | | | | | | | |
| 45 | | **NON TRANSMISSION TOTAL** | | | | | | |

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet I - Account 105 - Electric Plant Held for Use**

**II. Transmission**

| Line No. | LOC CODE &/OR REG | PLANT NAME | ACQUISITION DATE | ACQUISITION VALUE | ACCUM DEPR | AVG BOY and EOY | EST. YEAR IN SERVICE | COMMENT |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| 46 | | | | | | | | |
| 47 | | | | | | | | |
| 48 | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 49 | | | | | | | | |
| 50 | | | | | | | | |
| 51 | | | | | | | | |
| 52 | | | | | | | | |
| 53 | | | | | | | | |
| 54 | | | | | | | | |
| 55 | | | | | | | | |
| 56 | | | | | | | | |
| 57 | | | | | | | | |
| 58 | | | | | | | | |
| 59 | | | | | | | | |
| 60 | | | | | | | | |
| 61 | | | | | | | | |
| 62 | | **TOTAL ARKANSAS** | | 0 | | 0 | | |
| 63 | | **TOTAL OKLAHOMA** | | 0 | | 0 | | |
| 64 | | **TOTAL ALL** | | 0 | | 0 | | |
| 65 | | | | | | | | |
| 66 | | | | | | | | |
| 67 | | **TRANSMISSION ONLY** | | **0** | | Data tab line 61 | | |
| 68 | | | | | | | | |
| 69 | | **TOTAL COMPANY** | | 0 | | Form I, p.214, line47 | | |

NOTE:

1. To be included in transmission rate base, the land held for future use must be estimated to be in service within 10 years
2. When calculating the Baseline ATRR, use data from the year being trued-up to calculate "AVG BOY and EOY"; when calculating the Projected ATRR, use data from the most recent FERC Form 1 to calculate the "AVG BOY and EOY."

# OKLAHOMA GAS AND ELECTRIC COMPANY

**Worksheet J - Tax Apportionments by State**

**I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES**

| Line No. | | For Tax Year yyyy | | |
|---|---|---|---|---|
| 1 | State Income Tax Rate - Oklahoma | Note 1 | | |
| 2 | Apportionment Factor | Note 2 | | |
| 3 | Oklahoma State Income Tax Rate | (ln 1 * ln 2) | | 0.0000% |
| 4 | State Income Tax Rate - Arkansas | | | |
| 5 | Apportionment Factor | Note 2 | | |
| 6 | Arkansas State Income Tax Rate | (ln 4 * ln 5) | | 0.0000% |
| 7 | Total State Income Tax Rate | (sum ln 3 & ln 6) | | 0.0000% |

Note 1: The Oklahoma State Income Tax Rate of 6% is reduced to 5.66% due to the deductibility of Oklahoma State Income Taxes on the State Income Tax Return.

Note 2: Apportionment Factors are to be based on most recent annual income tax filings as calculated in Parts II. & III. Below

# OKLAHOMA GAS AND ELECTRIC COMPANY

**Worksheet J - Tax Apportionments by State**

**II. Calculation of Oklahoma Apportionment Factor**

| | | | Column A | Column B | A divided by B |
|---|---|---|---|---|---|
| 1. | | Value of real and tangible personal property used in the unitary business (by averaging the value at the beginning and ending of the tax period). | Total Within Oklahoma | Total Within and Without Oklahoma | Percentage Within Oklahoma |
| | (a) | Owned property (at original cost): | | | |
| | | (I) Inventories | | | |
| | | (II) Depreciable property | | | |
| | | (III) Land | | | |
| | | (IV) Total of section 1(a) | - | - | |
| | (b) | Rented property (capitalize at 8 times net rental paid) | | | |
| | (c) | TOTAL (sum of 1(a) and 1(b)) | - | - | 0.0000% |
| 2. | (a) | Payroll | | | |
| | (b) | Less: Officers salaries | | | |
| | (c) | TOTAL (subtract 2(b) from 2(a)) | - | - | 0.0000% |
| 3. | | Sales: | | | |
| | (a) | Sales delivered or shipped to Oklahoma purchasers: | | | |
| | | (I) Shipped from outside Oklahoma | | | |
| | | (II) Shipped from within Oklahoma | | | |
| | (b) | Sales shipped from Oklahoma to: | | | |
| | | (I) The United States Government | | | |
| | | (II) Purchasers in a state or country where the corporation is not taxable (i.e. under Public Law 85-272) | | | |
| | (c) | TOTAL (sum of 3(a) and 3(b)) | - | | 0.0000% |
| | | TOTAL PERCENTAGES (sum of items 1(c), 2(c) and 3(c)) | | | 0.0000% |
| | | Average of TOTAL PERCENTAGES (1/3 of total percent) | | | **0.0000%** |

**III. Calculation of Arkansas Apportionment Factor**

| | | | (A) Amounts in Arkansas | (B) Total Amounts | (C) Percentage (A) / (B) |
|---|---|---|---|---|---|
| 1. | | Property Used in Business: | | | |
| | (a) | Tangible Assets Used in Business and Inventories | | | |
| | | Less Construction in Progress: | | | |
| | | 1. Amount Beginning of Year: | | | |
| | | 2. Amount End of Year | | | |
| | | 3. Total: (sum of 1(a) 1 and 1(a) 2) | - | - | |
| | | 4. Average Tangible Assets: (divide 1(a) 3 by 2) | - | - | |
| | (b) | Rental Property: (8 times annual rent) | - | - | |
| | (c) | Average Value of Intangible Property: | - | - | |
| | (d) | TOTAL PROPERTY (sum of lines 1(a) 4, 1(b) and 1(c)) | - | - | 0.000000% |
| 2. | | Salaries, Wages, Commissions and Other Compensation Related to the Production of Business Income: | | | 0.000000% |
| 3. | | Sales/Receipts: | | | |
| | (a) | Destination Shipped From Within Arkansas: | | | |
| | (b) | Destination Shipped From Without Arkansas | | | |
| | (c) | Origin Shipped From Within Arkansas to U.S. Govt: | | | |
| | (d) | Origin Shipped From Within Arkansas to Other Non-taxable Jurisdictions: | | | |
| | (e) | Other Gross Receipts: | | | |
| | (f) | TOTAL SALES / RECEIPTS: (sum of lines 3(a) to 3(e)) | - | | 0.000000% |
| | (g) | DOUBLE WEIGHTED (Applies to tax years beginning on or after January 1, 1995) (Column C, Line 3(f) times 2) | | | 0.000000% |
| 4. | | TOTAL PERCENTAGES: (Column C sum of lines 1(d), 2 and 3(g)) | | | 0.000000% |
| 5. | | Average of TOTAL PERCENTAGES (Column C, Line 4 divided 4) | | | **0.000000%** |

**Worksheet K - 13 Month Average Balances and Long Term Debt Costs**

**I. Plant & Accumulated Depreciation Balances**

**Gross Plant** (Note 1)

| Line No. | | End. Balance Dec-08 | Jan-09 | Feb-09 | Mar-09 | Apr-09 | May-09 | Jun-09 | Jul-09 | Aug-09 | Sep-09 | Oct-09 | Nov-09 | End. Balance Dec-09 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Intangible | | | | | | | | | | | | | | 0 |
| 2 | Production-Redbud | | | | | | | | | | | | | | 0 |
| 3 | Production | | | | | | | | | | | | | | 0 |
| 4 | Transmission | | | | | | | | | | | | | | 0 |
| 5 | Distribution | | | | | | | | | | | | | | 0 |
| 6 | General Plant | | | | | | | | | | | | | | 0 |
| 7 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Accumulated Depreciation and Amortization** (Note 2)

| | | End. Balance Dec-08 | Jan-09 | Feb-09 | Mar-09 | Apr-09 | May-09 | Jun-09 | Jul-09 | Aug-09 | Sep-09 | Oct-09 | Nov-09 | End. Balance Dec-09 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Intangible | | | | | | | | | | | | | | 0 |
| 9 | Production-Redbud | | | | | | | | | | | | | | 0 |
| 10 | Production | | | | | | | | | | | | | | 0 |
| 11 | Transmission | | | | | | | | | | | | | | 0 |
| 12 | Distribution | | | | | | | | | | | | | | 0 |
| 13 | General Plant | | | | | | | | | | | | | | 0 |
| 14 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Net Plant** (Gross Plant less Accumulated Depreciation and Amortization)

| | | End. Balance Dec-08 | Jan-09 | Feb-09 | Mar-09 | Apr-09 | May-09 | Jun-09 | Jul-09 | Aug-09 | Sep-09 | Oct-09 | Nov-09 | End. Balance Dec-09 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | Production-Redbud | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Production | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | General Plant | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Notes:

1. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, the values for "Gross Plant" shall include net plant additions.
2. When calculating the Projected ATRR, the values for Accumulated Depreciation and Amortization shall include both accumulated depreciation and amortization on new plant projected to be in service as well as the accumulated depreciation and amortization on existing

plant through the end of the projected year.

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet K**

**II. Material and Supplies for Construction Balances**

| | | End Balance Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Jul-07 | Aug-07 | Sep-07 | Oct-07 | Nov-07 | End Balance Dec-07 | 13 Months Avg. Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22 | Production O&M | | | | | | | | | | | | | | 0 |
| 23 | Transmission O&M | | | | | | | | | | | | | | 0 |
| 24 | Distribution O&M | | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | |
| 25 | Prod. Construction | | | | | | | | | | | | | | 0 |
| 26 | Trans. Construction | | | | | | | | | | | | | | 0 |
| 27 | Dist. Construction | | | | | | | | | | | | | | 0 |
| 28 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Notes:
1. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, use the 13 month account balances ending December of the most recent FERC Form No. 1.

2. Transmission O&M (ln 23) and Transmission Construction (ln 26) are summed and reflected on page 3 of 6, line 64 of the Attachment H - Addendum 2-A.

**III. Debt and Equity Balances**

| | | End Balance Dec-06 | Jan-07 | Feb-07 | Mar-07 | Apr-07 | May-07 | Jun-07 | Jul-07 | Aug-07 | Sep-07 | Oct-07 | Nov-07 | End Balance Dec-07 | 13 Months Avg. Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | Long Term Debt (Face Value) | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| 30 | Propriety Capital | | | | | | | | | | | | | | - |
| 31 | Less: Acct. 204 | | | | | | | | | | | | | | - |
| 32 | Less: Acct. 216.1 | | | | | | | | | | | | | | - |
| 33 | Less: Acct. 219 | | | | | | | | | | | | | | - |
| 34 | Common Stock | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 35 | LTD / (LTD + Common Stock) | 0.0% | 0.0 % | 0.0% | 0.0 % | 0.0 % | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | #DIV/0! |

Notes:
1. Outstanding Long Term Debt are reported in Accts. 221-224 (112.18-21.c & d) and the calculation shall include only current period costs and shall not include any deferred costs, (except as authorized by FERC), interest rate hedging costs/gains/losses, or credit

facility expenses related to short-term indebtedness. Remove the value of any hedge contracts from Accts. 222-224 (257.h) for this purpose.
2. When calculating the Baseline ATRR, use the actual 13 month account balances for the year being trued-up. When calculating the Projected ATRR, use the 13 month account balances ending December of the most recent FERC Form No. 1.

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet K**

**IV. Account 165 - Prepayments**

| | | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance |
|---|---|---|---|---|
| 36 | | (111.57.d) | (111.57.c) | |
| 37 | Prepayments | | | 0 |
| | | | | |

Notes:
1. When calculating the Baseline ATRR, the "Relevant Year" is the year being trued-up. When calculating the Projected ATRR, the "Relevant Year" is the year of the most recent FERC Form No. 1.

**V. Long-Term Debt Costs**

| | Accounts | Reference | Calculation | Comments / Explanations |
|---|---|---|---|---|
| | | | | |
| 38 | Acct 427 - Long-term interest expense | (117.62.c) | | |
| | | | | |

| | | | | |
|---|---|---|---|---|
| 39 | Acct. 428 - Amortization of debt discount and expense | (117.63.c) | | |
| | | | | |
| 40 | Acct. 428.1 - Amortization of loss on reacquired debt | (117.64.c) | | |
| | | | | |
| 41 | Acct. 430 - Interest on Long-term debt to Associated Companies<br>in Acct. 223 (112.20.c) | (117.67.c) | | (per note on pg 450.1 for pg 256, col. i) |
| | | | | |
| 42 | Less: Acct. 429 - Premium on debt discount | (117.65.c) (enter negative) | | |
| | | | | |
| 43 | Less: Acct. 429.1 - Amortization of gain on reacquired debt | (117.66.c) (enter negative) | | |
| 44 | **Total Long Term Interest** | (sum lns 38 to 43) | **$ -** | |
| | | | | |
| 45 | Average of the 13 month balances outstanding long-term debt | (ln 29) | $ - | |
| 46 | **LONG TERM DEBT COST** | (ln 44 / ln 45) | **0.000%** | |
| | | | | |

Notes:
1. Unless approved in a Section 205 filing by FERC, gains and losses on interest rate hedging on long term debt shall not be flowed through interest expense; and the value of hedge contracts shall not be included in long term debt balances.

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet L - True-Up Adjustment with interest for Prior Year, Prior Period, Base Plan Projects and Prepayment Calculation.**

Line No.

**I. Prior Year True-Up with Interest Calculation**

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year.

| | | | Rate Year |
|---|---|---|---|
| 1 | Projected Revenue Requirement | | |
| 2 | Baseline Revenue Requirement | | 0 |
| 3 | True Up Adjustment Without Interest (TUA) | $ - | |
| 4 | Average Interest Rate on Amount of Refunds or Surcharges | | |
| 5 | calculated per Section V below | 0.0000% | |

| | | | [A] | [B] | [C] | [D] | [E] |
|---|---|---|---|---|---|---|---|
| | **Year** | | **Amount** | **Interest Rate** | **Months** | **Interest** | **Refund / (Surcharge)** |
| | | | | | | cols [A] x [B] x [C] | cols [A] + [D] |
| 6 | 0 | 6 months interest | $ - | 0.0000% | 6 | $ - | $ - |
| 7 | 1 | 12 months interest | $ - | 0.0000% | 12 | $ - | $ - |
| 8 | 2 | 6 months interest | $ - | 0.0000% | 6 | $ - | $ - |

**II. Prior Period Correction True-Up with Interest Calculation**

This section will calculate the interest on the True-up Adjustment (refund or surcharge) on a correction made in a Prior Period.

| | | | Correction Rate Year |
|---|---|---|---|
| 9 | Baseline Revenue Requirement | $ - | 0 |
| 10 | Revised Baseline Revenue Requirement | $ - | 0 |
| 11 | True Up Adjustment Without Interest (TUA) | $ - | |

12 Average Interest Rate on Amount of Refunds or Surcharges

13 calculated per Section V below **0.0000%**

| | | | [A] | [B] | [C] | [D] | [E] |
|---|---|---|---|---|---|---|---|
| | **Year** | | **Amount** | **Interest Rate** | **Months** | **Interest** | **Refund / (Surcharge)** |
| | | | | | | cols [A] x [B] x [C] | cols [A] + [D] |
| 14 | | 6 months interest | $ - | 0.0000% | 6 | $ - | $ - |
| 15 | | months interest | $ - | 0.0000% | | $ - | $ - |
| 16 | | 6 months interest | $ - | 0.0000% | 6 | $ - | $ - |
| 17 | **TOTAL PRIOR YEAR TRUE-UP ADJUSTMENT** | | (ln 8[E] + ln 16[E]) | | | | **$ -** |



**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Worksheet L**

**III. Base Plan Upgrade True-Up Calculations**

This section will calculate the interest on the True-up Adjustment (refund or surcharge) for the Prior Rate Year on Base Plan Upgrade Projects.

18 Average Interest Rate on Amount of Refunds or Surcharges calculated per Section V below.

| | Proj. No. | | Projected ATRR - Prior Year (1) | Baseline ATRR - Prior Year (2) | True-Up Adjustment Without Interest | Refund / (Surcharge) 0 | Refund / (Surcharge) 1 | Refund / (Surcharge) 2 |
|---|---|---|---|---|---|---|---|---|
| 19 | 1 | Reno-Sunny Lane 69kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | 2 | Richards Tap-Richards 138kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | 3 | Van Buren AVEC-Van Buren Interconnect 69kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | 4 | Brown Explorer Tap 138kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | 5 | NE Enid-Glenwood 138kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | 6 | Razorback-Short Mountain 69kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | 7 | Richards-Piedmont 138kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | 8 | OG&E Windfarm-WFEC Mooreland 138kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | 9 | Ft. Smith-Colony 161kV Line | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | 10 | Cedar Lane-Canadian 138kV Line | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 29 | | **TOTAL PRIOR YEAR BASE PLAN UPGRADE PROJECTS TRUE-UP ADJUSTMENT** | (sum ln 19 thru ln 28) | **$ -** |

NOTE:
(1) Projected ATRR for individual Base Plan Projects comes from the Prior Year's Projected ATRR calculation, Worksheet G and Worksheet P - Summary page
(2) Baseline ATRR for individual Base Plan Projects comes from the Prior Year Baseline ATRR calculation, Worksheet G and Worksheet P - Summary page

**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Worksheet L**

**IV. Calculation of Optional Prepayment and Prepayment Credit**

| | | | | "Customer 1" | "Customer 2" | "Customer 3" | "Customer 4" |
|---|---|---|---|---|---|---|---|
| 30 | Prepayment Amount | | | | | | |
| 31 | TUA with first year's interest | Line 6[E] above | | $ - | $ - | $ - | $ - |
| 32 | Line 31 plus 6 Months of year 2 Interest | (6 x Interest Rate on Line 7[B]+1) * Line 31 | | $ - | $ - | $ - | $ - |
| 33 | Customer's Load in year preceding the current Rate Year | (MW) | | | | | |
| 34 | System Load in year preceding the current Rate Year | (MW) | | | | | |
| 35 | Amount of Prepayment | Line 32 x (Line 33 / Line 34) | | $ - | $ - | $ - | $ - |
| 36 | Prepayment Adjustment (Note 1) | | | | | | |
| 37 | Customer's Load applicable in the current Rate Year | (MW) | | | | | |
| 38 | System Load applicable in the current Rate Year | (MW) | | | | | |
| 39 | Prepayment Adjustment | [(Line 37 / Line 38) / (Line 33 / Line 34) - 1] x Line 35 | | $ - | $ - | $ - | $ - |
| 40 | Line 39 plus 6 Months Interest | (6 x Interest Rate on Line 7[B]+1) * Line 39 | | $ - | $ - | $ - | $ - |
| 41 | Prepayment Credit | | | | | | |
| 42 | Total TUA with interest | Line 8[E] above | | $ - | $ - | $ - | $ - |
| 43 | Monthly Prepayment Credit | [Line 42 x (Line 33 / Line 34) / 12] | | $ - | $ - | $ - | $ - |

Note;

1. The Prepayment Adjustment is made to reflect any difference between the Network Customer's load ratio share percentage used to determine the Prepayment and the actual load ratio share

percentage applicable in the Rate Year during which the True-Up Adjustment would otherwise have been collected.



**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Worksheet L**

**V. Average Interest Rate / Debt Cost Calculations**

| | Quarter | Year | [A] FERC Quarterly Interest Rate | [B] OG&E Short Term Debt Rate | [C] Rate for Surcharges (lesser of A or B) | [D] Rate for Refunds (column A) |
|---|---|---|---|---|---|---|
| 44 | 3rd | 0 | | | 0.00% | 0.00% |
| 45 | 4th | 0 | | | 0.00% | 0.00% |
| 46 | 1st | 1 | | | 0.00% | 0.00% |
| 47 | 2nd | 1 | | | 0.00% | 0.00% |

| | | |
|---|---|---|
| 48 | Average Interest Rate Applicable to Surcharges from column [C] | 0.00% |
| 49 | Average Interest Rate Applicable to Refunds from column [D] | 0.00% |

NOTE: (1) The FERC Quarterly Interest Rate in column [A] is the interest applicable to the quarter indicated.

(2) The OG&E Short Term Debt Rate in column [B] is the weighted average Short Term Debt cost applicable to the quarter indicated.

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet M - Depreciation Rates**

Source: *OCC Cause No. PUD 201500273, Order #662059 and APSC Docket No* 16-052-U, Order #8

| Ln | Transmission Plant Account | Account Description | Rate |
|---|---|---|---|
| 1 | 350.2 | Land Rights | 1.00% |
| 2 | 350.3 | Land Rights - Power Supply | 1.00% |
| 3 | 352.0 | Structures and Improvements - Power Delivery | 1.66% |
| 4 | 352.1 | Structures and Improvements - Power Supply | *1.66*% |
| 5 | 353.0 | Station Equipment | 1.73% |
| 6 | 353.1 | Station Equipment - Step Up Transformers | 2.43% |
| 7 | 353.2 | Station Equipment - Security | 1.73% |
| 8 | 354.0 | Towers and Fixtures | 1.40% |
| 9 | 355.0 | Poles and Fixtures - Power Delivery | 2.29% |
| 10 | 355.1 | Poles and Fixtures - Power Supply | 2.29% |
| 11 | 356.0 | Overhead Conductors and Devices - Power Delivery | 2.29% |
| 12 | 356.1 | Overhead Conductors and Devices - Power Supply | 2.29% |

| | | | |
|---|---|---|---|
| 13 | 358 | Underground Conductors and Devices | *0.* 27% |

| Ln | General Plant Account | Account Description | Rate |
|---|---|---|---|
| 14 | 389.2 | Land and Land Rights | 2.78% |
| 15 | 390.0 | Structures and Improvements | 1.58% |
| *16* | 391.0 | Office Furniture and Equipment | 6.67% |
| *17* | 391.1 | Computer Equipment | 20.00% |
| 18 | 392.1 | Transportation Equipment - Cars and Trucks | 5.98% |
| 19 | 392.5 | Transportation Equipment - Heavy Trucks | 5.23% |
| 20 | 392.6 | Transportation Equipment - Trailers | 3.97% |
| 21 | 393.0 | Stores Equipment | *4.00*% |
| *22* | 394.0 | Tools, Shop and Garage Equipment | 4.00% |

**OKLAHOMA GAS AND ELECTRIC COMPANY**

**Worksheet M - Depreciation Rates**

Source: *OCC Cause No. PUD 201500273, Order #662059 and APSC Docket No. 10-067-U Order #6*

| Ln | General Plant Account | Account Description | Rate |
|---|---|---|---|
| 23 | 395.0 | Laboratory Equipment | 5.00% |
| 24 | 396.0 | Power Operated Equipment | 4.87% |
| 25 | 397.0 | Com*m*unication Equipment | 10.00% |
| 26 | 398.0 | Miscellaneous Equipment | 5.00% |

| | Intangible Plant Account | Account Description | Rate |
|---|---|---|---|
| 27 | 302.0 | Franchises and Consents | 4.22% |
| 28 | 303.2 | Misc. Intangible Plant - Software | 9.66% |

Note: These rates are fixed and will be changed only by a separate FPA 205 filing.

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet N - Unfunded Reserves**

**I. Labor Related**

| Line No. | Account No. | Account Title | Beginning Balance | Ending Balance | Average |
|---|---|---|---|---|---|
| 1 | 228.2 | Accumulated Provision for Injuries and Damages | | | $ - |
| 2 | 242 | Severance | | | $ - |
| 3 | 242 | Accrued Vacation Pay | | | $ - |
| 4 | 242 | Workers Compensation | | | $ - |
| 5 | 242 | Post Retirement Life Insurance | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 6 | 242 | Incentive Compensation | | | $ - |
| 7 | 242 | Public Liability | | | $ - |
| 8 | 242 | Miscellaneous | | | $ - |
| 9 | xxx | Reserved for future | | | $ - |
| 10 | | Sub-Total | $ - | $ - | $ - |
| 11 | | Wage & Salary Allocator | | | 0.000000 |
| 12 | | Total Labor Related Reserves (ln 10 times ln 11) | | | $ - |

**II. Plant Related**

| | | | | | |
|---|---|---|---|---|---|
| 13 | xxx | Reserved for future | $ - | $ - | $ - |
| 14 | xxx | Reserved for future | $ - | $ - | $ - |
| 15 | xxx | Reserved for future | $ - | $ - | $ - |
| 16 | | Sub-Total | $ - | $ - | $ - |
| 17 | | Gross Plant Allocator | | | 0.000000 |
| 18 | | Total Labor Related Reserves (ln 16 times ln 17) | | | $ - |
| 19 | | **TOTAL REDUCTION TO RATE BASE (negative of ln 12 plus ln 18)** | | | **$ -** |

Note:

The average of the beginning and ending balances of reserves that are unfunded (i.e. not set aside in an escrow) and whose balances have been included in the expenses recovered under the formula, will be deducted from rate base. This total will be represented as a negative amount on Line 58 of the Data tab.

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet N - Unfunded Reserves**

**I. Labor Related**

| Line No. | Account No. | Account Title | Beginning Balance | Ending Balance | Average |
|---|---|---|---|---|---|
| 1 | 228.2 | Accumulated Provision for Injuries and Damages | | | $ - |
| 2 | 242 | Severance | | | $ - |
| 3 | 242 | Accrued Vacation Pay | | | $ - |
| 4 | 242 | Workers Compensation | | | $ - |
| 5 | 242 | Post Retirement Life Insurance | | | $ - |
| 6 | 242 | Incentive Compensation | | | $ - |
| 7 | 242 | Public Liability | | | $ - |
| 8 | 242 | Miscellaneous | | | $ - |
| 9 | xxx | Reserved for future | | | $ - |
| 10 | | Sub-Total | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| 11 | | Wage & Salary Allocator | 0.000000 |
| 12 | | Total Labor Related Reserves (ln 10 times ln 11) | $ - |

**II. Plant Related**

| | | | | | |
|---|---|---|---|---|---|
| 13 | xxx | Reserved for future | $ - | $ - | $ - |
| 14 | xxx | Reserved for future | $ - | $ - | $ - |
| 15 | xxx | Reserved for future | $ - | $ - | $ - |
| 16 | | Sub-Total | $ - | $ - | $ - |
| 17 | | Gross Plant Allocator | | | 0.000000 |
| 18 | | Total Labor Related Reserves (ln 16 times ln 17) | | | $ - |
| 19 | | **TOTAL REDUCTION TO RATE BASE (negative of ln 12 plus ln 18)** | | | **$ -** |

Note:

The average of the beginning and ending balances of reserves that are unfunded (i.e. not set aside in an escrow) and whose balances have been included in the expenses recovered under the formula, will be deducted from rate base. This total will be represented as a negative amount on Line 58 of the Data tab.

# OKLAHOMA GAS AND ELECTRIC COMPANY



## Worksheet O - Amortizations

**I. Extraordinary O&M Amortization**

| Line No. | Justification | FERC Docket No | Effective Year | Amortization Term | Beginning O&M | Annual Amortization | Annual Year End Balance |
|---|---|---|---|---|---|---|---|

| | | (yrs) | Expense | n | |
|---|---|---|---|---|---|
| 1 | | | $ - | | $ - |
| 2 | | | $ - | | $ - |
| 3 | | | $ - | | $ - |
| 4 | | | $ - | | $ - |
| 5 | | | $ - | | $ - |
| 6 | | | $ - | | $ - |
| 7 | | | $ - | | $ - |
| 8 | | | $ - | | $ - |
| 9 | | | $ - | | $ - |
| 10 | | | $ - | | $ - |
| 11 | | | $ - | | $ - |
| | Total Extraordinary O&M | | $ | | |
| 12 | Amortization | | - | | |

# OKLAHOMA GAS AND ELECTRIC COMPANY



**Worksheet O - Amortizations**

**II. Storm Cost Amortization**

| | Justification | FERC Docket No | Effective Year | Amortization Term (yrs) | Beginning O&M Expense | Annual Amortization | Annual Year End Balance |
|---|---|---|---|---|---|---|---|
| 13 | 2007 Ice Storm expenses | | | | | $ - | $ - |
| 14 | | | | | | $ - | $ - |
| 15 | | | | | | $ - | $ - |
| 16 | | | | | | $ - | $ - |
| 17 | | | | | | $ - | $ - |
| 18 | | | | | | $ - | $ - |
| 19 | | | | | | $ - | $ - |
| 20 | | | | | | $ - | $ - |
| 21 | | | | | | $ - | $ - |
| 22 | | | | | | $ - | $ - |
| 23 | | | | | | $ - | $ - |
| 24 | | | | | | $ - | $ - |
| 25 | | | | | | $ - | - |
| 26 | Total Storm Costs Amortization | | | | | $ - | |
| 27 | **TOTAL AMORTIZATIONS** | (entered in Data tab on ln 93) | (sum of Ins 12 and 26) | | | | **$ -** |

## Worksheet P - Construction Work in Progress and Abandoned Plant

### I. Project Summary

**A. CWIP Annual Transmission Revenue Requirements**

| Proj. No. | Project Description | ATRR |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |
| 6 | | |
| 7 | | |
| 8 | | |
| 9 | | |
| 10 | | |

11

**CWIP Totals**

Proj. **B. Abandoned Plant Annual Transmission Revenue Requirements**

| No. | Project Description | ATRR |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |
| 6 | | |
| 7 | | |
| 8 | | |
| 9 | | |
| 10 | | |

11

**Abandoned Plant Totals**

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet P - Construction Work in Progress and Abandoned Plant Balances**

**II. Construction Work in Progress (CWIP) Balances**

| | Project 1 | Project 2 | Project 3 | Project 4 | Project 5 | Project 6 | Project 7 | Project 8 | Project 9 | Project 10 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|

| Line No. | Month | Year |
|---|---|---|
| 1 | **December** | 2010 |
| 2 | **January** | 2011 |
| 3 | **February** | 2011 |
| 4 | **March** | 2011 |
| 5 | **April** | 2011 |
| 6 | **May** | 2011 |
| 7 | **June** | 2011 |
| 8 | **July** | 2011 |
| 9 | **August** | 2011 |
| 10 | **September** | 2011 |
| 11 | **October** | 2011 |
| 12 | **November** | 2011 |
| 13 | **December** | 2011 |
| 14 | **Average Balances** | |

| | | | |
|---|---|---|---|
| 15 | **Return** | (Data Ln 140 * Ln 14) | 0 |
| 16 | **Taxes** | (Data Ln 108 * Ln 15) | 0 |
| 17 | **ATRR** | (Ln 15 + Ln 16) | 0 |

**OKLAHOMA GAS AND ELECTRIC COMPANY**



**Worksheet P - Construction Work in Progress and Abandoned Plant**

**III. Abandoned Plant**

| Line No. | | | Project 1 | Project 2 | Project 3 | Project 4 | Project 5 | Project 6 | Project 7 | Project 8 | Project 9 | Project 10 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | **Abandoned Plant Balance** | | | | | | | | | | | | |
| 19 | **Amortization Period (months)** | | | | | | | | | | | | |
| 20 | **Monthly Amortization Amount** | | | | | | | | | | | | |
| | Month | Year | | | | | | | | | | | |
| 21 | **December** | 2010 | | | | | | | | | | | |
| 22 | **January** | 2011 | | | | | | | | | | | |
| 23 | **February** | 2011 | | | | | | | | | | | |
| 24 | **March** | 2011 | | | | | | | | | | | |

| | | | |
|---|---|---|---|
| 25 | **April** | 2011 | |
| 26 | **May** | 2011 | |
| 27 | **June** | 2011 | |
| 28 | **July** | 2011 | |
| 29 | **August** | 2011 | |
| 30 | **September** | 2011 | |
| 31 | **October** | 2011 | |
| 32 | **November** | 2011 | |
| 33 | **December** | 2011 | |
| 34 | **Average Balances** | | |
| 35 | **Return** | (Data Ln 140 * Ln 34) | 0 |
| 36 | **Taxes** | (Data Ln 108 * Ln 35) | 0 |
| 37 | **Amortization Abandoned Plant (Beg. Bal. less End.** | | 0 |

**Bal.)**

| | | | |
|---|---|---|---|
| 38 | **ATRR** | (Ln 35 + Ln 36 + Ln 37) | 0 |

# ATTACHMENT H - ADDENDUM 2-B
# OG&E FORMULA RATE IMPLEMENTATION PROTOCOLS

## I. Annual Update and True-Up Adjustments

1.1 The formula rate template contained in Attachment H - Addendum 2-A and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Oklahoma Gas and Electric Company ("OG&E") for transmission service under the Open Access Transmission Tariff ("OATT") of the Southwest Power Pool, Inc. ("SPP"). OG&E shall follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR"), rates for its Point-to-Point transmission service, and the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades.

1.2 The Formula Rate shall initially be effective for service on and after July 1, 2008, through December 31, 2008, and shall be applicable thereafter for services in subsequent years on and after January 1 of each calendar year through December 31 of that calendar year ("Rate Year"). The purpose of these protocols is to establish a set of procedures that may be used by Interested Parties (as defined in Section 1.3(a)(4) herein) to review and challenge Annual Updates and True-Up Adjustments, as defined herein. Provided, however, (i) nothing herein shall limit the rights of OG&E or any Interested Party to initiate a proceeding at the Federal Energy Regulatory Commission ("Commission") at any time with respect to the Formula Rate consistent with the Party's rights under the Federal Power Act ("FPA") and the Commission's regulations and (ii) the provisions of these Protocols applicable to review and challenge of Annual Updates and True-Up Adjustments shall not apply to proceedings other than (a) Formal Challenges initiated in accordance with the procedures set forth herein and/or (b) proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment, and shall not be relied upon to alter any Party's rights or obligations under the FPA and the Commission's regulations in proceedings other than such Formal Challenges and/or proceedings initiated *sua sponte* by FERC challenging a True-Up Adjustment. The term "Party" or "Parties" is defined to include OG&E and/or one or more Interested Parties.

1.3 Posting of Annual Update and Related Procedures

(a) On or before September 1 of each calendar year (unless September 1 falls on a weekend or a holiday recognized by the Commission, in which case the date shall be the next business day), OG&E:

(1) shall recalculate the ATRR by (i) removing the 13-month average net plant balances and the 13-month average Construction Work in Progress ("CWIP") balances from the most recent Baseline ATRR and replacing them with projected 13-month average net plant and CWIP balances for the following Rate Year, and (ii) calculating the prorated accumulated deferred income taxes ("ADIT") for any additional plant projected to be in service during the Rate Year (the "Proration Adjustment") (the "Projected ATRR"). (The "OG&E ZONAL REVENUE

REQUIREMENT for SPP OATT Attachment H, Sec. 1, Col. 3" is the Projected ATRR, adjusted to take account of any related True-Up Adjustment(s).) OG&E shall also calculate the rates for its Point-to-Point transmission service, and shall calculate the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades, for the new Rate Year in accordance with the Formula Rate. (The calculations described in this Section 1.3(a)(1) are collectively referred to as the "Annual Update.");

(2) shall provide such Annual Update and supporting information to SPP, for posting on the publicly accessible portion of the SPP website (the date of such posting to be the "Posting Date"). For purposes of these Protocols, "supporting information" shall include, at minimum, a data-populated Formula Rate template in a fully-functioning Excel file (and/or as applicable, other native format) showing all calculations, any supporting calculations and workpapers that demonstrate or explain information not otherwise set out in OG&E's FERC Form No. 1 or the Formula Rate template, a Portable Document Format version of the data-populated Formula Rate template described above, and a side-by-side comparison of the Formula Rate template components (by line) as compared to the most recent Baseline ATRR (as defined in Section 1.4(a));

(3) shall provide SPP with the ATRR associated with each of OG&E's Base Plan and Balanced Portfolio Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR;

(4) shall provide the Annual Update and supporting information identified in Section 1.3(a)(2) above, and detailed information concerning the projected 13-month average net plant, CWIP balances (including project-specific information for planned additions) and Proration Adjustment, upon written request, including a standing request for all future Annual Updates and supporting information, to (i) any entity that is or may become a customer taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP; (ii) any entity served under the SPP OATT; (iii) any affected state and federal regulatory authorities; and (iv) FERC staff (collectively, "Interested Parties");

(5) shall notify SPP transmission customers taking Network Integration Transmission Service and/or Point-to-Point Transmission Service on the OG&E facilities operated by SPP, affected regulatory commissions and other parties that have made a request in accordance with Section 1.3(a)(4), of the Annual Update posting via email and / or United States mail to the most recent address provided to OG&E;

(b) After the Posting Date and before October 1 of each calendar year, OG&E shall convene a meeting ("Customer Meeting") to afford Interested Parties an opportunity to discuss and become better informed regarding the Annual Update. OG&E will provide at least fifteen days' notice of the Customer Meeting via a notice included with the Annual Update and posted on the SPP website; and

(c) After the Customer Meeting and before November 1 for each calendar year, OG&E shall provide timely notice of any errors found in the review process, any updates to the projections of 13-month average net plant and CWIP balances, resolutions of Preliminary Challenges and/or proceedings provided for in Section 3.6, and/or any corrections to that year's True-Up Adjustment that are agreed to by OG&E and an Interested Party, and Interested Parties may object in writing by November 8 to any such proposed corrections or updates. Notice shall be accomplished by providing such information to SPP for posting on the publicly accessible portion of the SPP website and by providing e-mail notice of such posting to any Interested Party that has submitted a request for information pursuant to Section 2.1. No later than November 15 of each calendar year, OG&E shall modify the Annual Update to reflect uncontested corrections and updates, and shall cause a revised Annual Update to be posted on the SPP website no later than December 1. At that time, OG&E shall also provide SPP with any updated ATRR associated with each of OG&E's Base Plan Upgrades such that SPP can calculate Base Plan Zonal ATRRs and the Base Plan Region-wide ATRR.

1.4 On June 1 of each calendar year (unless June 1 falls on a weekend or a holiday recognized by the FERC, in which case the date shall be the next business day) (the "Publication Date"), OG&E shall, in accordance with the Formula Rate, calculate the Baseline ATRR for the Rate Year that has most recently concluded, reconcile the Projected ATRR with the Baseline ATRR for the corresponding Rate Year and calculate the amount of any over- or under-recovery (all of which, plus any corrections pursuant to Section 1.10 or any changes to account for the resolution of any Preliminary Challenge, Formal Challenge, or a proceeding initiated sua sponte by FERC challenging a True-Up Adjustment, to the extent such changes have not been reflected in a prior Annual Update, shall be considered the "True-Up Adjustment"). On the Publication Date, OG&E shall submit the True-Up Adjustment to FERC for informational purposes only. The informational filing shall not require any action by the Commission.[1] On or before the Publication Date, OG&E shall follow the procedures set forth in Sections 1.3(a)(2)-(5) for disseminating the True-Up Adjustment and supporting information (as defined in Section 1.3(a)(2)). The True-Up Adjustment:

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[1] The transmittal letter accompanying the informational filing shall inform the Commission that the True-Up Adjustment is not intended to be subject to the Commission's notice requirements and it is not intended for the Commission to take action accepting the informational filing, and shall inform the Commission regarding the procedures contained in these Protocols for review and challenge of the True-Up Adjustment. If the Commission issues a notice of or an order accepting the informational filing, OG&E shall advise the Commission of the challenge process in these Protocols and shall work with the Settling Parties to seek rescission of such actions. No Commission action on the informational filing shall affect any rights under the Formula Rate or these Protocols.

(a) shall, to the extent specified in the Formula Rate, be based upon data properly recorded in the appropriate accounts, consistent with FERC accounting policies and accounting practices, in (i) OG&E's FERC Form No. 1 for the most recent calendar year (i.e., the most recently completed Rate Year), and (ii) the books and records of OG&E.[2] (The ATRR determined using these data shall be termed the "Baseline ATRR".);

(b) shall identify and provide an explanation of (i) any changes in OG&E accounting policies, practices or procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or Form No. 1 reporting requirements) from those in effect during the calendar year upon which the most recent Baseline ATRR was based and that have an impact on the Formula Rate or the calculations under the Formula Rate ("Accounting Changes"), and (ii) any known changes in the SPP OATT from the provisions of the SPP OATT in effect during the calendar year upon which the most recent Baseline ATRR was based and that have an impact on the Formula Rate or the calculations under the Formula Rate ("Tariff Changes"). To the extent Interested Parties, during the review process provided for by these Protocols, identify additional changes in OG&E accounting policies, practices or procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or Form No. 1 reporting requirements) or in the SPP OATT that depart from those in effect during the calendar year upon which the most recent Baseline ATRR was based and that have an impact on the Formula Rate or the calculations under the Formula Rate, those additional changes shall also be considered Accounting Changes or Tariff Changes, as applicable; and;

(c) shall,

(1) for the True-Up Adjustment to be filed in June of 2009, which shall apply to the rate period commencing July 1, 2008, and ending December 31, 2008 ("Transition Period"), be computed as one-half (1/2) of the difference produced by subtracting the Baseline ATRR for calendar year 2008 from the Projected ATRR for calendar year 2008.[3] The amount of any under- or over-recovery shall

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2 It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. Where the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

3 The Projected ATRR for calendar year 2008 is the ATRR that was projected using the formula filed by OG&E, as modified by OG&E's compliance filing, and which was incorporated into Attachment H, Section I.1, of the SPP OATT by SPP's filing on October 17, 2008, in Docket No. ER09-89-000, *et al*. The Projected ATRR for calendar year 2008 was $94,758,543.

be recovered or refunded, as appropriate, in accordance with Worksheet L of the Formula Rate; and

(2) beginning with the True-Up Adjustment to be filed in June of 2010, compare the Projected ATRR for the most recently completed Rate Year and the Baseline ATRR for that Rate Year ("most recent Baseline ATRR") to determine the amount to be refunded or surcharged during the subsequent Rate Year in order to true-up the Projected ATRR calculated in the prior year's Annual Update to the most recent Baseline ATRR. The amount of any under- or over-recovery shall be recovered or refunded, as appropriate, in accordance with Worksheet L of the Formula Rate.

1.5 Interested Parties may review and challenge the True-Up Adjustment with respect to, among other grounds enumerated in these Protocols, the prudence of any costs and expenditures included for recovery in the most recent Baseline ATRR, provided, however, that the initial burden to raise a serious doubt as to the prudence of any cost or expenditure shall be upon the Interested Party raising the challenge.

1.6 Interest on any over-recovery of the net revenue requirement shall be determined in accordance with Worksheet L. Interest on any under-recovery of the net revenue requirement shall be determined using the interest rate equal to OG&E's actual short-term debt costs capped at the applicable FERC refund interest rate as set forth in Worksheet L.

1.7 After posting of the True-Up Adjustment, a Network Customer in the OG&E zone may elect to prepay amounts calculated to be owed in accordance with Part I of Formula Rate Worksheet L and limit interest charges that would otherwise apply pursuant to Section 1.6. In the event of such election, such Prepayment shall be made on or before June 30 of the year in which the True-Up Adjustment is computed, and such Prepayment amount shall be subject to a Prepayment Adjustment. The Prepayment and the Prepayment Adjustment shall be calculated pursuant to Part IV of the Formula Rate Worksheet L. Such Prepayment Adjustment shall be reflected as a charge or credit in the first monthly billing for transmission services subsequent to the determination of the Network Customer's 12 CP demand and the TO's Transmission Network Load for the applicable Rate Year.

1.8 Neither the Annual Update nor the True-Up Adjustment shall seek to modify the Formula Rate and neither the Annual Update nor the True-Up Adjustment shall be subject to challenge by a Party seeking to modify the Formula Rate (*i.e.*, all such modifications to the structure of the Formula Rate and the stated values specified in Section 1.9 herein will require, as applicable, an appropriate filing with the FERC pursuant to FPA Section 205 or Section 206).

1.9 A change to the Formula Rate inputs related to (i) the rate of return on equity ("ROE"), (ii) depreciation and/or amortizations, (iii) storm damage deferrals, (iv) extraordinary property losses or other deferred costs, and (v) costs of post-employment benefits other than pensions ("PBOP") may not be made absent an appropriate filing with the FERC pursuant to Federal Power Act Section 205 or Section 206: provided, however, that OG&E may make a limited Section 205 filing to revise its depreciation rates and/or amortizations, extraordinary property losses or other deferred costs, PBOP expenses, its recovery of storm damage deferrals, or to reflect nominal changes to the FERC Form 1 reporting requirements (*i.e.*, changes in account descriptions or line numbers that do not reflect changes in the nature or type of costs or expenses recorded therein), in which the sole issue for examination shall be whether the proposed change is just and reasonable and not unduly discriminatory or preferential.

1.10 If OG&E files any corrections to its FERC Form 1 that would affect the application of the Formula Rate, such corrections shall be accounted for in the True-Up Adjustment for the next effective Rate Year, and any resulting refunds or surcharges that are the result of such correction(s) shall be included, with interest pursuant to Worksheet L from the beginning of the Rate Year(s) affected by the correction, in that True-Up Adjustment. If OG&E makes corrections to its books and records or otherwise identifies an error that would alter input data entered in the Formula Rate that are not derived from the FERC Form 1 for the current or any prior Rate Year, such corrections shall be accounted for in the True-Up Adjustment for the next effective Rate Year, and any resulting refunds or surcharges that are the result of such correction(s) shall be included, with interest pursuant to Worksheet L from the beginning of the Rate Year(s) affected by the correction, in that True-Up Adjustment. Provided, however, that this provision shall not bar the recognition of corrections more promptly through resolution of challenges to any then-pending True-Up Adjustment pursuant to Sections 3.6 or where the Parties otherwise agree.

## II. Review Procedures

2.1 Each Annual True-Up Adjustment shall be subject to the following review procedures ("Review Procedures"):

(a) Each year, after the Publication Date and before July 1, OG&E will convene a meeting ("True-Up Meeting") to afford Interested Parties an opportunity to discuss and become better informed regarding the True-Up Adjustment. OG&E will provide at least fifteen days' notice of the True-Up Meeting via a notice included with the True-Up Adjustment and posted on the SPP website;

(b) Interested Parties will have one-hundred and thirty-five (135) days after the Publication Date to serve reasonable information requests on OG&E concerning the (i) the True-Up Adjustment for the relevant Rate Year, (ii) the Projected

ATRR for the Rate Year that is the subject of the True-Up Adjustment, and (iii) the Projected ATRR for the subsequent calendar year, which will issue on or about September 1 following the True-Up Adjustment. Such information requests shall be limited to what is necessary to determine if OG&E has properly calculated and reasonably applied the Formula Rate according to its terms, including the procedures in this Attachment H - Addendum 2-B (including the extent and effect of any Accounting Changes and Tariff Changes, and including corrections pursuant to Section 1.10). Such information request may include requests for information concerning whether costs were prudently incurred (as provided for in Section 1.5) and whether the relevant True-Up Adjustment or Projected ATRR satisfies the requirements set forth at Sections 1.3 and 1.4 of these Protocols.

Such information requests shall not solicit information that solely relates to inputs that are stated values (as identified in Section 1.9) or cost allocation methods that have been determined by any final order by the Commission with respect to the Formula Rate (including an order accepting a settlement), except that such information requests shall be permitted if they seek to determine if there has been a material change in circumstances or to confirm consistency with the applicable order (and associated settlement, if any). In addition, such information requests shall not solicit information related to True-Up Adjustments from prior years except to determine whether and how a prior year's approach on a given matter was the same or different from the current year's approach, or in connection with corrections pursuant to Section 1.10;

(c) OG&E shall make a good faith effort to respond to information requests issued pursuant to Section 2.1(b) within fifteen (15) business days of receipt of such requests. Information requests received after 5 p.m. CPT shall be considered received the next business day. OG&E's responses to information requests shall not be entitled to protection as privileged settlement communications; provided, however, that: (a) any communications between OG&E and any Interested Party in connection with efforts to negotiate a resolution of a Preliminary Challenge or Formal Challenge shall be entitled to such protection; (b) if OG&E's response to an information request contains proprietary or trade secret information or critical energy infrastructure information, OG&E and the Interested Party or Parties receiving such information shall enter into appropriate arrangements to protect the confidentiality of such information; and (c) nothing herein shall require OG&E to provide information that is protected by the attorney-client privilege, the attorney work product doctrine, or any other legally recognized privilege. Nothing in these Protocols shall alter or affect any Party's right to offer into evidence or otherwise use information obtained pursuant to the Review Procedures provided for in these Protocols in any proceeding before the Commission or any other forum in

accordance with the Commission's Rules of Practice and Procedure or other applicable rules of evidence, nor shall these Protocols alter or affect any Party's right to oppose such use of information obtained pursuant to the Review Procedures provided for in these Protocols. The fact that information was obtained pursuant to the Review Procedures provided for in these Protocols shall not be grounds for opposing the use of such information in any proceeding before the Commission or any other forum;

(d) To the extent OG&E and any Interested Party are unable to resolve disputes related to information requests submitted in accordance with these Review Procedures, OG&E or any Interested Party may petition FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the authority to issue binding orders to resolve discovery disputes and to compel the production of documents or other information or materials in accordance with the Review Procedures and FERC's Rules of Practice and Procedure;

(e) Any Interested Party shall have until the later of one-hundred and eighty (180) days after the Publication Date or fifteen (15) days after OG&E's last response to reasonable information requests submitted pursuant to Section 2.1(b) above ("Review Period") to review the True-Up Adjustment and to notify OG&E in writing of any specific challenges to the True-Up Adjustment, including any corrections pursuant to Section 1.10 and any Accounting Changes or Tariff Changes ("Preliminary Challenges"). Preliminary Challenges shall include supporting documentation (or references to documentation provided in discovery). Other challenges, including challenges to the Formula Rate itself shall not be considered "Preliminary Challenges" for purposes of these Review Procedures; and,

(f) OG&E shall provide a written response to any Preliminary Challenge within fifteen (15) days of receipt, and such response shall include supporting documentation (or references to documentation provided in discovery).

## III. Resolution of Challenges

For each True-Up Adjustment:

3.1 If OG&E and any Interested Party(ies) have not resolved all Preliminary Challenges within forty-five (45) days of the date of written notice of a Preliminary Challenge provided for in Section 2.1(e), senior management of the interested party(ies) and OG&E shall negotiate in good faith to attempt to resolve the Preliminary Challenge. If such negotiations fail to resolve all Preliminary Challenges within seventy-five (75) days of the date of written notice of a Preliminary Challenge (the time period commencing on the date of written notice of a Preliminary Challenge and ending 75 days thereafter is the ("Resolution Period"), the Interested Party(ies) may file a complaint at the FERC pursuant to 18 C.F.R. § 385.206 challenging the True-Up Adjustment (including any corrections or Accounting Changes or Tariff Changes), with regard to such Preliminary Challenge(s) ("Formal Challenge"). Notwithstanding the foregoing, upon written agreement of OG&E, a Formal Challenge may be brought at any time.

3.2 If OG&E and an Interested Party agree upon a resolution to a Preliminary Challenge to a True-Up Adjustment by November 1, and such resolution is not objected to by any Interested Party, OG&E shall recalculate the True-Up Adjustment to reflect such resolution, which shall be reflected in the Annual Update for the following Rate Year as provided in Section 1.3(c).

3.3 In the event that an Interested Party has filed a Preliminary Challenge, such party may file a Formal Challenge within thirty (30) days after the end of the Resolution Period, unless OG&E and the party agree in writing to extend such time to permit further negotiations. The contents of such Formal Challenge need not be limited to issues that were the subject of Preliminary Challenge(s) submitted by the Interested Party with respect to the current True-Up Adjustment. In the event that an Interested Party did not file a Preliminary Challenge, such party may file a Formal Challenge within two hundred eighty-five days after the Publication Date. A copy of any Formal Challenge shall be served on OG&E by electronic service on the date of such filing. A party may not, thereafter, file a Formal Challenge as to the disputed Preliminary Challenge(s) for the then effective Rate Year. Failure to pursue a Preliminary Challenge or lodge a Formal Challenge regarding a Preliminary Challenge(s) as to a given True-Up Adjustment shall not bar the pursuit of any Preliminary Challenge or the lodging of a Formal Challenge as to such Preliminary Challenge(s) with regard to a subsequent True-Up Adjustment.

3.4 Any response by OG&E to a Formal Challenge must be submitted to the FERC within thirty (30) days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) by electronic service on the date of such filing.

3.5 In any Formal Challenge proceeding or proceeding initiated *sua sponte* by FERC challenging a True-Up Adjustment (including any corrections pursuant to Section 1.10 or any Accounting Changes or Tariff Changes contained therein), OG&E shall bear the burden of proving that it has reasonably adopted and applied any Accounting Changes or Tariff Changes; and that it has properly calculated and reasonably applied the Formula Rate pursuant to the Formula Rate and these Protocols, including compliance with the specific requirements set forth in Sections 1.4 and 1.5 of these Protocols, provided, however, that challenges to the prudency of costs shall be subject to Section 1.5 of these Protocols.

3.6 With regard to any changes, including to the data inputs (including but not limited to revisions to OG&E's FERC Form 1), resulting from the resolution of Preliminary Challenges, Formal Challenges initiated pursuant to Sections 3.1 or 3.3 above, or proceedings initiated *sua sponte* by FERC, where such resolution occurs on or after the Publication Date and before November 1, OG&E shall recalculate the then-pending True-Up Adjustment to take such changes into account, and which shall be reflected in the Annual Update for the following Rate Year. Where such resolution occurs on or after November 1 and before the subsequent Publication Date, OG&E shall incorporate any such changes into the next True-Up Adjustment. This reconciliation mechanism shall apply in lieu of mid-year adjustments to rates. However, in the event that the Formula Rate is replaced by a stated rate, actual refunds or surcharges (with interest pursuant to Worksheet L) shall be made no later than thirty (30) days after the effective date of the stated rate established by FERC.

3.7 Any refunds or surcharges attributable to changes resulting from the resolution of Preliminary Challenges, Formal Challenges initiated pursuant to Sections 3.1 or 3.3 above, or proceedings initiated *sua sponte* by FERC shall be calculated, with interest (pursuant to Worksheet L), from January 1 of the Rate Year that is the subject of the challenged True-Up Adjustment (except as to corrections applicable to a prior Rate Year which are governed by Section 1.10), and shall be reflected through the process provided in Section 3.6.

# ADDENDUM 35 TO ATTACHMENT H

## Western Area Power Administration-Upper Great Plains Region

# Western Area Power Administration (WAPA)

## Upper Great Plains Region (WAPA-UGP)

# Transmission and Ancillary Services Rate Calculation

## Effective October 1, 20__

## WAPA-UGP 20__ Rate Estimate Calculation

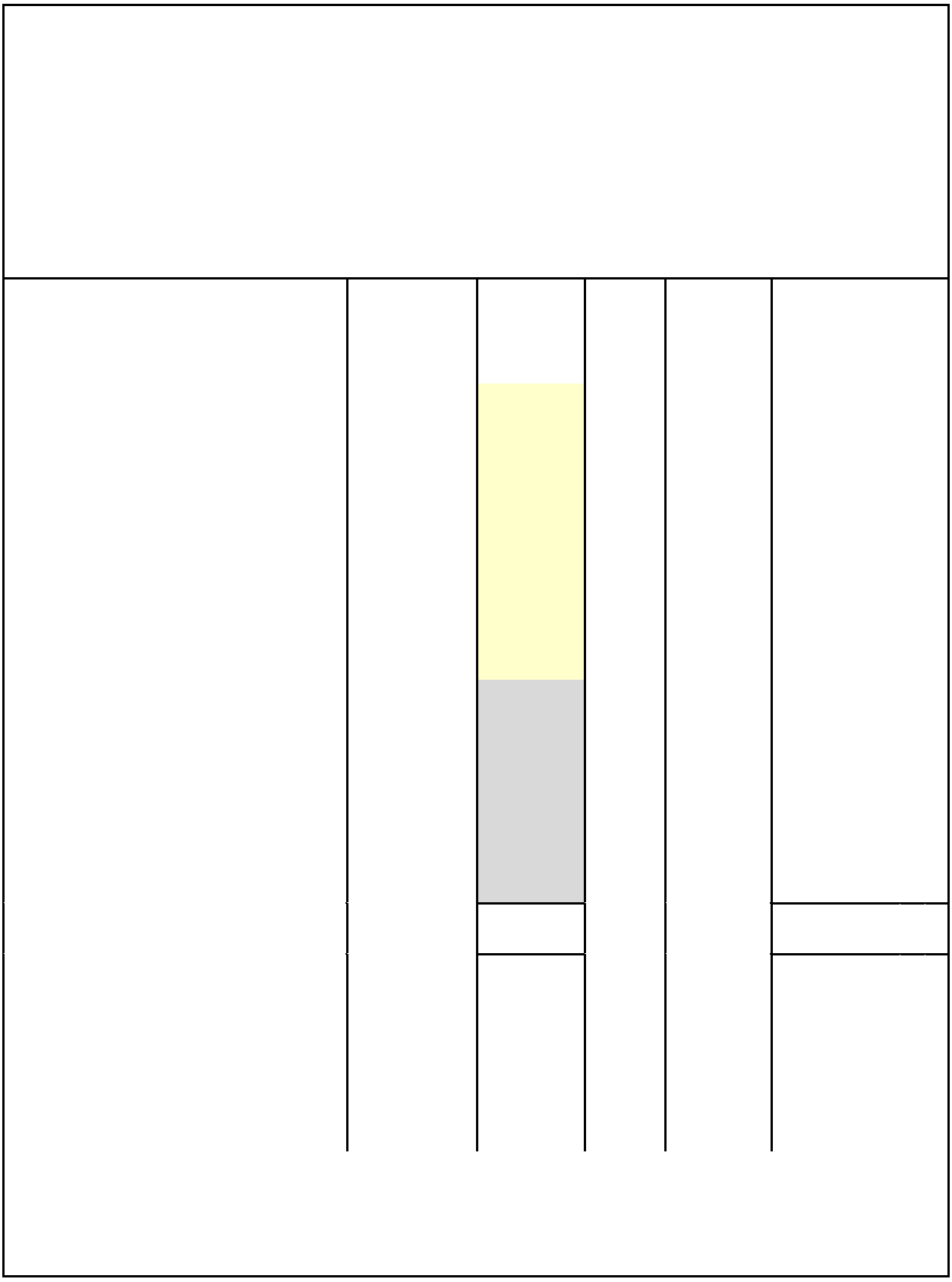
| Worksheet Tab Label | Worksheet Tab Description |
|---|---|
| Summary-ATRR | Worksheet "Summary-ATRR" -- Calculation of ATRRs |
| WS1-RateBase | Worksheet 1 -- Calculation of Rate Base |
| WS2-AllocFactor | Worksheet 2 -- Allocation Factors |
| WS3-RevCredits | Worksheet 3 -- Revenue Credit Detail |
| WS4-CostData | Worksheet 4 -- Cost Support Data |
| WS5-BPUz | Worksheet 5 -- SPP Base Plan Upgrades (BPU) - Zonal |
| WS6-BPUr | Worksheet 6 -- SPP Base Plan Upgrades (BPU) - Regional |
| WS7-BPUFac | Worksheet 7 -- SPP Base Plan Upgrades (BPU) - Facilities |
| WS8-TranFac | Worksheet 8 -- Transmission Facilities |
| WS9-AI-Incl | Worksheet 9 -- WAPA-UGP Facilities Included per SPP Tariff Attachment AI |
| WS10-AI-Excl | Worksheet 10 -- WAPA-UGP Facilities Excluded per SPP Tariff Attachment AI |
| WS11-FacChanges | Worksheet 11 -- Facility Changes Detail |
| WS12-SSCD | Worksheet 12 -- Scheduling, System Control and Dispatch Service (SSCD) ARR |
| WS13-SSCDFac | Worksheet 13 -- Scheduling, System Control and Dispatch Service (SSCD) Facilities |

WAPA-UGP 20__ Rate Estimate Calculation
Summary-ATRR - Calculation of ATRRs (Sched 9, Sched 11)
12 Months Ending 09/30/20__
ESTIMATE

| Line No. | (1) | REFERENCE | COMPANY TOTAL | ALLOCATOR | ALLOCATION % | TRANSMISSION ALLOCATED AMOUNT |
|---|---|---|---|---|---|---|
| | | (2) | (3) | | (4) | (5) |
| 1 | Gross Zonal Revenue Requirement-Sch 9 | WS1-RateBase C5L1 | | | | #REF! |
| 2 | REVENUE CREDITS | | | | | |
| 3 | Firm Point-to-Point Revenue Credit | WS3-RevCredits C5L3 | 0 | NA | 100% | 0 |
| 4 | Non-Firm Point-to-Point Revenue Credit | WS3-RevCredits C5L9 | 0 | NA | 100% | 0 |
| 5 | Revenue from Existing Transmission Agreements | WS3-RevCredits C5L12 | 0 | NA | 100% | 0 |
| 6 | Scheduling, System Control, and Dispatch Service Credit | WS3-RevCredits C5L15 | 0 | NA | 100% | 0 |
| 7 | Account No. 454 | WS3-RevCredits C5L18 | 0 | TP | 100% | 0 |
| 8 | Z2 Nonfirm Point-to-Point Revenue Credit | WS3-RevCredits C5L3 | 0 | NA | 100% | 0 |
| 9 | Shedule 11 Point-to-Point Revenue Credit | WS3-RevCredits C5L33 | 0 | NA | 100% | 0 |
| 10 | TOTAL REVENUE CREDITS | Subtotal L3:L8 | 0 | | | 0 |
| 11 | TRUE-UP ADJUSTMENT (from TRUEUP Sheet) | Summary-TrueUp L12 | | | | 0 |
| 12 | Net Revenue Requirement | Total L1-L9+L10 | | | | #REF! |
| 13 | | | | | | |
| 14 | | | | | | |

| Line N | | TOTAL PROJECT ATRR | ZONAL | REGIONAL | REVENUE CREDIT | ALLOCATED AMOUNT |
|---|---|---|---|---|---|---|

o. -1 (2) (3) (4) (5) (6)



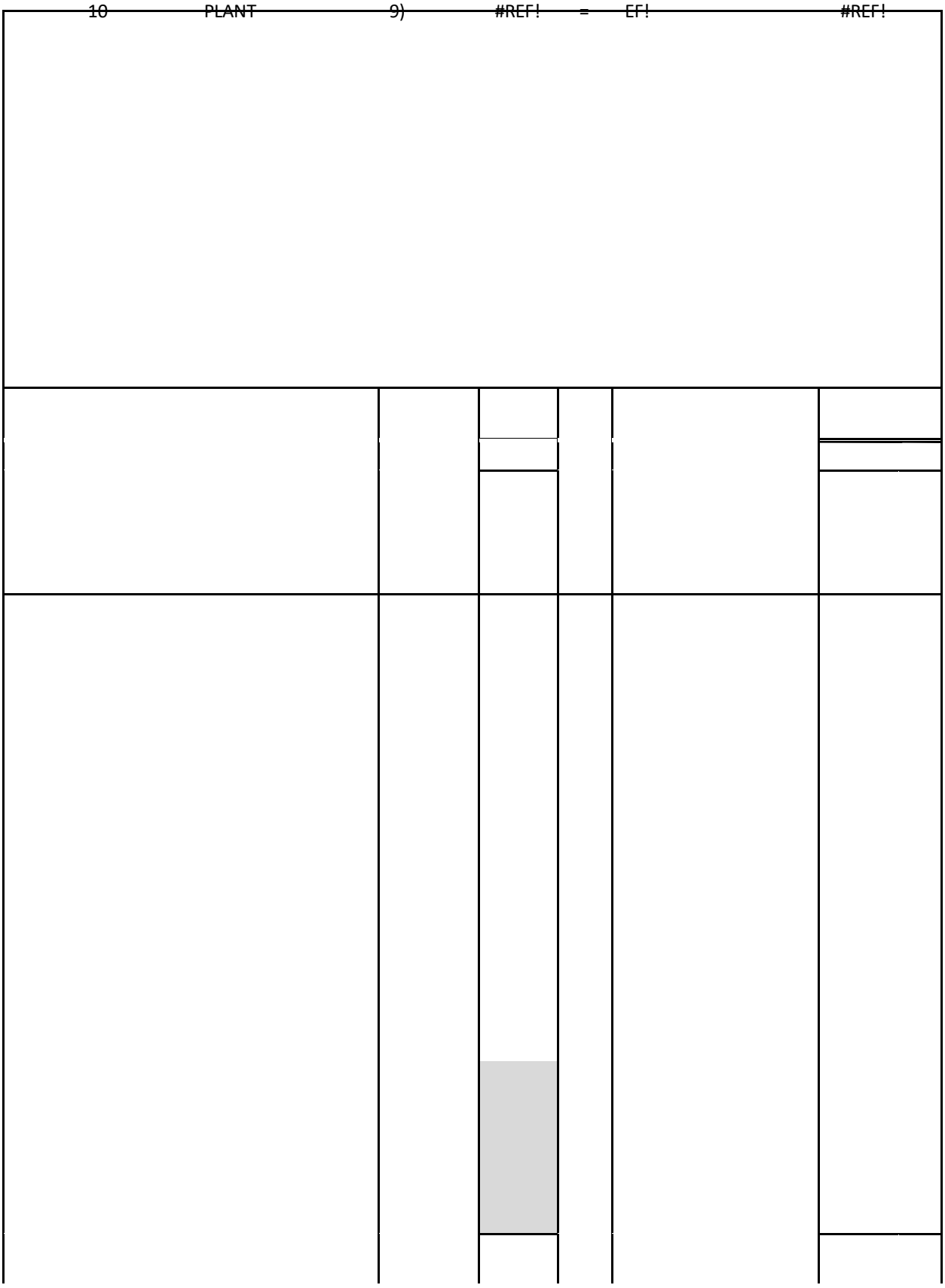
| | | | | | | |
|---|---|---|---|---|---|---|
| 14 | SPP Upgrades - Gross Revenue Requirement-Sch 11* | #DIV/0! | #DIV/0! | #DIV/0! | #REF! | #DIV/0! |
| 15 | Zonal less Revenue Credit | | | | | #DIV/0! |
| 16 | Regional less Revenue Credit | | | | | #DIV/0! |
| 17 | Breakout by Facility: | | | | | |
| 18 | | #DIV/0! | #DIV/0! | #DIV/0! | #REF! | #DIV/0! |
| 19 | | #DIV/0! | #DIV/0! | #DIV/0! | #REF! | #DIV/0! |
| 20 | | #DIV/0! | #DIV/0! | 0 | #REF! | #DIV/0! |

WAPA-UGP 20__ Rate Estimate Calculation
Worksheet 1 -
Schedule 9 Revenue Requirement - Non-Levelized
Utilizing Financial Statement Results of Operations (ROOs)

12 Months Ending 09/30/20__ ESTIMATE

| Line No. | (1) | REFERENCE (2) | COMPANY TOTAL (3) | ALLOCATOR | | TRANSMISSION ALLOCATED AMOUNT (5) |
|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | (L69) | #REF! | | | #REF! |
| 2 | REVENUE CREDITS | Estimate | 0 | | | 0 |
| 3 | PRIOR PERIOD TRUE-UP (Over-collection) | | 0 | | | 0 |
| 4 | NET REVENUE REQUIREMENT | (L1 + L2 + L3) | #REF! | | | #REF! (Col 3 times Col 4) |
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE | (Note A) | | | | |
| 5 | Production | WS4-CostData L4 C2+C3+C4 | #REF! | NA | | |
| 6 | Transmission | WS4-CostData L3 C2+C3+C4 | #REF! | TP | #REF! | #REF! |
| 7 | Distribution | WS4-CostData C2 L2-L3-L4 | #REF! | NA | | |
| 8 | General & Intangible | Bal Sheet - Other Assets - SGL 175002 | - | W/S | #REF! | #REF! |
| 9 | Common | | - | CE | #REF! | #REF! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 10 | TOTAL GROSS PLANT | (sum L5 : 9) | #REF! | = | GP #REF! | #REF! |



| | | | | | | |
|---|---|---|---|---|---|---|
| | ACCUMULATED DEPRECIATION | | | | | |
| 11 | Production | WS4-CostData L15 C2+C3+C4 | #REF! | NA | | |
| 12 | Transmission | WS4-CostData L14 C2+C3+C4 | #REF! | TP | #REF! | #REF! |
| 13 | Distribution | WS4-CostData C2 L14-L15-L16 | #REF! | NA | | |
| 14 | General & Intangible | Bal Sheet - Other Assets - SGL 175902 | 0 | W/S | #REF! | #REF! |
| 15 | Common | | 0 | CE | #REF! | #REF! |
| 16 | TOTAL ACCUM. DEPRECIATION | (sum L11 : 15) | #REF! | | | #REF! |
| | NET PLANT IN SERVICE | | | | | |
| 17 | Production | (L5 - L11) | #REF! | | | |
| 18 | Transmission | (L6 - L12) | #REF! | | | #REF! |
| 19 | Distribution | (L7 - L13) | #REF! | | | |
| 20 | General & Intangible | (L8 - L14) | 0 | | | #REF! |
| 21 | Common | (L9 - L15) | 0 | | | #REF! |
| 22 | TOTAL NET PLANT | (sum L17 : 21) | #REF! | NP= | #REF! | #REF! |
| | ADJUSTMENTS TO RATE BASE | (Note B) | | | | |
| 23 | Account No. 281 | (enter negative) | 0 | | 0.000000 | 0 |
| 24 | Account No. 282 | (enter negative) | 0 | NP | #REF! | #REF! |
| 25 | Account No. 283 | (enter negative) | 0 | NP | #REF! | #REF! |
| 26 | Account No. 190 | | 0 | NP | #REF! | #REF! |
| 27 | Account No. 255 | (enter negative) | 0 | NP | #REF! | #REF! |
| 28 | TOTAL ADJUSTMENTS | (sum L23 : 27) | 0 | | | #REF! |

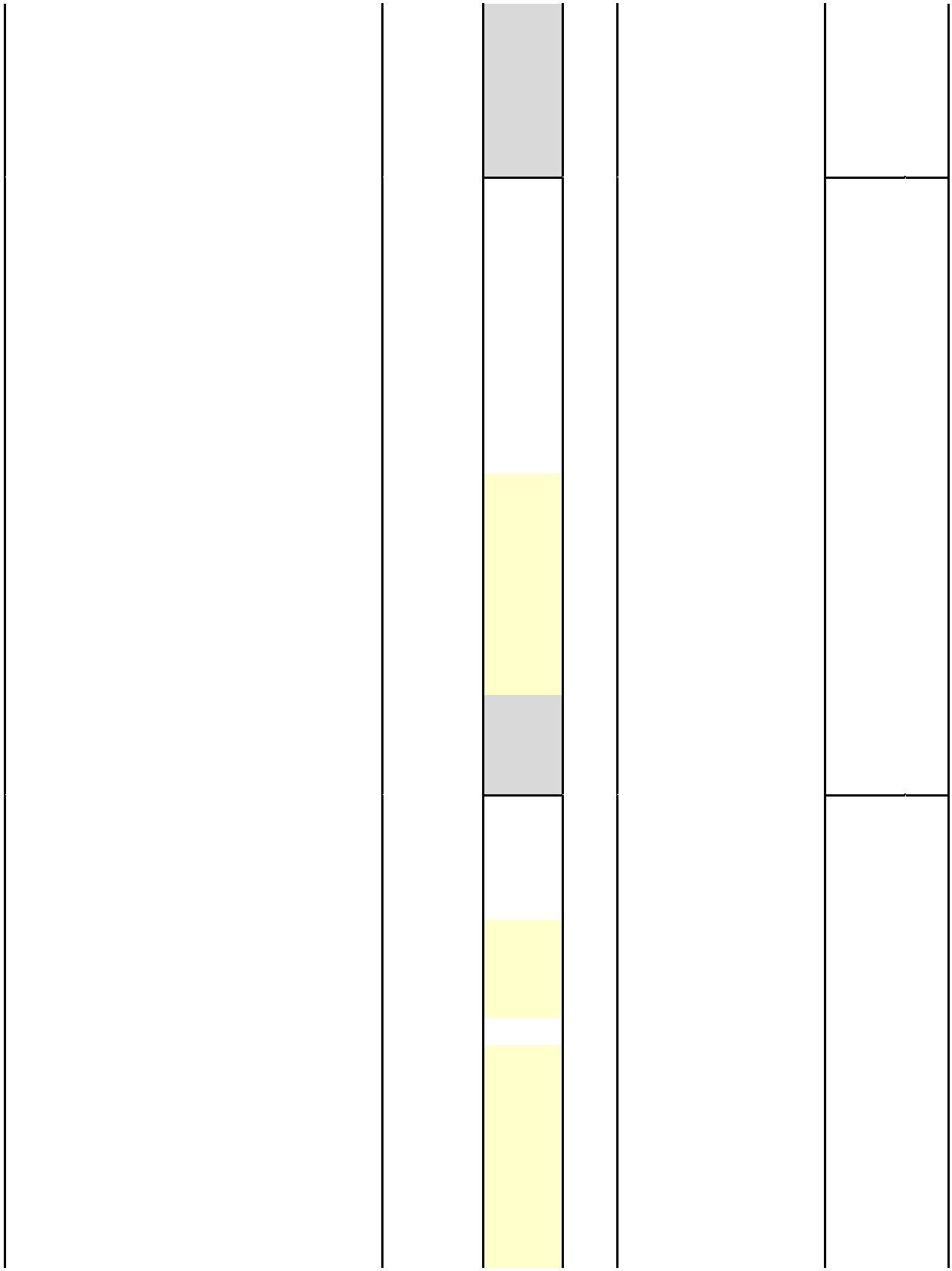
| | | | | | | |
|---|---|---|---|---|---|---|
| 29 | LAND HELD FOR FUTURE USE | (Note C) | 0 | TP | #REF! | #REF! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | WORKING CAPITAL | (Note D) | | | | |
| 30 | CWC | calculated | 0 | | | 0 |
| 31 | Materials & Supplies | Bal Sheet - Other Assets - SGL 151191 (Note C) | 0 | TE | #REF! | #REF! |
| 32 | Prepayments | Bal Sheet Other Assets | 0 | GP | #REF! | #REF! |
| 33 | TOTAL WORKING CAPITAL | (sum L30 : 32) | 0 | | | #REF! |
| 34 | RATE BASE | (sum L22, 28, 29, 33) | #REF! | | | #REF! |
| | O&M | | | | | |
| | Transmission | ROOs Schedule 11 (Note E) | | | | |
| 35 | Western-UGP | WS4-CostData L106 C2 | 0 | PTP/UGP | #REF! | #REF! |
| 36 | Western-RMR | WS4-CostData L106 C3 | 0 | PTP/RMR | #REF! | #REF! |
| 37 | COE | WS4-CostData L106 C4 | 0 | PTP/COE | #REF! | #REF! |
| 38 | Less Account 565 | (Note E) | | NA | 1.000000 | 0 |
| | A&G | ROOs Schedule 11 (Note F) | | | | |
| 39 | Western-UGP | WS4-CostData L79 C2 | 0 | PTP/UGP | #REF! | #REF! |
| 40 | Western-RMR | WS4-CostData L79 C3 | 0 | PTP/RMR | #REF! | #REF! |
| 41 | Less FERC Annual Fees | | 0 | W/S | #REF! | #REF! |
| 42 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad | (Note G) | 0 | W/S | #REF! | #REF! |
| | Plus | | | | #R | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 43 | Transmission | (Note G) | 0 | TE | EF! | #REF! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Related Reg. Comm. Exp | | | | | |
| 44 | Common | | 0 | CE | #REF! 1.000 | #REF! |
| 45 | Transmission Lease Payments | | 0 | NA | 0.000 | 0 |
| 46 | TOTAL O&M | (sum L35, 36, 37, 39, 40, 43, 44 less 38, 41, 42) | 0 | | | #REF! |
| | DEPRECIATION EXPENSE | | | | | |
| 47 | Transmission | ROOs Schedule 4 | | | | |
| 48 | Western-UGP | WS4-CostData L38 C2 | 0 | PTP/UGP | #REF! | #REF! |
| 49 | Western-RMR | WS4-CostData L38 C3 | 0 | PTP/RMR | #REF! | #REF! |
| 50 | COE | WS4-CostData L38 C4 | 0 | PTP/COE | #REF! | #REF! |
| 51 | General | | 0 | W/S | #REF! | #REF! |
| 52 | Common | | 0 | CE | #REF! | #REF! |
| 53 | TOTAL DEPRECIATION | (sum L47 : 52) | 0 | | | #REF! |
| | TAXES OTHER THAN INCOME TAXES | (Note H) | | | | |
| | LABOR RELATED | | | | | |
| 54 | Payroll | | 0 | W/S | #REF! | #REF! |
| 55 | Highway and vehicle | | 0 | W/S | #REF! | #REF! |
| | PLANT RELATED | | | | | |
| 56 | Property | | 0 | GP | #REF! | #REF! |
| 57 | Gross Receipts | | 0 | | 0.000 | 0 |
| 58 | Other | | 0 | GP | #REF! | #REF! |
| | Payments in | | | | #R | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 59 | lieu of taxes | | 0 | GP | EF! | #REF! |



| | | | | | | |
|---|---|---|---|---|---|---|
| 60 | TOTAL OTHER TAXES | (sum L54 : 59) | 0 | | | #REF! |
| | INCOME TAXES | (Note I) | | NA | | |
| 61 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | |
| 62 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | #REF! | | | |
| | where WCLTD= (line 100) and R= (line 102) and FIT, SIT & p are as given in footnote I. | | | | | |
| 63 | 1 / (1 - T) = (from line 61) | | 0.0000 | | | |
| 64 | Amortized Investment Tax Credit | (enter negative) | 0 | | | 0 |
| 65 | Income Tax Calculation | (L62 * L68) | #REF! | NA | | #REF! |
| 66 | ITC adjustment | (L63 * L64) | 0 | NP | #REF! | #REF! |
| 67 | Total Income Taxes | (L65 + L66) | #REF! | | | #REF! |
| 68 | RETURN [ Rate Base * Rate of Return] | (L34 * L102) | #REF! | NA | | #REF! |
| 69 | REV. REQUIREMENT | (sum L46, 53 ,60, 67, 68) | #REF! | | | #REF! |
| | | **SUPPORTING CALCULATIONS AND NOTES** | | | | |
| | TRANSMISSION PLANT INCLUDED IN UMZ RATES | | | | | |
| 70 | Total transmission plant | (L6, C3) | | | | #REF! |
| 71 | Less transmission plant excluded from UMZ rates | (Note K) | | | | 0 |
| 72 | Less transmission plant included in OATT Ancillary Services | (Note L) | | | | 0 |
| 73 | Transmission plant included in UMZ rates | (L70 less L71 and L72) | | | | #REF! |

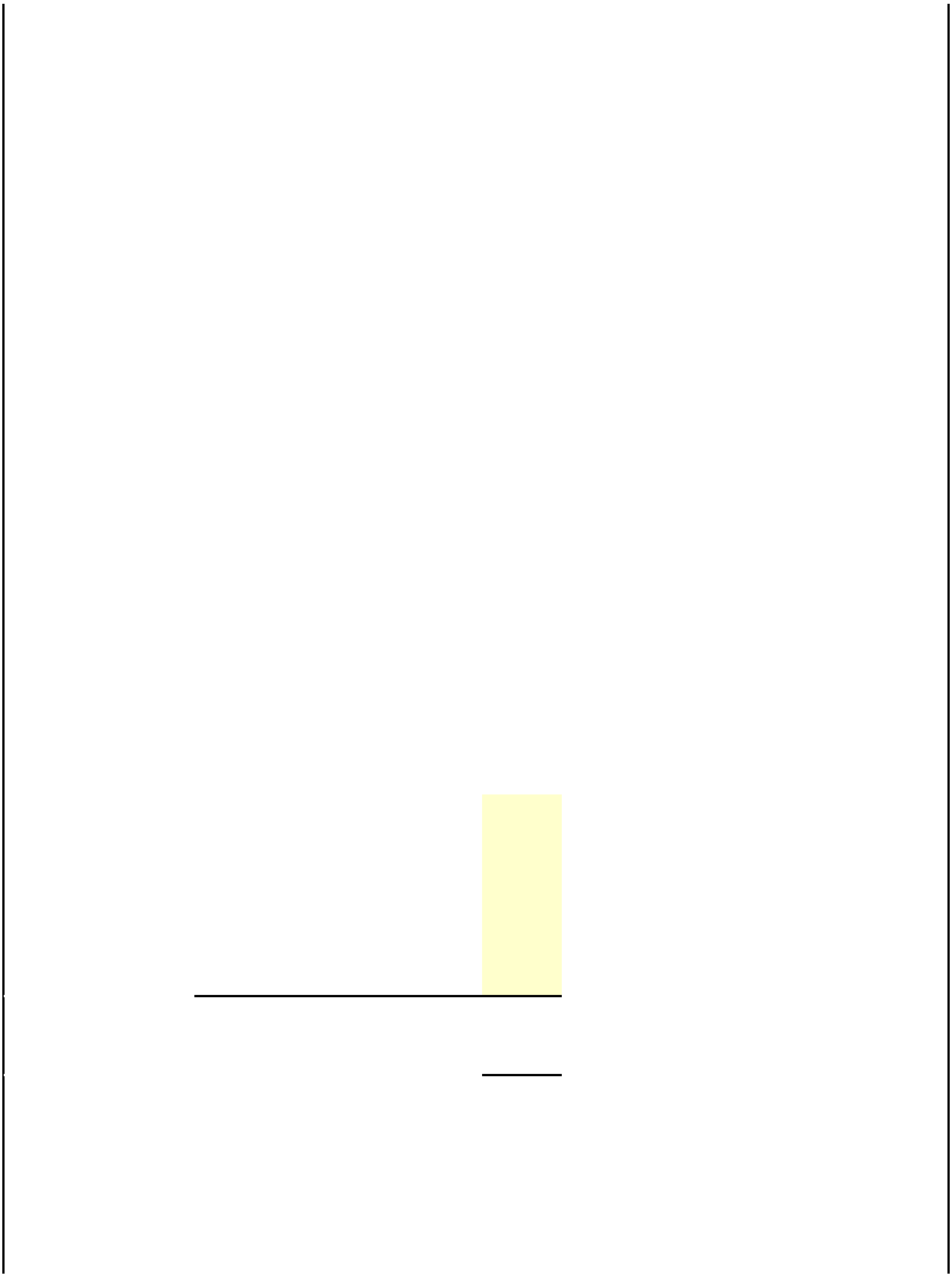
| | | | | | |
|---|---|---|---|---|---|
| 74 | Percentage of transmission plant | (L73 / L70) | | TP= | #REF! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | included in UMZ Rates | | | | | | | |
| | TRANSMISSION EXPENSES | | | | | | | |
| 75 | Total transmission expenses | (sum L35 to L37, C3) | | | | | | |
| 76 | Less transmission expenses included in OATT Ancillary Services | (Note J) | | | | | | 0 |
| 77 | Included transmission expenses | (L75 - L76) | | | | | | 0 |
| 78 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | (L77/ L75) | | | | | | 0.0000 |
| 79 | Percentage of transmission plant included in UMZ Rates | (L74) | | | | | TP | #REF! |
| 80 | Percentage of transmission expenses included in UMZ Rates | (L79 * L78) | | | | | TE= | #REF! |
| | WAGES & SALARY ALLOCATOR (W&S) | | | | | | | |
| | | | $ | TP | Allocation | | | |
| 81 | Production | | 0 | 0.00 | 0 | | | |
| 82 | Transmission | | #REF! | #REF! | #REF! | | | |
| 83 | Distribution | | 0 | 0.00 | 0 | | | W&S Allocator ($ / Allocation) |
| 84 | Other | | 0 | 0.00 | 0 | | | |
| 85 | Total | (sum L81 to L84) | #REF! | | #REF! | | = | #REF! |
| | PERCENTAGE OF TOTAL PLANT ALLOCATOR PTP | (Note M) | | | | | | |
| | | | $ | | | | | |
| | Transmission Plant | | | | | | | |

| | | |
|---|---|---|
| 86 | in Service Western-UGP | #REF! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 87 | Total Plant in Service Western-UGP | | #REF! | | | | | |
| 88 | UGP Percentage of Transmission Plant to Total Plant | (L86 / L87) | | PTP/UGP | = | #REF! | | |
| 89 | Transmission Plant in Service Western-RMR | | #REF! | | | | | |
| 90 | Total Plant in Service Western-RMR | | 0 | | | | | |
| 91 | RMR Percentage of Transmission Plant to Total Plant | (L89 / L90) | | PTP/RMR | = | #REF! | | |
| 92 | Transmission Plant in Service COE | | #REF! | | | | | |
| 93 | Total Plant in Service COE | | 0 | | | | | |
| 94 | COE Percentage of Transmission Plant to Total Plant | (L92 / L93) | | PTP/COE | = | #REF! | | |
| | COMMON PLANT ALLOCATOR (CE) | (Note N) | | | | | | CE |
| | | | $ | % Electric (L95 / L98) | | Labor Ratio = | (L85) | #REF! |
| 95 | Electric | | 0 | 0.0000 | | | | |
| 96 | Gas | | 0 | 00 | * | #REF! | | |
| 97 | Water | | 0 | | | | | |
| 98 | Total | (sum L95 : L97) | 0 | | | | | |
| | RETURN (R) | | $ | | | | | |
| 99 | Long Term Interest ROOs Schedule 5 | | #REF! | | | | | |
| | | | | | | | | = WCLT |
| | | | | Co | | | | |

st D



| | | | $ | % | (Note O) | | Weighted | |
|---|---|---|---|---|---|---|---|---|
| 100 | Long Term Debt | HFD Sch's 21RX & 21X Col 8 L23,25,26,29,30 | #REF! | #REF! | #REF! | | #REF! | =R |
| 101 | Proprietary Capital | | 0 | #REF! | 0.1238 | | #REF! | |
| 102 | Total (sum L31-32) | (sum L100 : 101) | #REF! | #REF! | | | #REF! | |
| 103 | | | | | | Proprietary Capital Cost Rate = | 12.38% | |
| 104 | | | | | | TIER = | #REF! | |
| | REVENUE CREDITS | | | | | | Load | |
| 105 | ACCOUNT 447 (SALES FOR RESALE) a. Bundled Non-RQ Sales for Resale | (Note P) | | | | | 0 | |
| 106 | b. Bundled Sales for Resale included in Divisor on page 1 | | | | | | 0 | |
| 107 | Total of (a)-(b) | | | | | | 0 | |
| 108 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | (Note Q) | | | | | 0 | |
| 109 | ACCOUNT 456 (OTHER ELECTRIC REVENUES) | | | | | | 0 | |
| 110 | a. Transmission charges for all transmission transactions | | | | | | 0 | |
| 111 | b. Transmission charges for all transmission transactions included in Divisor on page 1 | | | | | | 0 | |
| 112 | Total of (a)-(b) | | | | | | 0 | |
| Note | General Note: References to Results of Operations in this revenue requirement template indicate the Financial Statement Results of Operations (ROOs) Schedule where data is located. To the extent the references to ROOs data are missing, the entity will include a "Notes" | | | | | | | |

| Letter | |
|---|---|
| | section to provide this data. |
| A | Combines plant data for both the Western-Upper Great Plains Region (Western-UGP) and Western-Rocky Mountain Region (Western-RMR). |

| | |
|---|---|
| B | Does not apply to Western. For others, the balances in Accounts 190, 281, 282 and 283, as adjusted by any contra accounts identified as regulatory assets amounts in or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. |
| C | Transmission related only. |
| D | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at line 46 column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported in the Other Assets Section of the Balance Sheet. |
| E | For O&M Expense, Calculated from ROOs Schedule 11 as Total O&M less Purchase Power, Transmission Service Provided by Others (FERC 565), O&M Expense Fort Peck Powerhouse, Prior Year Adjustments, A&G Expense from ROOs Schedule 11, plus CME and Warehouse Interest from ROOs Schedule 5. Depreciation Expense from ROOs Schedule 4. |
| F | Totals of ROOs Schedule 11A Object Classes 1411, 1412, 1415, 1416, 1421, 1422, 1425, 1426, 1431, 1432, 1441, 1442. |
| G | Line 42 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 43 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting. |
| H | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| I | Western is not subject to Federal or State Income Tax.<br>Inputs Required: FIT = 0.00%<br>SIT= 0.00% (State Income Tax Rate or Composite SIT)<br>p = 0.00% (percent of federal income tax deductible for state purposes) |
| J | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Acct No. 561. Western does not include transmission expenses in ancillary service rates. |
| K | Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test). |
| L | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| M | Percentage of Total Plant Allocators are developed separately for Western-UGP and Western-RMR to allocate O&M, A&G, and Depreciation Expenses between Transmission and Generation. |
| N | Western does not have Common Plant. |
| O | Debt cost rate = long-term interest (line 99) / long term debt (line 100). The Proprietary |

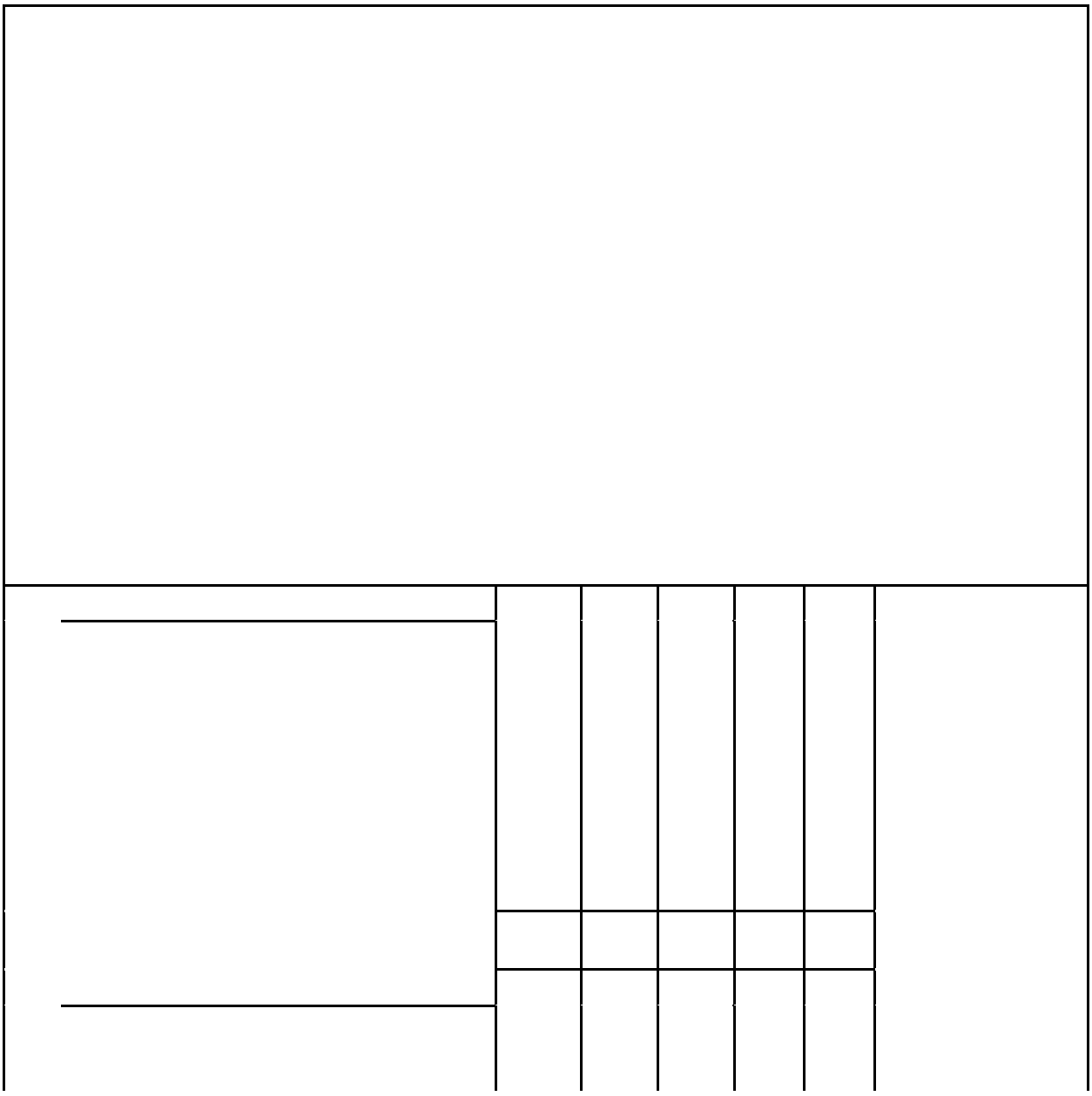
Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

| | |
|---|---|
| P | Line 105 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor. |
| Q | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. |
| R | The revenues credited shall include only the amounts received directly reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not included in this template (e.g., direct assignment facilites and GSUs) which are not recovered under this Revenue Requirement Template. |

WAPA-UGP 20__ Rate Estimate Calculation
Worksheet 2 - Allocation Factor, Determination of Pick-Sloan Missouri Basin Program--Eastern Division Annual Costs
12 Months Ending 09/30/20__ ESTIMATE

| Line No | DESCRIPTION | TRANSMISSION | GENERATION | COE GENERATION | BASE PLAN UPGRADES-REGIONAL | BASE PLAN UPGRADES-ZONAL | REFERENCE |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (5) | (4) | (5) | (6) |
| 1 | **A. Operation and Maintenance Expense** | | | | | | |
| 2 | O&M Expense | #REF! | #REF! | #REF! | #REF! | #REF! | WS4-Cost Data (O&M Expenses Worksheet) |
| 3 | Transmission of Electricity by Others | $0 | $0 | $0 | $0 | $0 | |
| 4 | Total O&M Expense | #REF! | #REF! | #REF! | #REF! | #REF! | L2 + L3 |
| 5 | Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | WS4-Cost-Data (Net Plant Investment Worksheet) |
| 6 | O&M as % of Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | L4/L5 |
| 7 | **B. A&G Expense** | | | | | | |
| | | | | | | | WS4-CostData |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 8 | A&G Expense | #REF! | #REF! | $0 | #REF! | #REF! | (A&G Expenses Worksheet) |



| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | L5 |
| 10 | A&G as % of Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | L8/L9 |
| 11 | **C. Depreciation Expense** | | | | | | |
| 12 | Depreciation Expense | #REF! | #REF! | #REF! | #REF! | #REF! | WS4-CostData (Depreciation Expense Worksheet) |
| 13 | Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | L5 |
| 14 | Depreciation as a % of Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | L12/L13 |
| 15 | **D. Taxes Other than Income Taxes for Transmission** | | | | | | |
| 16 | Not applicable. | | | | | | |
| 17 | **E. Allocation of General Plant** | | | | | | |
| 18 | No General Plant identified at this time, all plant is identified as either generation or transmission related. | | | | | | |
| 19 | **F. Cost of Capital** | | | | | | |
| 20 | Weighted Transmission Composite Interest Rate | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | WS4-CostData (Cost of Capital Worksheet) |
| 21 | **G. Fixed Charge Rate** | | | | | | |
| 22 | Operation and Maintenance Expense | #REF! | #REF! | #REF! | #REF! | #REF! | L6 |
| 23 | A&G Expense | #REF! | #REF! | #REF! | #REF! | #REF! | L10 |
| 24 | Depreciation Expense | #REF! | #REF! | #REF! | #REF! | #REF! | L14 |
| 25 | Taxes Other than Income Taxes | 0.000% | 0.00% | 0.00% | 0.00% | 0.00% | |
| 26 | Allocation of General Plant to Transmission | 0.000% | 0.00% | 0.00% | 0.00% | 0.00% | |
| 27 | Cost of Capital | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | L20 |
| 28 | Total | #REF! | #REF! | #REF! | #REF! | #REF! | |
| 29 | **H. Revenue Requirement** | | | | | | |
| 30 | Fixed Charge Rate | #REF! | #REF! | #REF! | #REF! | #REF! | L28 |
| 31 | Net Plant Investment | #REF! | #REF! | #REF! | #REF! | #REF! | L5 |
| 32 | Annual Western-UGPR Cost | #REF! | #REF! | #REF! | #REF! | #REF! | L30 * L31 |

WAPA-UGP Estimate Worksheet 3 - Revenue Calculation 20__ Rate Calculation Credit

12 Months Ending 09/30/20__ ESTIMATE

| Line No | ACCOUNT | MONTH | REFERENCE | COMPANY TOTAL | ALLOCATOR | ALLOCATION % | TRANSMISSION ALLOCATED AMOUNT |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | | (4) | (5) |
| 1 | Z2 Sch 7/8 | | Z2 | | NA | 100% | 0 |
| 2 | Z2 Sch 7/8 | Adjustments | | | | 100% | 0 |
| 3 | Subtotal | | | - | | | 0 |
| 4 | 45644 | | OTHER ELEC. REVENUE | | TP | 100% | 0 |
| 5 | 45644 | Adjustments | | | | 100% | 0 |
| 6 | Subtotal | | | - | | | 0 |
| 7 | 45645 | | OTHER ELEC. REVENUE | | TP | 100% | 0 |
| 8 | 45645 | Adjustments | | | TP | 100% | 0 |
| 9 | Subtotal | | | - | | | 0 |
| 10 | Sch 7/8 | | MISO SEAMS | | TP | 100% | 0 |
| 11 | Sch 7/8 | Adjustments | | | TP | 100% | 0 |
| 12 | Subtotal | | | - | | | 0 |
| 13 | 7088 | | SSCD | | NA | 100% | 0 |
| 14 | 7088 | Adjustments | | | NA | 100% | 0 |
| 15 | Subtotal | | | - | | | 0 |
| | | | RENT | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | 454 | | FROM | | | | |
| ~~6~~ | ~~20~~ | | ~~ELECTRIC~~ | | ~~TP~~ | ~~100%~~ | ~~0~~ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | PROPERTY | | | | |
| 17 | 45420 | Adjustments | | | TP | 100% | 0 |
| 18 | Subtotal | | | - | | | 0 |
| 19 | 45643 | | REVENUE FROM TRANS. | - | TP | 100% | 0 |
| 20 | 45643 | Adjustments | | - | TP | 100% | 0 |
| 21 | Subtotal | | | - | | | 0 |
| 22 | 70820 | | RESRV-SUPPLEMENTAL | - | NA | 100% | 0 |
| 23 | 70820 | Adjustments | | - | NA | 100% | 0 |
| 24 | Subtotal | | | - | | | 0 |
| 25 | 70829 | | RESRV-SPIN | - | NA | 100% | 0 |
| 26 | 70829 | Adjustments | | - | NA | 100% | 0 |
| 27 | Subtotal | | | - | | | 0 |
| 28 | 70931 | | REGULATION | - | NA | 100% | 0 |
| 29 | 70931 | Adjustments | | - | NA | 100% | 0 |
| 30 | Subtotal | | | - | | | 0 |
| 31 | Sch 11 | | PTP | | NA | 100% | 0 |
| 32 | Sch 11 | Adjustments | | | NA | 100% | 0 |
| 33 | Subtotal | | | - | | | 0 |
| 34 | NOTES: | Includes twelve months of revenue credits from January-December or February-January depending on when WAPA began receiving revenue credits from SPP. Revenue credit sheet may be updated or adjusted as necessary to include all revenue credits received. | | | | | |
| 35 | | Z2 Schedule 7/8 clawbacks | | | | | |
| 36 | | 45644 - Firm PTP Transmission revenues | | | | | |
| 37 | | | | | | | |

8 45645 - Non-Firm PTP Transmission revenues

3
9 Schedule 7/8 - MISO's SPP PTP Transmission service revenues
4
0 7088 - Scheduling, System Control and Dispatch Services revenues
4
1 45420 - Other Rental revenues
4
2 45643 - Firm Network Transmission revenues
4
3 7080 - Supplemental Reserves revenues
4
4 7089 - Spinning Reserves revenues
4
5 7091 - Regulation Service revenues
4
6 Schedule 11 PTP revenues

WAPA-UGP 20__ Rate Estimate Calculation
Worksheet 4 - Cost Support Data
12 Months Ending 09/30/20__
ESTIMATE

| Line No. | (1) | WESTERN-UGP (2) | | WESTERN-RMR (3) | | COE (4) | BOR (5) | | TOTAL (6) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Net Plant Investment Worksheet** | | | | | | | | |
| 2 | Total PS Plant-in-Service | #REF! | 1/ | | 2/ | | 3/ | 12/ | #REF! |
| 3 | PS-ED Transmission Plant-in-Service | #REF! | 4/ | #REF! | 5/ | #REF! | 6/ | 0 | #REF! |
| 4 | PS-ED Generation Plant-in-Service | #REF! | 7/ | 0 | | #REF! | L2-L3 | 0 | L2-L3 #REF! |
| 5 | PS-ED SSCD Plant-in-Service | #REF! | 8/ | | | | | | #REF! |
| 6 | BPU-Regional Plant-in-Service | #REF! | | | | | | | #REF! |

| | | | |
|---|---|---|---|
| 7 | BPU-Zonal Plant-in-Service | #REF! | # R |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | E F! |
| 8 | Generation Plant to Total Plant | #REF! | L4/L2 | #DIV/0! | L4/L2 | #REF! | L4/L2 | #DIV/0! | L4/L2 | |
| 9 | Transmission Plant to Total Plant | #REF! | L3/L2 | #REF! | L3/L2 | #REF! | L3/L2 | #DIV/0! | L3/L2 | |
| 10 | SSCD Plant to Total Plant | #REF! | L5/L2 | | | | | | | |
| 11 | BPU-Regional Plant to Total Plant | #REF! | | | | | | | | |
| 12 | BPU-Zonal Plant to Total Plant | #REF! | | | | | | | | |
| 13 | PS Accumulated Depreciation | | 9/ | | 10/ | | 11/ | | 13/ | 0 |
| 14 | PS-ED Trans. Accumulated Depreciation | #REF! | L13*L9 | #REF! | L13*L9 | #REF! | L13*L9 | #DIV/0! | L13*L9 | #REF! |
| 15 | PS-ED Gen. Accumulated Depreciation | #REF! | L13*L8 | 0 | | #REF! | L9-L10 | #DIV/0! | L13*L8 | #REF! |
| 16 | PS-ED SSCD Accumulated Depreciation | #REF! | L13*L10 | | | | | | | #REF! |
| 17 | BPU-Regional Accumulated Depreciation | #REF! | | | | | | | | #REF! |
| 18 | BPU-Zonal Accumulated Depreciation | #REF! | | | | | | | | #REF! |
| 19 | PS-ED Net Transmission Plant | #REF! | L3-L14 | #REF! | L3-L14 | #REF! | L3-L14 | #DIV/0! | L3-L14 | #REF! |
| 20 | PS-ED Net Generation Plant | #REF! | L4-L15 | 0 | L4-L10 | #REF! | L4-L15 | #DIV/0! | L4-L15 | #REF! |

| | | | | |
|---|---|---|---|---|
| 21 | PS-ED Net SSCD Plant | #REF! | L5-L16 | # R |

| | | | | |
|---|---|---|---|---|
| 22 | Regional Net Plant | #REF! | L6-L17 | #REF! |
| 23 | Base Plan Upgrade Net Plant | #REF! | L7-L18 | #REF! |
| 24 | 1/ Transmission Plant-in-Service Worksheet, C2L498 | | | |
| 25 | 2/ FY RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 1 | | | |
| 26 | 3/ FY Corps of Engineers Financial Statements, Electric and Power Multi-Purpose Plant in Service | | | |
| 27 | 4/ Transmission Plant-in-Service Worksheet, C5L498 | | | |
| 28 | 5/ Transmission Plant-in-Service Worksheet, C5L489 | | | |
| 29 | 6/ Transmission Plant-in-Service Worksheet, C5L496 | | | |
| 30 | 7/ Transmission Plant-in-Service Worksheet, C4L498 | | | |
| 31 | 8/ SSCD Plant-in-Service is based on a percentage of Watertown Operations Centers cost, based on FTE | | | |
| 32 | 9/ FY UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4 | | | |
| 33 | 10/ FY RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4 | | | |
| 34 | 11/ FY Corps of Engineers Financial Statements, Statement of Assets and Liabilities | | | |
| 35 | 12/ FY Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 15 | | | |
| 36 | 13/ FY Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 17 | | | |

WAPA-UGP 20__ Rate Estimate Calculation

| Line No. | (1) | WESTERN-UGP (2) | WESTERN-RMR (3) | COE (5) | BOR (6) | TOTAL (7) |
|---|---|---|---|---|---|---|
| 37 | **Depreciation Worksheet** | | | | | |
| 38 | PS Depreciation Expense | 1/ | 2/ L38 | #REF! | 3/ L38 | #DIV/0! 4/ L38 #REF! |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | PS-ED Transmission | | L38*L | | *L | E | *L | /0 | *L | E |
| 39 | Depreciation 5/ | #REF! | 9 | #REF! | 9 | F! | 9 | ! | 9 | F! |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 40 | PS-ED Generation Depreciation 6/ | #REF! | L38*L8 | 0 | L38*L8 | #REF! | L38*L8 | #DIV/0! | L38*L8 | #REF! |
| 41 | PS-ED SSCD Depreciation 7/ | #REF! | L38*L10 | | | | | | | #REF! |
| 42 | BPU-Regional Depreciation | #REF! | L38*L11 | | | | | | | #REF! |
| 43 | BPU-Zonal Depreciation | #REF! | L38*L12 | | | | | | | #REF! |
| 44 | 1/ FY UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Results of Operations, Schedule 4 | | | | | | | | | |
| 45 | 2/ FY RMCSR - Pick-Sloan Missouri River Basin Results of Operations, Schedule 4 | | | | | | | | | |
| 46 | 3/ FY Corps of Engineers Statement of Revenues and Expenses | | | | | | | | | |
| 47 | 4/ From data provided by BOR | | | | | | | | | |
| 48 | 5/ For Western-UGP, Western-RMR, COE, and BOR the portion of depreciation expense allocated to PS ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L7 of the Net Plant Investment Worksheet | | | | | | | | | |
| 49 | | | | | | | | | | |
| 50 | 6/ For Western-UGP, Western-RMR and BOR the portion of depreciation expense allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L6 of the Net Plant Investment Worksheet. COE generation depreciation is COE total depreciation less transmission depreciation | | | | | | | | | |
| 51 | | | | | | | | | | |
| 52 | 7/ For Western-UGP, the portion of depreciation expense allocated to PS-ED SSCD is based on the ratio of SSCD plant-in-service to total plant in service, calculated on L8 of the Net Plant Investment Worksheet | | | | | | | | | |
| 53 | | | | | | | | | | |

WAPA-UGP 20__ Rate Estimate Calculation

| Line No. | (1) | WESTERN-UGP (2) | WESTERN-RMR (3) | | COE (5) | | BOR (6) | | TOTAL (7) |
|---|---|---|---|---|---|---|---|---|---|
| 54 | **Cost of Capital Worksheet** | | | | | | | | |
| 55 | **Long Term Debt:** | | | | | | | | |
| 56 | FY Balances | | 1/ | | 1/ | | 1/ | | 0 |
| 57 | **Interest Expenses:** | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 58 | FY Interest | 13/ | 3/ | 2/ | 2/ | 0 | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 59 | Average Interest Rate | #DIV/0! | L58/L56 | #DIV/0! | L58/L56 | #DIV/0! | L58/L56 | #DIV/0! | 0.0000 | L58/L56 | | |
| 60 | Transmission Plant Factor | #REF! | 3/ | #REF! | 4/ | #REF! | 5/ | #REF! | 6/ | | | |
| 61 | Weighted Trans. Composite Rate | | | | | | | | | | #DIV/0! | 7/ |
| 62 | Generation Plant Factor | #REF! | 8/ | 0.0000 | 9/ | #REF! | 10/ | #REF! | 11/ | | | |
| 63 | Weighted Gen. Composite Rate | | | | | | | | | | #DIV/0! | 12/ |
| 64 | 1/ FY Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedules 21X and 21RX | | | | | | | | | | | |
| 65 | 2/ FY Historical Financial Data in Support of the Power Repayment Study for the P-SMBP, Schedule 33, 33A and ROOs Schedule 5 | | | | | | | | | | | |
| 66 | 3/ C2L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet | | | | | | | | | | | |
| 67 | 4/ C3L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet | | | | | | | | | | | |
| 68 | 5/ C4L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet | | | | | | | | | | | |
| 69 | 6/ C5L3, Net Plant Investment Worksheet/C6L3, Net Plant Investment Worksheet | | | | | | | | | | | |
| 70 | 7/ (C2L59*C2L62)+(C3L59*C3L62)+(C4L59*C4L62)+(C5L59*C5L62) | | | | | | | | | | | |
| 71 | 8/ C2L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet | | | | | | | | | | | |
| 72 | 9/ C3L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet | | | | | | | | | | | |
| 73 | 10/ C4L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet | | | | | | | | | | | |
| 74 | 11/ C5L4, Net Plant Investment Worksheet/C6L4, Net Plant Investment Worksheet | | | | | | | | | | | |
| 75 | 12/ (C2L59*C2L62)+(C3L59*C3L62)+(C4L59*C4L62)+(C5L59*C5L62) | | | | | | | | | | | |

13/ Interest from Results of Operations Schedule

| | |
|---|---|
| 76 | 5 |

WAPA-UGP 20__ Rate Estimate Calculation

| Line No. | (1) | WESTERN-UGP (2) | WESTERN-RMR (3) | COE (5) | BOR (6) | TOTAL (7) |
|---|---|---|---|---|---|---|
| 77 | **A&G Expenses Worksheet** | | | | | |
| 78 | | **WESTERN-UGP 1/** | **WESTERN-RMR 2/** | **COE 3/** | **BOR 3/** | **Total** |
| 79 | **PS Total Est. A&G** | | | 0 | 0 | 0 |
| 80 | **PS-ED Est. Transmission A&G 4/** | #REF! | #REF! | 0 | 0 | #REF! |
| 81 | **PS-ED Generation A&G 5/** | #REF! | 0 | 0 | 0 | #REF! |
| 82 | **PS-ED SSCD A&G 6/** | #REF! | 0 | 0 | 0 | #REF! |
| 83 | **BPU-Regional A&G** | #REF! | 0 | 0 | 0 | #REF! |
| 84 | **BPU-Zonal A&G** | #REF! | 0 | 0 | 0 | #REF! |
| 85 | 1/ Western-UGP A&G Est. Expenses are from the FY UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Budget | | | | | |
| 86 | 2/ Western RMR A&G Expenses are from the FY RMCSR - Pick-Sloan Missouri River Basin Budget | | | | | |
| 87 | 3/ A&G Expenses for COE and BOR are unavailable. All COE and BOR A&G expenses are included in O&M Expenses | | | | | |
| 88 | 4/ The portion of A&G expenses allocated to PS-ED transmission is based on the ratio of transmission plant-in-service to total plant-in-service, calculated on L7 of the Net Plant | | | | | |
| 89 | Investment Worksheet | | | | | |
| 90 | 5/ The portion of A&G expenses allocated to PS-ED generation is based on the ratio of generation plant-in-service to total plant-in-service, calculated on L6 of the Net Plant | | | | | |
| 91 | Investment Worksheet | | | | | |
| 92 | 6/ The portion of A&G expenses allocated to PS-ED SSCD is based on the ratio of SSCD plant-in-service to total plant-in-service, calculated on L8 of the Net Plant Investment Worksheet | | | | | |

WAPA-UGP 20__ Rate Estimate Calculation

| Line No. | (1) | WESTERN-UGP (2) | WESTERN-RMR (3) | COE (5) | BOR (6) | TOTAL (7) |
|---|---|---|---|---|---|---|
| 93 | **O&M Expenses Worksheet** | | | | | |
| 94 | | **WESTERN-UGP 1/** | **WESTERN-RMR 2/** | **COE 3/** | **BOR 4/** | |
| 95 | **Total Electric Operating Expense** | | | | | 0 |
| 96 | **Less:** | | | | | |
| 97 | **Other Power Supply Expenses** | | | | | |
| 98 | **A&G Expenses** | | | | | 0 |
| 99 | **Prior Year Adjustments** | | | | | |
| 100 | **Annual Reserve Sharing Group Cost** | | | | | 0 |
| 101 | **Plus:** | | | | | |
| 102 | **Moveable Property Interest** | | | | | 0 |
| 103 | **Warehouse Stores Interest** | | | | | |
| 104 | **Scheduling, System Control & Dispatch** | | | | | 0 |
| 105 | **COE/BOR Total** | | | | | 0 |
| 106 | **PS Total O&M** | 0 | | 0 | 0 | 0 |
| 107 | **PS-ED Transmission O&M 5/** | #REF! | #REF! | #REF! | #DIV/0! | #REF! |
| 108 | **PS-ED Generation O&M 6/** | #REF! | 0 | #REF! | #DIV/0! | #REF! |
| 109 | **BPU-Regional O&M** | #REF! | | | | #REF! |
| 110 | **BPU-Zonal O&M** | #REF! | | | | #REF! |
| 111 | 1/ All Western-UGP O&M Expenses are from the FY UGPCSR - Pick-Sloan Missouri River Basin and UGPCSR - Ft. Peck Power System Budget<br>2/ All Western RMR O&M Expenses are from the FY RMCSR - Pick-Sloan Missouri River Basin Results of | | | | | |

112 Operations, Schedule 11; except Moveable Property and Warehouse

113 Stores Interest, which are from Schedule 5

3/ Total Corps O&M Expenses are from the FY Corps of Engineers
114 Financial Statements
4/ Total BOR O&M Expenses are from the FY Historical Financial Data in Support of the Power
115 Repayment Study for the Pick-Sloan Missouri Basin Program, Schedule 14
5/ The portion of O&M expenses allocated to PS-ED transmission is based on the ratio of transmission
116 plant-in-service to total plant-in-service, calculated on L7 of the
Net Plant Investment
117 Worksheet
6/ The portion of O&M expenses allocated to PS-ED generation is based on the ratio of generation
118 plant-in-service to total plant-in-service, calculated on L6 of the
Net Plant Investment
119 Worksheet

WAPA-UGP 20__ Rate Estimate Calculation Worksheet 5 - Zonal SPP Upgrade Calculations
12 Months Ending 09/30/20__ ESTIMATE

| Line No. | Project Name and # | Type | Project Gross Plant (Zonal Allocation) | Allocation Factor % | Project Accumulated Depreciation | Allocation for Transmission O&M | Allocation for General Plant Depreciation | Allocation for A&G | Cost of Capital | Project Net Plant | Cost of Capital | Project ATRR | Revenue Credit Allocation | Net ATRR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | |
| | | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
| | | | | | | | | | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! |
| 1 | | TLSUB | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! | | | #REF! | |
| | | | | | | | | | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! |
| 2 | | BSUB | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! | | | #REF! | |
| | | | | | | | | | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! |
| 3 | | | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! | | | #REF! | |
| 4 | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | |
| 13 | **Revenue Credit Total** | | | | | | | | #REF! | | | | #REF! | |
| 14 | **Total** | | **#REF!** | **100 %** | **#REF!** | **#REF!** | **#REF!** | **#REF!** | | **#REF!** | **#DIV/0!** | **#DIV/0!** | **#REF!** | **#DIV/0!** |

WAPA-UGP 20__
Rate Estimate Calculation
Worksheet 6 - Base Plan Upgrades-Regional
12 Months Ending 09/30/20__
ESTIMATE

| Line No. | Project Name and # | Type | Project Gross Plant (Regional Allocation) | Allocation Factor % | Project Accumulated Depreciation | Allocation for Transmission O&M | Allocation for General Plant Depreciation | Allocation for A&G | Cost of Capital | Project Net Plant | Cost of Capital | Project ATRR | Revenue Credit Allocation | Net ATRR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) |
| 1 | | TLSUB | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | #DIV/0! | #REF! | #DIV/0! | #DIV/0! | #REF! | #DIV/0! |
| 2 | | | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | #DIV/0! | #REF! | #DIV/0! | #DIV/0! | #REF! | #DIV/0! |
| 3 | | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12 | | | | | | | | | | | | |
| | **Revenue** | | | | | | | #R | | | **#RE** | |
| 13 | **Credit Total** | | | | | | | EF! | | | **F!** | |
| **14** | **Total** | | **#REF!** | **100%** | **#REF!** | **#REF!** | **#REF!** | **#REF!** | **#REF!** | **#DIV/0!** | **#DIV/0!** | **#REF!** | **#DIV/0!** |
| WAPA-UGP 20__ Rate Estimate Calculation Worksheet 7 - SPP Base Plan Upgrades-Facilities 12 Months Ending 09/30/20__ ESTIMATE | | **FID** | **DESCRIPTION** | | | | **PRIOR YEAR FACILITY TOTALS ($)** | **FY20__-__ ESTIMATE ADD/REPL/RETIRE ($)** | **BASE PLAN UPGRADES-REGIONAL** | **BASE PLAN UPGRADES-ZONAL** | **FY20__ ESTSPP TOTALS ($)** |
| **20__ SPP ESTIMATE SUMMARY** | | | TOTAL | | | | #REF! | #REF! | #REF! | #REF! | #REF! |
| **20__ SPP ESTIMATE DETAIL:** | | **FID** | **DESCRIPTION** | | | | **FID COST DETAIL ($)** | **REG %** | **REG TOTAL ($)** | **ZONAL %** | **ZONAL TOTAL ($)** |
| | | | **FACILITY - SUBTOTAL (SPP directed Regional/Zonal Split of __%/__%)** | | | | #REF! | | #REF! | | #REF! |
| | | | **FACILITY - SUBTOTAL (SPP directed Regional/Zonal Split of __%/__%)** | | | | #REF! | | #REF! | | #REF! |
| | | | **FACILITY - SUBTOTAL (SPP directed Regional/Zonal Split of __%/__%)** | | | | #REF! | 0% | #REF! | | #REF! |
| | | | **TOTAL SPP UPGRADES** | | | | #REF! | | #REF! | | #REF! |

WAPA-UGP 20__ Rate Estimate Calculation
Worksheet 8 - Transmission Facilities
12 Months Ending 09/30/20__
ESTIMATE

| Line No. | | FID | DESCRIPTION | (1) PRIOR YEAR FACILITY TOTALS ($) | (2) EST ADD/REPL/RETIRE ($) | (3) ESTIMATED FACILITY TOTAL ($) | (4) ATTACHMENT AI ADJUSTMENTS ($) | (5) GENERATION ADJUSTMENTS ($) | (6) BASE UPGRADE ADUSTMENTS ($) | (7) FY20__ EST SPP TOTALS ($) |
|---|---|---|---|---|---|---|---|---|---|---|
| #REF! | TL Total | | TRANSMISSION LINES | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | SUB Total | | SUBSTATIONS | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! |
| #REF! | O&M Total | | O&M SERVICE & MAINT. CENTERS | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | OPS Total | | OPERATION CENTERS | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! | #REF! |
| #REF! | MOB Total | | MOBILE EQUIPMENT | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | GEN Total | | TRANSMISSION-RELATED GEN. FACILITIES | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | COM Total | | COMMUNICATION FACILITIES | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | MCCS Total | | MILES CITY CONVERTER STATION | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | DIST Total | | DISTRIBUTION FACILITIES | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | RMR Total | | ROCKY MOUNTAIN REGION FACILITIES | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | COE Total | | CORPS OF ENGINEERS FACILITIES | #REF! | #REF! | #REF! | #REF! | #REF! | | #REF! |
| #REF! | Grand Total | | TOTAL FACILITIES | - | - | - | - | - | - | - |
| #REF! | | | SUBTOTAL WESTERN-UGP ONLY | #REF! | #REF! | #REF! | #REF! | #REF! | - | #REF! |
| #REF! | | | 1/ Plant balance does not include customer liability for network upgrades. Investment is only brought into plant balance as WAPA incurs expense (e.g. if transmission credits are provided to customer) | | | | | | | |
| #REF! | | | DISTRIBUTION | | | | | | | |

| | | | |
|---|---|---|---|
| 504 | FACILITIES | #REF! | #REF! |

WAPA-UGP 20__
Rate Estimate
Calculation

Worksheet 9 - WAPA-UGP Facilities Included per SPP Tariff Attachment AI*

12 Months Ending 09/30/20__
ESTIMATE

| Line No. | Facility | Specific Plant Included | Attachment AI Criteria 1 | 1(b) | 2 | 3 | 4 | 5 | 6 | Further Description |
|---|---|---|---|---|---|---|---|---|---|---|
| | **Substations** | | | | | | | | | |
| | **One-Line Diagrams showing these included facilities are available upon request.** | | | | | | | | | |
| | **The diagrams include CEII material and therefore require execution of a Non-Disclosure Agreement with Western Area Power Administration - Upper Great Plains Region.** | | | | | | | | | |
| | Criteria 1: Non-Radial above 60-kV / (b) Two or More Eligible Customers | | | | | | | | | |
| | Criteria 2: Interconnect Zones / Surrounding Entities | | | | | | | | | |
| | Criteria 3: Control and Protection | | | | | | | | | |
| | Criteria 4: High Side of Transformer | | | | | | | | | |
| | Criteria 5: DC Interconnection | | | | | | | | | |
| | Criteria 6: 7 Factor Test | | | | | | | | | |

* Based upon Attachment AI of SPP's Tariff and consistent with criteria set forth in the "*Zone 19 (Upper Missouri Zone) - Attachment AI Guidance Document*", dated 06/14/2016, as prepared by the Attachment AI Working

Group in FERC docket ER15-1775-000.

WAPA-UGP 20__ Rate
Estimate Calculation

Worksheet 10 - WAPA-UGP Facilities Excluded under SPP Tariff Attachment AI*

12 Months Ending
09/30/20__ ESTIMATE

| Line No. | FID | Facility | Specific Plant NOT Included | Further Description |
|---|---|---|---|---|

* Based upon Attachment AI of SPP's Tariff and consistent with criteria set forth in the "*Zone 19 (Upper Missouri Zone) - Attachment AI Guidance Document",* dated 06/14/2016, as prepared by the Attachment

AI Working Group in FERC
docket ER15-1775-000.

WAPA-UGP 20__ Rate Estimate Calculation

Worksheet 11 - Facility Changes

12 Months Ending 09/30/20__ ESTIMATE

WAPA-UGP 20__ Rate Estimate Calculation

Worksheet 12 - Scheduling, System Control, and Dispatch Service

12 Months Ending 09/30/20__ ESTIMATE

| DESCRIPTION | SSCD | REFERENCE |
|---|---|---|
| | | |

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| Line No. | (1) | (2) | (3) |
|---|---|---|---|
| 1 | **A. Operation and Maintenance Expense** | $0 | WS4-CostData (O&M Expenses Worksheet) |
| 2 | **B. A&G Expense** | #REF! | WS4-CostData (A&G Expenses Worksheet) |
| 3 | **C. Depreciation Expense** | #REF! | WS4-CostData (Depreciation Expense Worksheet) |
| 4 | **D. Taxes Other than Income Taxes for Transmission** | $0 | Not Applicable |
| 5 | **E. Allocation of General Plant** | $0 | No General Plant identified at this time, all plant is identified as either generation or transmission related |
| 6 | **F. Cost of Capital** | | |
| 7 | Weighted Transmission Composite Interest Rate | #DIV/0! | WS4-CostData (C6 L61) |
| 8 | Net Plant Investment | #REF! | WS4-CostData (C2 L21) |
| 9 | Cost of Capital | #DIV/0! | L7*L8 |
| 10 | **H. Revenue Requirement** | | |
| 11 | Annual Western-UGPR Cost | #REF! | L1+L2+L3+L9 |
| 12 | **Estimated SSCD Revenue from non-Transmission facilities** | #REF! | L11*L16 |
| 13 | **Prior Year True-Up** | | Prior year true-up |
| 14 | **Revenue Requirement for SSCD for Transmission facilities** | #REF! | L11-L12+L13 |
| 15 | | | |
| 16 | Ratio for Line 12 | #REF! | WS8-TranFac (L504 C4/C7) |

WAPA-UGP 20__ Rate Estimate Calculation
Worksheet 13 - SSCD Facilities
12 Months Ending 09/30/20__
ESTIMATE

| 20__ SPP ESTIMATE SUMMARY | FID | DESCRIPTION | PRIOR YEAR FACILITY TOTALS ($) | FY20__ ESTIMATE ADD/REPL/RETIRE ($) | ATTACHMENT AI ADJUSTMENTS ($) | GENERATION ADJUSTMENTS ($) | FY20__ EST SPP TOTALS ($) |
|---|---|---|---|---|---|---|---|
| | | | - | - | 0 | - | - |

| 20__ SPP ESTIMATE DETAIL: | FID | DESCRIPTION | FID COST DETAIL ($) | SSCD % | SSCD TOTAL ($) | TRANS % | TRANS TOTAL ($) |
|---|---|---|---|---|---|---|---|
| | | TOTAL | #REF! | | #REF! | | #REF! |
| | | TOTAL | #REF! | | #REF! | | #REF! |
| | | TOTAL | #REF! | | #REF! | | #REF! |
| | | TOTAL | #REF! | | #REF! | | #REF! |
| | | TOTAL | #REF! | | #REF! | | #REF! |

# Western Area Power Administration - Upper Great Plains Region

# Transmission and Ancillary Formula Rate Implementation Protocols

The transmission and ancillary formula rate templates ("Formula Rate Templates") of Western Area Power Administration - Upper Great Plains Region ("Western-UGP" or "WAPA-UGP") and these Transmission and Ancillary Formula Rate Implementation Protocols ("Protocols") together comprise the filed rates ("Formula Rates") of WAPA-UGP for transmission and ancillary revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("SPP Tariff"). WAPA-UGP must follow the instructions specified in the Formula Rates to calculate its Annual Transmission Revenue Requirement ("ATRR") and the Annual Revenue Requirement ("ARRs") for Ancillary Services offered under the SPP Tariff.

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rates and Attachment AI and Attachment J, respectively, of the SPP Tariff. The ATRR and ARRs shall be determined for January 1 to December 31 of a given calendar year. The Formula Rates shall become effective for recovery of WAPA-UGP's ATRR and ARRs upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC"). The Deputy Secretary of Energy has the authority to confirm, approve and place such rates in effect on an interim basis. FERC has the exclusive authority to confirm, approve and place into effect on a final basis, and to remand or to disapprove rates developed by WAPA's Administrator. FERC's review is limited to (1) whether the rates are the lowest possible consistent with sound business principles; (2) whether the revenue levels generated are sufficient to recover the costs of producing and transmitting electric energy including repayment within the period permitted by law; and (3) the assumptions and projections used in developing the rates. FERC shall reject decisions of WAPA's Administrator only if it finds them to be arbitrary, capricious or in violation of the law.

The Formula Rates shall be applicable to service on and after January 1 of each calendar year through December 31 of the calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges, to the extent provided herein. These Protocols specify the dates applicable to the activities described herein. Should any due date fall on a weekend or a holiday recognized by FERC, then the due date shall be no later than the next Business Day.

## Section I Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

A. "Accounting Change" means any change in the WAPA-UGP Federal Power System (the System) financial statements including the financial position, results of operations and cash flows of WAPA-UGP, an agency of the U.S. Department of Energy (DOE), and the hydroelectric power generating functions of the U.S. Department of the Interior (DOI), Bureau of Reclamation (Reclamation), the U.S. Department of Defense (DOD), Army Corps of Engineers (Corps),

(collectively referred to as the generating agencies). For the generating agencies, only the individual power systems for which WAPA-UGP markets and transmits hydroelectric power are

included in the combined financial statements and included here. WAPA, a Federal power marketing administration, markets and transmits hydroelectric power generated from these power systems, which are operated and maintained by the generating agencies. It also means any change in the accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR and/or ARR calculations under the Formulas. Accounting Changes include any changes resulting from:

1. revisions to the System financial statements which are prepared following accounting principles generally accepted in the United States of America (U.S. GAAP). The combined financial statements also reflect FERC regulations, FERC's Uniform System of Accounts ("USoA") and DOE's accounting practices;

2. correction of errors and prior period adjustments that impact the ATRR and/or ARRs;

3. the implementation of new estimation methods or policies;

4. a change in WAPA-UGP's or the generating agencies' accounting policies and practices, which reflect specific legislation and executive directives issued by departments of the Federal government;

5. WAPA-UGP's or the generating agencies' own accounting changes (which constitute a change to the ATRR or ARR greater than or equal to $15,000) such as the addition or deletion of a subaccount not specified by FERC's USoA; or

6. a change in WAPA-UGP's or the generating agencies' cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

B. "Annual Revenue Requirement" or "ARR" means the net revenue requirement for the Ancillary Services calculated in accordance with the Formula Rates posted on the WAPA-UGP Open Access Same-Time Information System ("OASIS") and SPP OASIS, subject to review pursuant to the provisions of these Protocols.

C. "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate posted on the WAPA-UGP OASIS and SPP OASIS, subject to review pursuant to the provisions of these Protocols.

D. "Annual Meeting" means the meeting hosted by WAPA-UGP for exchanging information with Interested Parties regarding updates to the financial data in its Formula Rates.

E. "Annual Update" means WAPA-UGP's annual posting of its updates to the financial data in its Formula Rates, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

F. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

G. "Calendar Year" means January 1 through December 31 of a given year.

H. "Current Rate Year" means the Rate Year for which the Annual Update is posted on the WAPA-UGP OASIS and SPP OASIS (*e.g.*, if the Initial Posting of the Annual Update is posted on or around September 1, 2020, and the Final Posting of the Annual Update is posted on or around December 15, 2020, the Current Rate Year is January 1, 2021 through December 31, 2021).

I. "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS, service under Grandfathered Agreements, or PTP Transmission Service.

J. "FERC" or "Commission" means the Federal Energy Regulatory Commission.

K. "Final Posting" means the Annual Update information that WAPA-UGP posts to the WAPA-UGP OASIS and SPP posts to the SPP OASIS with changes agreed to during the informal review process.

L. "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is served on WAPA-UGP by electronic service.

M. "Formula Rate Template" means the WAPA-UGP transmission and ancillary formula rate templates set forth herein.

N. "Formula" means the Formula Rate Template set forth in Addendum 35 to Attachment H of the SPP Tariff.

O. "Formula Rate" has the meaning defined herein and means the WAPA-UGP Formula Rate Implementation Protocols together with the Formula Rate Templates.

P. "FPA" means the Federal Power Act.

Q. "Informal Challenge" means written notification by an Interested Party to WAPA-UGP, during the Review Period, of any specific challenge to the Annual Update.

R. "Information Request" means a written request submitted by an Interested Party to WAPA-UGP.

S. "Initial Posting" means the initial posting of WAPA-UGP's Annual Update to the WAPA-UGP OASIS.

T. "Interested Party" includes SPP Tariff Transmission Customers.

U. "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

V. "OASIS" means Open Access Same-Time Information System.

W. "OATT" or "SPP Tariff" means SPP's Open Access Transmission Tariff.

X. "Prior Rate Year" means the Rate Year two (2) years prior to the Current Rate Year (*e.g.*, if the Current Rate Year is January 1, 2021 through December 31, 2021, then the Prior Rate Year is January 1, 2019 through December 31, 2019).

Y. "PTP" means Point-to-Point Transmission Service as defined in the SPP Tariff.

Z. "Publication Date" means the date on which WAPA-UGP posts the Initial Posting to the WAPA-UGP OASIS, or the next Business Day following the actual posting date should that posting date fall on a weekend or a holiday recognized by FERC.

AA. "Rate Year" means January 1 of a given year through December 31 of the same Calendar year.

BB. "Review Period" means, unless otherwise extended in writing by WAPA-UGP, the period extending from the Publication Date through November 15, which includes a period for submission of Information Requests and a period for preparation of Informal Challenges.

CC. "SPP" means Southwest Power Pool, Inc. or its successor organization.

DD. "SPP Tariff" or "OATT" means SPP's Open Access Transmission Tariff.

EE. "USoA" means FERC's Uniform System of Accounts.

## Section II Annual Update

A. On or around September 1 of each calendar year (the Publication Date), WAPA-UGP shall:

1. For the Prior Rate Year and Current Rate Year, recalculate the ATRR utilized by SPP for zonal NITS service and the ARRs utilized by SPP for ancillary services for the applicable Rate Year in accordance with the applicable Formula Rate(s) and using the Formula Rate Templates. WAPA-UGP shall post its Annual Update to the "Rates" folder on the WAPA-UGP OASIS (the Initial Posting) and WAPA-UGP rates website[1]; and

2. Provide its Annual Update to SPP and request that SPP post such information to the SPP OASIS "Member Related Postings" under the "Western Area Power Administration UGP Information" link.

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[1] WAPA-UGP will post the Annual Update at the following locations, respectively: http://www.oasis.oati.com/wapa/index.html, and https://www.wapa.gov/regions/UGP/rates/Pages/rates.aspx.

B. Concurrent with the Initial Posting, WAPA-UGP shall provide notification of the Annual Update to Interested Parties by serving such notice electronically upon the Service List.[2]

C. The Annual Update shall:

1. Include workable populated Formula Rate Templates with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

2. Be based on the independently-audited books and records of WAPA-UGP and the generating agencies for the most recent fiscal year including combined financial statements accounted for under the provisions of the Financial Accounting Standards Board (FASB);

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rates;

4. With respect to any change in accounting that affects the inputs to the Formula Rates or the resulting charges billed under the Formula Rates, WAPA-UGP shall identify:

   a. Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR and/or ARRs.

   b. Any items included in the Formula Rates at an amount other than a historic cost basis.

   c. Individual impact of any changes in Section II.C (4)(a) above on charges billed under the Formula Rates.

   d. Accounting Changes related to any reorganization or merger transaction.

5. Not seek to modify the Formula Rates.

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[2] As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP website. As of June 2017, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/.

6. With each Annual Update, WAPA-UGP will include a list of any new transmission facilities included in the Formula Rate Templates that were not included in the prior Annual Update. New transmission facilities include but are not limited to additional substations, breakers, other major substation equipment, and additional transmission line miles. The list will indicate the Zone 19 Attachment AI Guidance Document criteria that WAPA-UGP believes supports each facility's inclusion in WAPA-UGP's ATRR and/or ARRs. This provision in no way limits the rights of any Interested Party to challenge inclusion of new facilities.

## Section III Review of Annual Update

Within twenty (20) calendar days of the Publication Date of WAPA-UGP's Annual Update, and with at least seven (7) calendar days' notice, WAPA-UGP will host a meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). WAPA-UGP shall provide notice of this meeting concurrent with the posting of the Annual Update accessible on the WAPA-UGP OASIS and the SPP OASIS. The notice shall include the date, time and location of the Annual Meeting and shall be provided to Interested Parties through the Service List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the WAPA-UGP OASIS and SPP OASIS.

A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Update and will have until October 15 to serve reasonable Information Requests on WAPA-UGP for information and work papers supporting the Annual Update. Such Information Requests shall be limited to that which is necessary to determine:

   a. The extent or effect of an Accounting Change;

   b. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

   c. The proper application of the Formula Rates and procedures in these Protocols;

   d. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

   e. The effect of any change to the underlying USoA or Formula Rate Templates; or

   f. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rates.

The information and document requests shall address the proper application of data in the Formula Rates, and not the Formula Rates themselves. WAPA-UGP

will not claim that responses to information and document requests pursuant the Protocols are subject to any settlement confidentiality provision; however, WAPA-UGP may require that Interested Parties execute a non-disclosure agreement to obtain access to material that WAPA-UGP deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR § 388.113(c)(1).

2. WAPA-UGP shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within fifteen (15) calendar days of receipt.

3. WAPA-UGP shall post on a publically accessible portion of the WAPA-UGP OASIS all Information Requests from Interested Parties and WAPA-UGP's response(s) to such requests, and a link to the posting will be electronically served on all Interested Parties via the Service List. WAPA-UGP will request that SPP also post the same information on the SPP OASIS. If responses to Information Requests contain information deemed by WAPA-UGP to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and WAPA-UGP.

4. If the deadline for Interested Parties falls on a weekend or holiday recognized by the FERC, the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until November 15 (or the first Business Day after November 15 if November 15 falls on a weekend or holiday) to notify WAPA-UGP in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. WAPA-UGP will make a good faith effort to respond to any Informal Challenge within twenty (20) calendar days of notification of such Informal Challenge. WAPA-UGP shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. WAPA-UGP will post on the WAPA-UGP OASIS all Informal Challenges from Interested Parties and WAPA-UGP's responses to the Informal Challenges, and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. WAPA-UGP will request that SPP also post the same information on the SPP OASIS. If responses to Informal Challenges contain information that is deemed by WAPA-UGP to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and WAPA-UGP.

3. Any changes or adjustments to the Annual Update resulting from the Information

Exchange and Informal Challenge procedures that are agreed to by WAPA-UGP and resolved prior to the end of the Review Period shall be reported in the Final Posting on the WAPA-UGP OASIS and SPP OASIS. Any changes or adjustments agreed to by

WAPA-UGP after this date will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges

1. An Interested Party shall have until January 15 (or the first Business Day after January 15 if January 15 falls on a weekend or holiday recognized by FERC) to file a Formal Challenge. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues. WAPA-UGP will make a good faith effort to respond to any Formal Challenge within twenty (20) calendar days of notification of such Formal Challenge. WAPA-UGP, and, if appropriate, SPP, shall appoint senior representatives, including WAPA's Administrator, to work with the Interested Party to resolve the Formal Challenge.

2. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rates or Protocols;

b. Explain how the action or inaction violates the filed Formula Rates or Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rates and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Templates; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rates.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or

inaction;

e. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

3. Formal Challenges shall be served upon WAPA-UGP in writing (which may be electronically) to the individual listed as the WAPA-UGP contact person in WAPA-UGP's Annual Update.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rates under the Challenge procedures (either Formal or Informal) set forth in these Protocols, and the Annual Update shall not be subject to challenge for modifying the Formula Rates.

2. A change to applicable WAPA-UGP Formula Rate fixed inputs may not be made absent the appropriate filing with FERC.

3. If WAPA-UGP makes a correction to a Mistake in its financial information during the Current Rate Year that would affect the Formula Rate for the Current Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs shall be incorporated into the Formula Rates and the charges produced by the Formula Rates in the Annual Update for the next effective Rate Year.

E. Final Posting

1. On or around December 15 of each year, WAPA-UGP shall post the Final Posting of its Annual Update to the WAPA-UGP OASIS and also request SPP to post the same information on the SPP OASIS.

2. This Final Posting must include the information that is reasonably necessary to determine:

    a. That input data under the Formula Rates is properly recorded in any underlying work papers;

    b. That WAPA-UGP has properly applied the updates to the financial data in the Formula Rates and these procedures;

    c. The accuracy of the data and the consistency with the Formula Rates of the ATRR and ARRs for the ancillary rates under review; and

    d. The extent of Accounting Changes that affect Formula Rates inputs.

3. The Final Posting must also describe all aspects of the Formula Rates or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Final Posting on the WAPA-UGP OASIS, WAPA-UGP shall provide notice of the Final Posting to Interested Parties via the Service List and request that SPP also post the Final Posting on the SPP OASIS.

## Section IV Joint SPP Transmission Owners' Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, WAPA-UGP intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to Interested Parties via the Formula Rate Posting Information Notification List no less than seven (7) days prior to such meetings.

## Section V WAPA-UGP Example Schedule

| Line No. | Action | Begin | End | Calendar Days from Publication Date |
|---|---|---|---|---|
| 1 | Rate Year | Jan. 1, 2021 | Dec. 31, 2021 | |
| 2 | Publication Date | | Sept. 1, 2020 * | |
| 3 | Annual Meeting of Interested Parties | | Sept. 21, 2020 * | Within 20 |
| 4 | Information Request Due Date | Sept. 1, 2020 * | Oct. 15, 2020 | ~45 |
| 5 | Informal Challenges Due Date | | Nov. 15, 2020 | ~75 |
| 6 | Final Posting | | Dec. 15, 2020 * | ~105 |
| 7 | Formal Challenge Due Date | | Jan. 15, 2021 | |

* On or around

## Addendum 38 to Attachment H

## Arkansas Electric Cooperative Corporation

**Southwest Power Pool Zonal ATRR, page 1 of 5**

**Arkansas Electric Cooperative Corporation**
**Formula Rate Template**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | RUS Form 12 Reference | Avg/Total Company Amount | Allocator | Transmission Amount |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 20, col. 5 | | | #DIV/0! |
| | REVENUE CREDITS | | Total | Allocator | |
| 2 | Account No. 454 (Rent from Electric Property) | Worksheet G, line 9, col. 5 | $0 | TP #DIV/0! | #DIV/0! |
| 3 | Account No. 456 Schedule 7 & 8 PTP Revenues | Worksheet G, line 9, col. 6 | $0 | DA 100.00% | $0 |
| 4 | Account No. 456 Other | Worksheet G, line 9, col. 7 | $0 | TP #DIV/0! | #DIV/0! |
| 5 | Base Plan Projects (Note H) | Worksheet H, page 2, line 2, col. 9 | $0 | DA 100.00% | $0 |
| 6 | TOTAL REVENUE CREDITS | sum lines 2 thru 5 | $0 | | #DIV/0! |
| 7 | NET REVENUE REQUIREMENT (Schedule 9 Zonal ATRR) | line 1 less line 6 | | | #DIV/0! |

| | | | |
|---|---|---|---|
| 8 | SPP SCHEDULE 1 REVENUE REQUIRMENT | 12I.A.2.a / 2.0 | |
| 9 | Zonal Allocation to Pricing Zone 1 (AEP) | Wks E Zone 1 Facility Investment * line 7 | #DIV/0! |
| 10 | Zonal Allocation to Pricing Zone 6 (OGE) | Wks E Zone 6 Facility Investment * line 7 | #DIV/0! |

Enter year of data used:



**Arkansas Electric Cooperative Corporation**
**Formula Rate Template**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | RUS Form 12 Reference | BOY Balance | EOY Balance | Avg/Total Company Amount | Allocator | Transmission Amount |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| | **RATE BASE** | | | | | | |
| | GROSS PLANT IN | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | SERVICE (Note G) | | | | | | |
| 1 | Production | 12h.A.6.e | | #DIV/0! | NA | 0.00% | #DIV/0! |
| 2 | Transmission | 12h.A.11.e | | #DIV/0! | TP | #DIV/0! | #DIV/0! |
| 3 | Distribution | 12h.A.16.e | | #DIV/0! | NA | 0.00% | #DIV/0! |
| 4 | General & Intangible | 12h.A.1&18.e | | #DIV/0! | W/S | #DIV/0! | #DIV/0! |
| 5 | TOTAL GROSS PLANT | sum lines 1 thru 4 | | #DIV/0! | **GP =** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note G) | | | | | | |
| 6 | Production | 12h.B.1-4.f | | #DIV/0! | NA | 0.00% | #DIV/0! |
| 7 | Transmission | 12h.B.5.f | | #DIV/0! | TP | #DIV/0! | #DIV/0! |
| 8 | Distribution | 12h.B.6.f | | #DIV/0! | NA | 0.00% | #DIV/0! |
| 9 | General & Intangible | 12h.B.7.f & 12h.B.12.f | | #DIV/0! | W/S | #DIV/0! | #DIV/0! |
| 10 | TOTAL ACCUM. DEPRECIATION | sum lines 7 thru 9 | | #DIV/0! | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | | |
| 11 | Production | (line 1- line 7) | | #DIV/0! | | | #DIV/0! |
| 12 | Transmission | (line 2- line 8) | | #DIV/0! | | | #DIV/0! |
| 13 | Distribution | (line 3 - line 9) | | #DIV/0! | | | #DIV/0! |
| 14 | General & Intangible | (line 4 - line 10) | | #DIV/0! | | | #DIV/0! |
| 15 | TOTAL NET PLANT | sum lines 11 thru 14 | | #DIV/0! | **NP =** | **#DIV/0!** | #DIV/0! |
| | WORKING CAPITAL (Note B) | | | | | | |
| 16 | CWC | 1/8th O&M | | $0 | | | #DIV/0! |
| 17 | Materials & Supplies | Worksheet A, | | #DIV/0! | T | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | | line 3, col. 5 | | 0! | E | V/0! |
| 18 | Prepayments | 12a.B.25 | | #DIV/0! | GP | #DIV/0! |
| 19 | TOTAL WORKING CAPITAL | sum lines 16 thru 18 | | #DIV/0! | | #DIV/0! |
| 20 | RATE BASE | sum lines 15 and 19 | | #DIV/0! | | #DIV/0! |



**Arkansas Electric Cooperative Corporation**
**Formula Rate Template**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | RUS Form 12 Reference | Avg/Total Company Amount | Allocator | Transmission Amount |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| | **OPERATING EXPENSES** | | | | |
| | O&M | | | | |
| 1 | Transmission | 12a.A.8.b + A.17.b | | TE | #DIV/0! | #DIV/0! |
| 2 | Less Account 565 | 12i.A.8.a | | TE | #DIV/0! | #DIV/0! |
| 3 | A&G | 12a.A.14.b + A.20.b | | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | Worksheet B, line 4 | $0 | W/ | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | S | | |
| | Less EPRI & Reg. | | | W | | |
| | Comm. Exp. & Non-safety | Worksheet C, | | / | #DI | |
| 5 | Ad. (Note C) | line 14 | $0 | S | V/0! | #DIV/0! |
| | Plus Transmission | | | W | | |
| | Related Reg. Comm. Exp. | Worksheet C, | | / | #DI | |
| 6 | (Note C) | line 15 | $0 | S | V/0! | #DIV/0! |
| | Transmission Lease | Worksheet C, | | D | 100. | |
| 7 | Payments | line 17 | $0 | A | 00% | $0 |
| 8 | TOTAL O&M | sum lines 1, 3, 6, and 7 less lines 2, 4, 5 | $0 | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note G) | | | | | |
| 9 | Transmission (Note A) | 12h.B.5.c | | | | #DIV/0! |
| | | | | W | | |
| 1 | | 12h.B.7.c & | | / | #DI | |
| 0 | General & Intangible | 12h.B.12.c | | S | V/0! | #DIV/0! |
| 1 | | sum lines 9 & | | | | |
| 1 | TOTAL DEPRECIATION | 10 | $0 | | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note D) | | | | | |
| | LABOR RELATED | | | | | |
| | | | | W | | |
| 1 | | Worksheet D, | | / | #DI | |
| 2 | Payroll | line 1 | $0 | S | V/0! | #DIV/0! |
| | | | | W | | |
| 1 | Highway and | Worksheet D, | | / | #DI | |
| 3 | vehicle | line 2 | $0 | S | V/0! | #DIV/0! |
| | PLANT RELATED | | | | | |
| 1 | | Worksheet D, | | G | #DI | |
| 4 | Property | line 3 | $0 | P | V/0! | #DIV/0! |
| 1 | | Worksheet D, | | N | 0.00 | |
| 5 | Gross Receipts | line 4 | $0 | A | % | $0 |
| 1 | | Worksheet D, | | G | #DI | |
| 6 | Other | line 5 | $0 | P | V/0! | #DIV/0! |
| 1 | Payments in lieu of | Worksheet D, | | G | #DI | |
| 7 | taxes | line 6 | $0 | P | V/0! | #DIV/0! |
| 1 | | sum lines 12 | | | | |
| 8 | TOTAL OTHER TAXES | thru 17 | $0 | | | #DIV/0! |
| 1 | | page 2, line 20 | #DIV/ | | | |
| 9 | RETURN | * WACC | 0! | | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 2 0 | GROSS REV. REQUIREMENT | sum lines 8, 11, 18, and 19 | #DIV/ 0! | | #DIV/0! |

**Southwest Power Pool Zonal ATRR, page 4 of 5**

**Arkansas Electric Cooperative Corporation**
**Formula Rate Template**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| **Line No.** | **Description** | **RUS Form 12 Reference** | **Avg/Total Company Amount** | **Allocator** | | **Transmission Amount** |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | | (5) |
| | **SUPPORTING CALCULATIONS** | | | | | |
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, col. 7 | | | | #DIV/0! |
| 2 | Less transmission plant excluded from SPP rates | Worksheet E, line 4 | | | | $0 |
| 3 | Transmission plant included in SPP rates | line 1 less line 2 | | | | #DIV/0! |
| 4 | Percentage of transmission plant included in SPP Rates | line 4 / line 1 | | | **TP=** | **#DIV/0!** |
| | TRANSMISSION EXPENSES | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5 | Total transmission expenses | page 3, line 1, col. 5 | | | | | $0 |
| 6 | Less transmission expenses included in MISO Ancillary Services (Note F) | 12I.A.2.a / 2.0 | | | | | |
| 7 | Included transmission expenses | line 5 less line 6 | | | | | $0 |
| 8 | Percentage of transmission expenses after adjustment | line 7 / line 5 | | | | | **0.00%** |
| 9 | Percentage of transmission plant included in SPP Rates | line 4 | | | | **TP** | **#DIV/0!** |
| 10 | Percentage of transmission expenses included in SPP Rates | line 8 * line 9 | | | | **TE=** | **#DIV/0!** |
| | WAGES & SALARY ALLOCATOR (W/S) | | $ | Allocator | | | Allocation |
| 11 | Production | Worksheet F, line 4 | $0 | NA | 0.00% | | $0 |
| 12 | Transmission | Worksheet F, line 7 | $0 | TP | #DIV/0! | | #DIV/0! |
| 13 | Distribution | Worksheet F, line 8 | $0 | NA | 0.00% | | $0 |
| 14 | Other | Worksheet F, line 9 | $0 | NA | 0.00% | | $0 |
| 15 | Total | sum lines 11 thru 14 | $0 | | | | #DIV/0! |
| 16 | W/S Allocator | line 15, col. 5 / col. 3 | | | | **W/S=** | **#DIV/0!** |
| | WEIGHTED AVERAGE COST OF CAPITAL (WACC) | | | | | | |
| 17 | Long Term Interest | 12a.A.24.b | | | | | |
| | | | $ | % | Cost (Note E) | | Weighted |
| 18 | Long Term Debt | 12a.B.46 + B.47 + B.52 + | | 0% | 0.00% | | 0.00% |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | B.53 + B.54 | | | | | |
| 1 | | | | 0 | 8.50 | | |
| 9 | Proprietary Capital | 12a.B.39 | | % | % | | 0.00% |
| 2 | | sum lines 18 & | | 0 | | **WACC** | |
| 0 | Total | 19 | $0 | % | | = | **0.00%** |

**Southwest Power Pool Zonal ATRR, page 5 of 5**

**Arkansas Electric Cooperative Corporation**
**Formula Rate Template**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

**NOTES**

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#). References to data from RUS Form 12 are indicated as: #.x.y.z (page,section, line, column).

Note

A SPP transmission plant depreciation expense is calculated in on page 3 by multiplying the SPP gross transmission plant (page 2, line 2) by 2.75%.

B Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on Section B, line 25 in the RUS 12.

C Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, SPP filings, or transmission siting.

D Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

E Cost of long term debt is calculated by dividing the amount shown on page 4, line 17 by the amount shown on page 4, line 18, col. 3. The cost of proprietary capital (ROE) is fixed at 8.50% (which includes a 50-basis point adder for RTO participation) per Docket No. ER16-1546. This ROE is fixed and will not change absent a 205 or 206 filing with the FERC.

F Removes dollar amount of transmission expenses recovered in MISO, 50% of Account No. 561.

G Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

H Revenue requirement for facilities included on Worksheet K and recovered through SPP Schedule 11.

**Arkansas Electric Cooperative Corporation**
**Worksheet A: Materials and Supplies**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | RUS Form 12 Reference | BOY Balance | EOY Balance | Avg/Total Company Amount |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| 1 | Station Transformers and Equipment | RUS Form 12, Part H, Section G, Line 4 | | | #DIV/0! |
| 2 | Line Materials and Supplies | RUS Form 12, Part H, Section G, Line 5 | | | #DIV/0! |
| 3 | Total Materials and Supplies | sum lines 1 & 2 | $0 | $0 | #DIV/0! |

**Arkansas Electric Cooperative Corporation**
**Worksheet B: FERC Fees**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Account | FERC fees recorded to expense during the year | Amount | Brief Description |
|---|---|---|---|---|
| 1 | | FERC fees paid to SPP via Schedule 12 | | |
| 2 | | FERC fees paid to SPP via Schedule 12-FERC | | |
| 3 | | Other FERC fees paid | | |
| 4 | | **Total** | $0 | |

**Arkansas Electric Cooperative Corporation**
**Worksheet C: Other Transmission Expenses**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Account | Description | Source Reference | Amount | Detail |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| | | EPRI Dues | | | |
| 1 | 921.3/930.2 | Electric Power Research Institute (EPRI) Costs/Dues | Company Records | | |
| | | Regulatory Commission Expense (provide a brief but descriptive list of charges) | | | |
| 2 | | Non-Transmission Related proceedings - Legal and Consultants | Company Records | | |
| 3 | | Transmission Related proceedings - Legal and Consultants | Company Records | | |
| 4 | | Other - provide description | Company Records | | |
| 5 | | Other - provide description | Company Records | | |
| 6 | | **Total Regulatory Commission Expense** | sum lines 2 thru 5 | **$0** | |
| | | Non Safety Advertising (provide a brief but descriptive list of charges | | | |
| 7 | 909 | Advertising Expense - Informational & Instructional Advertising | Company Records | | |
| 8 | 912.201 | Advertising Expense - Economic Develop - Commercial & Ind. Mktg | Company Records | | |
| 9 | 913 | Advertising Expense - Sales | Company Records | | |
| 10 | 930.1 | Misc. General Advertising Expenses | Company Records | | |
| 11 | 930.15 | Co-op Advertising | Company Records | | |
| 12 | 930.16 | Image Awareness Advertising | Company Records | | |
| 13 | | **Total Non-safety Advertising Expense** | sum lines 7 thru 12 | **$0** | |
| 14 | | **Total EPRI, Regulatory Commission Expenses, and Non-Safety Advertising** | sum lines 1, 6, and 13 | **$0** | |

| | | | |
|---|---|---|---|
| 15 | Total Transmission Related Regulatory Commission Expense | line 3 | $0 |

Transmission Lease Payments

| | | | |
|---|---|---|---|
| 16a | | | |
| 16b | | | |
| 16c | | | |
| … | | | |
| 17 | **Total Transmission Lease Payments** | sum lines 16a thru 16zz | **$0** |

**Arkansas Electric Cooperative Corporation**
**Worksheet D: Taxes Other than Income Taxes**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | Source Reference | Amount |
|---|---|---|---|
| | (1) | (2) | (3) |
| 1 | Payroll Taxes | Company Records | |
| 2 | Highway & Vehicle Taxes | Company Records | |
| 3 | Property Taxes | Company Records | |
| 4 | Gross Receipts Taxes | Company Records | |
| 5 | Other Taxes (Note A) | Company Records | |
| 6 | Payments in Lieu of Taxes | Company Records | |
| 7 | **Total (Note B)** | sum lines 1 thru 6 | **$0** |

Note

A Please provide a description below of the amounts included:

B Should tie to RUS Form 12 Part A, Section A, line 23, column b, please provide an explanation below if it does not:

C Amounts reported on this worksheet must meet the definition of USofA account 408.1.

D AECC records property taxes directly to each function, except for a small amount of property tax related to General Plant shown above.

E The property tax is for general plant. There are no Gross Receipts tax, no income tax, no highway and vehicle other than that included in property tax (related to General Plant) and no other taxes.

F The bulk of property taxes is recorded directly to O&M Accounts

**Arkansas Electric Cooperative Corporation**
**Worksheet E: Plant Excluded from SPP Rates**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | Source Reference | BOY Amount | EOY Amount | Average Amount | Percent |
|---|---|---|---|---|---|---|
| 1 | Total Transmission Investment | Zonal ATRR, page 2, line 2 | $0 | $0 | $0 | |
| 2 | Transmission Investment in SPP | line 9 | $0 | $0 | $0 | |
| 3 | Other Nonqualifying Transmission Investment | line 1 less line 2 | $0 | $0 | $0 | |
| 4 | Transmission Investment Excluded from SPP (Note A) | line 3 | | | $0 | |
| | **SPP Transmsision Facilitiy Investment** | | | | | |
| | **Zone 1 - AEP** | | | | | |
| 5a | Avoca 161/69 kV Substation | Company Records | | | #DIV/0! | |
| 5b | East Fayetteville 161/69 kV Substation | Company Records | | | #DIV/0! | |
| 5c | Elm Springs 161/69 kV Substation | Company Records | | | #DIV/0! | |
| 5d | Farmington 161/69 kV Substation | Company Records | | | #DIV/0! | |
| 5e | Fulton 115 kV Switching Station | Company Records | | | #DIV/0! | |
| 5f | Fulton to AEP (Couch & Turk) 115 kV TLs | Company Records | | | #DIV/0! | |
| 5g | Fulton to AEP (Couch & Turk) 115 kV TLs (NTC 20015, PID 351, UIDs 10460/10461) | Company Records | | | #DIV/0! | |
| 5h | South Foreman 138/69 kV Substation | Company Records | | | #DIV/0! | |
| … | | | | | #DIV/0! | |
| 6 | **Total Zone 1 Investment** | sum lines 5a thru 5zz | **$0** | **$0** | **#DIV/0!** | #DIV/0! |

**Zone 6 - OGE**

| | | | | | | |
|---|---|---|---|---|---|---|
| 7a | Fitzhugh 161 kV Switching Station | Company Records | | | #DIV/0! | |
| 7b | Fitzhugh to OGE (Altus & Helberg) 161 kV TLs | Company Records | | | #DIV/0! | |
| 7c | VBI North 69 kV Switching Station | Company Records | | | #DIV/0! | |
| … | | | | | #DIV/0! | |
| 8 | **Total Zone 6 Investment** | sum lines 7a thru 7zz | **$0** | **$0** | **#DIV/0!** | #DIV/0! |
| 9 | **Total SPP Investment** | line 6 + line 8 | **$0** | **$0** | **#DIV/0!** | |

Note A: If a zero is reported above, please confirm here in writing that you have no transmission plant that should be excluded from ISO rates.

**Arkansas Electric Cooperative Corporation**
**Worksheet F: Wages and Salaries**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | Source | Amount |
|---|---|---|---|
| | (1) | (2) | (3) |
| | Production | | |
| 1 | Operating/Generation | Company Records | |
| 2 | Maintenance | Company Records | |
| 3 | System Control and Load Dispatching | Company Records | |
| 4 | Total Production | sum lines 1 thru 3 | $0 |
| | Transmission | | |
| 5 | Operations | Company Records | |
| 6 | Maintenance | Company Records | |
| 7 | Total Transmission | sum lines 5 thru 6 | $0 |
| 8 | Distribution | Company Records | |
| 9 | Other (Note A) | Company Records | |
| 10 | Subtotal (Excluding A&G) | sum lines 4, 7, 8 and 9 | $0 |
| 11 | A&G (Note B) | Company Records | |
| 12 | Total Wages & Salaries (Note C) | sum lines 10 thru 11 | $0 |

Note

A Other is to include salaries charged to administer customer accounts 901 - 916 as defined by the USofA.

B Not reported in Zonal ATRR.

C Amount shown must reconcile to the RUS Form 12 Part H, Section J, Line 4. If not, please provide an explanation below:

D The above amounts do not contain any capitalized wages.
The amounts shown on lines 1 through 10 do **not** contain any A&G related wages.

**Arkansas Electric Cooperative Corporation**
**Worksheet G: Revenue Credits**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Account | Transmission Revenue Source | Description | Total Annual Account Balance | Account 454 | Account 456 Schedules 7 & 8 | Account 456 Other |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 1 | 456.XX | Sch 11 PtP | BP Point to Point | | | | |
| 2 | 456.XX | Sch 7 and 8 PtP | Zonal Point to Point | | | | |
| 3 | XX | XX | XX | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| 6 | | | | | | | |
| 7 | | | | | | | |
| 8 | | | | | | | |
| 9 | **Total** | | | **$0** | **$0** | **$0** | **$0** |

**Arkansas Electric Cooperative Corporation**
**Worksheet H: SPP Base Plan Uprgrades**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Description | Source Reference | Amount |
|---|---|---|---|
| | (1) | (2) | (3) |
| | **Fixed Charge Rate (FCR)** | | |
| 1 | Gross Revenue Requirement | ATRR, page 1, line 1 | #DIV/0! |
| 2 | Net SPP Transmission Plant (ATRR, Pg 2, Ln 14) | ATRR, page 2, line 12 | #DIV/0! |
| 3 | Rate of Return | ATRR, page 4, line 20, col. 5 | 0.00% |
| 4 | SPP Tranmission Depreciation Expense | ATRR, page 3, line 9 | #DIV/0! |
| 5 | Gross SPP Transmission Plant | ATRR, page 2, line 2 | #DIV/0! |
| 6 | **Fixed Charge Rate (FCR)** | (line 1-(line 2 * line 3))-line 4) / line 5 | **#DIV/0!** |



**Arkansas Electric Cooperative Corporation**
**Worksheet H: SPP Base Plan Uprgrades**
**Utilizing RUS Form 12 Data**

For the 12 months ended 12/31/

| Line No. | Project | Description | SPP Project ID | SPP Upgrade ID | Upgrade Type | In-Service Date | Investment | Pricing Zone | Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
| 1a | Project 1 | | | | | | | | |
| 1b | Project 2 | | | | | | | | |
| 1c | Project 3 | | | | | | | | |
| 1d | Project 4 | | | | | | | | |
| 1e | … | | | | | | | | |
| 2 | **Total (sum lines 1a - 1zz)** | | | | | | **$0** | | **$0** |

3 Investment Year: 0

4 **PTP Schedule 11 Revenues**

Note

A Revenue Requirement for SPP OATT Related Upgrades including Base Plan Upgrades, Transmission Service Upgrades and Sponsored or Economic Portfolio Upgrades, or any other upgrade type for which a revenue requirement must be supplied by the Transmission Owner in support of cost recovery pursuant to the SPP OATT.

B Point-to-point Schedule 11 revenues are listed on line 4. These revenues are allocated to the upgrades listed below based on revenue requirement.

**Arkansas Electric Cooperative Corporation**
**Worksheet H: SPP Base Plan Uprgrades**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

**Project 1:** FULTON - HOPE 115KV CKT 1

Details

| | | | |
|---|---|---|---|
| Investment | #DIV/0! | Current Year | **0** |
| Service Fiscal Year (yyyy) | | FCR | #DIV/0! |
| Service Fiscal Month (1-12) | 1 | | |
| Annual Depreciation Rate | 2.750% | Annual Depreciation Expense | #DIV/0! |

| Year | Investment Balance | Beginning Balance | Depreciation Expense | Ending Balance | Revenue Requirement | PTP Sch 11 Revenue | Rev. Req. for SPP Allocation |
|---|---|---|---|---|---|---|---|
| 2015 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2016 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2017 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2018 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2019 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2020 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2021 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2022 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2023 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2024 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2025 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2026 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2027 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2028 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2029 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2030 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2031 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2032 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2033 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2034 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2035 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2036 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2037 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | V/0! | V/0! | V/0! | /0! |
| 2038 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2039 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2040 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2041 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2042 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2043 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2044 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2045 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2046 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2047 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2048 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2049 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2050 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2051 | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

**Arkansas Electric Cooperative Corporation**
**Worksheet H: SPP Base Plan Uprgrades**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

**Project 2:**

| Details | | | |
|---|---|---|---|
| Investment | $0 | Current Year | **0** |
| Service Fiscal Year (yyyy) | 2015 | FCR | #DIV/0! |
| Service Fiscal Month (1-12) | | | |
| Annual Depreciation Rate | 2.750% | Annual Depreciation Expense | $0 |

| Year | Investment Balance | Beginning Balance | Depreciation Expense | Ending Balance | Revenue Requirement | PTP Sch 11 Revenue | Rev. Req. for SPP Allocation |
|---|---|---|---|---|---|---|---|
| 2015 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! | |
| 2016 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! | |
| 2017 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! | |
| 2018 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! | |
| 2019 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! | |
| 2020 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2021 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2022 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2023 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2024 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2025 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2026 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2027 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
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| 2030 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2031 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2032 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2033 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2034 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2035 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2036 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2037 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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| 2042 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2043 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2044 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2045 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2046 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2047 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
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| 2050 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
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| 2054 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2055 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2056 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2057 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2058 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |



**Arkansas Electric Cooperative Corporation**
**Worksheet H: SPP Base Plan Uprgrades**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

**Project 3:**

| Details | | | |
|---|---|---|---|
| Investment | $0 | Current Year | **0** |
| Service Fiscal Year (yyyy) | 2015 | FCR | #DIV/0! |
| Service Fiscal Month (1-12) | | | |
| Annual Depreciation Rate | 2.750% | Annual Depreciation Expense | $0 |

| **Investment Year** | **Beginning Balance** | **Depreciation Expense** | **Ending Balanc** | **Revenue Req** | **PTP Sch 11** | **Rev. Req. for SPP Alloc** |
|---|---|---|---|---|---|---|

| | | | e | uire ment | Re ven ue | ation |
|---|---|---|---|---|---|---|
| 2015 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2016 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2017 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2018 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2019 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2020 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2021 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2022 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2023 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2024 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2025 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2026 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2027 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2028 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2029 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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| 2030 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2031 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2032 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2033 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2034 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2035 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2036 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2037 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2038 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2039 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2040 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2041 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2042 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2043 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
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| 2045 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2046 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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| 2047 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2048 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2049 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2050 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2051 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2052 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2053 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2054 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2055 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2056 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2057 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2058 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2059 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2060 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2061 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2062 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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| 2063 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2064 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2065 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |



**Arkansas Electric Cooperative Corporation**
**Worksheet H: SPP Base Plan Uprgrades**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

**Project 4:**

| Details | | | |
|---|---|---|---|
| Investment | $0 | Current Year | **0** |
| Service Fiscal Year (yyyy) | 2015 | FCR | #DIV/0! |
| Service Fiscal Month (1-12) | | | |
| Annual Depreciation Rate | 2.750% | Annual Depreciation Expense | $0 |

| **Investment Year** | **Beginning Balance** | **Depreciation Expense** | **Ending Balance** | **Revenue Requirement** | **PTP Sch 11 Revenue** | **Rev. Req. for SPP Allocation** |
|---|---|---|---|---|---|---|
| 2015 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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|---|---|---|---|---|---|---|
| 2016 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2017 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2018 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2019 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2020 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2021 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2022 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2023 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2024 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2025 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2026 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2027 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2028 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2029 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2030 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2031 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2032 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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| 2035 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2036 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2037 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2038 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2039 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2040 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2041 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2042 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2043 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2044 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2045 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2046 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2047 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 2048 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

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| 2050 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2051 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2052 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2055 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2056 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2058 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2059 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2060 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2061 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2062 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2063 | $0 | $0 | $0 | V/0! | ! | /0! |
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| 2064 | $0 | $0 | $0 | V/0! | ! | /0! |

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| 2065 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

**Arkansas Electric Cooperative Corporation**
**Worksheet I: Depreciation Rates**
**Utilizing RUS Form 12 Data**
For the 12 months ended 12/31/

| Line No. | Account | Description | Monthly Rate | Annual Rate (Note A) |
|---|---|---|---|---|
| | (1) | (2) | (3) | (4) |
| | ***Transmission Plant*** | | | |
| 1 | 352-353 | Transmission Plant Substations | 0.23% | 2.75% |
| 2 | 354-356 | Transmission Plant Lines | 0.23% | 2.75% |
| 3 | ***General Plant*** | | | |
| 4 | 390 | 390 - Structures | 0.17% | 2.00% |
| 5 | 391 | 391 - Furniture | 0.40% | 4.80% |
| 6 | 391 | 391 - Equipment | 0.80% | 9.60% |
| 7 | 392 | 392 - Autos | 1.67% | 20.00% |
| 8 | 393 | 393 - Stores Equipment | 0.42% | 5.00% |
| 9 | 394 | 394 - Tools and Shop Equipment | 0.42% | 5.00% |
| 10 | 395 | 395 - Lab Equipment | 0.42% | 5.00% |
| 11 | 396 | 396 - Power Equipment | 1.25% | 15.00% |
| 12 | 397 | 397 - Communications Equipment | 0.67% | 8.00% |
| 13 | 398 | 398 - Misc. Equipment | 0.50% | 6.00% |

Note

A These rates are fixed per Docket No. ER16-1546 and will not change absent a 205 or 206 filing with the FERC.

**Arkansas Electric Cooperative Corporation**
**Formula Rate Protocols**

## Section I. Applicability

The following Annual Update, Information Exchange, and Challenge Procedures shall apply to Arkansas Electric Cooperative Corporation ("AECC"). The transmission formula rate template and protocols together comprise the filed rate.

## Section II. Annual Updates

A. Beginning July 1, 2016, the Annual Transmission Revenue Requirement derived under AECC's formula rate shall be applicable on and after June 1 of a given year through May 31 of the subsequent year (the "Rate Year").

B. On or before June 1, 2017, and on or before June 1 of each succeeding Rate Year, AECC shall recalculate its Annual Transmission Revenue Requirement, producing the Annual Update for the upcoming Rate Year, and shall provide such information to SPP and cause such information to be posted on the SPP Open Access Same-Time Information System ( "OASIS"). Within ten (10) days of such posting, SPP shall provide notice of such posting via an email exploder list. Interested Parties can subscribe to the SPP Formula Rate Posting Information Notification exploder list on the SPP website.

C. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date." Any delay in the Publication Date will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

D. The Annual Update for the Rate Year shall:

1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;
2. Be based on AECC's Rural Utilities Service ("RUS") Form No. 12. It is the intent of the formula rate, including the supporting explanations and allocations described therein, that each input to the formula rate will be either taken directly from the RUS Form 12 or reconcilable to the RUS Form 12 by the application of clearly identified and supported information. If the RUS Form 12 is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.
3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the formula rate that are not otherwise available in the RUS Form 12;
4. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.E of these protocols) to replicate the calculation of the formula results from the RUS Form 12;
5. Identify any changes in the formula references (page and line numbers) to the RUS Form 12;
6. Identify all material adjustments made to the RUS Form 12 data in determining formula inputs, including relevant footnotes to the RUS Form 12 and any adjustments not shown in an RUS Form 12;
7. Provide underlying data for formula rate inputs that provide greater granularity than is required for the RUS Form 12;

8. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

a. Identify any Accounting Changes, including

i. The initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the revenue requirement;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the formula rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the formula rate;

d. Provide, for each item identified pursuant to items II.D.8.a - II.D.8.c of these protocols, a narrative explanation of the individual impact of such changes on charges billed under the formula rate.

E. AECC shall hold an open meeting among Interested Parties ("Annual Meeting") between the Publication Date and September 1. No less than seven (7) days prior to

such Annual Meeting, AECC shall provide notice on the SPP OASIS of the time, date, and location of the Annual Meeting and SPP shall provide notice of such meeting to the Formula Rate Posting Information Notification email exploder list. AECC shall provide remote access for participation at the Annual Meeting. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual Meeting shall (i) permit AECC to explain and clarify its Annual Update and (ii) provide Interested Parties an opportunity to seek information and clarifications from AECC about the Annual Update.

F. Should AECC have transmission projects that utilize a regional cost sharing mechanism it shall participate in any joint informational meetings held to enable all interested parties to understand how AECC is implementing its formula rates for cost recovery of such projects. Notice of such joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to the Formula Rate Posting Information Notification email exploder list no less than seven (7) days prior to such meetings.

**Section III. Information Exchange Procedures**

Each Annual Update shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until December 1 following the Publication Date (unless such period is extended with the written consent of AECC or by FERC order) to serve reasonable information and document requests on AECC ("Information Exchange Period"). If December 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) the extent or effect of an Accounting Change;

(2) whether the Annual Update fails to include data properly recorded in accordance with these protocols;

(3) the proper application of the formula rate and procedures in these protocols;

(4) the accuracy of data and consistency with the formula rate of the charges shown in the Annual Update;

(5) the prudence of actual costs and expenditures;

(6) the effect of any change to the underlying Uniform System of Accounts or the RUS Form 12; or

(7) any other information that may reasonably have substantive

effect on the calculation of the charge pursuant to the formula. The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. AECC shall make a good faith effort to respond to information and document requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests. AECC shall respond to all information and document requests by no later than January 10 following the Publication Date, unless the Information Exchange Period is extended by AECC or FERC.

C. AECC will cause to be posted on the SPP OASIS all information requests from Interested Parties and AECC's response(s) to such requests; except, however, if responses to information and document requests include material deemed by AECC to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AECC and the requesting party.

D. AECC shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AECC's Annual Update.

**Section IV. Challenge Procedures**

A. Interested Parties shall have until January 31 following the Publication Date (unless such period is extended with the written consent of AECC or by FERC order) to review the inputs, supporting explanations, allocations, and calculations and to notify AECC in writing, which may be made electronically,

of any specific Informal Challenges. The period of time from the Publication Date until January 31 shall be referred to as the Review Period. If January 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

B. A party submitting an Informal Challenge to AECC must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. AECC shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. AECC, and where applicable, the Transmission Provider, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If AECC disagrees with such challenge, AECC will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31, and AECC must respond to all Informal Challenges by no later than February 28, unless the Review Period is extended by AECC or FERC.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

(1) A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

(b) Explain how the action or inaction violates the filed rate formula or protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) The extent or effect of an Accounting Change;

(ii) Whether the Annual Update fails to include data properly recorded in accordance with these protocols;

(iii) The proper application of the formula rate and procedures in these protocols;

(iv) The accuracy of data and consistency with the formula rate of the charges shown in the Annual Update;

(v) The prudence of actual costs and expenditures;

(vi) The effect of any change to the underlying Uniform System of Accounts or the RUS Form 12; or

(vii) Any other information that may reasonably have

substantive effect on the calculation of the charge pursuant to the formula.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(2) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on AECC. Service to AECC must be simultaneous with filing at the Commission. Simultaneous service

can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on AECC's Informational Filing required under Section VI of these protocols.

D. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the charges shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the RUS Form 12; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

E. AECC will cause to be posted all Informal Challenges from Interested Parties and AECC's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by AECC to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AECC and the requesting party.

F. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by

AECC will be reported in the Informational Filing required pursuant to Section VI of these protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these protocols.

G. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of AECC to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on AECC on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as AECC's Informational Filing discussed in Section VI of these protocols. AECC shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

H. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, AECC shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols, in that year's Annual Update. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

I. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AECC to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or

any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

J. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. The following formula rate inputs shall be stated values to be used in the formula rate until changed pursuant to a Federal Power Act section 205 or section 206 proceeding: (i) rate of return on equity; and (ii) depreciation and/or amortization rates.

K. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts or the RUS Form 12, shall first raise the matter with AECC in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to Annual Updates**

Any changes to the data inputs, including but not limited to revisions to AECC's RUS Form 12, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

Interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a ("FERC's Interest Rate"), and interest on any surcharge shall be calculated using the lower of FERC's Interest Rate or AECC's short-term borrowing rate, if applicable.

**Section VI. Informational Filings**

A. By March 15 of each year, AECC shall submit to FERC an informational filing ("Informational Filing") of its Annual Update. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that AECC has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Actual Transmission Revenue Requirement and rates under review; and (4) the extent of accounting changes that affect formula rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, SPP shall provide notice of the Informational Filing via the Formula Rate Posting Information Notification email exploder list and by posting the docket number assigned to each AECC's Informational Filing on the SPP OASIS.

B. Any challenges to the implementation of the AECC formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

# ADDENDUM 39 TO ATTACHMENT H

## Western Farmers Electric Cooperative, Inc.

## Part 1

**Index**

**Western Farmers Electric Cooperative, Inc.**

**INDEX**

**Year Ending December 31,**

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|---|---|---|
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| **2** | **Schedule 1** | **Schedule 1 Revenue Requirements** |
| **3** | **Worksheet A** | **Calculation of Rate Base** |
| **4** | **Worksheet B** | **O&M, Depreciation, and Return Expenses** |
| **5** | **Worksheet C** | **Capital Structure & Rate of Return based on Return on Equity** |
| **6** | **Worksheet D** | **Network Demand** |
| **7** | **Worksheet E** | **Allocation Factors** |
| **8** | **Worksheet F** | **General Input Section** |
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| **13** | **Worksheet K** | **Wage Input & Functionalization** |
| **14** | **Worksheet L** | **Annual Depreciation Expense** |
| **15** | **Worksheet M** | **Transmission Plant Functionalization** |
| **16** | **Worksheet N** | **Other Operating Revenue** |
| **17** | **Worksheet O** | **Construction Work in Process (CWIP)** |
| **18** | **Worksheet P** | **Construction Completed Not Classified** |
| **19** | **Worksheet Q** | **Plant Held for Future Use** |

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|---|---|---|
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| **22** | **Worksheet T** | **Qualified Lines** |
| **23** | **Worksheet U** | **Account 575/576 Expenses** |

| | |
|---|---|
| **Key** | **Denotes input values** |

**Summary ATRR**

**Western Farmers Electric Cooperative, Inc.**

**Summary of Total ATRR Revenue Requirement**

**Year Ending December 31,**

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| **Line No.** | **Account Number** | **Description** | **Reference** | **Total Company** | **Allocation Factor** | **Allocation %** | **Transmission ATRR** |
| **1** | | **A. Gross Revenue Requirement for Network Service** | | | | | |
| **2** | | **Transmission Costs** | **Worksheet B, Line 41, Col J** | | | | **#DIV/0!** |
| **3** | | **Revenue Credits- Operating** | | | | | |
| **4** | **451** | **Misc Svc Revenue** | **Worksheet N, Line 40 Column E** | **$ -** | **T-Plant** | **#DIV/0!** | **#DIV/0!** |
| **5** | **454** | **Rent from Property** | **Worksheet N, Line 41 Column E** | **$ -** | **T-Plant** | **#DIV/0!** | **#DIV/0!** |
| **6** | **456** | **Other Elect Rev- Production** | **Worksheet N, Line 42 Column E** | **$ -** | **Direct Zero** | **0.0 %** | **$ -** |
| **7** | **456** | **Other Elect Rev- Wheeling (NITS)** | **Worksheet N, Line 43 Column E** | **$ -** | **Direct Zero** | **0.0 %** | **$ -** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 8 | 456 | Other Elect Rev-NM Coops A&G | Worksheet N, Line 44 Column E | $ - | Direct Zero | 0.0 % | $ - |
| 9 | 456 | Sch 1-NITS | Worksheet N, Line 45 Column E | $ - | Direct Zero | 0.0 % | $ - |
| 10 | 456 | Sch 1-P2P | Worksheet N, Line 46 Column E | $ - | Direct Zero | 0.0 % | $ - |
| 11 | 456 | Sch 7 & 8 P2P | Worksheet N, Line 47 Column E | $ - | Direct 100 | 100.0% | $ - |
| 12 | 456 | Sch 11 P2P | Worksheet N, Line 48 Column E | $ - | Direct 100 | 100.0% | $ - |
| 13 | 456 | Direct Assigned Revenues | Worksheet N, Line 49 Column E | $ - | Direct 100 | 100.0% | $ - |
| 14 | 459 | Renewable Energy Credits | Worksheet N, Line 50 Column E | $ - | Direct Zero | 0.0 % | $ - |
| 15 | | Revenue Credits-Operating | Subtotal | $ - | | | #DIV/0! |
| 16 | | Revenue Requirement before SPP Adj and Prior Yr corrections | Line 2 + Line 15 | | | | #DIV/0! |
| 17 | | SPP Upgrades | -Worksheet H, Line 161, Col T | | | | #DIV/0! |
| 18 | | Adjustments to SPP Regional Projects | Worksheet I, Line 12, Col J | | | | $ - |
| 19 | | Reconciliation - Adjustment for Prior Year Corrections | Worksheet I, Line 6, Col J | | | | $ - |
| 2 | | Sum | Sum(Line 16 Thru Line 18) | | | | #DIV/0! |

| | | | |
|---|---|---|---|
| 20 | | | |
| 21 | **Network Transmission Load (MW)** | **Worksheet D, Line 14, Column C** | **-** |
| 22 | **B. Point-To-Point Service** | | |
| 23 | **Annual Point-to-Point Cost ($/MW-Yr)** | **Line 20 / Line 21** | **#DIV/0!** |
| 24 | **Monthly Point-to-Point ($/MW-Mo)** | **Line 23 / 12** | **#DIV/0!** |
| 25 | **Weekly Point-to-Point ($/MW-Week)** | **Line 23 / 52** | **#DIV/0!** |
| 26 | **Daily On-Peak Point-to-Point ($/MW-Day)** | **Line 23 / 260** | **#DIV/0!** |
| 27 | **Daily Off-Peak Point-to-Point ($/MW-Day)** | **Line 23 / 365** | **#DIV/0!** |
| 28 | **Hourly On-Peak Point-to-Point ($/MWh)** | **Line 23 / 4160** | **#DIV/0!** |
| 29 | **Hourly Off-Peak Point-to-Point ($/MWh)** | **Line 23 / 8760** | **#DIV/0!** |

**Page No.**

**Schedule 1**

**Western Farmers Electric Cooperative, Inc.**

**Schedule 1 Revenue Requirements**

**Year Ending December 31,**

| A | B | C | D | E |
|---|---|---|---|---|
| **Line No.** | **Account Number** | **Description** | **Reference** | **Amount** |
| **1** | | **A, Schedule 1: Annual Revenue Requirement** | | |
| **2** | | **Schedule 1 expenses** | **Worksheet B, Line 41 Col L** | **#DIV/0!** |
| **3** | | **Adjustments** | | |
| **4** | | **Transmission Service Studies** | **Worksheet F, Line 5 Col G** | **$ -** |
| **5** | | **Generation Interconnection Studies** | **Worksheet F, Line 6 Col G** | **$ -** |
| **6** | | **Regional Planning & Standards development** | **Worksheet F, Line 7 Col G** | **$ -** |
| **7** | | **NERC Assessment Fee** | **Worksheet F, Line 8 Col G** | **$ -** |
| **8** | | **FERC Assessment Fee** | **Worksheet F, Line 9 Col G** | **$ -** |
| **9** | | **SPP Schedule 1 Charges** | **Worksheet F, Line 10 Col G** | **$ -** |
| **10** | **561.0040** | **SPP Schedule 1A Charges** | **Worksheet F, Line 11 Col G** | **$ -** |

| | | | | |
|---|---|---|---|---|
| **11** | | **Schedule 1-Adjustment** | **Worksheet F, Line 12 Col G** | **$ -** |
| **12** | **456.7017** | **Sch 1-P2P Revenues** | **-Worksheet N, Line 46 Column E** | **$ -** |
| **13** | | **Revenue Credits** | **Subtotal** | **$ -** |
| **14** | | **Total** | **Line 2 - Line 13** | **#DIV/0!** |
| **15** | | **Less: Revenue Credit for transmission service not included in the divisor** | **Worksheet F, Line 13 Col G** | **$ -** |
| **16** | | **Schedule 1 True-Up adjustments (if any)** | **Worksheet F, Line 14 Col G** | **$ -** |
| **17** | | **Net Schedule 1 Revenue Requirement for Zone** | | **#DIV/0!** |
| **18** | | **Network Transmission Load (MW)** | **Worksheet D, Line 14, Column C** | **-** |
| | | **B. Schedule 1 Rate Calculations** | | |
| **19** | | **Annual Point-to-Point Cost ($/MW-Yr)** | **Line 17 / Line 18** | **#DIV/0!** |
| **20** | | **Monthly Point-to-Point ($/MW-Mo)** | **Line 19 / 12** | **#DIV/0!** |
| **21** | | **Weekly Point-to-Point ($/MW-Week)** | **Line 19 / 52** | **#DIV/0!** |
| **22** | | **Daily On-Peak Point-to-Point ($/MW-Day)** | **Line 19 / 260** | **#DIV/0!** |
| **23** | | **Daily Off-Peak Point-to-Point ($/MW-Day)** | **Line 19 / 365** | **#DIV/0!** |
| **24** | | **Hourly On-Peak Point-to-Point ($/MWh)** | **Line 19 / 4160** | **#DIV/0!** |
| **25** | | **Hourly Off-Peak Point-to-Point ($/MWh)** | **Line 19 / 8760** | **#DIV/0!** |

**Worksheet A**

**Western Farmers Electric Cooperative, Inc.**

**Calculation of Rate Base**

**Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account Number** | **Description** | **Reference** | **Beginning of Year** | **End of Year** | **Total Company** | **Allocation Factor** | **ATRR Allocation %** | **Transmission** | **Schedule 1 Allocation %** | **Schedule 1** |
| **1** | | **Plant in Service** | | | | | | | | | |
| **2** | **301-303** | **Intangible Plant** | **Worksheet F Line 77, Columns E thru G** | **$ -** | **$ -** | **$ -** | **T-Wage** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| **3** | **310** | **Steam Production Plant** | **Worksheet F Line 78, Columns E thru G** | **$ -** | **$ -** | **$ -** | **Direct Zero** | **0.0 %** | **$ -** | | |
| | **32** | **Nuclear Production** | **Worksheet F Line 79,** | **$** | **$** | **$** | **Direct** | **0.0** | **$** | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **4** | **0** | **Plant** | **Columns E thru G** | **-** | **-** | **-** | **Zero** | **%** | **-** |
| **5** | **330** | **Hydro Production Plant** | **Worksheet F Line 80, Columns E thru G** | **$ -** | **$ -** | **$ -** | **Direct Zero** | **0.0 %** | **$ -** |
| **6** | **340** | **Other Production Plant** | **Worksheet F Line 81, Columns E thru G** | **$ -** | **$ -** | **$ -** | **Direct Zero** | **0.0 %** | **$ -** |
| **7** | | **Total Production Plant** | **Subtotal** | **$ -** | **$ -** | **$ -** | | **#DIV/0!** | **$ -** |
| **8** | **350** | **Land and Land Rights** | **Worksheet F Line 83, Columns E thru G** | **$ -** | **$ -** | **$ -** | **T-Tran Stations** | **#DIV/0!** | **#DIV/0!** |
| **9** | **352** | **Structures and Improvements** | **Worksheet F Line 84, Columns E thru G** | **$ -** | **$ -** | **$ -** | **T-Tran Stations** | **#DIV/0!** | **#DIV/0!** |
| **10** | **353** | **Station Equipment** | **Worksheet F Line 85, Columns E thru G** | **$ -** | **$ -** | **$ -** | **T-Tran Stations** | **#DIV/0!** | **#DIV/0!** |
| **11** | **354-359** | **Other Transmission Plant** | **Worksheet F Line 86, Columns E thru G** | **$ -** | **$ -** | **$ -** | **T-Tran Lines** | **#DIV/0!** | **#DIV/0!** |
| **12** | | **Transmission Plant** | **Subtotal** | **$ -** | **$ -** | **$ -** | | **#DIV/0!** | **#DIV/0!** |
| **13** | **360** | **Land and Land Rights** | **Worksheet F Line 88, Columns E** | **$ -** | **$ -** | **$ -** | **Direct Zer** | **0.0 %** | **$ -** |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | thru G | | | | o | | | | | |
| 14 | 361 | Structures and Improvements | Worksheet F Line 89, Columns E thru G | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | | | |
| 15 | 362 | Station Equipment | Worksheet F Line 90, Columns E thru G | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | | | |
| 16 | 363-374 | Other Distribution Plant | Worksheet F Line 91, Columns E thru G | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | | | |
| 17 | | Total Distribution Plant | Subtotal | $ - | $ - | $ - | | #DIV/0! | $ - | | | |
| 18 | 380-386 | RTO/ISO Plant | Worksheet F, Line 93, Columns E thru G | $ - | $ - | $ - | Direct 100 | 100.0% | $ - | | | |
| 19 | 389-399.1 | Total General Plant | Worksheet F, Line 94, Columns E thru G | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 20 | | Gross Electric Plant in Service | Subtotal | $ - | $ - | $ - | | #DIV/0! | #DIV/0! | | #DIV/0! | |
| 21 | 105 | Electric Plant Held For Future Use | Worksheet F, Line 98 Col E thru G and Worksheet Q, Line 14, Col G | $ - | $ - | $ - | Direct | | $ - | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 22 | 106 | Completed Construction Not Classified | Worksheet F, Line 99 Col E thru G And Worksheet P, Line 94, Col F | $ - | $ - | $ - | Direct | | $ - |
| 23 | 114 | Acquisition Adjustment | Worksheet F, Line 100 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - |
| 24 | 107 | Construction Work in Progress | Worksheet F, Line 103 Col E thru G and Worksheet O, Line 89 Col L | $ - | $ - | $ - | Direct | | $ - |
| 25 | | Utility Plant | Sum | $ - | $ - | $ - | | #DIV/0! | #DIV/0! |
| 26 | | Accumulated Depreciation | | | | | | | |
| 27 | 108.1 | Depr Rsv of Steam Plant | Worksheet F, Line 106 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - |
| 28 | 108.2 | Depr Rsv of Nuclear Plant | Worksheet F, Line 107 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - |
| 29 | 108.3 | Depr Rsv of Hydraulic Plant | Worksheet F, Line 108 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - |
| 3 | 10 | Depr Rsv of | Worksheet F, Line 109 | $ | $ | $ | Direct | 0.0 | $ |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 8.4 | Other Prod Plant | Col E thru G | - | - | - | Zero | % | - | | |
| 31 | | Total Production Reserve | Sum | $ - | $ - | $ - | | #DIV/0! | $ - | | $ - |
| 32 | 10 8.5 | 108.5 Depreciation of Transmission Plant | Worksheet F, Line 110 Col E thru G | $ - | $ - | $ - | T-Trans Plant | #DIV/0! | #DIV/0! | | |
| 33 | 10 8.6 | 108.6 Depreciation of Distribution Plant | Worksheet F, Line 111 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - | | |
| 34 | 10 8.7 | 108.7 Depreciation of General Plant | Worksheet F, Line 112 Col E thru G | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 35 | 10 8.8 | 108.8 Retirement Work in Progress | Worksheet F, Line 113 Col E thru G | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 36 | 11 1 | 111 Amort of Electric Plant in Service | Worksheet F, Line 114 Col E thru G | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 37 | 11 5 | 115 Amort of Acquisition Adj | Worksheet F, Line 115 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - | | |
| 38 | | Total Accumulated Depreciation | Sum | $ - | $ - | $ - | | #DIV/0! | #DIV/0! | | #DIV/0! |
| 3 | | Total Net Plant in | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | Service | | | | | | |
| 40 | Net Intangible Plant | Line 2 - Line 36 | $ - | $ - | $ - | #DIV/0! | #DIV/0! |
| 41 | Net Production Plant | Line 7 - Line 31 | $ - | $ - | $ - | $ - | $ - |
| 42 | Net Transmission Plant | Line 12 + Line 18 - Line 32 | $ - | $ - | $ - | #DIV/0! | $ - |
| 43 | Net Distribution Plant | Line 17 - Line 33 | $ - | $ - | $ - | $ - | $ - |
| 44 | Net General Plant | Line 19 - Line 34 | $ - | $ - | $ - | #DIV/0! | #DIV/0! |
| 45 | Net Completed Construction Not Classified | Line 22 | $ - | $ - | $ - | $ - | $ - |
| 46 | Retirement work in progress | - Line 35 | $ - | $ - | $ - | #DIV/0! | #DIV/0! |
| 47 | Total Net Plant in Service | Sum | $ - | $ - | $ - | #DIV/0! | #DIV/0! |
| 48 | Adjustments to Rate Base | | | | | | |
| 49 | Plant Held for Future | Line 21 | $ - | $ - | $ - | $ - | $ - |
| 50 | Net Acquisition Adjustment | Line 23 - Line 37 | $ - | $ - | $ - | $ - | |
| 51 | CWIP | Line 24 | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | |
| 52 | | Working Capital | | | | | | | | |
| 53 | | Total Transmission O&M Costs | Worksheet B, Line 29, Columns G and J | | | $ - | | | #DIV/0! | #DIV/0! |
| 54 | | Billing Lag in Days | Worksheet F, Line 1 Col G | | | 45 | | | 45 | 45 |
| 55 | | Working Capital | Line 53 * Line 54 / 365 | | | $ - | | | #DIV/0! | #DIV/0! |
| 56 | 165 | Prepayments | Worksheet F, Line 64, Col's E Thru G | $ - | $ - | $ - | T-Plant | #DIV/0! | #DIV/0! | #DIV/0! |
| 57 | 151 | M&S Coal | Worksheet F, Line 118 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | $ - |
| 58 | 151 | M&S Other Fuel | Worksheet F, Line 119 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | $ - |
| 59 | 154 | M&S Production Plant Parts | Worksheet F, Line 120 Col E thru G | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | $ - |
| 60 | 154 | M&S Station Transformers & Equipment | Worksheet F, Line 121 Col E thru G | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | 15 | M&S Line Materials | Worksheet F, Line 122 Col E thru | $ - | $ - | $ - | T-Tran | #DIV | #DIV/0! | #DIV/0! |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **1** | **4** | **& Supplies** | **G** | | | | **Lines** | **/0!** | | |
| **6 2** | **15 6** | **M&S Other** | **Worksheet F, Line 123 Col E thru G** | **$ -** | **$ -** | **$ -** | **T-Plant** | **#DIV /0!** | **#DIV/0!** | **#DIV /0!** |
| **6 3** | | **Materials and Supplies** | **Sum** | **-** | **-** | **-** | | | **#DIV/0!** | **#DIV /0!** |
| **6 4** | | **Rate Base** | **Total** | | | **$ -** | | **#DIV /0!** | **#DIV/0!** | **#DIV /0!** |

**Note:**

**A. Acquisition adjustments will not be used in the calculation of ATRR absent Commission approval through a 205 or 206 filing.**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | **Worksheet B** |
| | | | | | | | | | | | | | | |
| | **Western Farmers Electric Cooperative, Inc.** | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | **O&M, Depreciation, and Return Expenses** | | | | | | | | | | | | | |
| | **Year Ending December 31,** | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** | **K** | **L** | | |
| | **Line No.** | **Account Number** | **Description** | **Reference** | **Lines** | **Stations** | **Total Company** | **Allocation Factor** | **Allocation %** | **Transmission** | **Schedule 1 Allocation %** | **Schedule 1** | | |
| | **1** | | **Transmission Operation & Maintenance Expenses** | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | **2** | **560** | **Supervision and Engineering** | **Worksheet G, Line 1 Cols D Thru F** | **$ -** | **$ -** | **$ -** | **T-Tran Plant** | **#DIV/0!** | **#DIV/0!** | | | | |
| | **3** | **561** | **Load Dispatching** | **Worksheet G, Line 2 Cols D and F** | **$ -** | **$ -** | **$ -** | **Direct Zero** | **0.0 %** | **$ -** | **100.0 %** | **$ -** | | |
| | **4** | **562** | **Station Expenses** | **Worksheet G, Line 3 Cols E Thru F** | **$ -** | **$ -** | **$ -** | **T-Tran Stations** | **#DIV/0!** | **#DIV/0!** | | | | |
| | **5** | **563** | **Overhead Line Expenses** | **Worksheet G, Line 4 Cols D and F** | **$ -** | **$ -** | **$ -** | **T-Tran Lines** | **#DIV/0!** | **#DIV/0!** | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 6 | 564 | Underground Line Expenses | Worksheet G, Line 5 Cols D and F | $ - | $ - | $ - | T-Tran Lines | #DIV/0! | #DIV/0! | | | | |
| | 7 | 566 | Miscellaneous Expenses | Worksheet G, Line 6 Cols D Thru F | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! | | | | |
| | 8 | 565 | Transmission of Electricity by others | Worksheet G, Line 8 Cols D and F | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - | | | | |
| | 9 | 567 | Rents | Worksheet G, Line 9 Cols D Thru F | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! | | | | |
| | 10 | 568 | Supervision and Engineering | Worksheet G, Line 11 Cols D Thru F | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! | | | | |
| | 11 | 569 | Structures | Worksheet G, Line 12 Cols E Thru F | | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! | | | | |
| | 12 | 570 | Station Equipment | Worksheet G, Line 13 Cols E Thru F | | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! | | | | |
| | 13 | 571 | Overhead Lines | Worksheet G, Line 14 Cols D and F | $ - | | $ - | T-Tran Lines | #DIV/0! | #DIV/0! | | | | |
| | 14 | 572 | Underground Lines | Worksheet G, Line 15 Cols D and F | $ - | | $ - | T-Tran Lines | #DIV/0! | #DIV/0! | | | | |
| | 15 | 573 | Miscellaneous Transmission Plant | Worksheet G, Line 16 Cols D Thru F | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! | | | | |
| | 16 | 575.1-.8 | RTO/ISO Expense - Operation | Worksheet U, Line 2 Cols D and F | | | $ - | Direct | | $ - | | | | |
| | 17 | 576. | RTO/ISO Expense - Maintenance | Worksheet U, Line 4 Cols D and F | | | $ - | Direct | | $ - | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 1-.5 | | | | | | | | | | | | |
| | 18 | | Transmission O&M | Subtotal | $ - | $ - | $ - | | | #DIV/0! | | $ - | | |
| | | | | | | | | | | | | | | |
| | 19 | 901-905 | Customer Accounting | Worksheet F, Line 30 Col G | | | $ - | Direct Zero | 0.0 % | $ - | | | | |
| | 20 | 907-910 | Customer Services & Information | Worksheet F, Line 31 Col G | | | $ - | Direct Zero | 0.0 % | $ - | | | | |
| | 21 | 911-916 | Sales | Worksheet F, Line 32 Col G | | | $ - | Direct Zero | 0.0 % | $ - | | | | |
| | 22 | | Customer Related Expense | Subtotal | | | $ - | | | $ - | | $ - | | |
| | | | | | | | | | | | | | | |
| | 23 | | <u>Administrative & General Expense</u> | | | | | | | | | | | |
| | 24 | 920-931 | Admin and General Operations Expense | Worksheet F, Line 33 Col G Less Account 928 | | | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| | 25 | 928 | SPP Commission and Regulatory Expenses | Worksheet R, Line 10, Col F | | | $ - | Direct 100 | 100.0 % | $ - | | | | |
| | | | Non-SPP | Worksheet | | | $ | | 0.0 | $ | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 26 | 928 | Commission and Regulatory Expenses | R, Line 10, Col E | | | - | Direct Zero | % | - | | | | |
| | 27 | 935 | Maintenance Expense General Plant | Worksheet F, Line 40 Col G | | | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| | 28 | | Total A&G Expenses | Subtotal | | | $ - | | | #DIV/0! | | #DIV/0! | | |
| | | | | | | | | | | | | | | |
| | 29 | | Subtotal O&M | Line 18 + Line 22 + Line 28 | | | $ - | | | #DIV/0! | | #DIV/0! | | |
| | | | | | | | | | | | | | | |
| | | | | | | | Total Company | | | | | | | |
| | 30 | | <u>Depreciation Expense</u> | | | | | | | | | | | |
| | 31 | 403 | Depreciation Expense-Production | Worksheet L, Line 14, Col G | | | $ - | Direct Zero | 0.0% | $ - | | | | |
| | 32 | 403 | Depreciation Expense-Trans Substations | Worksheet L, Line 14, Col H | | | #DIV/0! | T-Tran Stations | #DIV/0! | #DIV/0! | | | | |
| | 33 | 403 | Depreciation Expense-Tran Lines | Worksheet L, Line 14, Col I | | | #DIV/0! | T-Tran Lines | #DIV/0! | #DIV/0! | | | | |
| | 34 | 403 | Depreciation Expense-Distribution | Worksheet L, Line 14, Col J | | | $ - | Direct Zero | 0.0% | $ - | | | | |
| | 35 | 403 | Depreciation Expense-General | Worksheet L, Line 14, Col K | | | $ - | T-Wage | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| | 36 | | Retirement Work in Process | Worksheet L, Line 14, Col L | | | $ - | T-Wage | #DIV/0! | | #DIV/0! | #DIV/0! | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **37** | | **Amort of Intangible Plant** | **Worksheet L, Line 14, Col M** | | | **$ -** | **T-Wage** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |
| | **38** | | **Total Depreciation & Amortization** | | | | **#DIV/0!** | | | **#DIV/0!** | | **#DIV/0!** | |
| | | | | | | | | | | | | | |
| | **39** | | **Taxes** | **Worksheet F, Line 44 Col G** | | | **$ -** | **T-Tran Plant** | **#DIV/0!** | **#DIV/0!** | | | |
| | **40** | | **Return** | **Worksheet C, Line 7, Col I** | | | | | | **#DIV/0!** | | **#DIV/0!** | |
| | | | | | | | | | | | | | |
| | **41** | | **Revenue Requirement** | **Line 29 + Line 38 + Line 39 + Line 40** | | | | | | **#DIV/0!** | | **#DIV/0!** | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | **Worksheet C** |
| | | | | | | | | | | | | |
| **Western Farmers Electric Cooperative, Inc.** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| **Capital Structure & Rate of Return based on Return on Equity** | | | | | | | | | | | | |
| **Year Ending December 31,** | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** | | |
| | **Line No** | **Description** | **Reference** | **Total Co EoY** | **Cap Str Weight** | **Target Capital Str** | **Interest, Margin or Annual Cost** | **Cost of Capital** | **Weighted Rate of Return** | **Schedule 1** | | |
| | | | | | | | | | | | | |
| | **1** | **Capital Structure & Return** | | | | | | | | | | |
| | **2** | **Total Long Term Debt** | **Worksheet F, Line 70, Col G and Line 45, Col G** | **$ -** | **#DIV/0!** | **#DIV/0!** | **$ -** | **#DIV/0!** | **#DIV/0!** | | | |
| | **3** | **Notes Payable** | **Worksheet F, Line 72, Col G and Line 47, Col G if balance is positive.** | **$ -** | **#DIV/0!** | **#DIV/0!** | **$ -** | **0.0 %** | **#DIV/0!** | | | |
| | **4** | **Total Margins and Equities** | **Worksheet F, Line 69, Col G ROE is from Worksheet F Line 3** | **$ -** | **#DIV/0!** | **#DIV/0!** | | **9.3 %** | **#DIV/0!** | | | |
| | **5** | **Total Capitalization** | **Subtotal** | **$ -** | **#DIV/0!** | | **$ -** | | **#DIV/0!** | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | **ATRR** | **Schedule 1** | | |
| | **6** | **Rate Base** | **Worksheet A, Line 64, Col J and L** | | | | | | **#DIV/0!** | **#DIV/0!** | | |
| | **7** | **Return** | **Line 5 * Line 6** | | | | | | **#DIV/0!** | **#DIV/0!** | | |
| | | | | | | | | | | | | |
| | **8** | **Notes:** | | | | | | | | | | |
| | **9** | **A. The cost of capital for Total Margins and Equities and the floor is fixed and cannot be changed absent Commission approval through a Section 205 or 206 filing.** | | | | | | | | | | |
| | **10** | **B. The cost of capital for Total Margins and Equities reflects a 50 basis point incentive adder per the commission's order in Docket No. ER16-177.** | | | | | | | | | | |

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|---|---|---|---|---|---|
| | | | | | **Worksheet D** |
| **Western Farmers Electric Cooperative, Inc.** | | | | | |
| **Network Demand** | | | | | |
| **Year Ending December 31,** | | | | | |
| **A** | **B** | **C** | | | |
| **Line No** | **Description** | **Network Load (MW)** | | | |
| **1** | **January** | | | | |
| **2** | **February** | | | | |
| **3** | **March** | | | | |
| **4** | **April** | | | | |
| **5** | **May** | | | | |
| **6** | **June** | | | | |
| **7** | **July** | | | | |
| **8** | **August** | | | | |
| **9** | **September** | | | | |
| **10** | **October** | | | | |
| **11** | **November** | | | | |
| **12** | **December** | | | | |
| **13** | **Total (MW-Mo)** | **0** | | | |
| **14** | **Average (MW-Mo)** | **0** | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | **Worksheet E** |
| **Western Farmers Electric Cooperative, Inc.** | | | | | | | | |
| | | | | | | | | |
| **Allocation Factors** | | | | | | | | |
| **Year Ending December 31,** | | | | | | | | |
| | | | | | | | | |
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | | |
| **Line No.** | **Description** | **Reference** | **Total** | **Allocation Factor** | **ATRR Allocated** | **Schedule 1 Allocated** | | |
| **1** | **Production Wages** | **Worksheet K, Line 254, Col G** | **$ -** | **0.0%** | **$ -** | | | |
| **2** | **Transmission Wages & Salaries** | **Worksheet K, Line 254, Col H** | **$ -** | **#DIV/0!** | **#DIV/0!** | | | |
| **3** | **561 Load Dispatch Wages & Salaries** | **Worksheet K, Line 254, Col N** | **$ -** | | **$ -** | **$ -** | | |
| **4** | **Distribution Wages & Salaries** | **Worksheet K, Line 254, Col I** | **$ -** | **0.0%** | **$ -** | | | |
| **5** | **Customer Accounting** | **Worksheet K, Line 254, Col J** | **$ -** | **0.0%** | **$ -** | | | |
| **6** | **Customer Service** | **Worksheet K, Line 254, Col K** | **$ -** | **0.0%** | **$ -** | | | |
| **7** | **Customer Sales** | **Worksheet K, Line 254, Col L** | **$ -** | **0.0%** | **$ -** | | | |
| **8** | | **Sum** | **$ -** | | **#DIV/0!** | **$ -** | | |
| **9** | **T-Wage** | | | | **#DIV/0!** | **#DIV/0!** | | |
| | | | | | | | | |
| **10** | **Step Up Transformers** | **Worksheet M, Line 45, Col G** | **#DIV/0!** | **0.0%** | **#DIV/0!** | | | |
| **11** | **Transmission Substations** | **Worksheet M, Line 45, Col H** | **#DIV/0!** | **0.0%** | **#DIV/0!** | | | |
| **12** | **350-353 Transmission Stations** | **Sum** | **#DIV/0!** | | **#DIV/0!** | | | |
| **13** | **T-Tran Stations** | | | | **#DIV/0!** | | | |
| | | | | | | | | |
| **14** | **Generator Leads** | **Worksheet M, Line 45, Col I** | **#DIV/0!** | **0.0%** | **#DIV/0!** | | | |
| **15** | **Tran Lines-345 kV** | **Worksheet M, Line 45, Col J** | **#DIV/0!** | **0.0%** | **#DIV/0!** | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **16** | **Tran Lines-138 kV** | **Worksheet M, Line 45, Col K and Worksheet T Line 291 Col E** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | | | |
| **17** | **Tran Lines- 69 kV** | **Worksheet M, Line 45, Col L and Worksheet T Line 292 Col E** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | | | |
| **18** | **Transmission Lines** | **Calculated Weighted Average** | **#DIV/0!** | | **#DIV/0!** | | | |
| **19** | **T-Tran Lines** | | | | **#DIV/0!** | | | |
| | | | | | | | | |
| **20** | **Transmission Qualifying Plant** | **Worksheet A, Line 12 Col G and J** | **$ -** | | **#DIV/0!** | | | |
| **21** | **T-Tran Plant** | | | | **#DIV/0!** | **#DIV/0!** | | |
| | | | | | | | | |
| **22** | **Plant in Service** | **Worksheet A, Line 20 Col G and J** | **$ -** | | **#DIV/0!** | | | |
| **23** | **T-Plant** | | | | **#DIV/0!** | **#DIV/0!** | | |
| **24** | **Completed Construction, not Classified** | **Worksheet F, Column G Line 99 and Worksheet P Line 94 Col F** | **$ -** | | **$ -** | | | |
| **25** | **T-Completed** | | | | **100.0%** | | | |
| | | | | | | | | |
| **26** | **Direct Zero** | **Fixed allocation** | | | **0.0%** | | | |
| **27** | **Direct 100** | **Fixed allocation** | | | **100.0%** | | | |

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| | | | | | | | | **Worksheet F** |
| | | | | | | | | |
| | | | | | | | | |
| **Western Farmers Electric Cooperative, Inc.** | | | | | | | | |
| | | | | | | | | |
| **General Input Section** | | | | | | | | |
| **Year Ending December 31,** | | | | | | | | |
| | | | | | | | | |
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | | |
| **Line No.** | **Account Number** | **Description** | **Reference** | **BoY** | **EoY** | **Value or Amount $** | | |
| **1** | | **Billing Lag in days** | **Industry Standard** | | | **45** | | |
| **2** | | **CWIP to included in Rate Base** | **ER16-1774 Settlement** | | | **50%** | | |
| **3** | | **Return on Equity** | **ER16-1774 Settlement** | | | **9.27%** | | |
| **4** | | **Target Equity Floor** | **ER16-1774 Settlement** | | | **35.24%** | | |
| | | | | | | | | |
| | | | | | | **Year End r 31,** | | |
| **5** | **561.60** | **Transmission Service Studies** | **Trial Balance Amount** | | | | | |
| **6** | **561.70** | **Generation Interconnection Studies** | **Trial Balance Amount** | | | | | |
| **7** | **561.80** | **Regional Planning & Standards development** | **Trial Balance Amount** | | | | | |
| **8** | | **NERC Assessment Fee** | **Trial Balance Amount** | | | | | |
| **9** | | **FERC Assessment Fee** | **Trial Balance Amount** | | | | | |
| **10** | | **SPP Schedule 1 Charges** | **Trial Balance Amount** | | | | | |
| **11** | **561.0040** | **SPP Schedule 1A Charges** | **Trial Balance Amount** | | | | | |
| **12** | | **Schedule 1-Adjustment** | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **13** | | **Less: Revenue Credit for transmission service not included in the divisor (enter as negative)** | | | | | | |
| **14** | | **Schedule 1 True-Up adjustments (if any)** | | | | | | |
| | | | | | | | | |
| **15** | | **Data from Substation/Segments Spreadsheet** | | | | **Year End r 31,** | | |
| **16** | | **Tran Subs Qualified Gross Plant** | **Worksheet S, Line 111, Col D** | | | **0.000%** | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **17** | | **Form-12 Input** | | | | | | |
| **18** | | **Electric Energy Revenues** | **Form 12, Part A, Sect A, L01b** | | | | | |
| **19** | | **Income From Leased Property** | **Form 12, Part A, Sect A, L02b** | | | | | |
| **20** | | **Other Operating Revenue & Income** | **Form 12, Part A, Sect A, L03b** | | | | | |
| **21** | | **Total Operating Revenues & Patronage Capital** | **Subtotal** | | | **$ -** | | |
| | | | | | | | | |
| **22** | | **Part A. Section A-Statement of Operations:** | | | | | | |
| **23** | | **Operating Expense** | | | | | | |
| **24** | | **Op Exp-Production excluding fuel** | **Form 12, Part A, Sect A, L05b** | | | | | |
| **25** | | **Op Exp-Production fuel** | **Form 12, Part A, Sect A, L06b** | | | | | |
| **26** | | **Op Exp-Other Power Supply** | **Form 12, Part A, Sect A, L07b** | | | | | |
| **27** | | **Op Exp-Transmission** | **Form 12, Part A, Sect A, L08b** | | | | | |
| **28** | | **Op Exp-RTO/ISO** | **Form 12, Part A, Sect A, L09b** | | | | | |
| **29** | | **Op Exp-Distribution** | **Form 12, Part A, Sect A, L10b** | | | | | |
| **30** | | **Op Exp-Consumer Accounts** | **Form 12, Part A, Sect A, L11b** | | | | | |
| **31** | | **Op Exp-Customer Service** | **Form 12, Part A, Sect A, L12b** | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 32 | | Op Exp-Sales | Form 12, Part A, Sect A, L13b | | | | | |
| 33 | | Op Exp-Admin and General | Form 12, Part A, Sect A, L14b | | | | | |
| 34 | | Total Operation Expense | Subtotal | | | $ - | | |
| | | | | | | | | |
| 35 | | Maintenance Expense | | | | | | |
| 36 | | Maint Exp-Production | Form 12, Part A, Sect A, L16b | | | | | |
| 37 | | Maint Exp-Transmission | Form 12, Part A, Sect A, L17b | | | | | |
| 38 | | Maint Exp-RTO/ISO | Form 12, Part A, Sect A, L18b | | | | | |
| 39 | | Maint Exp-Distribution | Form 12, Part A, Sect A, L19b | | | | | |
| 40 | | Maint Exp-General Plant | Form 12, Part A, Sect A, L20b | | | | | |
| 41 | | Total Maintenance Expense | Subtotal | | | $ - | | |
| | | | | | | | | |
| 42 | | Interest, Taxes and Other Deductions | | | | | | |
| 43 | | Depreciation & Amortization Expense | Form 12, Part A, Sect A, L22b | | | | | |
| 44 | | Taxes | Form 12, Part A, Sect A, L23b | | | | | |
| 45 | | Interest on Long Term Debt | Form 12, Part A, Sect A, L24b | | | | | |
| 46 | | Interest Charged to Construction - Credit | Form 12, Part A, Sect A, L25b | | | | | |
| 47 | | Other Interest Expense | Form 12, Part A, Sect A, L26b | | | | | |
| 48 | | Asset Retirement Obligations | Form 12, Part A, Sect A, L27b | | | | | |
| 49 | | Other Deductions | Form 12, Part A, Sect A, L28b | | | | | |
| 50 | | Total Cost of Electric Service | Subtotal | | | $ - | | |
| 51 | | Operating Margins | Calculated | | | $ - | | |
| | | | | | | | | |
| | | | | | | | | |
| 52 | | Interest Income | Form 12, Part A, Sect A, L31b | | | | | |
| 53 | | Allowance For Funds Used During Construction | Form 12, Part A, Sect A, L32b | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **54** | | **Income (Loss) from Equity Investments** | **Form 12, Part A, Sect A, L33b** | | | | | |
| **55** | | **Other Non-operating Income (Net)** | **Form 12, Part A, Sect A, L34b** | | | | | |
| **56** | | **Generations & Transmission Capital Credits** | **Form 12, Part A, Sect A, L35b** | | | | | |
| **57** | | **Other Capital Credits and Patronage Dividends** | **Form 12, Part A, Sect A, L35b** | | | | | |
| **58** | | **Extraordinary Items** | **Form 12, Part A, Sect A, L36b** | | | | | |
| **59** | | **Net Patronage Capital or Margins** | **Calculated** | | | **$ -** | | |
| | | | | | | | | |
| **60** | | **Part A. Section B- Balance Sheet** | | | | | | |
| **61** | | **Assets** | | **BoY** | **EoY** | **Average** | | |
| **62** | | **Construction Work in Progress** | **Form 12, Part A, Section B, Line 2** | | | **$ -** | | |
| **63** | | **Notes Receivable (Net)** | **Form 12, Part A, Section B, Line 19** | | | **$ -** | | |
| **64** | | **Prepayments *(Acct 165)*** | **Form 12, Part A, Section B, Line 25** | | | **$ -** | | |
| **65** | | **Other Current and Accrued Assets** | **Form 12, Part A, Section B, Line 26** | | | **$ -** | | |
| **66** | | **Accumulated Deferred Income Taxes *(Acct 190)*** | **Form 12, Part A, Section B, Line 31** | | | **$ -** | | |
| | | | | | | | | |
| **67** | | **Liabilities** | | | | **Year End r 31,** | | |
| **68** | | **Patronage Capital - Net** | **Form 12, Part A, Section B, Line 34d** | | | | | |
| **69** | | **Total Margins & Equities** | **Form 12, Part A, Section B, Line 39** | | | | | |
| **70** | | **Total Long Term Debt** | **Form 12, Part A, Sect B, L46** | | | | | |
| **71** | | **Obligations Under Capital Leases - Non Current** | **Form 12, Part A, Sect B, L47** | | | | | |
| **72** | | **Notes Payable** | **Form 12, Part A, Sect B, L50** | | | | | |
| **73** | | **Current Maturities Long Term Debt** | **Form 12, Part A, Sect B, L52** | | | | | |
| **74** | | **Current Maturities Long Term Debt - Rural Dev.** | **Form 12, Part A, Sect B, L53** | | | | | |

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| **75** | | **Accumulated Deferred Income Taxes *(Acct 283)*** | **Form 12, Part A, Sect B, L60** | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **76** | | **Part H. Section A- Utility Plant** | | **BoY** | **EoY** | **Average** | | |
| **77** | **301-303** | **Intangible Plant** | **Form 12, Suppl, Part H, Section A, Line 1** | | | **$ -** | | |
| | | | | | | | | |
| **78** | **310** | **Steam Plant** | **Form 12, Suppl, Part H, Section A, Line 2** | | | **$ -** | | |
| **79** | **320** | **Nuclear Plant** | **Form 12, Suppl, Part H, Section A, Line 3** | | | **$ -** | | |
| **80** | **330** | **Hydro Plant** | **Form 12, Suppl, Part H, Section A, Line 4** | | | **$ -** | | |
| **81** | **340** | **Other Prod Plant** | **Form 12, Suppl, Part H, Section A, Line 5** | | | **$ -** | | |
| **82** | | **Total Production Plant** | **Subtotal** | **$ -** | **$ -** | **$ -** | | |
| | | | | | | | | |
| **83** | **350** | **Land & Land Rights** | **Form 12, Suppl, Part H, Section A, Line 7** | | | **$ -** | | |
| **84** | **352** | **Structures and Improvements** | **Form 12, Suppl, Part H, Section A, Line 8** | | | **$ -** | | |
| **85** | **353** | **Station Equipment** | **Form 12, Suppl, Part H, Section A, Line 9** | | | **$ -** | | |
| **86** | **354-359.1** | **Other Transmission Plant** | **Form 12, Suppl, Part H, Section A, Line 10** | | | **$ -** | | |
| **87** | | **Total Transmission Plant** | **Subtotal** | **$ -** | **$ -** | **$ -** | | |
| | | | | | | | | |
| **88** | **360** | **Land and Land Rights** | **Form 12, Suppl, Part H, Section A, Line 12** | | | **$ -** | | |
| **89** | **361** | **Structures and Improvements** | **Form 12, Suppl, Part H, Section A, Line 13** | | | **$ -** | | |
| **90** | **362** | **Station Equipment** | **Form 12, Suppl, Part H, Section A,** | | | **$ -** | | |

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| | | | **Line 14** | | | | | |
| **91** | **363-374** | **Other Distribution Plant** | **Form 12, Suppl, Part H, Section A, Line 15** | | | **$ -** | | |
| **92** | | **Total Distribution Plant** | **Subtotal** | **$ -** | **$ -** | **$ -** | | |
| | | | | | | | | |
| **93** | **380-386** | **RTO/ISO Plant** | **Form 12, Suppl, Part H, Section A, Line 17** | | | **$ -** | | |
| **94** | **389-399.1** | **Total General Plant** | **Form 12, Suppl, Part H, Section A, Line 18** | | | **$ -** | | |
| **95** | | **Electric Plant In Service** | **Subtotal** | **$ -** | **$ -** | **$ -** | | |
| | | | | | | | | |
| **96** | **102** | **Electric Plant Purchased or Sold** | | | | **$ -** | | |
| **97** | **104** | **Electric Plant Leased to Others** | | | | **$ -** | | |
| **98** | **105** | **Electric Plant Held For Future Use** | **Form 12, Suppl, Part H, Section A, Line 22** | | | **$ -** | | |
| **99** | **106** | **Completed Construction Not Classified** | **Form 12, Suppl, Part H, Section A, Line 23** | | | **$ -** | | |
| **100** | **114** | **Acquisition Adjustment** | **Form 12, Suppl, Part H, Section A, Line 24** | | | **$ -** | | |
| **101** | **118** | **Other Utility Plant** | | | | **$ -** | | |
| **102** | **120** | **Nuclear Fuel Assemblies** | | | | **$ -** | | |
| **103** | **107** | **Construction Work in Progress (CWIP)** | **Form 12, Suppl, Part H, Section A, Line 28** | | | **$ -** | | |
| **104** | | **Total Utility Plant** | **Subtotal** | **$ -** | **$ -** | **$ -** | | |
| | | | | | | | | |
| **105** | | **Part H. Section B-Depreciation and Amortization Reserves** | | **BoY** | **EoY** | **Average** | | |
| **106** | **108.1** | **Depr Rsv of Steam Plant** | **Form 12, Suppl, Part H, Section B, Line 1** | | | **$ -** | | |
| **1** | **108.** | **Depr Rsv of Nuclear** | | | | **$** | | |

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| 07 | 2 | Plant | | | | - | | |
| 108 | 108.3 | Depr Rsv of Hydraulic Plant | | | | $ - | | |
| 109 | 108.4 | Depr Rsv of Other Prod Plant | Form 12, Suppl, Part H, Section B, Line 4 | | | $ - | | |
| 110 | 108.5 | Depreciation of Transmission Plant | Form 12, Suppl, Part H, Section B, Line 5 | | | $ - | | |
| 111 | 108.6 | Depreciation of Distribution Plant | Form 12, Suppl, Part H, Section B, Line 6 | | | $ - | | |
| 112 | 108.7 | Depreciation of General Plant | Form 12, Suppl, Part H, Section B, Line 7 | | | $ - | | |
| 113 | 108.8 | Retirement Work in Progress | Form 12, Suppl, Part H, Section B, Line 8 | | | $ - | | |
| 114 | 111 | Amort of Electric Plant in Service | Form 12, Suppl, Part H, Section B, Line 12 | | | $ - | | |
| 115 | 115 | Amort of Acquisition Adj | Form 12, Suppl, Part H, Section B, Line 15 | | | $ - | | |
| 116 | | Total Depr Reserves for Elect Plant | Subtotal | $ - | $ - | $ - | | |
| | | | | | | | | |
| | | | | | | | | |
| 117 | | **Part H. Section G-Materials and Supplies Inventory** | | **BoY** | **EoY** | **Average** | | |
| 118 | | M&S Coal | Form-12, Part H, Section G, Line 1 | | | $ - | | |
| 119 | | M&S Other Fuel | Form-12, Part H, Section G, Line 2 | | | $ - | | |
| 120 | | M&S Production Plant Parts | Form-12, Part H, Section G, Line 3 | | | $ - | | |
| 121 | | M&S Station Transformers & Equipment | Form-12, Part H, Section G, Line 4 | | | $ - | | |
| 122 | | M&S Line Materials & Supplies | Form-12, Part H, Section G, Line 5 | | | $ - | | |
| 1 | | M&S Other | Form-12, Part H, | | | $ | | |

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| 23 | | | Section G, Line 6 | | | - | | |
| 124 | | Materials and Supplies | Subtotal | $ - | $ - | $ - | | |
| | | | | | | | | |
| 125 | | Part H. Section H-Long Term Debt and Debt Service Requirements | | | | Year End r 31, | | |
| 126 | | RUS Debt Service Billed | Form 12, Annual Supplement, Sect H, Line 1, Col d | | | | | |
| 127 | | Principal Payments on Debt | Form 12, Annual Supplement, Sect H, Line Total, Col c | | | | | |
| 128 | | | | | | | | |
| 129 | Note: | | | | | | | |
| 130 | A. Acquisition adjustments will not be used in the calculation of ATRR absent Commission approval through a 205 or 206 filing. | | | | | | | |

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| | | | | | | | **Worksheet G** |
| **Western Farmers Electric Cooperative, Inc.** | | | | | | | |
| | | | | | | | |
| **O&M Input - RUS Form 12** | | | | | | | |
| **Year Ending December 31,** | | | | | | | |
| | | | | | | | |
| **A** | **B** | **C** | **D** | **E** | **F** | | |
| | | | | | | | |
| **Section A. Expenses and Costs** | | | | | | | |
| **Item** | | **Account Name** | **Lines (a)** | **Stations (b)** | **Total (c)** | | |
| **Transmissions Operations** | | | | | | | |
| **1** | **Supervision and Engineering** | **560** | | | **$ -** | | |
| **2** | **Load Dispatching** | **561** | | | **$ -** | | |
| **3** | **Station Expenses** | **562** | | | **$ -** | | |
| **4** | **Overhead Line Expenses** | **563** | | | **$ -** | | |
| **5** | **Underground Line Expenses** | **564** | | | **$ -** | | |
| **6** | **Miscellaneous Expenses** | **566** | | | **$ -** | | |
| **7** | **Subtotal (1 thru 6)** | | **$ -** | **$ -** | **$ -** | | |
| **8** | **Transmission of Electricity by others** | **565** | | | **$ -** | | |
| **9** | **Rents** | **567** | | **$ -** | **$ -** | | |
| **10** | **Total Transmission Operations (7 thru 9)** | | **$ -** | **$ -** | **$ -** | | |
| **Transmission Maintenance** | | | | | | | |
| **11** | **Supervision and Engineering** | **568** | | | **$ -** | | |
| **12** | **Structures** | **569** | | | **$ -** | | |
| **13** | **Station Equipment** | **570** | | | **$ -** | | |
| **14** | **Overhead Lines** | **571** | | | **$ -** | | |
| **15** | **Underground Lines** | **572** | | | **$ -** | | |
| | **Miscellaneous Transmission** | **573** | | | **$** | | |

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|---|---|---|---|---|---|---|---|
| **16** | **Plant** | | | | **-** | | |
| **17** | **Total Transmission Maintenance (11 thru 16)** | | **$ -** | **$ -** | **$ -** | | |
| **18** | **Total Transmission Expense (10+17)** | | **$ -** | **$ -** | **$ -** | | |
| **19** | **RTO/ISO Expense - Operation** | **575.1-575.8** | | | **$ -** | | |
| **20** | **RTO/ISO Expense - Maintenance** | **576.1-576.5** | | | **$ -** | | |
| **21** | **Total RTO/ISO Expense (19+20)** | | **-** | **-** | **$ -** | | |
| **22** | **Distribution Expense - Operation** | **580-589** | | | **$ -** | | |
| **23** | **Distribution Expense - Maintenance** | **590-598** | | | **$ -** | | |
| **24** | **Total Distribution Expense (22+23)** | | **$ -** | **$ -** | **$ -** | | |
| **25** | **Total Operation and Maintenance (18+21+24)** | | **$ -** | **$ -** | **$ -** | | |
| **Fixed Costs** | | | | | | | |
| **26** | **Depreciation - Transmission** | **403.5** | | | **$ -** | | |
| **27** | **Depreciation - Distribution** | **403.6** | | | **$ -** | | |
| **28** | **Interest - Transmission** | **427** | | | **$ -** | | |
| **29** | **Interest - Distribution** | **427** | | | **$ -** | | |
| **30** | **Total Transmission (18+26+28)** | | **$ -** | **$ -** | **$ -** | | |
| **31** | **Total Distribution (24+27+29)** | | **$ -** | **$ -** | **$ -** | | |
| **32** | **Total Lines and Stations (21+30+31)** | | **$ -** | **$ -** | **$ -** | | |
| **Note:** | | | | | | | |
| **A. Lines can be added or removed from this Worksheet only if there are corresponding changes in the RUS Form 12 format.** | | | | | | | |

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| | | | | | | | | | | | | | | | | | | | | | | | | |
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| **Western Farmers Electric Cooperative, Inc.** | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | |
| **SPP Upgrades** | | | | | | | | | | | | | | | | | | | | | | | | |
| **Year Ending December 31,** | | | | | | | | | | | | | | | | | | | | | | | | |
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| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** | **K** | **L** | **M** | **N** | **O** | **P** | **Q** | **R** | **S** | **T** | | | | | |
| **Line Number** | **NTC ID** | **Project ID** | **Upgrade ID** | **Cost Allocation Voltage** | **Cost Allocation Type** | **BPF %** | **Final Costs** | **Upgrade Name** | **In-Service Date** | **Upgrade Status** | **InSvc? ("CLOSED OUT" OR "COMPLETE") [1=True, 0=False]** | **Days In Svc to Test Year End** | **Base Plan Funded %** | **Final In-service Cost** | **Accum Depr Reserve (Depr Rate/365 * C** | **Net Plant** | **Base Plan Funded Gross Plant** | **Base Plan Funded Net Plant** | **ATRR for Each Project (Col 's T** | | | | | |

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| 161 | Total | | | | | | | | | | | | | | $ - | $ - | $ - | $ 0 | $ 0 | #DIV/0! | | | | |
| 162 | | Reference | | | | | | | | | | | | | | | | | | | | | | |
| 163 | Year | | | 31 | | | | | | | | | | | | | | | | | | | | |
| 164 | End of | | | 12/31/ | | | | | | | | | | | | | | | | | | | | |

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| | Year Date | | | 1931 | | | | | | | | | | | | | | | | | | | |
| 165 | Depreciation Rate | Worksheet J, Line 14, Col H | | 2.748% | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | |
| 166 | ATRR | Summary ATRR, Line 16, Col H | | #DIV/0! | | | | | | | | | | | | | | | | | | | |
| 167 | Net Tran Plant | Worksheet A, Line 42, Col J | | #DIV/0! | | | | | | | | | | | | | | | | | | | |
| 168 | Carrying Charge | Line 166 / Line 167 | | #DIV/0! | | | | | | | | | | | | | | | | | | | |
| 169 | | | | | | | | | | | | | | | | | | | | | | | |
| 170 | SPP Net Plant | Line 161, Col S | | $ - | | | | | | | | | | | | | | | | | | | |
| 171 | SPP ATRR | Line 170 * Line 168 | | #DIV/0! | | | | | | | | | | | | | | | | | | | |

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| 172 | **Notes:** | | | | | | | | | | | | | | | | | | | | | | |
| 173 | **A. Source: NTC.xls** | | | | | | | | | | | | | | | | | | | | | | |
| 174 | **B. Check column K (Upgrade Status) to determine if project is complete** | | | | | | | | | | | | | | | | | | | | | | |
| 175 | **C. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years.** | | | | | | | | | | | | | | | | | | | | | | |
| 176 | **Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.** | | | | | | | | | | | | | | | | | | | | | | |
| 177 | **Additional line items or line deletions will not require FPA Section 205 or 206 filings. WEC will describe such changes in the Annual** | | | | | | | | | | | | | | | | | | | | | | |
| 178 | **Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation Protocols. WFEC may not change the columns or the** | | | | | | | | | | | | | | | | | | | | | | |
| 179 | **formulas included in these Worksheets during the Annual Update.** | | | | | | | | | | | | | | | | | | | | | | |

**Work sheet I**

**Western Farmers Electric Cooperative, Inc.**

**Reconciliation Items, Refunds and Surcharges**

**Year Ending December 31,**

| A | | B | | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **ADJUSTMENTS TO GROSS ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:** | | | | | | | | | | | |
| **Line** | **ERROR IDENTIFICATION** | | | **Formula Reference** | **Rate Year (A)** | **Incorrect Amount** | **Correct Amount** | **Difference (Cred)/ Chg** | **Impact on ATRR (Cred)/Chg** | **Calculated Interest (B)** | **Total Adjustment to ATRR** |
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| **6** | **Total Adjustment to Gross ATRR:** | | | | | | | | | | **$ -** | | | | |
| **ADJUSTMENTS TO SPP REGIONAL PROJECTS' ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:** | | | | | | | | | | | | | | | |
| **Line** | **ERROR IDENTIFICATION** | | | **Formula Reference** | **Rate Year (A)** | **Incorrect Amount** | **Correct Amount** | **Difference (Cred)/ Chg** | **Impact on ATRR (Cred)/Chg** | **Calculated Interest (B)** | **Total Adjustment to ATRR** | | | | |
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| **9** | | | | | | | | **$ -** | | **$ -** | **$ -** | | | | |
| **10** | | | | | | | | **$ -** | | **$ -** | **$ -** | | | | |
| **11** | | | | | | | | **$ -** | | **$ -** | **$ -** | | | | |
| **12** | **Total Adjustment to SPP Regional Projects' ATRR:** | | | | | | | | | | **$ -** | | | | |
| **13** | | **Period Star** | | **Period End** | **Year Descriptio** | **Beginning** | **Accumulation** | **FERC Ann** | **Quarterly Inter** | **Ending Balan** | | | | | |

| | | t | | ing | n | Bala nce | or Payb ack | ual Inte rest Rate | est Amo unt | ce | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | |
| **Interest calculation for Item #1** | | | | | | | | | | | | | | | |
| **14** | | | | | **Rate Year** | | **$ -** | | **$ -** | **$ -** | | | | | |
| **15** | | | | | **Rate Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **16** | | | | | **Rate Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **17** | | | | | **Rate Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **18** | | | | | | **$ -** | | | **$ -** | **$ -** | | | | | |
| **19** | | | | | | **$ -** | | | **$ -** | **$ -** | | | | | |
| **20** | | | | | | **$ -** | | | **$ -** | **$ -** | | | | | |
| **21** | | | | | | **$ -** | | | **$ -** | **$ -** | | | | | |
| **22** | | | | | **True -Up Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **23** | | | | | **True -Up Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **24** | | | | | **True -Up Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **25** | | | | | **True -Up Year** | **$ -** | **$ -** | | **$ -** | **$ -** | | | | | |
| **26** | | **Tot al** | | | | | | | **$ -** | | | | | | |
| **27** | | | | | | | | | | | | | | | |
| **28** | **Interest calculation for Item #2…** | | | | | | | | | | | | | | |
| **29** | **(Repeat the above interest calculation for other items as necessary.)** | | | | | | | | | | | | | | |
| **30** | **Not es:** | | | | | | | | | | | | | | |
| **31** | **A. Rate Year in which the error occurred and affected the ATRR and rates paid by customers.** | | | | | | | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **32** | **B. Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.** | | | | | | | |
| **33** | **C. The interest calculation may need to be modified to recognize the implementation partial year.** | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | **Worksheet J** |
| | | | | | | | | | | | |
| **Western Farmers Electric Cooperative, Inc.** | | | | | | | | | | | |
| | | | | | | | | | | | |
| **Depreciation Rates** | | | | | | | | | | | |
| **Year Ending December 31,** | | | | | | | | | | | |
| | | | | | | | | | | | |
| **A** | **B** | **C** | **D** | **E** | **F** | | **G** | | **H** | | |
| **Line No.** | **Account** | **Group** | **Description** | **Code** | **Unit** | | **Asset ID** | | **Percent** | | |
| **1** | **105.10** | **Non-Depreciable** | **Electric Plant Held for Future Use** | | **WFECO** | | **WFECO10510** | | **0.000%** | | |
| **2** | **114.00** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11400** | | **5.000%** | | |
| **3** | **114.01** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11401** | | **5.000%** | | |
| **4** | **114.02** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11402** | | **3.846%** | | |
| **5** | **114.03** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11403** | | **5.581%** | | |
| **6** | **114.04** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11404** | | **4.182%** | | |
| **7** | **114.05** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11405** | | **5.021%** | | |
| **8** | **114.06** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11406** | | **5.000%** | | |
| **9** | **114.07** | **Utility Plant** | **Electric Plant Acquisition Adjustments** | | **WFECO** | | **WFECO11407** | | **6.667%** | | |
| **10** | **301.00** | **Non-Depreciable** | **Organizations** | | **WFECO** | | **WFECO30100** | | **0.000%** | | |
| **11** | **303.** | **Intangible** | **Miscellaneous Intangible Plant** | | **WFEC** | | **WFECO30** | | **5.000** | | |

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|---|---|---|---|---|---|---|---|---|---|---|
| | 00 | Plant | | | O | | 300 | | % | |
| 12 | 303.01 | Intangible Plant | Miscellaneous Intangible Plant | | WFECO | | WFECO303001 | | 2.7748% | |
| 13 | 303.02 | Intangible Plant | Miscellaneous Intangible Plant | | WFECO | | WFECO303002 | | 2.7748% | |
| 14 | 352.04 | Transmission Plant | Structures and Improvements | SPA Pole Yard | WFECO | | WFECO352004 | | 2.7748% | |
| 15 | 353.00 | Transmission Plant | Station Equipment | | WFECO | | WFECO353000 | | 2.7748% | |
| 16 | 353.02 | Transmission Plant | Station Equipment | SCADA | WFECO | | WFECO353002 | | 9.9960% | |
| 17 | 350.01 | Intangible Plant | Land Lease | | WFECO | | WFECO350001 | | 5.0000% | |
| 18 | 350.02 | Intangible Plant | Land Lease | | WFECO | | WFECO350002 | | 8.0000% | |
| 19 | 389.21 | Intangible Plant | Land Lease | | WFECO | | WFECO389021 | | 15.000% | |
| 20 | 350.04 | Non-Depreciable | Land | | WFECO | | WFECO350004 | | 0.0000% | |
| 21 | 350.05 | Non-Depreciable | Land | | WFECO | | WFECO350005 | | 0.0000% | |
| 22 | 350.20 | Non-Depreciable | Land | | WFECO | | WFECO350020 | | 0.0000% | |
| 23 | 350.30 | Non-Depreciable | Land | | WFECO | | WFECO350030 | | 0.0000% | |
| 24 | 350.45 | Non-Depreciable | Land | | WFECO | | WFECO350045 | | 0.0000% | |
| 25 | 350.00 | Non-Depreciable | Land | | WFECO | | WFECO350000 | | 0.0000% | |
| 26 | 353.10 | Transmission Plant | Station Equipment | Moorland Tran | WFECO | | WFECO353310 | | 2.7748% | |
| 27 | 353.12 | Transmission Plant | Station Equipment | Moorland Gen | WFECO | | WFECO353312 | | 2.7748% | |
| 28 | | | Station | Combined | WF | | WFE | | 2.7 | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 353.30 | Transmission Plant | Equipment | Cycle Tran | ECO | | CO35330 | | 48% | |
| 29 | 353.32 | Transmission Plant | Station Equipment | Combined Cycle Gen | WFECO | | WFECO35332 | | 2.7483% | |
| 30 | 353.35 | Transmission Plant | Station Equipment | Anadarko Stm Tran | WFECO | | WFECO35335 | | 2.7483% | |
| 31 | 353.37 | Transmission Plant | Station Equipment | Anadarko Stm Gen | WFECO | | WFECO35337 | | 2.7483% | |
| 32 | 353.40 | Transmission Plant | Station Equipment | Hugo Gen | WFECO | | WFECO3534G | | 2.7483% | |
| 33 | 353.40 | Transmission Plant | Station Equipment | Hugo Retired | WFECO | | WFECO3534R | | 2.7483% | |
| 34 | 353.48 | Transmission Plant | Station Equipment | Hugo Non Lease | WFECO | | WFECO35348 | | 2.7483% | |
| 35 | 353.49 | Transmission Plant | Station Equipment | Hugo SH | WFECO | | WFECO35349 | | 2.7483% | |
| 36 | 354.00 | Transmission Plant | Towers and Fixtures | Unitized | WFECO | | WFECO35400 | | 2.7483% | |
| 37 | 354.10 | Transmission Plant | Towers and Fixtures | 69 KV | WFECO | | WFECO35410 | | 2.7483% | |
| 38 | 354.49 | Transmission Plant | Towers and Fixtures | Hugo SH | WFECO | | WFECO35449 | | 2.7483% | |
| 39 | 355.00 | Transmission Plant | Poles and Fixtures | 69 KV Unitized | WFECO | | WFECO35500 | | 2.7483% | |
| 40 | 355.30 | Transmission Plant | Poles and Fixtures | 135 KV Unitized | WFECO | | WFECO35530 | | 2.7483% | |
| 41 | 355.45 | Transmission Plant | Poles and Fixtures | 345 KV Tenaska Line | WFECO | | WFECO35545 | | 3.333% | |
| 42 | 356.00 | Transmission Plant | Overhead Conductors and Devices | 69 KV | WFECO | | WFECO35600 | | 2.7483% | |
| 43 | 356.30 | Transmission Plant | Overhead Conductors and Devices | 138 KV | WFECO | | WFECO35630 | | 2.7483% | |
| 44 | 356.49 | Transmission Plant | Overhead Conductors and Devices | Hugo SH | WFECO | | WFECO35649 | | 2.7483% | |

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| **45** | **359.00** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO35900** | | **0.000%** | |
| **46** | **359.20** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO35920** | | **0.000%** | |
| **47** | **359.24** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO35924** | | **0.000%** | |
| **48** | **360.00** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO36000** | | **0.000%** | |
| **49** | **360.06** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO36006** | | **0.000%** | |
| **50** | **362.00** | **Distribution Plant** | **Station Equipment** | | **WFECO** | | **WFECO36200** | | **2.880%** | |
| **51** | **362.02** | **Distribution Plant** | **Station Equipment** | | **WFECO** | | **WFECO36202** | | **9.996%** | |
| **52** | **362.10** | **Distribution Plant** | **Station Equipment** | | **WFECO** | | **WFECO36210** | | **2.880%** | |
| **53** | **362.20** | **Distribution Plant** | **Station Equipment** | | **WFECO** | | **WFECO36220** | | **16.670%** | |
| **54** | **364.00** | **Distribution Plant** | **Poles Towers and Fixtures** | | **WFECO** | | **WFECO36400** | | **3.060%** | |
| **55** | **365.00** | **Distribution Plant** | **Overhead Conductors and Devices** | | **WFECO** | | **WFECO36500** | | **3.060%** | |
| **56** | **389.00** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO38900** | | **0.000%** | |
| **57** | **389.10** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO38910** | | **0.000%** | |
| **58** | **389.20** | **Non-Depreciable** | **Land** | | **WFECO** | | **WFECO38920** | | **0.000%** | |
| **59** | **390.00** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39000** | | **3.000%** | |
| **60** | **390.10** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39010** | | **3.000%** | |
| **61** | **390.** | **General Plant** | **Structures and Improvements** | | **WFEC** | | **WFECO39** | | **3.00** | |

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|---|---|---|---|---|---|---|---|---|---|---|
| | **20** | | | | **O** | | **020** | | **%** | |
| **62** | **390.30** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39030** | | **3.000%** | |
| **63** | **390.40** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39040** | | **3.000%** | |
| **64** | **390.50** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39050** | | **3.000%** | |
| **65** | **390.60** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39060** | | **3.000%** | |
| **66** | **390.70** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39070** | | **3.000%** | |
| **67** | **390.80** | **General Plant** | **Structures and Improvements** | | **WFECO** | | **WFECO39080** | | **3.000%** | |
| **68** | **391.00** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39100** | | **6.000%** | |
| **69** | **391.01** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39101** | | **6.000%** | |
| **70** | **391.05** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39105** | | **6.000%** | |
| **71** | **391.06** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39106** | | **6.000%** | |
| **72** | **391.07** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39107** | | **33.330%** | |
| **73** | **391.10** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39110** | | **6.000%** | |
| **74** | **391.20** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39120** | | **16.670%** | |
| **75** | **391.21** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39121** | | **10.000%** | |
| **76** | **391.22** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39122** | | **16.670%** | |
| **77** | **391.23** | **General Plant** | **Office Furniture and Equipment** | | **WFECO** | | **WFECO39123** | | **16.670%** | |
| **78** | | **General** | **Office Furniture** | | **WF** | | **WFE** | | **16.** | |

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|---|---|---|---|---|---|---|---|---|---|---|
| | 391.25 | Plant | and Equipment | | ECO | | CO39125 | | 668% | |
| 79 | 391.26 | General Plant | Office Furniture and Equipment | | WFECO | | WFECO39126 | | 33.330% | |
| 80 | 391.30 | General Plant | Office Furniture and Equipment | | WFECO | | WFECO39130 | | 6.000% | |
| 81 | 391.40 | General Plant | Office Furniture and Equipment | | WFECO | | WFECO39140 | | 6.000% | |
| 82 | 391.41 | General Plant | Office Furniture and Equipment | | WFECO | | WFECO39141 | | 16.670% | |
| 83 | 391.49 | General Plant | Office Furniture and Equipment | | WFECO | | WFECO39149 | | 6.000% | |
| 84 | 391.50 | General Plant | Office Furniture and Equipment | | WFECO | | WFECO39150 | | 6.000% | |
| 85 | 392.00 | General Plant | Transportation Equipment | | WFECO | | WFECO39200 | | 33.330% | |
| 86 | 392.01 | General Plant | Transportation Equipment | | WFECO | | WFECO39201 | | 20.000% | |
| 87 | 392.02 | General Plant | Transportation Equipment | | WFECO | | WFECO39202 | | 10.000% | |
| 88 | 392.03 | General Plant | Transportation Equipment* | | WFECO | | WFECO39203 | | 25.000% | |
| 89 | 392.04 | General Plant | Transportation Equipment* | | WFECO | | WFECO39204 | | 25.000% | |
| 90 | 392.05 | General Plant | Transportation Equipment* | | WFECO | | WFECO39205 | | 10.000% | |
| 91 | 392.06 | General Plant | Transportation Equipment* | | WFECO | | WFECO39206 | | 7.143% | |
| 92 | 392.07 | General Plant | Transportation Equipment* | | WFECO | | WFECO39207 | | 10.000% | |
| 93 | 392.08 | General Plant | Transportation Equipment* | | WFECO | | WFECO39208 | | 33.330% | |
| 94 | 392.40 | General Plant | Transportation Equipment | | WFECO | | WFECO39 24R | | 6.000% | |

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| **95** | **392.48** | **General Plant** | **Transportation Equipment** | | **WFECO** | | **WFECO39248** | | **6.000%** | |
| **96** | **392.49** | **General Plant** | **Transportation Equipment** | | **WFECO** | | **WFECO39249** | | **6.000%** | |
| **97** | **393.00** | **General Plant** | **Stores Equipment** | | **WFECO** | | **WFECO39300** | | **6.000%** | |
| **98** | **393.10** | **General Plant** | **Stores Equipment** | | **WFECO** | | **WFECO39310** | | **6.000%** | |
| **99** | **393.20** | **General Plant** | **Stores Equipment** | | **WFECO** | | **WFECO39320** | | **6.000%** | |
| **100** | **394.00** | **General Plant** | **Tools, Shop and Garage Equipment** | | **WFECO** | | **WFECO39400** | | **6.000%** | |
| **101** | **394.01** | **General Plant** | **Tools, Shop, Garage Equipment** | | **WFECO** | | **WFECO39401** | | **6.000%** | |
| **102** | **394.10** | **General Plant** | **Tools, Shop and Garage Equipment** | | **WFECO** | | **WFECO39410** | | **6.000%** | |
| **103** | **394.20** | **General Plant** | **Tools, Shop and Garage Equipment** | | **WFECO** | | **WFECO39420** | | **6.000%** | |
| **104** | **394.30** | **General Plant** | **Tools, Shop and Garage Equipment** | | **WFECO** | | **WFECO39430** | | **6.000%** | |
| **105** | **394.48** | **General Plant** | **Tools, Shop and Garage Equipment** | | **WFECO** | | **WFECO39448** | | **6.000%** | |
| **106** | **394.49** | **General Plant** | **Tools, Shop and Garage Equipment** | | **WFECO** | | **WFECO39449** | | **6.000%** | |
| **107** | **395** | **General Plant** | **Laboratory Equipment** | | **WFECO** | | **WFECO39500** | | **6.000%** | |
| **108** | **395** | **General Plant** | **Laboratory Equipment** | | **WFECO** | | **WFECO39502** | | **6.000%** | |
| **109** | **395.1** | **General Plant** | **Laboratory Equipment** | | **WFECO** | | **WFECO39510** | | **6.000%** | |
| **110** | **395.5** | **General Plant** | **Laboratory Equipment** | | **WFECO** | | **WFECO39550** | | **6.000%** | |
| **111** | **395.6** | **General Plant** | **Laboratory Equipment** | | **WFEC** | | **WFECO39** | | **6.000** | |

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|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | **O** | | **560** | | **%** | |
| **112** | **395.7** | **General Plant** | **Laboratory Equipment** | | **WFECO** | | **WFECO3960570** | | **6.000%** | |
| **113** | **396** | **General Plant** | **Power Operated Equipment** | | **WFECO** | | **WFECO3960600** | | **6.000%** | |
| **114** | **396.1** | **General Plant** | **Power Operated Equipment** | | **WFECO** | | **WFECO3960610** | | **6.000%** | |
| **115** | **396.2** | **General Plant** | **Power Operated Equipment** | | **WFECO** | | **WFECO3960620** | | **6.000%** | |
| **116** | **397** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970700** | | **8.004%** | |
| **117** | **397.01** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970701** | | **6.000%** | |
| **118** | **397.02** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970702** | | **8.004%** | |
| **119** | **397.03** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970703** | | **6.000%** | |
| **120** | **397.04** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970704** | | **8.004%** | |
| **121** | **397.05** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970705** | | **8.004%** | |
| **122** | **397.06** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970706** | | **6.000%** | |
| **123** | **397.1** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970710** | | **8.004%** | |
| **124** | **397.49** | **General Plant** | **Communication Equipment** | | **WFECO** | | **WFECO3970749** | | **8.004%** | |
| **125** | **398** | **General Plant** | **Miscellaneous Equipment** | | **WFECO** | | **WFECO3970800** | | **6.000%** | |
| **125** | **Note:** | | | | | | | | | |
| **125** | **A. Stated Values" in Column H are fixed and cannot be changed absent Commission approval through a Section 205 or 206 filing.** | | | | | | | | | |

# ADDENDUM 39 TO ATTACHMENT H

## Western Farmers Electric Cooperative, Inc.

## Part 2

Worksheet K

**Western Farmers Electric Cooperative, Inc.**

## Wage Input & Functionalization

**Year Ending December 31,**

| A<br>Line No. | B<br>Account | C<br>Account Description | D<br>Actual | E<br>Account Major | F<br>Account Minor | G<br>Production | H<br>Trans | I<br>Distb | J<br>Cust-Acct | K<br>Cust-Svc | L<br>Cust-Sales | M<br>Admin & Gen | N<br>Load Dispatch |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Regular Straight Time** | | | | | | | | | | | | |
| 2 | 50001 | Oper,Supv // WfecPr Reg | | 500 | 01 | $ - | | | | | | | |
| 3 | 5010101 | Fuel // WfecPr Reg/Gas-Direct | | 501 | 0101 | $ - | | | | | | | |
| 4 | 5010104 | Fuel // WfecPr Reg/Coal Steam | | 501 | 0104 | $ - | | | | | | | |
| 5 | 50201 | Exp // WfecPr | | 502 | 01 | $ - | | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6 | 50501 | Reg Elect Exp // WfecPr Reg | | 505 | 01 | $ - |
| 7 | 50601 | Misc Steam // WfecPr Reg | | 506 | 01 | $ - |
| 8 | 5060145 | Misc Steam // WfecPr Reg/NERC Maint,S&E // WfecPr Reg | | 506 | 0145 | $ - |
| 9 | 51001 | Maint,Stru // WfecPr Reg | | 510 | 01 | $ - |
| 10 | 51101 | Maint,Blr // WfecPr Reg | | 511 | 01 | $ - |
| 11 | 51201 | Maint,El // WfecPr Reg | | 512 | 01 | $ - |
| 12 | 51301 | Maint,El // WfecPr Reg/Environ | | 513 | 01 | $ - |
| 13 | 5130101 | Mt,Misc St // WfecPr Reg | | 513 | 01 | $ - |
| 14 | 51401 | Ops // WfecPr Reg | | 514 | 01 | $ - |
| 15 | 54601 | Ops // WfecPr Reg/Environ | | 546 | 01 | $ - |
| 16 | 5460101 | Fuel-Gas // WfecPr Reg/Gas | | 546 | 01 | $ - |
| 17 | 54701 | Dir Gen Exp // WfecPr Reg | | 547 | 01 | $ - |
| 18 | 54801 | MiscGen Exp // | | 548 | 01 | $ - |
| 19 | 54901 | | | 549 | 01 | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | 54901 45 | WfecPr Reg MiscGen Exp//WfecPr Reg/NERC Maintnance // | | 549 | 01 45 | $ - | | | | | |
| 21 | 55101 | WfecPr Reg Mt,Structr // | | 551 | 01 | $ - | | | | | |
| 22 | 55201 | WfecPr Reg Maint, Gen // | | 552 | 01 | $ - | | | | | |
| 23 | 55301 | WfecPr Reg Mt,MiscOP // | | 553 | 01 | $ - | | | | | |
| 24 | 55401 | WfecPr Reg SysCntrl // | | 554 | 01 | $ - | | | | | |
| 25 | 55601 01 | WfecPr Reg/Ops SysCntrl // | | 556 | 01 01 | $ - | | | | | |
| 26 | 55601 03 | WfecPr Reg/Support Op-Sup-Eng // | | 556 | 01 03 | $ - | | | | | |
| 27 | 56001 | WfecPr Reg Load Disp // | | 560 | 01 | $ - | | | | | |
| 28 | 56101 | WfecPr Reg Load Disp // | | 561 | 01 | | | | | $ - | |
| 29 | 56101 01 | WfecPr Reg/Ops Load Disp // | | 561 | 01 01 | | | | | $ - | |
| 30 | 56101 03 | WfecPr Reg/Sup prt Load Disp//WfecPr | | 561 | 01 03 | | | | | $ - | |
| 31 | 56101 04 | Reg/RTO ASE | | 561 | 01 04 | | | | | $ - | |

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|---|---|---|---|---|---|---|---|---|
| 32 | 56101 45 | Load Disp // WfecPr Reg/NERC | | 561 | 01 45 | | | $ - |
| 33 | 56201 | Sta Exp // WfecPr Reg | | 562 | 01 | $ - | | |
| 34 | 56201 01 | Sta Exp // WfecPr Reg/69kv &Up | | 562 | 01 | $ - | | |
| 35 | 56201 07 | Sta Exp // WfecPr Reg / MW | | 562 | 01 07 | $ - | | |
| 36 | 56301 | Ovhd Line // WfecPr Reg | | 563 | 01 | $ - | | |
| 37 | 56601 | MiscTR Exp // WfecPr Reg | | 566 | 01 | $ - | | |
| 38 | 56601 01 | MiscTR Exp//WfecPR Reg/Ec Dev | | 566 | 01 | $ - | | |
| 39 | 56601 45 | MiscTR Exp // WfecPr Reg/NERC | | 566 | 01 45 | $ - | | |
| 40 | 57001 | Maint, Sta // WfecPr Reg | | 570 | 01 | $ - | | |
| 41 | 57101 | Maint, OH // WfecPr Reg | | 571 | 01 | $ - | | |
| 42 | 57101 01 | Maint OH//WfecPr Reg/Herb App | | 571 | 01 | $ - | | |
| 43 | 57101 02 | Maint OH // WfecPr Reg / Veg | | 571 | 01 02 | $ - | | |

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|---|---|---|---|---|---|---|---|---|
| 4 | | Mt,MiscTR // WfecPr | | 57 | | $ | | |
| 4 | 57301 | Reg O, S & Eng // WfecPr | | 3 | 01 | - | | |
| 4 | | Reg | | 58 | | | $ | |
| 5 | 58001 | Statn Exp // WfecPr | | 0 | 01 | | - | |
| 4 | | Reg | | 58 | | | $ | |
| 6 | 58201 | Statn Exp // WfecPr | | 2 | 01 | | - | |
| 4 | 58201 | Reg/Mbr | | 58 | 01 | | $ | |
| 7 | 01 | Cps Statn Exp // WfecPr | | 2 | 01 | | - | |
| 4 | 58201 | Reg/NER | | 58 | 01 | | $ | |
| 8 | 45 | C Meter Exp // WfecPr | | 2 | 45 | | - | |
| 4 | | Reg | | 58 | | | $ | |
| 9 | 58601 | MiscDst // WfecPr | | 6 | 01 | | - | |
| 5 | | Reg | | 58 | | | $ | |
| 0 | 58801 | Mt,StaEqmt // WfecPr | | 8 | 01 | | - | |
| 5 | | Reg | | 59 | | | $ | |
| 1 | 59201 | Mt,StaEqmt // WfecPrReg/SubAut | | 2 | 01 | | - | |
| 5 | 59201 | | | 59 | 01 | | $ | |
| 2 | 03 | Maint,Metr // WfecPr | | 2 | 03 | | - | |
| 5 | | Reg | | 59 | | | $ | |
| 3 | 59701 | Maint,Misc // WfecPr | | 7 | 01 | | - | |
| 5 | | Reg | | 59 | | | $ | |
| 4 | 59801 | Meter Rdng // WfecPr | | 8 | 01 | | - | |
| 5 | | Reg | | 90 | | | | $ |
| 5 | 90201 | CstBilling // WfecPr | | 2 | 01 | | | - |
| 5 | | Reg | | 90 | | | | $ |
| 6 | 90301 | | | 3 | 01 | | | - |

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|---|---|---|---|---|---|---|---|---|
| 57 | | Demo,Sell // WfecPrReg | | 912 | 01 | | $ - | |
| 58 | 92001 | Admin,Genl // WfecPrReg | | 920 | 01 | | | $ - |
| 59 | 93501 03 | Mt,Gen Plt // WfecPrReg/Ana HQ | | 935 | 01 03 | | | $ - |
| 60 | 93501 04 | Mt,GenPlt//WfecPrReg/Frederick | | 935 | 01 04 | | | $ - |
| 61 | 93501 05 | Mt,GenPlt /WfecPrReg/McAlester | | 935 | 01 05 | | | $ - |
| 62 | 93501 06 | Mt,GenPlt // WfecPrReg / Mlrnd | | 935 | 01 06 | | | $ - |
| 63 | 93501 07 | Mt,GenPlt/WfecPrReg/Comanche | | 935 | 01 07 | | | $ - |
| 64 | 93501 08 | Mt,GenPlt/WfecPrReg / Antlers | | 935 | 01 08 | | | $ - |
| 65 | 93501 09 | Mt,GenPlt/WfecPrReg/Elk City | | 935 | 01 09 | | | $ - |
| 66 | 93501 10 | Mt,GenPlt/WfecPrReg/Shawnee | | 935 | 01 10 | | | $ - |
| 67 | 93501 11 | Mt,GenPlt/WfecPrReg/Ana T&DS | | 935 | 01 11 | | | $ - |
| 68 | 93501 13 | Mt,GenPlt/WfecPrReg/Kingston | | 935 | 01 13 | | | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 69 | 93501 14 | Mt,GenPlt/WfecPr Reg/Stck Cnyn | | 93 5 | 01 14 | | | | | | | $ - | | |
| 70 | 93501 15 | Mt,GenPlt/WfecPr Reg/Hennessey | | 93 5 | 01 15 | | | | | | | $ - | | |
| 71 | 93501 16 | Mt,GenPlt/WfecPr Reg/Ana PeaBut | | 93 5 | 01 16 | | | | | | | $ - | | |
| 72 | | Total | $ - | | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | |
| 73 | **Overtime** | | | | | | | | | | | | | |
| 74 | 50002 | Oper,Supv // WfecPr OT | | 50 0 | 02 | $ - | | | | | | | | |
| 75 | 50102 01 | Fuel // WfecPr OT/Gas-Direct | | 50 1 | 02 01 | $ - | | | | | | | | |
| 76 | 50202 | Steam Exp // WfecPr OT | | 50 2 | 02 | $ - | | | | | | | | |
| 77 | 50502 | Elect Exp // WfecPr OT | | 50 5 | 02 | $ - | | | | | | | | |
| 78 | 50602 | Misc Steam // WfecPr OT | | 50 6 | 02 | $ - | | | | | | | | |
| 79 | 50602 45 | Misc Steam // WfecPr OT/NERC | | 50 6 | 02 45 | $ - | | | | | | | | |
| 80 | 51002 | Maint,S&E // WfecPr OT | | 51 0 | 02 | $ - | | | | | | | | |
| 81 | 51102 | Maint,Stru // WfecPr OT | | 51 1 | 02 | $ - | | | | | | | | |
| 82 | 51202 | Maint,Blr // WfecPr | | 51 2 | 02 | $ - | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|
| 83 | 51302 | OT Maint,El // WfecPr OT Maint,El // WfecPr OT | | 513 | 02 | $ - | | |
| 84 | 51302 01 | OT/Environ Mt,Misc St // WfecPr OT Ops // WfecPr OT Fuel // WfecPr OT/Gas-Direct Gen Exp // WfecPr OT MiscGen Exp // WfecPr OT Maintnance // WfecPR OT Mt,Structr // WfecPr OT Maint, Gen // WfecPr OT Mt,MiscOP // WfecPr OT SysCntrl // WfecPr OT/Support Load Disp // WfecPr OT/Ops | | 513 | 02 01 | $ - | | |
| 85 | 51402 | | | 514 | 02 | $ - | | |
| 86 | 54602 | | | 546 | 02 | $ - | | |
| 87 | 54702 01 | | | 547 | 02 01 | $ - | | |
| 88 | 54802 | | | 548 | 02 | $ - | | |
| 89 | 54902 | | | 549 | 02 | $ - | | |
| 90 | 55102 | | | 551 | 02 | $ - | | |
| 91 | 55202 | | | 552 | 02 | $ - | | |
| 92 | 55302 | | | 553 | 02 | $ - | | |
| 93 | 55402 | | | 554 | 02 | $ - | | |
| 94 | 55602 03 | | | 556 | 02 03 | $ - | | |
| 95 | 56102 01 | | | 561 | 02 01 | | $ - | |
| 96 | 56102 03 | Load Disp // | | 561 | 02 03 | | $ - | |

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|---|---|---|---|---|---|---|---|---|
| 97 | 56102 04 | WfecPr OT/Suppr t Load Disp // WfecPR OT/RTO ASE | | 561 | 02 04 | | | $ - |
| 98 | 56202 | Sta Exp // WfecPr OT | | 562 | 02 | $ - | | |
| 99 | 56202 01 | Sta Exp // WfecPr OT/69kv &Up | | 562 | 02 01 | $ - | | |
| 100 | 56202 07 | Sta Exp // WfecPr OT / MW | | 562 | 02 07 | $ - | | |
| 101 | 56302 | Ovhd Line // WfecPr OT | | 563 | 02 | $ - | | |
| 102 | 56602 | MiscTR Exp // WfecPr OT | | 566 | 02 | $ - | | |
| 103 | 56602 01 | MiscTR Exp//WfecPr OT/Ec Dev | | 566 | 02 01 | $ - | | |
| 104 | 56602 45 | MiscTr Exp // WfecPr OT/NERC | | 566 | 02 45 | $ - | | |
| 105 | 57002 | Maint, Sta // WfecPr OT | | 570 | 02 | $ - | | |
| 106 | 57102 | Maint, OH // WfecPr OT | | 571 | 02 | $ - | | |
| 107 | 57102 01 | Maint OH//WfecPr OT/Herb App | | 571 | 02 01 | $ - | | |
| 108 | 57102 02 | Maint OH // WfecPr | | 571 | 02 | $ - | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Mt,GenPlt//WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/Frede | | 93 | 02 | | | | | | | | $ |
| 1 | 04 | rick | | 5 | 04 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/McAl | | 93 | 02 | | | | | | | | $ |
| 2 | 05 | ester | | 5 | 05 | | | | | | | | - |
| 1 | | Mt,GenPlt // WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT / | | 93 | 02 | | | | | | | | $ |
| 3 | 06 | Mrlnd | | 5 | 06 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/Coma | | 93 | 02 | | | | | | | | $ |
| 4 | 07 | nche | | 5 | 07 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/Antler | | 93 | 02 | | | | | | | | $ |
| 5 | 08 | s | | 5 | 08 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT / Elk | | 93 | 02 | | | | | | | | $ |
| 6 | 09 | City | | 5 | 09 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/Shaw | | 93 | 02 | | | | | | | | $ |
| 7 | 10 | nee | | 5 | 10 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/Ana | | 93 | 02 | | | | | | | | $ |
| 8 | 11 | T&DS | | 5 | 11 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 2 | 93502 | OT/Kings | | 93 | 02 | | | | | | | | $ |
| 9 | 13 | ton | | 5 | 13 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 3 | 93502 | OT/StckC | | 93 | 02 | | | | | | | | $ |
| 0 | 14 | nyn | | 5 | 14 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 3 | 93502 | OT/Henn | | 93 | 02 | | | | | | | | $ |
| 1 | 15 | essey | | 5 | 15 | | | | | | | | - |
| 1 | | Mt,GenPlt/WfecPr | | | | | | | | | | | |
| 3 | 93502 | OT/AnaP | | 93 | 02 | | | | | | | | $ |
| 2 | 16 | eaBut | | 5 | 16 | | | | | | | | - |
| 1 | | | $ | | | $ | $ | $ | $ | | $ | $ | $ |
| 3 | | Total | - | | | - | - | - | - | | - | - | - |

3

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|---|---|---|---|---|---|---|
| 1 | **Other** | | | | | |
| 3 | **Labor** | | | | | |
| 4 | **Costs** | | | | | |
| 1 3 5 | 50005 | Oper,Sup v // CashAwards | | 500 | 05 | $ - |
| 1 3 6 | 50205 | Steam Exp // CashAwards | | 502 | 05 | $ - |
| 1 3 7 | 50505 | Elect Exp // CashAwards | | 505 | 05 | $ - |
| 1 3 8 | 50603 | Misc Steam // WfecPrTemp | | 506 | 03 | $ - |
| 1 3 9 | 50605 | Misc Steam // CashAwards | | 506 | 05 | $ - |
| 1 4 0 | 51005 | Maint,S&E // CashAwards | | 510 | 05 | $ - |
| 1 4 1 | 51103 | Maint,Stru // WfecPrTemp | | 511 | 03 | $ - |
| 1 4 2 | 51205 | Maint,Blr // CashAwards | | 512 | 05 | $ - |
| 1 4 3 | 51305 | Maint,El // CashAwards | | 513 | 05 | $ - |
| 1 4 4 | 54605 | Ops // CashAwards | | 546 | 05 | $ - |
| 1 4 5 | 54803 | Gen Exp // WfecPrTemp | | 548 | 03 | $ - |
| 1 4 | 54805 | Gen Exp // | | 548 | 05 | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | CashAwards MiscGen | | | | | | | | | | | |
| 1 | | Exp // | | | | | | | | | | | |
| 4 | | WfecPrTemp | | 549 | 03 | $ - | | | | | | | |
| 7 | 54903 | MiscGen | | | | | | | | | | | |
| 1 | | Exp // | | | | | | | | | | | |
| 4 | | CashAwards | | 549 | 05 | $ - | | | | | | | |
| 8 | 54905 | SysCntrl | | | | | | | | | | | |
| 1 | | // | | | | | | | | | | | |
| 4 | 55605 | CashAwards/Ops | | 556 | 05 | $ - | | | | | | | |
| 9 | 01 | Op-Sup-Eng // | | | 01 | | | | | | | | |
| 1 | | CashAwards | | 560 | | $ - | | | | | | | |
| 5 | | Load Disp // | | | | | | | | | | | |
| 0 | 56005 | CashAwards | | 560 | 05 | | | | | | | | |
| 1 | | Load Disp // | | | | | | | | | | | |
| 5 | | CashAwards | | 561 | 05 | | | | | | | $ - | |
| 1 | 56105 | Load Disp // | | | | | | | | | | | |
| 5 | 56105 | CashAwards/Ops | | 561 | 05 | | | | | | | $ - | |
| 2 | 01 | Sta Exp // | | | 01 | | | | | | | | |
| 1 | | WfecPrTemp | | 562 | | $ - | | | | | | | |
| 5 | 56203 | Sta Exp // | | | 03 | | | | | | | | |
| 3 | | WfecPrTemp/MW | | 562 | 03 | $ - | | | | | | | |
| 1 | 56203 | Ovhd Line // | | | 7 | | | | | | | | |
| 5 | 7 | WfecPrTemp | | 563 | | $ - | | | | | | | |
| 4 | | Ovhd Line // | | | 03 | | | | | | | | |
| 1 | | CashAwards | | 563 | | $ - | | | | | | | |
| 5 | 56303 | MiscTR Exp // | | | 05 | | | | | | | | |
| 6 | | WfecPrTemp | | 566 | | $ - | | | | | | | |
| 1 | 56305 | MiscTR Exp // | | | 03 | | | | | | | | |
| 5 | | CashAwards | | 566 | | $ - | | | | | | | |
| 7 | 56603 | Maint, Sta // | | | 05 | | | | | | | | |
| 1 | | CashAwards | | 570 | | $ - | | | | | | | |
| 5 | | | | | | | | | | | | | |
| 8 | 56605 | | | 605 | 05 | | | | | | | | |
| 1 | | | | | | | | | | | | | |
| 5 | | | | 570 | | $ | | | | | | | |
| 9 | 57005 | CashAwa | | 0 | 05 | - | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | rds | | | | | | | | | | | |
| 160 | 57103 | Maint, OH // WfecPrTemp | | 571 | 03 | $ - | | | | | | | |
| 161 | 57103 01 | Maint OH//WfecPr Temp/Herb App | | 571 | 03 01 | $ - | | | | | | | |
| 162 | 57103 02 | Maint OH // WfecPr Temp / Veg | | 571 | 03 02 | $ - | | | | | | | |
| 163 | 57303 | Mt,MiscTR // WfecPrTemp | | 573 | 03 | $ - | | | | | | | |
| 164 | 58203 | Statn Exp // WfecPrTemp | | 582 | 03 | | $ - | | | | | | |
| 165 | 58205 | Statn Exp // CashAwards | | 582 | 05 | | $ - | | | | | | |
| 166 | 58605 | Meter Exp // CashAwards | | 586 | 05 | | $ - | | | | | | |
| 167 | 59203 | Mt,StaEqmt // WfecPrTemp | | 592 | 03 | | $ - | | | | | | |
| 168 | 59205 | Mt,StaEqmt // CashAwards | | 592 | 05 | | $ - | | | | | | |
| 169 | 91203 | Demo,Sell // WfecPrTemp | | 912 | 03 | | | $ - | | | | | |
| 170 | 91205 | Demo,Sell // CashAwards | | 912 | 05 | | | $ - | | | | | |
| 171 | 92003 | Admin,Genl // WfecPrTemp | | 920 | 03 | | | | $ - | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 172 | 92005 | Admin,Genl // CashAwards | | 920 | 05 | | | | | | | $ - | | |
| 173 | 9210502 | Office Sup // Cash Awards/Fit | | 921 | 05 02 | | | | | | | $ - | | |
| 174 | 9350303 | Mt,Gen Plt // WfecPrTemp/Ana HQ | | 935 | 03 03 | | | | | | | $ - | | |
| 175 | 9350308 | Mt,GenPlt/WfecPrTemp/Antlers | | 935 | 03 08 | | | | | | | $ - | | |
| 176 | 9350311 | Mt,GenPlt/WfecPrTemp/Ana T&DS | | 935 | 03 11 | | | | | | | $ - | | |
| 177 | 9350316 | Mt,GenPlt/WfecPrTemp/AnaPeaBut | | 935 | 03 16 | | | | | | | $ - | | |
| 178 | | Total | $ - | | | $ - | $ - | $ - | | | $ - | $ - | $ - | |
| 179 | | **TOTAL O&M LABOR** | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 180 | | **CAPITALIZED LABOR** | | | | | | | | | | | | |
| 181 | | **TOTAL LABOR (*excludes benefits*)** | **$ -** | | | | | | | | | | | |
| 182 | | **Benefit Allocation** | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|
| 183 | 50025 | Oper,Supv // AlloBen&Tx | | 500 | 25 | $ - |
| 184 | 5012501 | Fuel // AlloBen&Tx/Gas-Direct | | 501 | 2501 | $ - |
| 185 | 5012504 | Fuel // AlloBen&Tx/Coal Steam | | 501 | 2504 | $ - |
| 186 | 50225 | Exp // AlloBen&Tx | | 502 | 25 | $ - |
| 187 | 50525 | Elect Exp // AlloBen&Tx | | 505 | 25 | $ - |
| 188 | 50625 | Misc Steam // AlloBen&Tx | | 506 | 25 | $ - |
| 189 | 5062545 | Misc Steam // AlloBen&Tx/NERC | | 506 | 2545 | $ - |
| 190 | 51025 | Maint,S&E // AlloBen&Tx | | 510 | 25 | $ - |
| 191 | 51125 | Maint,Stru // AlloBen&Tx | | 511 | 25 | $ - |
| 192 | 51225 | Maint,Blr // AlloBen&Tx | | 512 | 25 | $ - |
| 193 | 51325 | Maint,El // AlloBen&Tx | | 513 | 25 | $ - |
| 194 | 5132501 | Maint,El // AlloBen&Tx/Environ | | 513 | 2501 | $ - |
| 195 | 51425 | Mt,Misc St // | | 514 | 25 | $ - |

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|---|---|---|---|---|---|---|
| 195 | | AlloBen&Tx Ops // AlloBen&Tx | | 546 | 25 | $ - |
| 197 | 5462501 | AlloBen&Tx/Environ | | 546 | 2501 | $ - |
| 198 | 5472501 | Fuel-Gas // AlloBen&Tx/Gas Dir | | 547 | 2501 | $ - |
| 199 | 54825 | Gen Exp // AlloBen&Tx | | 548 | 25 | $ - |
| 200 | 54925 | MiscGen Exp // AlloBen&Tx | | 549 | 25 | $ - |
| 201 | 5492545 | MiscGen Exp//AlloBen&Tx/NERC | | 549 | 2545 | $ - |
| 202 | 55125 | Maintnance // AlloBen&Tx | | 551 | 25 | $ - |
| 203 | 55225 | Mt,Structr // AlloBen&Tx | | 552 | 25 | $ - |
| 204 | 55325 | Maint, Gen // AlloBen&Tx | | 553 | 25 | $ - |
| 205 | 55425 | Mt,MiscOP // AlloBen&Tx | | 554 | 25 | $ - |
| 206 | 5562501 | SysCntrl // AlloBen&Tx/Ops | | 556 | 2501 | $ - |
| 207 | 5562503 | SysCntrl // AlloBen&Tx/Support | | 556 | 2503 | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|
| 208 | 56025 | Op-Sup-Eng // AlloBen&Tx Load | | 560 | 25 | $ - | | | | |
| 209 | 56125 | Disp // AlloBen&Tx Load | | 561 | 25 | | | | | $ - |
| 210 | 56125 01 | Disp // AlloBen&Tx/Ops Load | | 561 | 25 01 | | | | | $ - |
| 211 | 56125 03 | Disp // AlloBen&Tx/Supprt Load | | 561 | 25 03 | | | | | $ - |
| 212 | 56125 04 | Disp//AlloBen&Tx/RTO ASE Load | | 561 | 25 04 | | | | | $ - |
| 213 | 56125 45 | Disp // AlloBen&Tx/NERC | | 561 | 25 45 | | | | | $ - |
| 214 | 56225 | Sta Exp // AlloBen&Tx | | 562 | 25 | $ - | | | | |
| 215 | 56225 01 | Sta Exp // AlloBen&Tx/69kv&Up | | 562 | 25 01 | $ - | | | | |
| 216 | 56225 07 | Sta Exp // AlloBen&Tx / MW | | 562 | 25 07 | $ - | | | | |
| 217 | 56325 | Ovhd Line // AlloBen&Tx MiscTR | | 563 | 25 | $ - | | | | |
| 218 | 56625 | Exp // AlloBen&Tx MiscTR | | 566 | 25 | $ - | | | | |
| 219 | 56625 01 | Exp//AlloBen&Tx/Ec Dev MiscTR | | 566 | 25 01 | $ - | | | | |
| 220 | 56625 45 | Exp // AlloBen&Tx/NERC | | 566 | 25 45 | $ - | | | | |
| 221 | 57025 | Maint, | | 570 | 25 | $ | | | | |

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|---|---|---|---|---|---|---|---|
| 21 | | Sta // AlloBen& Tx Maint, | | 0 | | - | |
| 22 | 57125 | OH // AlloBen& Tx Maint | | 57 1 | 25 | $ - | |
| 23 | 57125 01 | OH//AlloBen&Tx/Herb App Maint OH // | | 57 1 | 25 01 | $ - | |
| 24 | 57125 02 | AlloBen& Tx / Veg Mt,MiscTR // | | 57 1 | 25 02 | $ - | |
| 25 | 57325 | AlloBen& Tx O, S & Eng // | | 57 3 | 25 | $ - | |
| 26 | 58025 | AlloBen& Tx Statn Exp // | | 58 0 | 25 | $ - | |
| 27 | 58225 | AlloBen& Tx Statn Exp // | | 58 2 | 25 | $ - | |
| 28 | 58225 01 | AlloBen& Tx/MbrCps Statn Exp // | | 58 2 | 25 01 | $ - | |
| 29 | 58225 45 | AlloBen& Tx/NERC Meter Exp // | | 58 2 | 25 45 | $ - | |
| 30 | 58625 | AlloBen& Tx MiscDst // | | 58 6 | 25 | $ - | |
| 31 | 58825 | AlloBen& Tx Mt,StaEqmt // | | 58 8 | 25 | $ - | |
| 32 | 59225 | AlloBen& Tx Mt,StaEqmt | | 59 2 | 25 | $ - | |
| 33 | 59225 03 | //AlloBen&Tx/Sub | | 59 2 | 25 03 | $ - | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | | Aut Maint,Metr // AlloBen& | | 597 | | $ | | | | | |
| 24 | 59725 | Tx | | | 25 | - | | | | | |
| 23 | | Maint,Misc // AlloBen& | | 598 | | $ | | | | | |
| 25 | 59825 | Tx | | | 25 | - | | | | | |
| 23 | | Meter Rdng // AlloBen& | | 902 | | | $ | | | | |
| 26 | 90225 | Tx | | | 25 | | - | | | | |
| 23 | | CstBilling // AlloBen& | | 903 | | | $ | | | | |
| 27 | 90325 | Tx | | | 25 | | - | | | | |
| 23 | | Demo,Sell // AlloBen& | | 912 | | | | $ | | | |
| 28 | 91225 | Tx | | | 25 | | | - | | | |
| 23 | | Admin,Genl // AlloBen& | | 920 | | | | | $ | | |
| 29 | 92025 | Tx | | | 25 | | | | - | | |
| 24 | 93525 03 | Mt,Gen Plt // AlloBen& Tx/AnaHQ | | 935 | 25 03 | | | | | $ - | |
| 24 | 93525 04 | Mt,GenPlt//AlloBen &Tx/Frederick | | 935 | 25 04 | | | | | $ - | |
| 24 | 93525 05 | Mt,GenPlt /AlloBen& Tx/McAlestr | | 935 | 25 05 | | | | | $ - | |
| 24 | 93525 06 | Mt,GenPlt // AlloBen& Tx/Mlrnd | | 935 | 25 06 | | | | | $ - | |
| 24 | 93525 07 | Mt,GenPlt/AlloBen &Tx/Comanche | | 935 | 25 07 | | | | | $ - | |
| 24 | 93525 08 | Mt,GenPlt/AlloBen &Tx / Antlers | | 935 | 25 08 | | | | | $ - | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 246 | 93525 09 | Mt,GenPlt/AlloBen&Tx/Elk City | | 935 | 2509 | | | | | | | $ - | | |
| 247 | 93525 10 | Mt,GenPlt/AlloBen&Tx/Shawnee | | 935 | 2510 | | | | | | | $ - | | |
| 248 | 93525 11 | Mt,GenPlt/AlloBen&Tx/AnaT&DS | | 935 | 2511 | | | | | | | $ - | | |
| 249 | 93525 13 | Mt,GenPlt/AlloBen&Tx/Kingston | | 935 | 2513 | | | | | | | $ - | | |
| 250 | 93525 14 | Mt,GenPlt/AllocBen&Tx/StckCnyn | | 935 | 2514 | | | | | | | $ - | | |
| 251 | 93525 15 | Mt,GenPlt//AllBen&Tx/Hennessey | | 935 | 2515 | | | | | | | $ - | | |
| 252 | 93525 16 | Mt,GenPlt/AlloBen&Tax/AnaPeaBu | | 935 | 2516 | | | | | | | $ - | | |
| 253 | | Total | $ - | | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | |
| 254 | | **Total Labor** | **$ -** | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |

Source:
Company
Records

Notes:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years.

Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.

Additional line items or line deletions will not require FPA Section 205 or 206 filings. WFEC will

describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation Protocols. WFEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet L

**Western Farmers Electric Cooperative, Inc.**

**Annual Depreciation Expense Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No** | **Account** | | | **Description** | **Year End Balance** | **Production** | **Tran-Station** | **Tran Lines** | **Distribution** | **General** | **Retirement** | **Amort.** |
| 1 | 40300 | 403 | 00 | Depr Exp // | | $ - | | | | | | |
| 2 | 40310 | 403 | 10 | Depr Exp // Steam Plant | | $ - | | | | | | |
| 3 | 40340 | 403 | 40 | Depr Exp // Other Production | | $ - | | | | | | |
| 4 | 40345 | 403 | 45 | Depr Exp // Other Prod/Lovngtn | | | | | | | | |
| 5 | 40350 | 403 | 50 | Depr Exp // Transm Plant | | | | | | | | |
| 6 | 40360 | 403 | 60 | Depr Exp // Dist Plant | | | | | $ - | | | |
| 7 | 40370 | 403 | 70 | Depr Exp // General | | | | | | $ - | | |
| 8 | 40375 | 403 | 75 | Depr Exp // General/Lovngtn | | | | | | $ - | | |
| 9 | 40 | 40 | 80 | Depr Exp | | $ | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 380 | 3 | | // ARO-Steam | | - | | | | | | |
| | 40 | | | Depr Exp | | | $ | | | | | |
| | 39 | 40 | | // ARC- | | | - | | | | | |
| 10 | 0 | 3 | 90 | Tmn | | | | | | | | |
| | 40 | | | | | | | | | | | |
| | 40 | 40 | | AmtLimTer | | | | | | | | $ |
| 11 | 0 | 4 | 00 | m // Plant | | | | | | | | - |
| | | | | RegDebits | | | | | | | | |
| | 40 | | | // | | | | | | | | |
| | 73 | 40 | | BoltsTrans | | | | | | | | |
| 12 | 0 | 7 | 30 | Costs | | | | | | | | |
| | 40 | | | RegDebits | | $ | | | | | | |
| | 73 | 40 | | // Lease | | - | | | | | | |
| 13 | 4 | 7 | 34 | Term Loss | | | | | | | | |
| | | | | Totals | $ | **$** | | **$** | **$** | **$** | **$** | **$** |
| 14 | | | | | - | **-** | | **-** | **-** | **-** | **-** | **-** |

| | | | |
|---|---|---|---|
| 15 | Depreciation Values from Form-12, Part I, Section A, Line 26. (used to allocate between Subs & Lines) | | - |
| 16 | Note: | | |
| 17 | A. Lines representing detail and sub-accounts can be added only at the same depreciation rates shown in the groupings originally listed. | | |

Worksheet M

**Western Farmers Electric Cooperative, Inc.**

**Transmission Plant Functionalization Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Account Major | Account Minor | Category | Western Farmers Electric Co-op | ASSET BALANCE | Step Up Substations (GSUs) | Other Substations | OH Lines-Generator Lead | OH Lines-345 kV | OH Lines-138 kV | OH Lines-69 kV |
| 1 | 350 | 00 | 35000 | Land/Rights - Trans 69 kV | | | $ - | | | | |
| 2 | 350 | 01 | 35001 | Land/Rights -Trans 69 kV-Term L 20-yr | | | $ - | | | | |
| 3 | 350 | 02 | 35002 | Land/Rights -Trans 69 kV-Term L 50-yr | | | $ - | | | | |
| 4 | 350 | 04 | 35004 | Land/Rights - SPA Trans | | | $ - | | | | |
| 5 | 350 | 05 | 35005 | Land/Rights - Off Sys Acq | | | $ - | | | | |
| 6 | 350 | 20 | 35020 | Land/Rights - Laverne | | | $ - | | | | |
| 7 | 350 | 30 | 35030 | Land/Rights - Woodward | | | $ - | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 0 | | | | | | | | |
| | | | 35 | Land/Rights | | | | | | | |
| | 35 | | 04 | -Tenaska | | $ | | | | | |
| 8 | 0 | 45 | 5 | 345 | | - | | | | | |
| | | | 35 | Struct & | | | | | | | |
| | 35 | | 20 | Impr - SPA | | | $ | | | | |
| 9 | 2 | 04 | 4 | Pole Yd | | | - | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 30 | - 69 kV | | | $ | | | | |
| 0 | 3 | 00 | 0 | Trans | | | - | | | | |
| | | | 35 | Sta & Eq - | | | | | | | |
| 1 | 35 | | 30 | 69 kV Trans | | | $ | | | | |
| 1 | 3 | 02 | 2 | - SCADA | | | - | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 31 | - 69 kV | | | $ | | | | |
| 2 | 3 | 10 | 0 | Mrlnd Tran | | | - | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 31 | - 69 kV | | $ | | | | | |
| 3 | 3 | 12 | 2 | Mrlnd - Ge | | - | | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 33 | - Comb | | | $ | | | | |
| 4 | 3 | 30 | 0 | Cycle - Tra | | | - | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 33 | - Comb | | $ | | | | | |
| 5 | 3 | 32 | 2 | Cycle - Gen | | - | | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 33 | - Ana Stm - | | | $ | | | | |
| 6 | 3 | 35 | 5 | Trans | | | - | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 33 | - Ana Stm - | | $ | | | | | |
| 7 | 3 | 37 | 7 | Gen | | - | | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 1 | 35 | | 34 | - Hugo - | | | $ | | | | |
| 8 | 3 | 48 | 8 | Non Lease | | | - | | | | |
| | | | 35 | | | | | | | | |
| 1 | 35 | | 34 | Sta & Equip | | | $ | | | | |
| 9 | 3 | 49 | 9 | - Hugo - SH | | | - | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 2 | 35 | 4 | 34 | - Hugo - | | $ | | | | | |
| 0 | 3 | G | G | Gen | | - | | | | | |
| | | | 35 | Sta & Equip | | | | | | | |
| 2 | 35 | 4 | 34 | - 69 kV | | | $ | | | | |
| 1 | 3 | R | R | Hugo - Ret | | | - | | | | |
| | | | 35 | Tower & Fix | | | | | | | |
| 2 | 35 | | 40 | - 69 kV | | | | | | | $ |
| 2 | 4 | 00 | 0 | Unitized | | | | | | | - |
| | | | 35 | | | | | | | | |
| 2 | 35 | | 41 | Tower & Fix | | | | | | | $ |
| 3 | 4 | 10 | 0 | - 69 kV | | | | | | | - |
| 2 | 35 | | 35 | Tower & Fix | | | | $ | | | |
| 4 | 4 | 49 | 44 | - Hugo - SH | | | | - | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 9 | | | | | | | | | |
| | | | 35 | Poles & Fix | | | | | | | | |
| 2 | 35 | | 50 | - 69 kV | | | | | | | | $ |
| 5 | 5 | 00 | 0 | Unitized | | | | | | | | - |
| | | | 35 | Poles & Fix | | | | | | | | |
| 2 | 35 | | 53 | - 138 kV | | | | | | | $ | |
| 6 | 5 | 30 | 0 | Unitized | | | | | | | - | |
| | | | 35 | 345 KV | | | | | | | | |
| 2 | 35 | | 54 | TENASKA | | | | | | $ | | |
| 7 | 5 | 45 | 5 | LINE | | | | | | - | | |
| | | | 35 | | | | | | | | | |
| 2 | 35 | | 60 | OH Cond & | | | | | | | | $ |
| 8 | 6 | 00 | 0 | Dev - 69 kV | | | | | | | | - |
| | | | 35 | OH Cond & | | | | | | | | |
| 2 | 35 | | 63 | Dev - 138 | | | | | | | $ | |
| 9 | 6 | 30 | 0 | kV | | | | | | | - | |
| | | | 35 | OH Cond & | | | | | | | | |
| 3 | 35 | | 64 | Dev - Hugo | | | | | $ | | | |
| 0 | 6 | 49 | 9 | - SH | | | | | - | | | |
| | | | 35 | Roads/Trail | | | | | | | | |
| 3 | 35 | | 90 | s - 69 kV | | | | | | | | $ |
| 1 | 9 | 00 | 0 | Unitized | | | | | | | | - |
| | | | 35 | Roads/Trail | | | | | | | | |
| 3 | 35 | | 92 | s - 138 kV | | | | | | | $ | |
| 2 | 9 | 20 | 0 | Unitized | | | | | | | - | |
| | | | 35 | Roads/Trail | | | | | | | | |
| 3 | 35 | | 92 | s - SPA | | | | | | | | $ |
| 3 | 9 | 24 | 4 | Trans | | | | | | | | - |
| 3 | | | | | | $ | $ | $ | $ | $ | $ | $ |
| 4 | | | | Total | | - | - | - | - | - | - | - |
| 3 | Subtotals of the | | | | | | | | | | | |
| 5 | above lines: | | | | | | | | | | | |
| 3 | 35 | | | Land & | | $ | | | | | | |
| 6 | 0 | | | Land rights | | - | | | | | | |
| | | | | Structures & | | | | | | | | |
| 3 | 35 | | | Improveme | | $ | | | | | | |
| 7 | 2 | | | nts | | - | | | | | | |
| 3 | 35 | | | Station | | $ | | | | | | |
| 8 | 3 | | | Equipment | | - | | | | | | |
| 3 | | | | Substations | *$* | | | | | | | |
| 9 | | | | Total | - | | | | | | | |
| 4 | 35 | | | Tower & | | $ | | | | | | |
| 0 | 4 | | | Fixtures | | - | | | | | | |
| 4 | 35 | | | Poles & | | $ | | | | | | |
| 1 | 5 | | | Fixtures | | - | | | | | | |
| 4 | 35 | | | OH | | $ | | | | | | |

| | | | |
|---|---|---|---|
| 2 | 6 | Conductors & Devices | - |
| 4 | 35 | Roads & | $ |
| 4 | 9 | Trails | - |
| 4 | | OH Lines | $ |
| 3 | | Total | - |
| 4 | | Transmissio | $ |
| 5 | | n Total | - |

4 Source: Gross Plant
6 Transmission Accounts.xlsx
4 No
7 te:
A. The addition of new lines and the removal of outdated lines may be necessary in
4 order to accurately provide information, and populate or remove data in the
8 Worksheet with changes in future years.
Where appropriate, these changes will provide detail and
4 linkage to updated Form 12 data requirements or other similar
9 supporting documentation.
Additional line items or line deletions will not require
5 FPA Section 205 or 206 filings. WFEC will describe
0 such changes in the Annual
Update, and the changes will be subject to the review of Interested Parties under
5 the procedures set forth in WFEC's Implementation Protocols. WFEC may not
1 change the columns or the
formulas included in these
5 Worksheets during the Annual
2 Update.

Worksheet N

**Western Farmers Electric Cooperative, Inc.**

**Other Operating Revenue**

**Year Ending December 31,**

| A | B | C | D | E |
|---|---|---|---|---|
| **Line No.** | **REA Account** | **REA Account Description** | **Reference** | **EoY Balance** |
| 1 | 40101 | Oper Rev // Capacity Payments | | |
| 2 | 40102 | Oper Rev // Fixed O&M Payments | | |
| 3 | 40103 | Oper Rev // Variable O&M Pmnts | | |
| 4 | 40104 | Oper Rev // Engine Reserve | | |
| 5 | 40109 | Oper Rev // Station Power | | |
| 6 | 45000 | FortfdDisc // | | |
| 7 | 45100 | MiscSrvRev // | | |
| 8 | 4510001 | MiscSrvRev // 345kv Tenaska | | |
| 9 | 4510002 | MiscSrvRev // 345kvMaintTenask | | |
| 10 | 45400 | Othr E Rev // Rent fromElectPr | | |
| 11 | 45600 | Othr E Rev // | | |
| 12 | 45610 | Othr E Rev // Sale of Fly Ash | | |
| 13 | 45620 | Othr E Rev // Sale of Fuel Oil | | |
| 14 | 45630 | Othr E Rev // Gas Transport | | |
| 15 | 45631 | Othr E Rev // Pulverizr Patent | | |
| 16 | 45640 | Othr E Rev // Emission Allwnce | | |
| 17 | 45645 | Othr E Rev // Sale of Green Cr | | |
| 18 | 45650 | Othr E Rev // OMPA Wheeling | | |
| 19 | 45651 | Othr E Rev // Anthony Wheeling | | |
| 20 | 45652 | Othr E Rev // GRDA AS & Fac Ch | | |

| | | | | | |
|---|---|---|---|---|---|
| 21 | 45653 | Othr E Rev // OMPA AS & Fac Ch | | | |
| 22 | 45654 | Othr E Rev // Rossville Fac Ch | | | |
| 23 | 45655 | Othr E Rev // PEC Fac & Tr Ch | | | |
| 24 | 45670 | Othr E Rev // Transm/Adjustment | | | |
| 25 | 4567010 | Othr E Rev // Transm/Rev CR | | | |
| 26 | 4567015 | Othr E Rev // Transm/NITS (less Line 36) | | | |
| 27 | 4567016 | Othr E Rev // Transm/Sch 1-NITS | | | |
| 28 | 4567017 | Othr E Rev // Transm/Sch 1-P2P | | | |
| 29 | 4567018 | Othr E Rev // Transm/Sch 7&8 P2P | | | |
| 30 | 4567019 | Othr E Rev // Transm/Sch 11 | | | |
| 31 | 4567020 | Othr E Rev//Tran/Sch9WFEC | | | |
| 32 | 4567021 | Othr E Rev//Tran/Sch1WFEC | | | |
| 33 | 4567022 | Othr E Rev//Tran/Sch7WFEC | | | |
| 34 | 4567023 | Othr E Rev//Transm/Sch11WFEC | | | |
| 35 | 45680 | Othr E Rev // NM Coops A&G | | | |
| 36 | 456 | Direct Assigned Revenues | | | |
| 37 | 45900 | Othr E Rev // Renew Enrgy Cred | | | |
| 38 | | Total Other Operating Revenue and Income | | | **$ -** |
| 39 | | **Summary of above information:** | | | |
| 40 | 451 | Misc Svc Revenue | Line 7 thru 9 | | 0 |
| 41 | 454 | Rent from Property | | | 0 |
| 42 | 456 | Other Elect Rev-Production | Line 11 thru 17 | | 0 |
| 43 | 456 | Other Elect Rev-Wheeling (NITS) | Line 18 thru 26 and Lines 31 thru 34 | | 0 |
| 44 | 456 | Other Elect Rev-NM Coops A&G | Line 35 | | 0 |
| 45 | 456.7016 | Sch 1-NITS | Line 27 | | 0 |
| 46 | 456.7017 | Sch 1-P2P | Line 28 | | 0 |

| | | | | |
|---|---|---|---|---|
| 47 | 456.7018 | Sch 7 & 8 P2P | Line 29 | 0 |
| 48 | 456.0000 | Sch 11 P2P | Line 30 | 0 |
| 49 | 456 | Direct Assigned Revenues | Line 36 | 0 |
| 50 | 459 | Renewable Energy Credits | Line 37 | 0 |
| 51 | | Other Revenues Total | | 0 |

52 Note:
A. The addition of new lines and the removal of outdated lines may be
53 necessary in order to accurately provide
information, and populate or remove data in the Worksheet with changes
54 in future years. Where appropriate, these
changes will provide detail and linkage to updated Form 12 data
55 requirements or other similar supporting
documentation. Additional line items or line deletions will not require FPA
56 Section 205 or 206 filings. WFEC will
describe such changes in the Annual Update, and the changes will be
57 subject to the review of Interested Parties under
the procedures set forth in WFEC's Implementation Protocols. WFEC
58 may not change the columns or the formulas
included in these Worksheets during
59 the Annual Update.

Wor
kshe
et O

**Western Farmers Electric Cooperative, Inc.**

**Construction Work in Process (CWIP) Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Project Description** | **Approval Docket No.** | **Recovery Approved** | **Pricing Zone** | **Approximate Construction Start Date** | **In-Service Date (Estimated)** | **BoY Balance** | **EoY Balance** | **Average Balance** (Col I through J) /2 | **Includable in Rate Base** (Col E * Col K) |
| 1 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 2 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 3 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 4 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 5 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 6 | | | ER16-177 | 50% | 13 | | | | | $ - | $ - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 4 | | | | | | | | |
| 7 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 8 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 9 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 10 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 11 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 12 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 13 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 14 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 15 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 16 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 17 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 18 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 19 | | | ER1 | 50 | | | | | | $ | $ |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | 6-1774 | % | 13 | | | | - | - |
| 20 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 21 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 22 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 23 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 24 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 25 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 26 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 27 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 28 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 29 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 30 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 31 | | | ER16-177 | 50 % | 13 | | | | $ - | $ - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 4 | | | | | | | | |
| 32 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 33 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 34 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 35 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 36 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 37 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 38 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 39 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 40 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 41 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 42 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 43 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 44 | | | ER1 | 50 | | | | | | $ | $ |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 6-1774 | % | 13 | | | | - | - |
| 45 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 46 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 47 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 48 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 49 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 50 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 51 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 52 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 53 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 54 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 55 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 56 | | | ER16-177 | 50% | 13 | | | | $ - | $ - |

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| | | | 4 | | | | | | | | |
| 57 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 58 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 59 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 60 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 61 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 62 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 63 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 64 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 65 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 66 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 67 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 68 | | | ER16-1774 | 50% | 13 | | | | $ - | $ - |
| 69 | | | ER1 | 50 | | | | | $ | $ |

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|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 6-1774 | % | 13 | | | | - | - |
| 70 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 71 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 72 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 73 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 74 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 75 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 76 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 77 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 78 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 79 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 80 | | | ER16-1774 | 50 % | 13 | | | | $ - | $ - |
| 81 | | | ER16-177 | 50 % | 13 | | | | $ - | $ - |

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| | | | 4 | | | | | | | | |
| 82 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 83 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 84 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 85 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 86 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 87 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 88 | | | ER16-1774 | 50% | 13 | | | | | $ - | $ - |
| 89 | **Totals** | | | | | | | | | **$ -** | **$ -** | **$ -** | **$ -** |

90 Notes:

A. Percentage recovery cannot be
91 added or changed absent approval from FERC

B. CWIP amounts should be
92 directly assigned to pricing zone on Summary

C. AFUDC ceases when CWIP is recovered in rate base.

93 No CWIP will be included in rate base absent FERC authorization.

Accounting procedures must be provided during
94 the annual update to ensure that there is no duplicate recovery of

95 CWIP and corresponding AFUDC

capitalized. Projects are transmission related only.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.

Additional line items will not require FPA Section 205 or 206 filings. WFEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation Protocols. WFEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Works
heet P

**Western Farmers Electric Cooperative, Inc.**

**Construction Completed Not Classified**

**Year Ending December 31,**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Project Description** | **BoY Balance** | **EoY Balance** | **Average Balance** (Col D through E) /2 |
| 1 | | | | | $ - |
| 2 | | | | | $ - |
| 3 | | | | | $ - |
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| 94 | **Total** | **$ -** | **$ -** | **$ -** |

95 Note:

96 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide

97 information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these

98 changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting

99 documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. WFEC will

100 describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under

101 the procedures set forth in WFEC's Implementation Protocols. WFEC may not change the columns or the formulas

102 included in these Worksheets during the Annual Update.

Worksheet Q

**Western Farmers Electric Cooperative, Inc.**

**Plant Held for Future Use**
**Year Ending December 31,**

| A Line No | B Facility No. | C Asset No. | D Description | E BoY Investment | F EOY Investment | G Average Investment |
|---|---|---|---|---|---|---|
| 1 | | | | | | $ - |
| 2 | | | | | | $ - |
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| 12 | | | | | | $ - |
| 13 | | | | | | $ - |
| 14 | | | Total Transmission Future Use Assets | $ - | $ - | $ - |
| 15 | | | Note: | | | |
| 16 | | | A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide | | | |

information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. WFEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation Protocols. WFEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet R

**Western Farmers Electric Cooperative, Inc.**

**Regulatory and Commission Expenses**
**Year Ending December 31,**

| A Line No. | B Account 928 | C Description | D Total Company | E Non-SPP Expenses | F SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
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| 10 | | Total | $ - | $ - | $ - |

11 Note:
12 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with
13 changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12
14 data requirements or other similar supporting documentation. Additional line items or line deletions will not require
15 FPA Section 205 or 206 filings. WFEC will describe such changes in the Annual Update, and the changes will be
16 subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation Protocols. WFEC
17 may not change the columns or the formulas included in these Worksheets
18 during the Annual Update.

Worksheet S

**Western Farmers Electric Cooperative, Inc.**

**Qualified Substations Year Ending December 31,**

| A | B | C | D | E |
|---|---|---|---|---|
| Line No. | Name | Long Name | Voltage (kV) | Property Description (Located in following counties) |
| 1 | | | | |
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| 111 | Tran Subs Qualified Gross Plant | |

112 Note:

113 A. The addition of new lines and the removal of outdated lines may be

necessary in order to accurately
provide information, and populate or remove data in the Worksheet with changes in future years.
Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or
other similar supporting documentation. Additional line items or line deletions will not require FPA Section
205 or 206 filings. WFEC will describe such changes in the Annual Update, and the changes will be
subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation
Protocols. WFEC may not change the columns or the formulas included in these Worksheets during
the Annual Update.

**Western Farmers Electric Cooperative, Inc.**

Worksheet T

**Qualified Lines**
**Year Ending December 31,**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Line No. | From | To | Voltage (kV) | LENGTH (Miles) | Property Description (Located in following counties) |
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| 286 | | | | | |
| 287 | | | | | |
| 288 | | | | | |

| | | |
|---|---|---|
| 289 | Total Qualified Miles | - |

| | Description | Owned Miles | Qualified Miles | Ratio |
|---|---|---|---|---|
| 291 | Tran Qual Ckt Miles - 138 kV | | - | |
| 292 | Tran Qual Ckt Miles - 69 kV | | - | |
| 293 | Total 138 & 69 kV | | - | |

294 Note:
295 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately
296 provide information, and populate or remove data in the Worksheet with changes in future years.
297 Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or
298 other similar supporting documentation. Additional line items or line deletions will not require FPA Section
299 205 or 206 filings. WFEC will describe such changes in the Annual Update, and the changes will be
300 subject to the review of Interested Parties under the procedures set forth in WFEC's Implementation
301 Protocols. WFEC may not change the columns or the formulas included in these Worksheets during
302 the Annual Update.

Work sheet U

# Western Farmers Electric Cooperative, Inc.

**Account 575/576 Expenses**
**Year Ending December 31,**

| Line | B Account No. | C Description | D Annual Expense Amount | E % Included in SPP | F SPP Amount |
|---|---|---|---|---|---|
| | | **575.1-575.8 RTO/ISO Expense - Operation** | | | |
| 1a | | | $0.00 | 100% | $0.00 |
| 1b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 2 | | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)** | $0.00 | | $0.00 |
| | | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | |
| 3a | | | $0.00 | 100% | $0.00 |
| 3b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 4 | | **576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)** | $0.00 | | $0.00 |

5 Notes
6 A. The total on line 2, column D must reconcile to the amounts shown on RUS12.
7 B. The total on line 4, column D must reconcile to the amounts shown on RUS12.
8 C. Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for inclusion in SPP Zone 13 ATRR following a change in

accounting procedures to the RUS Form 12 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that this occurs, WFEC may file a single-issue Section 205 filing with the Commission to seek recovery of these amounts in Zone 13 rates. WFEC may not include any costs absent authroization from FERC via a Section 205 or 206 filing.

D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

# Western Farmers Electric Cooperative

# Transmission Formula Rate Implementation Protocols

## Section I. Introduction

1. WFEC's Formula Rate Template and these Protocols together comprise the filed rate for transmission service in Zone 13 of the SPP footprint. The Formula Rate will become effective for recovery of WFEC's ATRR upon the effective date authorized by FERC.

2. WFEC will follow the instructions specified in the Formula Rate to calculate its ATRR upon which the rates for NITS and PTP in SPP Zone 13 are based.

3. Recovery of costs associated with existing and new facilities will be consistent with Attachment AI and Attachment J, respectively, of the SPP Tariff, as well as with the Formula Rate.

4. Defined terms are set forth in section III below.

## Section II. Annual Update

1. The Formula Rate will be applicable to service on and after July 1 of each calendar year through June 30 of the following calendar year, subject to review, challenge and refunds or surcharges with interest, to the extent provided herein. The ATRR will be determined using the most recent historical calendar year financial and operating data.

2. On or before April 15 of each calendar year, WFEC will (a) calculate the ATRR for the Rate Year starting July 1 of that calendar year in accordance with the Formula Rate utilizing the most recent historical calendar year financial and operating data; (b) calculate, for illustrative purposes, the corresponding rates for NITS and PTP in SPP's Zone 13 for the Rate Year; and (c) provide its Annual Update to SPP and cause such information to be accessible on SPP's website and OASIS.

   If the date for posting the Annual Update falls on a weekend or a holiday, then the posting will be due on the next business day. If preparation and/or posting of the Annual Update is delayed past April 15 for reasons beyond WFEC's reasonable control, WFEC will post the Annual Update as soon thereafter as practical.

3. Concurrent with the Annual Update posting, WFEC will provide a notice of such posting to Interested Parties through the email Service List maintained by SPP.

4. The Annual Update will:

   (a) Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update with the most recent

historical calendar year financial and operating data along with the underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

(b) Be based on the independently audited books and records of WFEC for the most recent historical calendar year including its RUS Financial and Operating Report – Electric Power Supply (formerly known as the RUS Form No. 12);

(c) Include WFEC's completed RUS Financial and Operating Report – Electric Power Supply for the most recent calendar year;

(d) Provide sufficient information to enable Interested Parties to replicate the calculation of the results from the Formula Rate;

(e) Identify changes in accounting that affect the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, including:

i. Any accounting changes, such as the initial implementation of an accounting standard or policy, the initial implementation of accounting practices for unusual or unconventional items where the RUS has not provided specific direction, or the correction of errors and prior period adjustments that impact the ATRR;

ii. Any items included in the Formula Rate at an amount other than a historical cost basis;

iii. Individual impact of any changes in section II.4(e)i above on charges billed under the Formula Rate; and

iv. Accounting changes related to any reorganization or merger transaction and the effect of those changes on inputs to the formula rate; and

(f) Not seek to modify the Formula Rate.

5. Any modification to the Formula Rate will require a filing under FPA Section 205 or FPA Section 206.

## Section III. Definitions

For purposes of these Protocols, the following capitalized terms will have the meanings set forth below. Capitalized terms not defined in these Protocols will have the meanings ascribed to them in the SPP Tariff.

(a) "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services for WFEC under the SPP Tariff (Zone 13) calculated, posted and filed in accordance with the Formula Rate.

(b) "Annual Meeting" means the meeting hosted by WFEC for the purpose of exchanging information with Interested Parties regarding the Annual Update.

(c) "Annual Update" means WFEC's annual posting of its Formula Rate, in a working Excel™ format, in accordance with these Protocols.

(d) "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and federal holidays.

(e) "Critical Energy Infrastructure Information" or "CEII" has the meaning set forth in 18 C.F.R. § 388.113(c)(1).

(f) "Customers" means the customers taking NITS service, service under Grandfathered Agreements, or PTP service.

(g) "FERC" or "Commission" means the Federal Energy Regulatory Commission.

(h) "Final Posting" means the Annual Update information posted to the SPP website and OASIS with changes agreed to during the Review Period, as set forth in section IV.B.5 below.

(i) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with the Commission, and served on WFEC by electronic service on the date of such filing.

(j) "Formula Rate" means these Protocols together with the Formula Rate Template.

(k) "Formula Rate Template" means the WFEC transmission formula rate template incorporated in the SPP Tariff and accepted by FERC.

(l) "FPA" means Federal Power Act.

(m) "Grandfathered Agreement" means those agreements listed in Attachment W of the SPP Tariff to which WFEC is a party.

(n) "Informal Challenge" means written notification by an Interested Party to WFEC, during the Review Period, of any specific challenge to the Annual Update.

(o) "Information Request" means a written request submitted by an Interested Party to WFEC during the Review Period in accordance with these Protocols.

(p) "Informational Filing" means WFEC's annual filing with the Commission of the information specified in these Protocols.

(q) "Initial Posting" means the Annual Update data and information which WFEC posts, or causes to be posted, to the SPP website and OASIS in accordance with section II.2 of these Protocols.

(r) "Initial Posting Date" means the date on which the Initial Posting is actually made.

(s) "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a(a)(2)(iii), or successor regulation.

(t) "Interested Party" includes but is not limited to Customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

(u) "Mistake" means errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors, but excluding matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the Annual Update review process.

(v) "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

(w) "OASIS" means SPP's Open Access Same-Time Information System.

(x) "Protocols" means these Transmission Formula Rate Protocols, as they may be amended from time to time.

(y) "PTP" means Point-to-Point Transmission Service as defined in the SPP Tariff.

(z) "Rate Year" means July 1 of a given year through June 30 of the subsequent year.

(aa) "Review Period" means, unless otherwise extended in writing by WFEC, the period that begins on the Initial Posting Date and ends 60 days after the Initial Posting Date.

(bb) "RUS" means the Rural Utilities Service.

(cc) "Service List" means the email service list maintained by SPP for distribution of formula rate notices.

(dd) "SPP" means Southwest Power Pool, Inc.

(ee) "SPP Tariff" means SPP's Open Access Transmission Tariff.

(ff) "Stated Values" means inputs to the Formula Rate that are fixed and not subject to change in an Annual Update, including: (i) the base return on equity, (ii) any approved adders to the base return on equity, (iii) any return on equity incentives for SPP regional transmission projects, (iv) depreciation and amortization rates, and (v) the hypothetical equity ratio floor established in Docket No. ER16-1774-000.

(gg) "USoA" means the RUS Uniform System of Accounts.

(hh) "WFEC" means Western Farmers Electric Cooperative.

## Section IV. Review of Annual Update

## A. Annual Meeting

Within 20 calendar days of the Initial Posting Date, WFEC will host a meeting for Interested Parties to discuss the Annual Update. WFEC will provide notice of this meeting concurrently with the posting of the Annual Update accessible on SPP's OASIS. The notice will include the date, time and location of the Annual Meeting, and will be provided to Interested Parties through the email Service List maintained by SPP. The Annual Meeting will also be available by telephone and/or web access with all meeting materials provided electronically from the SPP OASIS.

## B. Information Exchange & Final Posting

1. During the Review Period, Interested Parties may submit to WFEC reasonable requests for information, data and work papers supporting the Annual Update that was posted on the Initial Posting Date that commenced such Review Period. Information Requests will be limited to that which is necessary to determine:

   (a) The extent or effect of an accounting change;

   (b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

   (c) The proper application of the Formula Rate and procedures in these Protocols;

   (d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

   (e) The effect of any change to the underlying USoA or Formula Rate Template; and

   (f) Any other information that may reasonably have a substantive effect on the calculation of the ATRR pursuant to the Formula Rate.

   Information Requests may not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. WFEC will not claim that responses to Information Requests pursuant the Protocols are subject to any settlement confidentiality provision; however, WFEC may require that Interested Parties execute a non-disclosure agreement to obtain access to material that WFEC deems commercially sensitive or otherwise confidential or that WFEC asserts is CEII.

2. WFEC will make a good faith effort to respond to each Information Request within 7 Business Days of receipt of the Information Request.

3. WFEC will post, or cause to be posted, on a publicly accessible portion of the SPP OASIS all Information Requests from Interested Parties and WFEC's response(s) to such Information Requests, and a link to the website will be electronically served by WFEC on all Interested Parties via the email Service List maintained by SPP and provided to WFEC. If responses to Information Requests contain information deemed by WFEC to be commercially sensitive or otherwise confidential or CEII, such responses will not be publicly posted but will be made available by separate means to Interested Parties that have executed a non-disclosure agreement with WFEC.

4. Any changes or adjustments to the Annual Update resulting from the Information Request procedures that are agreed to by WFEC and resolved prior to the end of the Review Period will be reported in a revised and final posting of the Annual Update on the SPP OASIS.

5. Any changes or adjustments to the Annual Update resulting from the Information Request procedures that are agreed to by WFEC after the Review Period will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year.

6. If the Review Period ends on a weekend or holiday, the Review Period will be extended to the next Business Day.

7. WFEC will post, or cause to be posted, the Final Posting on a publicly accessible portion of the SPP OASIS, and a link to the website will be electronically served by WFEC on all Interested Parties via the email Service List maintained by SPP. The Final Posting will be made within 15 days after the end of the Review Period (or the first Business Day thereafter if the 15th day falls on a weekend or holiday).

## C. Informal Challenge Procedures

1. Interested Parties will have until the conclusion of the Review Period to notify WFEC in writing (which may be electronically) of any Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocation calculations, or other information to which the Interested Party objects, and provide an appropriate explanation and documents to support the objection. WFEC will make a good faith effort to respond to any Informal Challenge within 20 calendar days of receipt of such Informal Challenge. WFEC, and if appropriate SPP, will appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. WFEC will post, or cause to be posted, on a publicly accessible portion of the SPP OASIS all Informal Challenges from Interested Parties and WFEC's responses to the Informal Challenges, and a link to the website will be electronically served by WFEC on all Interested Parties via the email Service List maintained by SPP. If responses to

Informal Challenges contain information deemed by WFEC to be commercially sensitive or otherwise confidential or CEII, such information will not be publicly posted but will be made available by separate means to Interested Parties that have executed a non-disclosure agreement with WFEC.

3. Any changes or adjustments to the Annual Update resulting from the Informal Challenge procedures that are agreed to by WFEC and resolved prior to the end of the Review Period will be reported in the Final Posting on the SPP OASIS. Any changes or adjustments to the Annual Update resulting from the Informal Challenge procedures that are agreed to by WFEC after the Review Period will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year. An Interested Party that pursues or fails to pursue an Informal Challenge does not implicitly waive its rights to raise a Formal Challenge with FERC or file a complaint under FPA Section 206.

## D. Formal Challenges

1. A Formal Challenge will:

(a) Clearly identify the action or inaction which is alleged to violate the Formula Rate;

(b) Explain how the action or inaction violates the Formula Rate;

(c) Set forth the business, commercial, economic, or other issues presented by the action or inaction as they relate to or affect the Interested Party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate Template and the procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying USoA or Formula Rate Template; and

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate;

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the Interested Party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all information and documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the Interested Party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges will be filed with FERC, either in the FERC docket assigned to the Informational Filing or via Section 206 of the FPA, and must be served upon WFEC contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in WFEC's Informational Filing.

3. Any response by WFEC to a Formal Challenge must be submitted to the Commission within 30 days of the date of the filing of the Formal Challenge (unless the Commission prescribes or allows a different response date), and will be served on the filing party or parties and the Service List by electronic service on the date of such filing. If the last date for WFEC's response falls on a non-Business Day, then the deadline will be extended to the next Business Day.

4. In any Commission proceeding concerning a Formal Challenge (other than an FPA Section 206 complaint, investigation or other proceeding initiated by an Interested Party or the Commission), WFEC will bear the burden of demonstrating that it has properly applied the Formula Rate and that it has reasonably and accurately calculated the Annual Update.

## E. Modification of Formula Rate or Annual Update

1. Any modification to the Formula Rate will require a filing under FPA Section 205 or FPA Section 206. The procedures for the Annual Update, Informal Challenges, and Formal Challenges set forth in these Protocols may not be used to modify the Formula Rate.

2. The Stated Values in the Formula Rate may not be modified through the Annual Update, Informal Challenge, or Formal Challenge procedures. Modifications to the Stated Values require a filing with FERC pursuant to the FPA Section 205 or FPA Section 206.

3. If WFEC makes a correction to a Mistake during a Rate Year that would affect the ATRR for that Rate Year, such corrections and any resulting refunds or surcharges will be reflected in the Annual Update for the next Rate Year with Interest.

4. Any changes to the Formula Rate data inputs or to the Formula Rate that are the result of a Section 205 or Section 206 proceeding will be incorporated into the Formula Rate, and the charges produced by the Formula Rate, in the Annual Update for the next Rate Year.

5. Any refund required as a result of changes to the ATRR as provided in this section IV.E will include Interest calculated in accordance with 18 C.F.R. § 35.19a(a)(2).

## F. FERC Informational Filing

1. No later than 15 days after the Final Posting, WFEC will submit to FERC an informational filing of its Annual Update.

2. The Informational Filing must include the information that is reasonably necessary to determine:

   (a) That input data under the Formula Rate is properly recorded in any underlying work papers;

   (b) That WFEC has properly applied the Formula Rate Template and the procedures in these Protocols;

   (c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   (d) The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal Challenge or Formal Challenge procedures.

4. Unless otherwise directed by FERC, WFEC will submit all Informational Filings in the same docket assigned to WFEC's first Informational Filing.

5. Contemporaneously with the submission to FERC of the Informational Filing, WFEC will provide notification of the Informational Filing to Interested Parties via the email Service List maintained by SPP and by posting, or causing to be posted, the docket number assigned to the Informational Filing on SPP's OASIS.

# Section V. Joint SPP Transmission Owners' Meeting

As applicable, each year WFEC will exercise commercially reasonable efforts to coordinate with other SPP transmission owners using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing

mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects. Notice of joint informational meetings, including the time, date, and location, will be posted on the SPP OASIS and distributed to Interested Parties by WFEC via the email Service List maintained by SPP no less than 7 calendar days prior to such meetings.

## Section VI. WFEC Example Schedule

**Example Schedule - Implementation Protocols**

| | Date | Days Since Initial Posting |
|---|---|---|
| Initial Posting (SPP Website and OASIS) | April 15 | - |
| Annual Meeting, Interested Parties | April 30 | 15 |
| Interested Parties Review Period ending | June 15 | 61 |
| Final Informal Challenges Due | June 30 | 61 |
| Final Posting (SPP Website and OASIS) | June 30 | 76 |
| Informational Filing With FERC | July 15 | |
| Rate Year | July 1 - June 30 | |

The foregoing schedule is for illustrative purposes only, and is not intended to modify the filing and other dates outlined in these Protocols.

# ADDENDUM 40 TO ATTACHMENT H

## Denison Municipal Utilities



**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Index
12 Months Ended June 30, 2XXX

| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |
| Schedule 9 | Revenue Credits | Yes |
| Schedule 10 | Other Rate Base Balances | Yes |
| Schedule 11 | Supplemental O&M Expense Detail | Yes |
| Schedule 12 | Supplemental Transmission Expense Detail | Yes |
| Workpaper 1 | Electric Depreciation | Yes |
| Workpaper 2 | Power Bills | Yes |
| Workpaper 3 | PILOT | Yes |

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H (Utilizing EIA Form 412 - Nonlevelized)

12 Months Ended June 30, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Allocator | Transmission Amount ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | GROSS REVENUE REQUIREMENT | Page 3, Line 19 | | | #DIV/0! |
| | REVENUE CREDITS | | | | |
| 2 | Account No. 454 | Schedule 9, Column C, Line 2 | - | TP 0.00% | - |
| 3 | Transmission charges for all transmission transactions | Schedule 9, Column D, Line 2 | - | TP 0.00% | - |
| 4 | Transmission charges for all transmission transactions included in Native Load | Schedule 9, Column E, Line 2 | - | TP 0.00% | - |
| 5 | Account No. 456.1 | (line 3 less line 4) | - | TP 0.00% | - |
| 6 | Revenues from service provided by the ISO at a discount | Schedule 9, Column F, Line 2 | - | TP 0.00% | - |
| 7 | TOTAL REVENUE CREDITS | (sum lines 2, 5, 6) | | | - |
| 8 | ATRR for SPP Directed Projects | Schedule 1, Column I, Line 2 | | | #DIV/0! |
| 9 | NET REVENUE REQUIREMENT | (line 1 minus lines 7 | | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| | | and 8) | | | |
| 10 | Date of Data Used to Calculate Revenue Requirement | Enter Last Date of 12-Month Period | | | 6/30/XX |



**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | | **Transmission Amount ($)** |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | | (e) |
| | **RATE BASE** | | | | | |
| | GROSS PLANT IN SERVICE (Note D) | | | | | |
| 1 | Production | Schedule 4, Column H, Line 6 | - | NA | 0.00% | - |
| 2 | Transmission | Schedule 4, Column H, Line 7 | - | TP | 0.00% | - |
| 3 | Distribution | Schedule 4, Column H, Line 8 | - | NA | 0.00% | - |
| 4 | General & Intangible | Schedule 4, Column H, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | TOTAL GROSS PLANT | (sum lines 1-4) | - | **GP=** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note D) | | | | | |
| 6 | Production | Schedule | | N | 0.0 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | 4, Column P, Line 6 | - | A | 0% | - |
| 7 | Transmission | Schedule 4, Column P, Line 7 | - | TP | 0.00% | - |
| 8 | Distribution | Schedule 4, Column P, Line 8 | - | NA | 0.00% | - |
| 9 | General & Intangible | Schedule 4, Column P, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 10 | TOTAL ACCUM. DEPRECIATION | (sum lines 6-9) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 11 | Production | (line 1 - line 6) | - | | | - |
| 12 | Transmission | (line 2 - line 7) | - | | | - |
| 13 | Distribution | (line 3 - line 8) | - | | | - |
| 14 | General & Intangible | (line 4 - line 9) | - | | | #DIV/0! |
| 15 | TOTAL NET PLANT | (sum lines 11-14) | - | **NP =** | **#DIV/0!** | #DIV/0! |
| 16 | LAND HELD FOR FUTURE USE | Schedule 10, Columns C & D, Line 2 | - | Direct Assign - Sch. 10 | | - |
| | WORKING CAPITAL (Note A) | | | | | |
| 17 | CWC | (1/8 * page 3, line 9) | - | | | #DIV/0! |
| 18 | Materials & Supplies | Schedule 10, Columns C & D, Line 4 | - | Direct Assign - Sch. 10 | | - |
| 19 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 20 | TOTAL WORKING CAPITAL | (sum lines 17 - 19) | - | | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 21 | RATE BASE | (sum lines 15, 16, and 20) | - | | #DIV/0! |



**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Allocator | Transmission Amount ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | O&M | | | | |
| 1 | Transmission | Schedule 7, Column E, Line 8 | - | TE 0.00% | - |
| 2 | Less LSE Expenses included in Transmission O&M Accounts | Schedule 11, Column C, Line 2 | - | TE 0.00% | - |
| 3 | Less Account 565 | Schedule 7, Column C, Line 8a | - | TE 0.00% | - |
| 4 | A&G | Schedule 7, Column E, Line 15 | - | W/S #DIV/0! | #DIV/0! |
| 5 | Less FERC Annual Fees | Schedule 11, Column C, Line 4 | - | W/S #DIV/0! | #DIV/0! |
| 6 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad | Schedule 11, Column C, Line 6 | - | W/S #DIV/0! | #DIV/0! |
| 7 | Plus Transmission Related Reg. Comm. Exp. | Schedule 11, Column D, Line 6 | - | W/S #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | Transmission Lease Payments | Schedule 11, Column C, Line 8 | - | T | 0.00% | - |
| 9 | TOTAL O&M | (sum lines 1, 4, 7, 8 less lines 2, 3, 5, 6) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note D) | | | | | |
| 10 | Transmission | Schedule 4, Column Q, Line 7 | - | TP | 0.00% | - |
| 11 | General & Intangible | Schedule 4, Column Q, Line 1 and Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 12 | TOTAL DEPRECIATION | (Sum lines 10 - 11) | - | | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note B) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S | #DIV/0! | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S | #DIV/0! | #DIV/0! |
| | PLANT RELATED | | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP | #DIV/0! | #DIV/0! |
| 16 | Payments in lieu of taxes | Schedule 5, Column B, Line 7 | - | GP | #DIV/0! | #DIV/0! |
| 17 | TOTAL OTHER TAXES | (sum lines 13, 14, 15, 16) | - | | | #DIV/0! |
| 18 | RETURN | (page 2, line 21 * R) | #DIV/0! | | | #DIV/0! |
| 19 | GROSS REVENUE REQUIREMENT | (sum lines 9,12,17,18) | #DIV/0! | | | #DIV/0! |

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Allocator | Transmission Amount ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | |
| 1 | Total transmission plant | Page 2, Column E, Line 2 | | | - |
| 2 | Less transmission plant excluded from ISO rates | Schedule 12, Column E, Line 2 | | | - |
| 3 | Less transmission plant included in OATT Ancillary Services | Schedule 12, Column E, Line 4 | | | - |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | - |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | **TP =** | **0.00 %** |
| | TRANSMISSION EXPENSES | | | | |
| 6 | Total transmission expenses | Page 3, Column C, Line 1 | | | - |
| 7 | Less transmission expenses included in OATT Ancillary Services | Schedule 12, Page 2, Column D, Line 2 | | | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | Included transmission expenses | (line 6 less line 7) | | | | | | - |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | | | | 0.00 % |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line 5) | | | | **TE =** | | **0.00 %** |
| | WAGES & SALARIES | | | | | | | |
| 11 | Production | Schedule 8, Column E, Line 2 | - | | NA | 0.00% | | - |
| 12 | Transmission | Schedule 8, Column E, Line 5 | - | | TP | 0.00% | | - |
| 13 | Distribution | Schedule 8, Column E, Line 8 | - | | NA | 0.00% | | - |
| 14 | Other | Schedule 8, Column E, Line 11 | - | | NA | 0.00% | | - |
| 15 | Total | (sum lines 11-14) | - | | | | | - |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | | |
| 17 | Wages & Salaries Allocator (Note F) | (line 15, Column E divided by Column C) | | | | **W/S =** | | **#DIV/0!** |
| | RATE OF RETURN (R) | | | | | | | |
| 18 | Long Term Interest (Note C) | Schedule 3, Column B, Line 16 | - | | | | | |
| | | | $ Amount | % | Cost (Note O) | | | Weighted |
| 1 | Long Term Debt | Schedule | | #DI | 0.0 | | | #DI |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | | 2, Column D, Line 37 | - | V/0! | 0% | V/0! |
| 20 | Proprietary Capital | Schedule 2, Column D, Line 32 | - | #DIV/0! | 10.10% | #DIV/0! |
| 21 | Total | (sum lines 25, 26) | - | #DIV/0! | | #DIV/0! |



**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

Notes:

A Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165.

B Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,
since they are recovered elsewhere.

C Include only the amount from Accounts 427, 428, 429 and 430.

D Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation and Acquisition Adjustment amounts unless authorized by FERC.

E Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate.

F If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant

| | |
|---|---|
| | includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| G | The weighted average cost of capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The weighted average cost of capital includes the incentive adder of 50 basis points approved in Docket No. ER17-426. |

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

12 Months Ended June 30, 2XXX

| **Line No.** | **Description** | **Source Reference** | **Transmission Amount ($)** |
|---|---|---|---|
| | (a) | (b) | (c) |
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, Page 2, Column E, Line 2 | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, Page 2, Column E, Line 8 | - |
| 3 | Net Transmission Plant - SPP (Note B) | (line 1 less line 2) | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, Page 3, Column E, Line 8 | #DIV/0! |
| **5** | **Annual Allocation Factor for O&M** | **(line 4 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, Page 3, Column E, Line 19 | #DIV/0! |
| **7** | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| **8** | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, Page 3, Column E, Line 12 | #DIV/0! |

| | | | |
|---|---|---|---|
| 10 | Return | Attach H, Page 3, Column E, Line 20 | #DIV/0! |
| 11 | Depreciation plus return | (line 9 plus line 10) | #DIV/0! |
| **12** | **Annual Allocation Factor for Depreciation and Return** | **(line 11 divided by line 3)** | **#DIV/0!** |



**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1: SPP Directed Projects ATRR
12 Months Ended June 30, 2XXX

| Line No. | Upgrade Name | Upgrade ID | Upgrade Gross Plant | Annual Allocation Factor for Expense | Annual Expense Charge | Upgrade Net Plant | Annual Allocation Factor for Depreciation & Return | Annual Charge for Depreciation & Return | Net Annual Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | (Note C) | (Page 1 line 8) | (Col. C * Col. D) | Note D | (Page 1 line 12) | (Col. F * Col. G) | (Sum Col. E & H) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1 | Project 6 | | $ | #DIV/ | #DIV/ | $ | #DIV/ | #DIV/ | #DIV/0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| f | Project 6 | - | 0! | 0! | - | 0! | 0! | ! |
| ... | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | | | | | | |
| 2 | Annual Totals | | | | | | | #DIV/0! |

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 1a- Line 2.

D Net Plant is derived from Schedule 1a- Line 6 and includes all CWIP

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1a: SPP Directed Projects
12 Months Ended June 30, 2XXX

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **July** | **August** | **September** | **October** | **November** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **12 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | |
| 1a | Project 1 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 1b | Project 2 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 1c | Project 3 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 1d | Project 4 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 1e | Project 5 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 1f | Project 6 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| **2** | **Total Gross Plant in Service** | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | |
| 3a | Project 1 | | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | |
| 4 | **Total Accumulated Depreciation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Net Plant in Service** | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | |
| 6 | **Total Net Plant in Service** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 2: Electric Balance Sheet (EIA Form 412)
12 Months Ended June 30, 2XXX

| Column | A | B | | C | D |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| 1 | **ELECTRIC PLANT** Electric Plant & Adjustments (101-106,114,116) | | 29 | **PROPIETARY CAPITAL** Investment of Municipality (208) | $ - |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | $ - |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and Depletion (108,111,115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | $ - |
| 7 | **Net Electric Plant including Nuclear Fuel** | **$ -** | 34 | Advances from Municipality and Other Long Term Debt (223, 224) | $ - |
| 8 | **OTHER PROPERTY & INVESTMENTS** Non-Electric Plant Property (121) | $ - | 35 | Unamortized Premium on Long Term Debt (225) | $ - |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | $ - | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | $ - | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| 13 | **CURRENT & ACCRUED ASSETS** Cash, Working Funds & Investments (131-136) | | 38 | Accumulated Operating Provisions (228.1-.4) | |
| | | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Receivable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | $ - |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | |
| 26 | Miscellaneous Debt, Research and Development Expenses | | 51 | Unamortized gain on | |

| | | | | | |
|---|---|---|---|---|---|
| | & Unamortized Losses (184-191) | | | Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | $ - |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | $ - |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | **$ -** |
| 8 | **NET ELECTRIC OPERATING INCOME** | **$ -** |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | **$ -** |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | $ - |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | $ - |
| 15 | Electric Income | **$ -** |
| 16 | Income Deductions from Interest on Long Term Debt (427) | $ - |
| 17 | Other Income Deductions (428-431) | $ - |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | $ - |

| | | |
|---|---|---|
| 19 | Total Income Deductions | **$ -** |
| 20 | Income Before Extraordinary Items | **$ -** |
| 21 | Extraordinary Items (434) | $ - |
| 22 | Extraordinary Deductions (435) | $ - |
| 23 | **NET INCOME** | **$ -** |

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 4: Electric Plant (EIA Form 412)
12 Months Ended June 30, 2XXX



**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 4: Electric Plant (EIA Form 412)
12 Months Ended June 30, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjustment to BOY Balance (Note A) | Adjusted Beginning Balance | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjustment to BOY Balance (Note A) | Adjusted Beginning Balance | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | | | | | | |
| 2 | Steam Production (310- | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 316) | | | | | | | | | | | | | | | | | | |
| 3 | Nuclear Production (320-325) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | | $ - | $ - | $ - | $ - | $ - | |
| 4 | Hydraulic Production (330-336) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | | $ - | $ - | $ - | $ - | $ - | |
| 5 | Other Production (340-346) | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | | $ - | $ - | $ - | $ - | $ - | |
| 6 | **Total Production Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |
| | | | | | | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | | | $ - | $ - | $ - | $ - | | | | | $ - | | $ - | $ - | $ - | |
| 8 | Distribution Plant (360-373) | | | | | $ - | $ - | $ - | $ - | | | | | $ - | | $ - | $ - | $ - | |
| 9 | General Plant (389-399) | | | | | $ - | $ - | $ - | $ - | | | | | $ - | $ - | $ - | $ - | $ - | |
| 10 | **Total Electric** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Plant In Service** | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | **Total Electric Plant & Adj's** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

Notes:

| | |
|---|---|
| A | One time adjustment for transition to SPP year, will be hardcoded with zeros following initial year<br>Adjustments reflect a one time provision to account for year of transition to SPP and will be hardcoded with zeroes after the initial year. |

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 5: Taxes other than Income Taxes (EIA Form 412)
12 Months Ended June 30, 2XXX

| Line No. | Description | Amount ($) | Source Reference | Notes/Comments |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | **Taxes other than Income Taxes, Operating Income** | | | |
| | **Payroll Taxes:** | | | |
| 1 | FICA Taxes | | | |
| 2 | Unemployment Taxes | $ - | | |
| | **Plant Related Taxes:** | | | |
| 3 | Highway Taxes | $ - | | |
| 4 | Property Taxes | $ - | | 0 |
| 5 | Payment In Lieu of Taxes (Transfer) | | | |

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended June 30, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | N/A |
| 3 | 351 | Energy Storage Equipment - Transmission | 30 | 3.3% |
| 4 | 352 | Structures & Improvements | 28.5 | 3.5% |
| 5 | 353 | Station Equipment | 28.5 | 3.5% |
| 6 | 354 | Towers & Fixtures | 30 | 3.3% |
| 7 | 355 | Poles & Fixtures | 28.5 | 3.5% |
| 8 | 356 | Overhead Conductors and Devices | 30 | 3.3% |
| 9 | 357 | Underground Conduit | 30 | 3.3% |
| 10 | 358 | Underground Conductors and Devices | 30 | 3.3% |
| 11 | 359 | Roads and Trails | 30 | 3.3% |
| 12 | | **General Plant** | | |
| 13 | 390 | Structures & Improvements | 40 | 2.5% |
| 14 | 391 | Office Furniture and Equipment | 7.5 | 13.3% |
| 15 | 392 | Transportation Equipment | 10 | 10.0% |
| 16 | 393 | Stores Equipment | 10 | 10.0% |
| 17 | 394 | Tools, Shop and Garage Equipment | 10 | 10.0% |
| 18 | 395 | Laboratory Equipment | 7 | 14.3% |
| 19 | 396 | Power Operated Equipment | 10 | 10.0% |
| 20 | 397 | Communication Equipment | 5 | 20.0% |
| 21 | 398 | Miscellaneous Equipment | 10 | 10.0% |

| | | | | |
|---|---|---|---|---|
| 22 | | **Intangible Plant** | | |
| 23 | 301 | Organization | 30 | 3.3% |
| 24 | 302 | Franchises and consents | 30 | 3.3% |
| 25 | 303 | Miscelaaneous intangible plant | 30 | 3.3% |

*** Land is not depreciable.**

**Note: These depreciation/amortization rates will not be changed absent a FERC order.**

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: O&M Expense (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | $ - | | $ - | $ - |
| 5 | Purchased Power (555) | $ - | | $ - | $ - |
| 6 | Other Production Expenses (556-557) | $ - | $ - | $ - | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-564 and 566-567, 568-573) | XXXXXXXXXXXX | $ - | | $ - |
| 8a | Transmission of Electricity by Others (565) | | $ - | | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXXX | $ - | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXXX | | $ - | $ - |
| 11 | Customer Service & Information Expenses (907-910) | XXXXXXXXXXXX | | $ - | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXX | | $ - | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXX | | $ - | $ - |
| 14 | Adjustment to Remove Payroll Taxes | XXXXXXXXXXXX | | | $ - |
| 15 | Adjusted A&G Expense (line 13 less 14) | XXXXXXXXXXXX | $ - | $ - | $ - |
| 16 | Total Electric Operation and Maintenance Expenses | **$** - | **$** - | **$** - | **$** - |

| | | |
|---|---|---|
| 17 | Total Number of Full Time Employees | 30 |
| 18 | Total Number of Part Time Employees | 1 |

| | | | | | |
|---|---|---|---|---|---|
| 19 | Common O&M Expense | $ - | $ - | $ - | $ - |

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | | Accounts | Salaries | |
| 1 | | | Production / Generation | | |
| 2 | | | Salaries | $ - | $ - |
| 3 | | | | | |
| 4 | | | Transmission: | | |
| 5 | | | Salaries | | $ - |
| 6 | | | | | |
| 7 | | | Distribution: | | |
| 8 | | | Salaries | | $ - |
| 9 | | | | | |
| 10 | | | Customer Service & Information | | |
| 11 | | | Meter Reading Salaries | | $ - |
| 12 | | | | | |
| 13 | | | Administrative & General | | |
| 14 | | | Salaries | | $ - |
| 15 | | | | | |
| 16 | | | **Total** | $ - | $ - |

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 9: Revenue Credits

12 Months Ended June 30, 2XXX

| Line No. | Description (Note A) | Source Reference | Account 454 (Note B) | Transmission Charges for All Transactions | Transmission Charges for All Transactions in Native Load | Revenues from Services Provided by the ISO at a Discount |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1a | | | | | | |
| 1b | | | | | | |
| 1c | | | | | | |
| … | | | | | | |
| | | | | | | |
| 2 | **Total Amounts** | (sum lines 1a thru 1xx) | $0 | $0 | $0 | $0 |

Notes:

A Only amounts included in the calculation of Vermillion's SPP Zone 19 revenue requirement should be included. The amounts credited shall only include amounts directly received from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this formula rate template.

B Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 10: Other Rate Base Balances
12 Months Ended June 30, 2XXX

| Line No. | Description (Note A) | Source Reference | Total Company Amount ($) | SPP Transmission Amount ($) (Note A) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | LAND HELD FOR FUTURE USE | | | |
| 1a | | | | |
| 1b | | | | |
| 1c | | | | |
| … | | | | |
| | | | | |
| 2 | **Total Land Held for Future Use** | (sum lines 1a thru 1xx) | $0 | $0 |
| | MATERIALS AND SUPPLIES | | | |
| 3a | | | | |
| 3b | | | | |
| 3c | | | | |
| … | | | | |
| | | | | |
| 4 | **Total Materials and Supplies** | (sum lines 3a thru 3xx) | $0 | $0 |

Notes:
A Transmission related only.

**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 11: Supplemental O&M Expense Detail

12 Months Ended June 30, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Transmission Amount ($) (Note A) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | LSE Expenses Included in Transmission O&M Accounts | | | |
| 1a | | | | |
| 1b | | | | |
| 1c | | | | |
| … | | | | |
| | | | | |
| 2 | **Total LSE Expenses** | (sum lines 1a thru 1xx) | $0 | $0 |
| | FERC Annual Fees | | | |
| 3a | | | | |
| 3b | | | | |
| 3c | | | | |
| … | | | | |
| | | | | |
| 4 | **Total FERC Annual Fees** | (sum lines 3a thru 3xx) | $0 | $0 |
| | EPRI, Regulatory Commission, and Non-Safety Related Advertising | | | |
| 5a | | | | |
| 5b | | | | |
| 5c | | | | |
| … | | | | |
| | | | | |
| 6 | **Total FERC Annual Fees** | (sum lines 5a thru 5xx) | $0 | $0 |
| | Transmission Lease Payments | | | |
| 7a | | | | |

| | | | | |
|---|---|---|---|---|
| 7b | | | | |
| 7c | | | | |
| … | | | | |
| | | | | |
| 8 | **Total FERC Annual Fees** | (sum lines 7a thru 7xx) | $0 | $0 |

Notes:

A Line 6 should reflect Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

**Denison (Iowa) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 12: Supplemental Transmission Expense Detail
12 Months Ended June 30, 2XXX

| Line No. | Description | Source Reference | BOY Balance ($) | EOY Balance ($) | Avg BOY/EOY Balance |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | Transmission Plant Excluded from ISO Rates (Note A) | | | | |
| 1a | | | | | $0 |
| 1b | | | | | $0 |
| 1c | | | | | $0 |
| … | | | | | $0 |
| | | | | | $0 |
| 2 | **Total Plant Excluded from ISO Rates** | (sum lines 1a thru 1xx) | $0 | $0 | $0 |
| | Transmission Plant Included in OATT Ancillary Services (Note B) | | | | |
| 3a | | | | | $0 |
| 3b | | | | | $0 |
| 3c | | | | | $0 |
| … | | | | | $0 |
| | | | | | $0 |
| 4 | **Total Plant Included in OATT Ancillary Services** | (sum lines 3a thru 3xx) | $0 | $0 | $0 |

Notes:

A Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

B Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.



**Denison (Iowa) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 12: Supplemental Transmission Expense Detail

#DIV/0!

| Line No. | Description (Note A) | Source Reference | Total Amount ($) | Amount Included in Ancillary Services ($) | Amount Not Included in Ancillary Services ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | Transmission Expenses Included in OATT Ancillary Services (Note C) | | | | |
| 1a | | | | | $0 |
| 1b | | | | | $0 |
| 1c | | | | | $0 |
| … | | | | | $0 |
| | | | | | $0 |

| | | | | | |
|---|---|---|---|---|---|
| 2 | **Total Transmission Expenses Included in OATT Ancillary Services** | (sum lines 1a thru 1xx) | $0 | $0 | $0 |

Notes:

C Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

# PROTOCOLS
# FOR
# DENISON MUNICIPAL UTILITIES'
# HISTORIC COST BASED FORMULA RATE

## Section I. Applicability

The formula rate template ("Template") and these formula rate protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Denison Municipal Utilities ("DMU") contained in the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("Tariff") for determining the transmission revenue requirement for DMU on an annual basis. DMU shall follow the instructions specified in the Formula Rate to calculate annually its Annual Transmission Revenue Requirement ("ATRR"), which is based on actual data from the prior year. The ATRR derived under the Formula Rate shall be applicable to services on and after June 1 of a given year through May 31 of the subsequent year (the "Rate Year").

## Section II. Annual Review Procedures[1]

A. **Posting and Content of Annual Update**: By May 1 each year, DMU shall post[2] a populated version of its Template with an ATRR for the upcoming Rate Year based on historic data from the previous year ("Annual Update"). DMU shall coordinate with SPP to notify Interested Parties[3] of the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within one business day of the posting.[4] Each Annual Update shall:

1. Include a workable data-populated Template and underlying work papers in native format with all formulae intact;
2. Be based on and include DMU's audited financial statements for the prior fiscal year;
3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the Template that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;
4. With each Annual Update, DMU will include a list of any new facilities included since the prior Calendar Year's Annual Update. For example, an additional substation, breaker, other major substation equipment, or additional transmission line miles would constitute new facilities and be listed. The list will indicate the Attachment AI Guidance Document criteria for each facility supporting inclusion as well as the beginning-of-year and end-of-year balances associated with that facility. This provision in no way limits the rights of any party to challenge inclusion of new facilities;
5. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);
6. Identify any Accounting Changes,[5] including:
    i. The initial implementation of an accounting standard or policy;
    ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
    iii. Correction of errors and prior period adjustments;

iv. The implementation of new estimation methods or policies that change prior estimates; and
v. Changes to income tax elections (if applicable);

7. Identify items included in the Template at an amount other than on a historic cost basis (e.g., fair value adjustments);
8. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Template; and
9. Provide, for each item identified pursuant to items II.A.6-8 above, a narrative explanation of the individual impact of such changes on the Template.

B. **Annual Update Meeting**: By September 1 of each year, DMU shall hold an open meeting ("Annual Update Meeting") for Interested Parties. No less than seven calendar days prior to the Annual Update Meeting, DMU shall provide notice on the DMU Related Posting section of the SPP OASIS of the time, date, and location of the Annual Update Meeting. In addition, DMU shall coordinate with SPP to notify Interested Parties of the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within one business day of the posting. DMU shall provide remote access for participation of Interested Parties at such meetings. The Annual Update Meeting shall (i) permit DMU to explain and clarify its Template and (ii) provide Interested Parties an opportunity to seek information and clarifications from DMU about the Template.

C. **Joint Informational Meetings For Regionally Cost Shared Projects:** If DMU constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via the SPP "Formula Rate Posting Information Notification" email exploder list no less than seven calendar days prior to such meeting.

D. **Information Exchange Procedures:** Once DMU has posted the Annual Update, Interested Parties may send reasonable information requests ("Information Requests") to DMU.

1. **Scope**: Information Requests shall not be directed to ascertaining whether the Formula Rate is just and reasonable and rather shall be limited to what is necessary to determine:
    i. The extent or effect of an accounting change;
    ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;
    iii. The proper application of the Formula Rate;
    iv. The accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;
    v. The prudence of actual costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or the Template; or
vii. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

2. **Last day for Information Requests**: The last day for Interested Parties to submit Information Requests to DMU is September 10.
3. **Responses**: DMU shall make a good faith effort to respond to information requests within ten business days of receipt of such requests. DMU shall respond to all information requests received by September 10 by no later than September 20.
4. **Posting of Information Requests and Responses**: DMU will cause to be posted on the DMU Related Postings section of the SPP OASIS all information requests from Interested Parties regarding the Annual Update and DMU's response(s) to such requests; except, however, if they include material deemed by DMU to be confidential, commercially sensitive, or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1) in which case such information will not be publicly posted but will be made available to requesting parties pursuant to a non-disclosure agreement to be executed by DMU and the requesting party. In addition, DMU shall coordinate with SPP to notify Interested Parties of the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within one business day of the posting. DMU shall not claim that non-confidential responses to information requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing DMU's Annual Update.

E. **Challenge Procedures**

1. **Scope of Informal and Formal Challenges**: No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols and the Formula Rate shall not be subject to challenge by anyone for the purpose of modifying the Template. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. Failure to pursue at least one issue through an Informal Challenge shall bar pursuit of any issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update. Any Interested Party that pursues at least one issue through an Informal Challenge may pursue other, new issues through Formal Challenges with respect to the same Annual Update. Regardless of whether an Interested Party pursues or fails to pursue Informal or Formal Challenges, an Interested Party may file a complaint under section 206 of the Federal Power Act at any time. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine:
    i. The extent or effect of an accounting change;
    ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;
    iii. The proper application of the Formula Rate;

iv. The accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;
v. The prudence of actual costs and expenditures;
vi. The effect of any change to the underlying Uniform System of Accounts or the Template; or
vii. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

2. **Informal Challenges**: Interested Parties shall have until October 1 to notify DMU in writing (including electronically) of any specific Informal Challenges.
   i. **Specification**: A party submitting an Informal Challenge to DMU must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.
   ii. **Notice**: DMU shall share Informal Challenges via the "Formula Rate Posting Information Notification" exploder list and on the DMU Related Posting section of the SPP OASIS. However, if an Informal Challenge includes material deemed by DMU to be confidential information, DMU will provide written notice to all Interested Parties of such challenge, but the confidential information will not be publicly posted and will be made available to requesting parties pursuant to a confidentiality agreement to be executed by DMU and the requesting party.
   iii. **Response**: within fifteen calendar days of receiving an Informal Challenge, DMU shall post its response on the DMU Related Posting section of the SPP OASIS and serve it on Interested Parties via the "Formula Rate Posting Information Notification" email exploder list (unless it includes material deemed by DMU to be confidential, commercially sensitive, or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1), in which case DMU will notify Interested Parties of the availability of the response, but such information will not be publicly posted and will be made available to requesting parties pursuant to a non-disclosure agreement to be executed by DMU and the requesting party). The response shall specify the extent to which DMU agrees or disagrees with the position raised in the Informal Challenge, and what, if any, modifications to the Annual Update will result. If DMU disagrees with the issue(s) raised in the Informal Challenge, it shall provide supporting documentation with its response.
   iv. **Negotiations**: DMU and party lodging the Informal Challenge shall make good faith efforts to resolve the Informal Challenge through negotiations and shall allow any Interested Party to participate in such negotiations. Any Interested Party that has filed an Informal Challenge to the Annual Update which has not been resolved by December 1 may then file with FERC a Formal Challenge to Annual Update, as noted below.
   v. **Modifications**: If agreed upon modifications to the Annual Update result in changes to the ATRR, such changes shall be incorporated pursuant to Section IV ("Changes to the ATRR") below.

3. **Formal Challenges:** An Interested Party shall have until December 1 to file a Formal Challenge with FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues.
    i. **Specification**: A Formal Challenge shall:
        1. Clearly identify the action or inaction which is alleged to violate the Formula Rate, explain the alleged violation, and make a good faith effort to quantify the financial impact or burden (if any) on the filing party as a result of the alleged violation;
        2. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
        3. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
        4. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
        5. State whether the filing party utilized the Informal Challenge procedures above to dispute the alleged violation raised by the Formal Challenge, and, if not, describe why not.
    ii. **Service**. The party filing the Formal Challenge must serve a copy of it on DMU via email simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3). The party filing the Formal Challenge shall serve the individual listed as the contact person on DMU's Informational Filing.
    iii. **Response**: DMU shall respond to the Formal Challenge by the deadline established by FERC.
    iv. **Burden of Proof**: In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, DMU shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

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[1] All the dates in this section II apply unless extended with the written consent of DMU or by Federal Energy Regulatory Commission ("FERC") order. In the event that a date falls on a weekend or holiday recognized by FERC, the deadline shall be extended to the next business day.

[2] Specifically, DMU shall cause an electronic version of the Annual Update to be posted on the SPP Open Access Same Time Information System ("OASIS").

[3] "Interested Party" includes, but is not limited to, Zone 19 customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

[4] Any delay in serving notice on the "Formula Rate Posting Information Notification" email exploder list shall result in an equal extension of all other deadlines under this section II.

[5] An "Accounting Change" is any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate.

**Section III. Informational Filings at FERC**

1. **Submission of Informational Filing**: By March 15 of each year, DMU shall submit to FERC an informational filing ("Informational Filing") summarizing the previous year's Annual Update process. DMU shall submit each year's Informational Filing in the same docket assigned to its initial informational filing (subject to the determination of the FERC's Secretary).
2. **Scope**: The transmittal letter accompanying the Informational Filing shall inform FERC that the Informational Filing is not intended to be subject to FERC's notice requirements and that it is not being submitted for the purpose of having FERC assign a docket number to the filing nor for the purpose of obtaining FERC acceptance, approval or other review of the filing.
3. **Notice**: DMU shall provide notification of each Informational Filing by causing it to be posted on the DMU Related Posting section of the SPP OASIS and coordinating with SPP to notify Interested Parties of the sub-docket number assigned to each Informational Filing and the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within five calendar days of FERC assigning such a number.
4. **Content of Informational Filing:**
    a. The Informational Filing must include the information that is reasonably necessary to determine:
        i. That input data under the Formula Rate is properly recorded in any underlying work papers;.
        ii. That DMU has properly applied the Formula Rate;
        iii. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and,
        iv. The extent of accounting changes that affect Formula Rate inputs.
    b. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by DMU will be reported in the Informational Filing. The Informational Filing must also describe any corrections or adjustments made and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

**Section IV. Changes to the ATRR**

Any changes to the ATRR resulting from the outcome of a FERC proceeding or otherwise agreed to by DMU shall be incorporated into the Annual Update for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of FERC's regulations. Should such a reconciliation mechanism be applied, DMU will provide, in its Annual Update, supporting workpapers and calculations that sufficiently explain the mechanism. The base return on equity and the asset depreciation and amortization rates set forth in DMU's Formula Rate will remain fixed and may not be changed absent a filing pursuant to section 205

or section 206 of the Federal Power Act. If DMU corrects an Error[6] in its financial information during a Rate Year that would affect the ATRR for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next Rate Year with interest computed in accordance with section 7 of the SPP Tariff.

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[6] Error shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Error shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input.

## Summary Timeline of Annual Procedures for DMU's Historic Cost Based Formula Rate Under a June 1 – May 31 Rate Year

| | |
|---|---|
| **By May 1** | Post Annual Update; first day to submit Information Requests |
| **June 1** | Rate Year Begins |
| **By September 1** | Annual Update Meeting |
| **September 10** | Last day to submit Information Requests |
| **October 1** | Last day to submit Informal Challenges |
| **December 1** | Last day to file Formal Challenges |
| **By March 15** | Submit Informational Filing at FERC (summarizing previous year's Annual Update process) |

# ADDENDUM 41 TO ATTACHMENT H

## Vermillion Light & Power



**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Index
12 Months Ended 12 Months Ended December 31, 2XXX

| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |
| Schedule 9 | Revenue Credits | Yes |
| Schedule 10 | Other Rate Base Balances | Yes |
| Schedule 11 | Supplement O&M Expense Detail | Yes |
| Schedule 12 | Excluded Transmission Plant & Expenses | Yes |
| Schedule 13 | Capital Structure | Yes |
| Schedule 14 | Transfers Out | Yes |
| Workpaper 1 | Electric Depreciation | Yes |
| Workpaper 2 | CIP | Yes |
| Workpaper 3 | Power Bills | Yes |
| Workpaper 4 | Vermillion O&M to FERC acts | Yes |

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Allocator | Transmission Amount ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 19 | | | #DIV/0! |
| | REVENUE CREDITS | | | | |
| 2 | Account No. 454 | Schedule 9, line 2, col. C | - | TP 0.00 % | - |
| 3 | Transmission charges for all transmission transactions | Schedule 9, line 2, col. D | - | TP 0.00 % | - |
| 4 | Transmission charges for all transmission transactions included in Native Load | Schedule 9, line 2, col. E | - | TP 0.00 % | - |
| 5 | Account No. 456.1 | (line 3 less line 4) | - | TP 0.00 % | - |
| 6 | Revenues from service provided by the ISO at a discount | Schedule 9, line 2, col. F | - | TP 0.00 % | - |
| 7 | TOTAL REVENUE CREDITS | (sum lines 2, 5, and 6) | | | - |
| 8 | ATRR for SPP Directed Projects | Schedule 1, line 2, col I | | | #DIV/0! |
| 9 | NET REVENUE REQUIREMENT | (line 1 less lines 7 and 8) | | | #DIV/0! |
| 1 | Date of Data Used to Calculate Revenue | Enter Last | | | 12/3 |

| | | | |
|---|---|---|---|
| 0 | Requirement | Date of 12-Month Period | 1/15 |



**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Allocator | Transmission Amount ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **RATE BASE** | | | | |
| | GROSS PLANT IN SERVICE (Note D) | | | | |
| 1 | Production | Schedule 4, Column F, Line 6 | - | NA 0.00 % | - |
| 2 | Transmission | Schedule 4, Column F, Line 7 | - | TP 0.00 % | - |
| 3 | Distribution | Schedule 4, Column F, Line 8 | - | NA 0.00 % | - |
| 4 | General & Intangible | Schedule 4, Column F, Line 1 + Line 9 | - | W/S #DIV/0! | #DIV/0! |
| 5 | TOTAL GROSS PLANT | (sum lines 1 thru 4) | - | **GP = #DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note D) | | | | |
| 6 | Production | Schedule 4, Column L, Line 6 | - | NA 0.00 % | - |
| 7 | Transmission | Schedule 4, Column | - | TP 0.00 % | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | L, Line 7 | | | | |
| 8 | Distribution | Schedule 4, Column L, Line 8 | - | NA | 0.00% | - |
| 9 | General & Intangible | Schedule 4, Column L, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 10 | TOTAL ACCUM. DEPRECIATION | (sum lines 6 thru 9) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 11 | Production | (line 1 - line 7) | - | | | - |
| 12 | Transmission | (line 2 - line 8) | - | | | - |
| 13 | Distribution | (line 3 - line 9) | - | | | - |
| 14 | General & Intangible | (line 4 - line 10) | - | | | #DIV/0! |
| 15 | TOTAL NET PLANT | (sum lines 11 thru 14) | - | **NP =** | **#DIV/0!** | #DIV/0! |
| 16 | LAND HELD FOR FUTURE USE | Schedule 10, line 2, cols. C & D | - | Direct Assign - Sch. 10 | | - |
| | WORKING CAPITAL (Note A) | | | | | |
| 17 | CWC | (1/8 * page 3, line 9) | - | | | #DIV/0! |
| 18 | Materials & Supplies | Schedule 10, line 4, cols. C & D | - | Direct Assign - Sch. 10 | | - |
| 19 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 20 | TOTAL WORKING CAPITAL | (sum lines 17 thru 19) | - | | | #DIV/0! |
| 21 | RATE BASE | (sum lines 15, 16, and 20) | - | | | #DIV/0! |



**City of Vermillion (South Dakota)**

Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Allocator | | Transmission Amount ($) |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | | (e) |
| | O&M (Note E) | | | | | |
| 1 | Transmission | Schedule 7, Column E, Line 8 & 8a | - | TE | 0.00% | - |
| 2 | Less LSE Expenses included in Transmission O&M Accounts (Note H) | Schedule 11, line 2, col. C | - | TE | 100.00% | - |
| 3 | Less Account 565 | Schedule 7, Column C, Line 8a | - | TE | 0.00% | - |
| 4 | A&G | Schedule 7, Column E, Line 13 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less FERC Annual Fees | Schedule 11, line 4, col. C | - | W/S | #DIV/0! | #DIV/0! |
| 6 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad | Schedule 11, line 6, col. C | - | W/S | #DIV/0! | #DIV/0! |
| 7 | Plus Transmission Related Reg. Comm. Exp. | Schedule 11, line 6, col. D | - | W/S | #DIV/0! | #DIV/0! |
| 8 | Transmission Lease Payments | Schedule 11, line 8, col. D | - | TE | 0.00% | - |
| 9 | TOTAL O&M | (sum lines 1, 4, 7, 8 less lines 2, 3, 5, 6) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note D) | | | | | |
| 10 | Transmission | Schedule 4, Column M, Line 7 | - | TP | 0.00% | - |

| | | | | | |
|---|---|---|---|---|---|
| 11 | General & Intangible | Schedule 4, Column M, Line 1 and Line 9 | - | W/S #DIV/0! | #DIV/0! |
| 12 | TOTAL DEPRECIATION | (Sum lines 10 thru 11) | - | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note B) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S #DIV/0! | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S #DIV/0! | #DIV/0! |
| | PLANT RELATED | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP #DIV/0! | #DIV/0! |
| 16 | Payments in lieu of taxes | Schedule 5, Column B, Line 6 | - | Sch. 14, Col. C, Row 16 | #DIV/0! |
| 17 | TOTAL OTHER TAXES | (sum lines 13, 14, 15, 16) | - | | #DIV/0! |
| 18 | RETURN | (page 2, line 21 * R) | #DIV/0! | | #DIV/0! |
| 19 | GROSS REVENUE REQUIREMENT | (sum lines 9, 12, 17, and 18) | #DIV/0! | | #DIV/0! |



**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line N | Description | Source | Total Company Amo | Allocat | Transmission Amo |
|---|---|---|---|---|---|

| o. | | Reference | unt ($) | or | | unt ($) |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | | (e) |
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, column e | | | | - |
| 2 | Less transmission plant excluded from ISO rates | Schedule 12, page 1, line 2, col. E | | | | - |
| 3 | Less transmission plant included in OATT Ancillary Services | Schedule 12, page 1, line 4, col. E | | | | - |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | | - |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | | **TP =** | **0.00 %** |
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses | page 3, line 1, column 3 | | | | - |
| 7 | Less transmission expenses included in OATT Ancillary Services | Schedule 12, page 2, line 2, col. D | | | | - |
| 8 | Included transmission expenses | (line 6 less line 7) | | | | - |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | | 0.00 % |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line 5) | | | **TE =** | **0.00 %** |
| | WAGES & SALARIES | | | | | |
| 11 | Production | Schedule 8, Column E, Line 2 | - | NA | 0.00 % | - |
| 12 | Transmission | Schedule 8, Column E, Line 5 | - | TP | 0.00 % | - |
| 1 | Distribution | Schedule | | N | 0.00 | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 3 | | 8, Column E, Line 8 | - | A | % | | - |
| 14 | Other | Schedule 8, Column E, Line 11 | - | NA | 0.00 % | | - |
| 15 | Total | (sum lines 11 thru 14) | - | | | | - |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | |
| 17 | Wages & Salaries Allocator (Note F) | (line 15, col E divided by col C) | | | | **W/S =** | **#DIV/0!** |
| | RATE OF RETURN (R) | | | | | | |
| 18 | Long Term Interest (Note C) | Schedule 3, Column B, Line 16 | - | | | | |

| | | | $ Amount | % | Cost (Note G) | | Weighted |
|---|---|---|---|---|---|---|---|
| 19 | Long Term Debt | Schedule 13, column E, line 1 | - | #DIV/0! | 0.00 % | | #DIV/0! |
| 20 | Proprietary Capital | Schedule 13, column E, line 2 | - | #DIV/0! | 10.10% | | #DIV/0! |
| 21 | Total | (sum lines 19 and 20) | - | #DIV/0! | | **R =** | #DIV/0! |



**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

Notes:

A Cash Working Capital assigned to transmission is one-eighth of O&M

| | |
|---|---|
| | allocated to transmission at page 3, line 9, column E. |
| | Prepayments are the electric related prepayments booked to Account No. 165. |
| B | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| C | Include only the amount from Accounts 427, 428, 429 and 430. |
| D | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation and Acquisition Adjustment amounts unless authorized by FERC. |
| E | Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate. |
| F | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| G | The cost of proprietary capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The cost of long-term debt is calculated by dividing long-term interest (line 18, col C) by the amount of long-term debt (line 19, col C). The cost of proprietary capital includes the incentive adder of 50 basis points approved in Docket No. ER17-428. |
| H | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1: SPP Directed Projects ATRR
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | Transmission Amount ($) |
|---|---|---|---|
| | (a) | (b) | (c) |
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, page 2, line 2 col E | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, page 2, line 7 col E | - |
| 3 | Net Transmission Plant - SPP (Note B) | **(line 1 less line 2)** | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 3, line 9 col E | #DIV/0! |
| 5 | **Annual Allocation Factor for O&M** | **(line 4 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, page 3, line 17 col E | #DIV/0! |
| 7 | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| 8 | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, p 3, line 12 col E | #DIV/0! |

| | | | |
|---|---|---|---|
| 10 | Return | Attach H, p 3, line 18 col E | #DIV/0! |
| 11 | Depreciation plus return | (line 9 plus line 10) | #DIV/0! |
| 12 | **Annual Allocation Factor for Depreciation and Return** | **(line 11 divided by line 3)** | **#DIV/0!** |



**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1: SPP Directed Projects ATRR
12 Months Ended December 31, 2XXX

| Line No. | Upgrade Name | Upgrade ID | Upgrade Gross Plant | Annual Allocation Factor for Expense | Annual Expense Charge | Upgrade Net Plant | Annual Allocation Factor for Depreciation & Return | Annual Charge for Depreciation & Return | Net Annual Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | (Note C) | (Page 1 line 7) | (Col. D * Col. E) | Note D | (Page 1 line 12) | (Col. F * Col. G) | (Sum Col. E & H) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1 | Project 6 | | $ | #DIV/ | #DIV/ | $ | #DIV/ | #DIV/ | #DIV/0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| f | Project 6 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| ... | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | | | | | | |

2 **Annual Totals** **#DIV/0!**

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 1a- Line 2.

D Net Plant is derived from Schedule 1a- Line 6 and includes all CWIP

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1a: SPP Directed Projects
12 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **12 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| **2** | **Total Gross Plant in Service** | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | |
| 3a | Project 1 | | | | | | | | | | | | | | - |
| 3 | Project | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| b | 2 | | | | | | | | | | | | | - |
| 3 c | Project 3 | | | | | | | | | | | | | - |
| 3 d | Project 4 | | | | | | | | | | | | | - |
| 3 e | Project 5 | | | | | | | | | | | | | - |
| 3 f | Project 6 | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | |
| **4** | **Total Accumulated Depreciation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Net Plant in Service** | | | | | | | | | | | | | |
| 5 a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | |
| **6** | **Total Net Plant in Service** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 2: Electric Balance Sheet (EIA Form 412)
12 Months Ended December 31, 2XXX

| Column | A | B | | C | D |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| | **ELECTRIC PLANT** | | | **PROPIETARY CAPITAL** | |
| 1 | Electric Plant & Adjustments (101-106,114,116) | | 29 | Investment of Municipality (208) | $ - |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | $ - |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and Depletion (108,111,115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | |
| 7 | **Net Electric Plant including Nuclear Fuel** | **$ -** | 34 | Advances from Municipality and Other Long Term Debt (223, 224) | $ - |
| | **OTHER PROPERTY & INVESTMENTS** | | 35 | Unamortized Premium on Long Term | |
| 8 | Non-Electric Plant Property (121) | $ - | | Debt (225) | $ - |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | $ - | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| | **CURRENT & ACCRUED ASSETS** | | 38 | Accumulated Operating Provisions (228.1-.4) | |
| 13 | Cash, Working Funds & Investments (131-136) | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Receivable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | |
| 26 | Miscellaneous Debt, Research and Development Expenses | | 51 | Unamortized gain on | |

| | | | | | |
|---|---|---|---|---|---|
| | & Unamortized Losses (184-191) | | | Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**City of Vermillion (South Dakota)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | $ - |
| 8 | **NET ELECTRIC OPERATING INCOME** | $ - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | $ - |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | $ - |
| 15 | Electric Income | $ - |
| 16 | Income Deductions from Interest on Long Term Debt (427) | |
| 17 | Other Income Deductions (428-431) | |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | $ - |
| 19 | Total Income Deductions | $ - |
| 20 | Income Before Extraordinary Items | $ - |

| | | |
|---|---|---|
| 21 | Extraordinary Items (434) | $ - |
| 22 | Extraordinary Deductions (435) | $ - |
| 23 | **NET INCOME** | **$ -** |

Page 2 of 2

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 4: Electric Plant (EIA Form 412)
12 Months Ended December 31, 2XXX

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 4: Electric Plant (EIA Form 412)
12 Months Ended December 31, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| | | | | | | | | | | | | | | |
| 2 | Steam Production (310-316) | | | | | $ - | **$ -** | | | | $ - | $ - | **$ -** | $ - |
| 3 | Nuclear Production (320-325) | | | | | $ - | **$ -** | | | | $ - | $ - | **$ -** | $ - |
| 4 | Hydraulic Production (330-336) | | | | | $ - | **$ -** | | | | $ - | $ - | **$ -** | $ - |
| 5 | Other Production (340-346) | | | | | $ - | **$ -** | | | | $ - | $ - | **$ -** | $ - |
| 6 | **Total** | | | | | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** | **$** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Production Plant** | | | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | | | $ - | **$ -** | | | | | $ - | **$ -** | $ - |
| 8 | Distribution Plant (360-373) | | | | | $ - | **$ -** | | | | | $ - | **$ -** | $ - |
| 9 | General Plant (389-399) | | | | $ - | $ - | **$ -** | | | $ - | | $ - | **$ -** | $ - |
| 10 | **Total Electric Plant In Service** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | |
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | | | | | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 16 | **Total Electric** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Plant & Adj's** | | | | | | | | | | | | | |

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 5: Taxes other than Income Taxes (EIA Form 412)
12 Months Ended December 31, 2XXX

| Line No. | Description | Amount ($) | Source Reference | Notes/Comments |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | **Taxes other than Income Taxes, Operating Income** | | | |
| | **Payroll Taxes:** | | | |
| 1 | FICA Taxes | | | |
| 2 | Unemployment Taxes | | | |
| | **Plant Related Taxes:** | | | |
| 3 | Highway Taxes | | | |
| 4 | Property Taxes | | | |
| 6 | Payment In Lieu of Taxes (Transfer) | $ - | Schedule 14, Column C, Line 21 | |

**City of Vermillion (South Dakota)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended December 31, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | N/A |
| 3 | 351 | Energy Storage Equipment - Transmission | 35 | 2.86% |
| 4 | 352 | Structures & Improvements | 35 | 2.86% |
| 5 | 353 | Station Equipment | 35 | 2.86% |
| 6 | 354 | Towers & Fixtures | 35 | 2.86% |
| 7 | 355 | Poles & Fixtures | 35 | 2.86% |
| 8 | 356 | Overhead Conductors and Devices | 35 | 2.86% |
| 9 | 357 | Underground Conduit | 35 | 2.86% |
| 10 | 358 | Underground Conductors and Devices | 35 | 2.86% |
| 11 | 359 | Roads and Trails | 35 | 2.86% |
| 12 | | **General Plant** | | |
| 13 | 390 | Structures & Improvements | 33 | 3.03% |
| 14 | 391 | Office Furniture and Equipment | 7.5 | 13.33% |
| 15 | 392 | Transportation Equipment | 7.5 | 13.33% |
| 16 | 393 | Stores Equipment | 7.5 | 13.33% |
| 17 | 394 | Tools, Shop and Garage Equipment | 5 | 20.00% |
| 18 | 395 | Laboratory Equipment | 5 | 20.00% |
| 19 | 396 | Power Operated Equipment | 5 | 20.00% |
| 20 | 397 | Communication Equipment | 5 | 20.00% |
| 21 | 398 | Miscellaneous Equipment | 7.5 | 13.33% |

| | | | | | |
|---|---|---|---|---|---|
| 22 | | **Intangible Plant** | | | |
| 23 | | 301 | Organization | 33 | 3.03% |
| 24 | | 302 | Franchises and consents | 33 | 3.03% |
| 25 | | 303 | Miscelaaneous intangible plant | 33 | 3.03% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 7: O&M Expense (EIA Form 412)
12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | $ - | | $ - | $ - |
| 5 | Purchased Power (555) | $ - | | | $ - |
| 6 | Other Production Expenses (556-557) | $ - | | | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-564, 566-567, 568-573) | XXXXXXXXXXX XX | | | $ - |
| 8a | Transmission of Electricity by Others (565) | | | | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXX XX | | | $ - |
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXX XX | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 11 | Customer Service & Information Expenses (907-910) | XXXXXXXXXXXXX | | | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXXX | | | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXXX | | | $ - |
| 14 | Total Electric Operation and Maintenance Expenses | $ - | $ - | $ - | $ - |

| | | |
|---|---|---|
| 15 | Total Number of Full Time Employees | |
| 16 | Total Number of Part Time Employees | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Common O&M Expense | $ - | $ - | $ - | $ - |

**City of Vermillion (South Dakota)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | | Accounts | Salaries | |
| 1 | | | Production / Generation | | |
| 2 | | | Salaries | $ - | $ - |
| 3 | | | | | |
| 4 | | | Transmission: | | |
| 5 | | | Salaries | $ - | $ - |
| 6 | | | | | |
| 7 | | | Distribution: | | |
| 8 | | | Salaries | | $ - |
| 9 | | | | | |
| 10 | | | Customer Service & Information | | |
| 11 | | | Meter Reading Salaries | | $ - |
| 12 | | | | | |
| 13 | | | Administrative & General | | |
| 14 | | | Salaries | | $ - |
| 15 | | | | | |
| 16 | | | **Total** | $ - | $ - |

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 9: Revenue Credits
12 Months Ended December 31, 2XXX

| Line No. | Description (Note A) | Source Reference | Account 454 (Note B) | Transmission Charges for All Transactions | Transmission Charges for All Transactions in Native Load | Revenues from Services Provided by the ISO at a Discount |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1a | | | | | | |
| 1b | | | | | | |
| 1c | | | | | | |
| … | | | | | | |
| | | | | | | |
| 2 | **Total Amounts** | (sum lines 1a thru 1xx) | $0 | $0 | $0 | $0 |

Notes:

A Only amounts included in the calculation of Vermillion's SPP Zone 19 revenue requirement should be included. The amounts credited shall only include amounts directly received from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this formula rate template.

B Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 10: Other Rate Base Balances
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | SPP Transmission Amount ($) (Note A) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | LAND HELD FOR FUTURE USE | | | |
| 1a | | | | |
| 1b | | | | |
| 1c | | | | |
| … | | | | |
| 2 | **Total Land Held for Future Use** | (sum lines 1a thru 1xx) | $0 | $0 |
| | MATERIALS & SUPPLIES | | | |
| 3a | Inventory of Supplies | 2XXX VLP Annual Report (Page XX) | | |
| 3b | | | | |
| 3c | | | | |
| … | | | | |
| 4 | **Total Materials & Supplies** | (sum lines 3a thru 3xx) | $0 | $0 |

Notes:
A Transmission related amounts only.

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 11: Supplemental O&M Expense Detail
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | Total Company Amount ($) | Transmission Amount ($) (Note A) |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | LSE Expenses Included in Transmission O&M Accounts | | | |
| 1a | | | | |
| 1b | | | | |
| 1c | | | | |
| … | | | | |
| | | | | |
| 2 | **Total LSE Expenses** | (sum lines 1a thru 1xx) | $0 | $0 |
| | FERC Annual Fees | | | |
| 3a | | | | |
| 3b | | | | |
| 3c | | | | |
| … | | | | |
| | | | | |
| 4 | **Total FERC Annual Fees** | (sum lines 3a thru 3xx) | $0 | $0 |
| | EPRI, Regulatory Commission, and Non-Safety Related Advertising | | | |
| 5a | | | | |
| 5b | | | | |
| 5c | | | | |
| … | | | | |
| | | | | |
| 6 | **Total FERC Annual Fees** | (sum lines 5a thru 5xx) | $0 | $0 |
| | Transmission Lease Payments | | | |
| 7a | | | | |

| | | | | |
|---|---|---|---|---|
| 7b | | | | |
| 7c | | | | |
| … | | | | |
| | | | | |
| 8 | **Total FERC Annual Fees** | (sum lines 7a thru 7xx) | $0 | $0 |

Notes:

A Line 6 should reflect Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 12: Excluded Transmission Plant & Expenses
12 Months Ended December 31, 2XXX

| Line No. | Description (Note A) | Source Reference | BOY Balance ($) | EOY Balance ($) | Avg BOY/EOY Balance |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | Transmission Plant Excluded from ISO Rates (Note A) | | | | |
| 1a | | | | | $0 |
| 1b | | | | | $0 |
| 1c | | | | | $0 |
| … | | | | | $0 |
| | | | | | $0 |
| 2 | **Total Plant Excluded from ISO Rates** | (sum lines 1a thru 1xx) | $0 | $0 | $0 |
| | Transmission Plant Included in OATT Ancillary Services (Note B) | | | | |
| 3a | | | | | $0 |
| 3b | | | | | $0 |
| 3c | | | | | $0 |
| … | | | | | $0 |
| | | | | | $0 |
| 4 | **Total Plant Included in OATT Ancillary Services** | (sum lines 3a thru 3xx) | $0 | $0 | $0 |

Notes:

| | |
|---|---|
| A | Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test). |
| B | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |



**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 12: Excluded Transmission Plant & Expenses
12 Months Ended December 31, 2XXX

| Line No. | Description (Note A) | Source Reference | Total Amount ($) | Amount Included in Ancillary Services ($) | Amount Not Included in Ancillary Services ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | Transmission Expenses Included in OATT Ancillary Services (Note C) | | | | |
| 1a | | | | | $0 |
| 1b | | | | | $0 |
| 1c | | | | | $0 |
| … | | | | | $0 |
| | | | | | $0 |
| 2 | **Total Expenses Included in OATT Ancillary Services** | (sum lines 1a thru 1xx) | $0 | $0 | $0 |

Notes:

C Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 13: Capital Structure
12 Months Ended December 31, 2XXX

| Line No. | Description | Source Reference | BOY Amount ($) | EOY Amount ($) | Avg BOY/EOY Amount ($) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| 1 | Long Term Debt | 2XXX/2XXX VLP Annual Report (Page XX) | | | $0 |
| 2 | Proprietary Capital | 2XXX VLP Annual Report (Page XX) | | | $0 |
| 3 | Total | (sum lines 1 thru 2) | $0 | $0 | $0 |

**City of Vermillion (South Dakota)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 14: Transfers Out
12 Months Ended December 31, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **TRANSFERS** | **Source** | | |
| 2 | Transmission Plant | Attachment H, Page 2, Column E, Line 2 | $ - | |
| 3 | | | | |
| 6 | Actual Gross Plant | Attachment H, Page 2, Column C, Line 5 | $ - | |
| 7 | | | | |
| 8 | Gross Plant Allocator | Attachment H, Page 2, Column D, Line 5 | #DIV/0! | |
| 9 | | | | |
| 10 | Actual Payment in Lieu of Taxes at 12/31/15 | Column C, Line 21 | $ - | |
| 11 | | | | |
| 12 | Allocated Company PILOT | =Line 6 * Line 8 | #DIV/0! | |
| 13 | | | | |
| 14 | PILOT Amt as agreed to in ER17-428 (Note A) | | $ 115,000 | |
| 15 | | | | |

| | | | | |
|---|---|---|---|---|
| 16 | Lesser of lines 12 and 14 | =min of Line 12 or Line 14 | #DIV/0! | Inserted into Attachment H, Page 3, Column E, Line 16 |
| 17 | | | | |
| 18 | **TRANSFERS** | | | |
| 19 | Payment In Lieu of Taxes (Transfer) | Schedule 3, Column B, Line 6 | | |
| 20 | Reduction of PILOT | | - | Engineering services provided by the City Staff to the Electric Utility |
| 21 | Total PILOT Included in ATRR Calculation | | $ - | |

Notes:

A The amount shown on line 14 is fixed and will not change absent FERC approval

# PROTOCOLS

# FOR THE HISTORIC COST BASED FORMULA RATE OF VERMILLION LIGHT & POWER

## Section I. Applicability

The formula rate template ("Template") and these formula rate protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Vermillion Light & Power ("VLP") contained in the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("Tariff") for determining the transmission revenue requirement for VLP on an annual basis. VLP shall follow the instructions specified in the Formula Rate to calculate annually its Annual Transmission Revenue Requirement ("ATRR"), which is based on actual data from the prior year. The ATRR derived under the Formula Rate shall be applicable to services on and after June 1 of a given year through May 31 of the subsequent year (the "Rate Year").

## Section II. Annual Review Procedures[1]

A. **Posting and Content of Annual Update**: By May 1 each year, VLP shall post[2] a populated version of its Template with an ATRR for the upcoming Rate Year based on historic data from the previous year ("Annual Update"). VLP shall coordinate with SPP to notify Interested Parties[3] of the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within one business day of the posting.[4] Each Annual Update shall:

1. Include a workable data-populated Template and underlying work papers in native format with all formulae intact;
2. Be based on and include VLP's audited financial statements for the prior fiscal year;
3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the Template that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;
4. With each Annual Update, VLP will include a list of any new facilities included since the prior Calendar Year's Annual Update. For example, an additional

substation, breaker, other major substation equipment, or additional transmission line miles would constitute new facilities and be listed. The list will indicate the Attachment AI Guidance Document criteria for each facility supporting inclusion as well as the beginning-of-year and end-of-year balances associated with that facility. This provision in no way limits the rights of any party to challenge inclusion of new facilities, including but not limited to the potential inclusion of any loop extension associated with the Northeast Substation;

5. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);
6. Identify any Accounting Changes,[5] including:
    i. The initial implementation of an accounting standard or policy;
    ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
    iii. Correction of errors and prior period adjustments;
    iv. The implementation of new estimation methods or policies that change prior estimates; and
    v. Changes to income tax elections (if applicable);
7. Identify items included in the Template at an amount other than on a historic cost basis (e.g., fair value adjustments);
8. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Template; and
9. Provide, for each item identified pursuant to items II.A.6-8 above, a narrative explanation of the individual impact of such changes on the Template.

B. **Annual Update Meeting**: By September 1 of each year, VLP shall hold an open meeting ("Annual Update Meeting") for Interested Parties. No less than seven calendar days prior to the Annual Update Meeting, VLP shall provide notice on the VLP Related Posting section of the SPP OASIS of the time, date, and location of the Annual Update Meeting. In addition, VLP shall coordinate with SPP to notify Interested Parties of the website

address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within one business day of the posting. VLP shall provide remote access for participation of Interested Parties at such meetings. The Annual Update Meeting shall (i) permit VLP to explain and clarify its Template and (ii) provide Interested Parties an opportunity to seek information and clarifications from VLP about the Template.

C. **Joint Informational Meetings For Regionally Cost Shared Projects:** If VLP constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of joint informational meetings shall be posted on the SPP OASIS and distributed to Interested Parties via the SPP "Formula Rate Posting Information Notification" email exploder list no less than seven calendar days prior to such meeting.

D. **Information Exchange Procedures:** Once VLP has posted the Annual Update, Interested Parties may send reasonable information requests ("Information Requests") to VLP.

1. **Scope**: Information Requests shall not be directed to ascertaining whether the Formula Rate is just and reasonable and rather shall be limited to what is necessary to determine:
    i. The extent or effect of an accounting change;
    ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;
    iii. The proper application of the Formula Rate;
    iv. The accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;
    v. The prudence of actual costs and expenditures;
    vi. The effect of any change to the underlying Uniform System of Accounts or the Template; or

vii. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

2. **Last day for Information Requests**: The last day for Interested Parties to submit Information Requests to VLP is September 10.
3. **Responses**: VLP shall make a good faith effort to respond to information requests within ten business days of receipt of such requests. VLP shall respond to all information requests received by September 10 by no later than September 20.
4. **Posting of Information Requests and Responses**: VLP will cause to be posted on the VLP Related Postings section of the SPP OASIS all information requests from Interested Parties regarding the Annual Update and VLP's response(s) to such requests; except, however, if they include material deemed by VLP to be confidential, commercially sensitive, or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1) in which case such information will not be publicly posted but will be made available to requesting parties pursuant to a non-disclosure agreement to be executed by VLP and the requesting party. In addition, VLP shall coordinate with SPP to notify Interested Parties of the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within one business day of the posting. VLP shall not claim that non-confidential responses to information requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing VLP's Annual Update.

E. **Challenge Procedures**

1. **Scope of Informal and Formal Challenges**: No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols and the Formula Rate shall not be subject to challenge by anyone for the purpose of modifying the Template. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. Failure to pursue at least one issue through an Informal Challenge shall bar pursuit of any issue with respect to that Annual Update, but shall not bar pursuit of such issue or

the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update. Any Interested Party that pursues at least one issue through an Informal Challenge may pursue other, new issues through Formal Challenges with respect to the same Annual Update. Regardless of whether an Interested Party pursues or fails to pursue Informal or Formal Challenges, an Interested Party may file a complaint under section 206 of the Federal Power Act at any time. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine:

i. The extent or effect of an accounting change;
ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;
iii. The proper application of the Formula Rate;
iv. The accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;
v. The prudence of actual costs and expenditures;
vi. The effect of any change to the underlying Uniform System of Accounts or the Template; or
vii. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

2. **Informal Challenges**: Interested Parties shall have until October 1 to notify VLP in writing (including electronically) of any specific Informal Challenges.
    i. **Specification**: A party submitting an Informal Challenge to VLP must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.
    ii. **Notice**: VLP shall share Informal Challenges via the "Formula Rate Posting Information Notification" exploder list and on the VLP Related Posting section of the SPP OASIS. However, if an Informal Challenge includes material deemed by VLP to be confidential information, VLP will provide written notice to all Interested Parties of such challenge, but the confidential information will not be publicly posted and will be made

available to requesting parties pursuant to a confidentiality agreement to be executed by VLP and the requesting party.

iii. **Response**: within fifteen calendar days of receiving an Informal Challenge, VLP shall post its response on the VLP Related Posting section of the SPP OASIS and serve it on Interested Parties via the "Formula Rate Posting Information Notification" email exploder list (unless it includes material deemed by VLP to be confidential, commercially sensitive, or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1), in which case VLP will notify Interested Parties of the availability of the response, but such information will not be publicly posted and will be made available to requesting parties pursuant to a non-disclosure agreement to be executed by VLP and the requesting party). The response shall specify the extent to which VLP agrees or disagrees with the position raised in the Informal Challenge, and what, if any, modifications to the Annual Update will result. If VLP disagrees with the issue(s) raised in the Informal Challenge, it shall provide supporting documentation with its response.

iv. **Negotiations**: VLP and party lodging the Informal Challenge shall make good faith efforts to resolve the Informal Challenge through negotiations and shall allow any Interested Party to participate in such negotiations. Any Interested Party that has filed an Informal Challenge to the Annual Update which has not been resolved by December 1 may then file with FERC a Formal Challenge to Annual Update, as noted below.

v. **Modifications**: If agreed upon modifications to the Annual Update result in changes to the ATRR, such changes shall be incorporated pursuant to Section IV ("Changes to the ATRR") below.

3. **Formal Challenges:** An Interested Party shall have until December 1 to file a Formal Challenge with FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues.

i. **Specification**: A Formal Challenge shall:
    1. Clearly identify the action or inaction which is alleged to violate the Formula Rate, explain the alleged violation, and make a good faith effort to quantify the financial impact or burden (if any) on the filing party as a result of the alleged violation;
    2. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
    3. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;
    4. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
    5. State whether the filing party utilized the Informal Challenge procedures above to dispute the alleged violation raised by the Formal Challenge, and, if not, describe why not.

ii. **Service**. The party filing the Formal Challenge must serve a copy of it on VLP via email simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3). The party filing the Formal Challenge shall serve the individual listed as the contact person on VLP's Informational Filing.

iii. **Response**: VLP shall respond to the Formal Challenge by the deadline established by FERC.

iv. **Burden of Proof**: In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, VLP shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

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1 All the dates in this section II apply unless extended with the written consent of VLP or by Federal Energy Regulatory Commission ("FERC") order. In the event that a date falls on a weekend or holiday recognized by FERC, the deadline shall be extended to the next business day.

2 Specifically, VLP shall cause an electronic version of the Annual Update to be posted on the SPP Open Access Same-Time Information System ("OASIS").

3 "Interested Party" includes, but is not limited to, Zone 19 customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

4 Any delay in serving notice on the "Formula Rate Posting Information Notification" email exploder list shall result in an equal extension of all other deadlines under this section II.

5 An "Accounting Change" is any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate.

**Section III. Informational Filings at FERC**

1. **Submission of Informational Filing**: By March 15 of each year, VLP shall submit to FERC an informational filing ("Informational Filing") summarizing the previous year's Annual Update process. VLP shall submit each year's Informational Filing in the same docket assigned to its initial informational filing (subject to the determination of the FERC's Secretary).
2. **Scope**: The transmittal letter accompanying the Informational Filing shall inform FERC that the Informational Filing is not intended to be subject to FERC's notice requirements and that it is not being submitted for the purpose of having FERC assign a docket number to the filing nor for the purpose of obtaining FERC acceptance, approval or other review of the filing.
3. **Notice**: VLP shall provide notification of each Informational Filing by causing it to be posted on the VLP Related Posting section of the SPP OASIS and coordinating with SPP to notify Interested Parties of the sub-docket number assigned to each Informational Filing and the website address where such information is posted via the SPP "Formula Rate Posting Information Notification" email exploder list within five calendar days of FERC assigning such a number.
4. **Content of Informational Filing:**

a. The Informational Filing must include the information that is reasonably necessary to determine:
    i. That input data under the Formula Rate is properly recorded in any underlying work papers;
    ii. That VLP has properly applied the Formula Rate;
    iii. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and,
    iv. The extent of accounting changes that affect Formula Rate inputs.
b. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by VLP will be reported in the Informational Filing. The Informational Filing must also describe any corrections or adjustments made and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

**Section IV. Changes to the ATRR**

Any changes to the ATRR resulting from the outcome of a FERC proceeding or otherwise agreed to by VLP shall be incorporated into the Annual Update for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of FERC's regulations. Should such a reconciliation mechanism be applied, VLP will provide, in its Annual Update, supporting workpapers and calculations that sufficiently explain the mechanism. The base return on equity and the asset depreciation and amortization rates set forth in VLP's Formula Rate will remain fixed and may not be changed absent a filing pursuant to section 205 or section 206 of the Federal Power Act. If VLP corrects an Error[6] in its financial information during a Rate Year that would affect the ATRR for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next Rate Year with interest computed in accordance with section 7 of the SPP Tariff.

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6 Error shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Error shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input.

## Summary Timeline of Annual Procedures for VLP's Historic Cost Based Formula Rate Under a June 1 – May 31 Rate Year

| | |
|---|---|
| **By May 1** | Post Annual Update; first day to submit Information Requests |
| **June 1** | Rate Year Begins |
| **By September 1** | Annual Update Meeting |
| **September 10** | Last day to submit Information Requests |
| **October 1** | Last day to submit Informal Challenges |
| **December 1** | Last day to file Formal Challenges |
| **By March 15** | Submit Informational Filing at FERC (summarizing previous year's Annual Update process) |

# ADDENDUM 43 TO ATTACHMENT H

## South Central MCN LLC

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | page 1 of 5 |
| | Attachment H | | | | | | | | | |
| | Formula Rate - Non-Levelized | South Central MCN LLC | Rate Formula Template | | | | | | | For the 12 months ended 12/31/___ |
| | | | Utilizing FERC Form 1 Data | | | | | | | |
| | | | South Central MCN LLC | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | (1) | (2) | (3) | | | (4) | | (5) | | |
| Line | | | | | | | | Allocated | | |
| No. | | | | | | | | Amount | | |
| 1 | GROSS REVENUE REQUIREMENT | (page 3, line 47) | | | | | | $ - | | |
| | | | | | | | | | | |
| | REVENUE CREDITS | (Note O) | Total | | Allocator | | | | | |
| 2 | Account No. 454 | (page 4, line 29) | - | | TP | - | | - | | |
| 3 | Account No. 456.1 | (page 4, line 33) | - | | TP | - | | - | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Account No. 457.1 Scheduling | Attachment 5, line 36, col e | - | | TP | - | | - | | |
| 5 | Revenues from Grandfathered Interzonal Transactions | (Note N) | - | | TP | - | | - | | |
| 6 | Revenues from service provided by the ISO at a discount | | - | | TP | - | | - | | |
| 7 | TOTAL REVENUE CREDITS | (Sum of Lines 2 through 6) | - | | | | | - | | |
| | | | | | | | | | | |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus line 7) | | | | | | $ - | | |
| | | | | | | | | | | |
| 9 | True-up Adjustment with Interest | Attachment 3, Col. J | - | | DA | 1.000 00 | | - | | |
| | | | | | | | | | | |
| 10 | NET REVENUE REQUIREMENT | (line 8 plus line 9) | | | | | | $ - | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | page 2 of 5 |
| | | | | | | | | | | |
| | Formula Rate - Non-Levelized | | Rate Formula Template | | | | | | | For the 12 months ended 12/31/___ |
| | | | Utilizing FERC Form 1 Data | | | | | | | |
| | | | South Central MCN LLC | | | | | | | |
| | | | | | | | | | | |
| | (1) | (2) | (3) | | | (4) | | (5) | | |
| | | | | | | | | **Transmission** | | |
| Line | | **Source** | **Company Total** | | **Allocator** | | | (Col 3 times Col 4) | | |
| No. | **RATE BASE:** | | | | | | | | | |
| | GROSS PLANT IN SERVICE (Notes U and R) | | | | | | | | | |
| 1 | Production | 205.46.g for end of year, records for other months | - | | NA | | | - | | |
| 2 | Transmission | Attachment 4, Line 14, Col. (b) | - | | TP | - | | - | | |
| 3 | Distribution | 207.75.g for end of year, records for other months | - | | NA | - | | - | | |
| 4 | General & | Attachment 4, | | | W/S | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Intangible | Line 14, Col. (c) | - | | | - | | - | | |
| 5 | Common | 356.1 for end of year, records for other months | - | | CE | - | | - | | |
| 6 | TOTAL GROSS PLANT | (Sum of Lines 1 through 5) | - | | GP = | - | | - | | |
| | | | | | | | | | | |
| 7 | ACCUMULATED DEPRECIATION (Notes U and R) | | | | | | | | | |
| 8 | Production | 219.20-24.c for end of year, records for other months | - | | NA | | | - | | |
| 9 | Transmission | Attachment 4, Line 14, Col. (h) | - | | TP | - | | - | | |
| 10 | Distribution | 219.26.c for end of year, records for other months | - | | NA | - | | - | | |
| 11 | General & Intangible | Attachment 4, Line 14, Col. (i) | - | | W/S | - | | - | | |
| 12 | Common | 356.1 for end of year, records for other months | - | | CE | - | | - | | |
| 13 | TOTAL ACCUM. DEPRECIATION | (Sum of Lines 8 through 12) | - | | | | | - | | |
| | | | | | | | | | | |
| 14 | NET PLANT IN SERVICE | | | | | | | | | |
| 15 | Production | (line 1 - line 8) | - | | | | | - | | |
| 16 | Transmission | (Line 2 minus Line 9) | - | | | | | - | | |
| 17 | Distribution | (line 3 - line 10) | - | | | | | - | | |
| 18 | General & Intangible | (Line 4 minus Line 11) | - | | | | | - | | |
| 19 | Common | (line 5 - line 12) | - | | | | | - | | |
| 20 | TOTAL NET PLANT | (Sum of Lines 15 through 19) | - | | NP = | - | | - | | |
| | | | | | | | | | | |
| 21 | ADJUSTMENTS TO RATE BASE (Note R) | | | | | | | | | |
| 2 | Account No. 281 | Attachment 4, | | | NA | zero | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2 | (enter negative) | Line 28, Col. (d) (Notes B and X) | - | | | | | - | | |
| 23 | Account No. 282 (enter negative) | Attachment 4, Line 28, Col. (e) (Notes B and X) | - | | NP | - | | - | | |
| 24 | Account No. 283 (enter negative) | Attachment 4, Line 28, Col. (f) (Notes B and X) | - | | NP | - | | - | | |
| 25 | Account No. 190 | Attachment 4, Line 28, Col. (g) (Notes B and X) | - | | NP | - | | - | | |
| 26 | Account No. 255 (enter negative) | Attachment 4, Line 28, Col. (h) (Notes B and X) | - | | NP | - | | - | | |
| 26a | Unfunded Reserves (enter negative) | Attachment 4, Line 31, Col. (h) | - | | DA | 1.000 00 | | - | | |
| 27 | CWIP | Attachment 4, Line 14, Col. (d) | - | | DA | 1.000 00 | | - | | |
| 28 | Unamortized Regulatory Asset | Attachment 4, Line 28, Col. (b) (Note T) | - | | DA | 1.000 00 | | - | | |
| 29 | Unamortized Abandoned Plant | Attachment 4, Line 28, Col. (c) (Note S) | - | | DA | 1.000 00 | | - | | |
| 30 | TOTAL ADJUSTMENTS | (Sum of Lines 22 through 29) | - | | | | | - | | |
| | | | | | | | | | | |
| 31 | LAND HELD FOR FUTURE USE | Attachment 4, Line 14, Col. (e) (Note C) | - | | TP | - | | - | | |
| | | | | | | | | | | |
| 32 | WORKING CAPITAL | (Note D) | | | | | | | | |
| 33 | CWC | 1/8*(Page 3, Line 14 minus Page 3, Line 11) | - | | | | | - | | |
| 34 | Materials & Supplies | Attachment 4, Line 14, Col. (f) (Note C) | - | | TP | - | | - | | |
| 35 | Prepayments (Account 165) | Attachment 4, Line 14, Col. (g) | - | | GP | - | | - | | |
| 36 | TOTAL WORKING CAPITAL | (Sum of Lines 33 through 35) | - | | | | | - | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 37 | RATE BASE | (Sum of Lines 20, 30, 31 & 36) | - | | | | | - | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | page 3 of 5 |
| | | | | | | | | | | |
| | Formula Rate - Non-Levelized | | Rate Formula Template | | | | | | | For the 12 months ended 12/31/___ |
| | | | Utilizing FERC Form 1 Data | | | | | | | |
| | | | South Central MCN LLC | | | | | | | |
| | | | | | | | | | | |
| | (1) | (2) | (3) | | | (4) | | (5) | | |
| Line | | | | | | | | **Transmission** | | |
| No. | | **Source** | **Company Total** | | **Allocator** | | | (Col 3 times Col 4) | | |
| | O&M | | | | | | | | | |
| 1 | Transmission | 321.112.b Attach. 5, Line 13, Col. (a) | - | | TP | - | | - | | |
| 2 | Less Account 566 (Misc Trans Expense) | 321.97.b Attach. 5, Line 13, Col. (b) | - | | TP | - | | - | | |
| 3 | Less Account 565 | 321.96.b Attach. 5, Line 13, Col. | - | | TP | - | | - | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (c) | | | | | | | | |
| 4 | A&G | 323.197.b Attach. 5, Line 13, Col. (d) | - | | W/S | - | | - | | |
| 5 | Less FERC Annual Fees | Attach. 5, Line 13, Col. (e) | - | | W/S | - | | - | | |
| 6 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad. | (Note E) Attach. 5, Line 13, Col. (f) | - | | W/S | - | | - | | |
| 6a | Less PBOP Expense in Year | Attachment 7, Line 8, Col. (g) | - | | W/S | - | | - | | |
| 7 | Plus Transmission Related Reg. Comm. Exp. | (Note E) Attach. 5, Line 13, Col. (g) | - | | TP | - | | - | | |
| 7a | Plus PBOP Expense Allowed Amount | Attachment 7, Line 6, Col. (g) | - | | W/S | - | | - | | |
| 8 | Common | 356.1 | - | | CE | - | | - | | |
| 9 | Transmission Lease Payments | Attach. 5, Line 13, Col (h) | - | | DA | 1.0000 | | - | | |
| 10 | Account 566 | | | | | | | | | |
| 11 | Amortization of Regulatory Asset | (Note T) Attach. 5, Line 13, Col. (i) | - | | DA | 1.0000 | | - | | |
| 12 | Miscellaneous Transmission Expense (less amortization of regulatory asset) | Attach. 5, Line 13, Col .(j) | - | | TP | - | | - | | |
| 13 | Total Account 566 | (Line 11 plus Line 12) Ties to 321.97.b | - | | | | | - | | |
| 14 | TOTAL O&M | (Sum of Lines 1, 4, 7, 7a, 8, 9, 13 less Lines 2, 3, 5, 6, 6a) | - | | | | | - | | |
| | | | | | | | | | | |
| 15 | DEPRECIATION EXPENSE (Note U) | | | | | | | | | |
| 16 | Transmission | 336.7.b, d &e Attach. 5, Line | - | | TP | - | | - | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 13, Col. (k) | | | | | | | | |
| 17 | General & Intangible | 336.10.b, d &e, 336.1.b, d &e Attach. 5, Line 26, Col. (a) | - | | W/S | - | | - | | |
| 18 | Common | 336.11.b, d &e | - | | CE | - | | - | | |
| 19 | Amortization of Abandoned Plant | (Note S) Attach. 5, Line 26, Col. (b) | - | | DA | 1.0000 | | - | | |
| 20 | TOTAL DEPRECIATION | (Sum of Lines 16 through 19) | - | | | | | - | | |
| | | | | | | | | | | |
| 21 | TAXES OTHER THAN INCOME TAXES | (Note F) | | | | | | | | |
| 22 | LABOR RELATED | | | | | | | | | |
| 23 | Payroll | 263.i Attach. 5, Line 26, Col. (c) | - | | W/S | - | | - | | |
| 24 | Highway and vehicle | 263.i Attach. 5, Line 26, Col. (d) | - | | W/S | - | | - | | |
| 25 | PLANT RELATED | | | | | | | | | |
| 26 | Property | 263.i Attach. 5, Line 26, Co.l (e) | - | | GP | - | | - | | |
| 27 | Gross Receipts | 263.i Attach. 5, Line 26, Col. (f) | - | | NA | zero | | - | | |
| 28 | Other | 263.i Attach. 5, Line 26, Col. (g) | - | | GP | - | | - | | |
| 29 | Payments in lieu of taxes | 263.i Attach. 5, Line 26, Col. (h) | - | | GP | - | | - | | |
| 30 | TOTAL OTHER TAXES | (Sum of Lines 23 through 29) | - | | | | | - | | |
| | | | | | | | | | | |
| 31 | INCOME TAXES | (Note G) | | | | | | | | |
| 32 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | WCLTD = Page 4, Line 20 | - | | | | | | | |
| 33 | CIT=(T/1-T) * (1-(WCLTD/R)) = | R = Page 4, Line 23 | - | | | | | | | |
| 34 | FIT & SIT & P | (Note G) | | | | | | | | |
| 35 | | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 36 | 1 / (1 - T) = (from line 32) | | - | | | | | | | |
| 37 | Amortized Investment Tax Credit | 266.8f (enter negative) Attach. 5, Line 26, Col. (i) | - | | | | | | | |
| 38 | Excess Deferred Income Taxes | (enter negative) Attach. 5, Line 26, Col. (j) | - | | | | | | | |
| 39 | Tax Effect of Permanent Differences | Attach. 5, Line 26, Col. (k) (Note W) | - | | | | | | | |
| 40 | Income Tax Calculation | Page 4, line 36, Col. (d) | - | | NA | | | - | | |
| 41 | ITC adjustment | (Line 36 times Line 37) | - | | NP | - | | - | | |
| 42 | Excess Deferred Income Tax Adjustment | (Line 36 times Line 38) | - | | NP | - | | - | | |
| 43 | Permanent Differences Tax Adjustment | (Line 36 times Line 39) | - | | NP | - | | - | | |
| 44 | Total Income Taxes | (Sum of Lines 40 through 43) | - | | | | | - | | |
| | | | | | | | | | | |
| 45 | RETURN | | | | | | | | | |
| 46 | Rate Base times Return | (Page 2, Line 37 times Page 4, Line 23) | - | | NA | | | - | | |
| | | | | | | | | | | |
| 47 | REV. REQUIREMENT | (Sum of Lines 14, 20, 30, 44 & 46) | - | | | | | - | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | page 4 of 5 |
| | | | | | | | | | | |
| | Formula Rate - Non-Levelized | | Rate Formula Template | | | | | | | For the 12 months ended 12/31/___ |
| | | | Utilizing | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | FERC Form 1 Data | | | | | | | |
| | | | South Central MCN LLC | | | | | | | |
| | | | | | | | | | | |
| | (1) | (2) | (3) | | | (4) | | (5) | | |
| | | | | | | | | | | |
| | | **SUPPORTING CALCULATIONS AND NOTES** | | | | | | | | |
| Line | | | | | | | | | | |
| No. | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | | | | | |
| 1 | Total Transmission plant | (Page 2, Line 2, Column 3) | | | | | | - | | |
| 2 | Less Transmission plant excluded from ISO rates | (Note H) | | | | | | - | | |
| 3 | Less Transmission plant included in OATT Ancillary Services | (Note I) | | | | | | - | | |
| 4 | Transmission plant included in ISO rates | (Line 1 minus Lines 2 & 3) | | | | | | - | | |
| | | | | | | | | | | |
| 5 | Percentage of Transmission plant included in ISO Rates | (Line 4 divided by Line 1) | | | | | TP= | - | | |
| | | | | | | | | | | |
| 6 | WAGES & SALARY ALLOCATOR | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | (W&S) | | | | | | | | | |
| | | Form 1 Reference | $ | TP | | Allocation | | | | |
| 7 | Production | 354.20.b | - | - | | - | | | | |
| 8 | Transmission | 354.21.b | - | - | | - | | | | |
| 9 | Distribution | 354.23.b | - | - | | - | | W&S Allocator | | |
| 10 | Other | 354.24,25,26.b | - | - | | - | | ($ / Allocation) | | |
| 11 | Total (W& S Allocator is 1 if lines 7-10 are zero) | (Sum of Lines 7 through 10) | - | | | - | = | - | = | WS |
| | | | | | | | | | | |
| 12 | COMMON PLANT ALLOCATOR (CE) (Note J and X) | | **$** | | | % Electric | | W&S Allocator | | |
| 13 | Electric | 200.3.c | - | | | (line 13 / line 16) | | (line 11) | | CE |
| 14 | Gas | 201.3.d | - | | | - | * | - | = | - |
| 15 | Water | 201.3.e | - | | | | | | | |
| 16 | Total | (Sum of Lines 13 through 15) | - | | | | | | | |
| | | | | | | | | | | |
| 17 | RETURN (R) | (Note V) | | | | | | $ | | |
| 18 | | | | | | Cost | | | | |
| 19 | | | $ | % | | (Notes K, Q, & R) | | Weighted | | |
| 20 | Long Term Debt | (Notes Q & R) | - | - | | - | | - | =WCLTD | |
| 21 | Preferred Stock (112.3.c) | (Notes Q & R) | - | - | | - | | - | | |
| 2 | Common Stock | (Notes K, Q & R) | | | | 10.30 | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | - | - | | % | | - | | |
| 23 | Total | (Sum of Lines 20 through 22) | - | | | | | - | = R | |
| | | | | | | | | | | |
| 24 | REVENUE CREDITS | | | | | | | | | |
| | | | | | | | | | | |
| 25 | ACCOUNT 447 (SALES FOR RESALE) (Note L) | 310 -311 | | | | | | | | |
| 26 | a. Bundled Non-RQ Sales for Resale | 311.x.h | | | | | | - | | |
| 27 | b. Bundled Sales for Resale | Attach 5, line 36, col (a) | | | | | | - | | |
| 28 | Total of (a)-(b) | | | | | | | - | | |
| | | | | | | | | | | |
| 29 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | (Note M) Attach 5, line 36, col (b) | | | | | | - | | |
| | | | | | | | | | | |
| 30 | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | 330.x.n | | | | | | | | |
| 31 | a. Transmission charges for all transmission transactions | Attach 5, line 36, col (c) | | | | | | - | | |
| 32 | b. Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10. | Attach 5, line 36, col (d) | | | | | | - | | |
| 33 | Total of (a)-(b) | | | | | | | - | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | (a) | (b) | (c) | | | (d) | | | | |
| | Income Taxes | % Ownership that has Actual or Potential Income Tax Liability | [1-Col. (c)] | | | Total Income Taxes | | | | |
| 3 | Ownership | | | | | | | | | |

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| 4 | | - | - | | | | | | | |
| 35 | Return from Page 3, Line 46 times % in Line 34 | - | - | | | | | | | |
| 36 | Income Tax Page 3, line 33 {CIT=(T/1-T) * (1-(WCLTD/R))] x Line 35 | - | N/A | | | - | | | | |
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| | | | | | | | | | | page 5 of 5 |
| | | | | | | | | | | |
| | Formula Rate - Non-Levelized | | Rate Formula Template | | | | | | | For the 12 months ended 12/31/___ |
| | | | Utilizing FERC Form 1 Data | | | | | | | |
| | | | South Central MCN LLC | | | | | | | |
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| | General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#) | | | | | | | | | |
| | References to data from FERC Form 1 are indicated as: #.y.x (page, line, | | | | | | | | | |

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| | column) | | | | | | | | | |
| Note | | | | | | | | | | |
| Letter | | | | | | | | | | |
| A | Reserved | | | | | | | | | |
| B | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated. | | | | | | | | | |
| C | Identified in Form 1 as being only transmission related. | | | | | | | | | |
| D | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1. | | | | | | | | | |
| E | Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1 found at 323.191.b. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h. | | | | | | | | | |
| F | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. | | | | | | | | | |
| G | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes" and TEP = "the tax exempt ownership interest". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T). | | | | | | | | | |
| | Inputs Required: | FIT = | - | | | | | | | |
| | | SIT= | - | (State Income Tax Rate or Composite SIT) | | | | | | |
| | | p = | | (percent of federal income | | | | | | |

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| | | | - | tax deductible for state purposes) | | | | | | |
| | | | | | | | | | | |
| H | Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test). | | | | | | | | | |
| I | Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. | | | | | | | | | |
| J | Enter dollar amounts | | | | | | | | | |
| K | ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. | | | | | | | | | |
| L | Page 4, Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1. | | | | | | | | | |
| M | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. | | | | | | | | | |
| N | Company will not have any grandfathered agreements. Therefore, this line shall remain zero. | | | | | | | | | |
| O | The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. Revenue Credits do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not included in this template (e.g., direct assignment facilities and GSUs) the costs of which are not recovered under this Rate Formula Template. | | | | | | | | | |
| P | Reserved | | | | | | | | | |
| Q | Prior to obtaining long term debt, the cost of debt, will be 1.99%. If SCMCN obtains project financing, the long term debt rate will be determined using the methodology in Attachment 8 and Attachment 9 contains the internal rate of return methodology; the methodology will be applied to actual amounts for use in Attachment H. Once there is $100 million in rate base, SCMCN will use the its actual cost of long term debt determined in Attachment 5. The capital structure will be 60% equity and 40% debt during the construction period, after any asset is placed in service, it will be based on the actual capital structure. | | | | | | | | | |
| R | Calculate using 13 month average balance, except ADIT which is calculated based on the average of the beginning and the end of the year balances. | | | | | | | | | |
| S | Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must receive FERC authorization before recovering the cost of abandoned plant. | | | | | | | | | |
| T | Recovery of Regulatory Assets is permitted only for pre-commercial and formation expenses as authorized by the Commission. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rate year when costs are first recovered. | | | | | | | | | |
| U | Excludes Asset Retirement Obligation balances | | | | | | | | | |
| V | Company shall be allowed recovery of costs | | | | | | | | | |

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| | related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges. | | | | | | | | | |
| W | The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference | | | | | | | | | |
| X | Calculate using a simple average of beginning of year and end of year balances reconciling to FERC Form No. 1 by Page, Line and Column as shown in Column 2. | | | | | | | | | |
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| | | | | | | Attachment 1 | | | | | | | | | | | | Page 1 of 2 |
| | | | | | | Project Revenue Requirement Worksheet | | | | | | | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | | | | | | | |
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| | | To be completed in con | | | | | | | | | | | | | | | | |

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| | | junction with Attachment H. | | | | | | | | | | | | | | | | |
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| | | (1) | | (2) | | | | (3) | | | (4) | | | | | | | |
| | | | | **Attachment H** | | | | | | | | | | | | | | |
| Line | | | | **Page, Line, Col.** | | | | **Transmission** | | | **Allocator** | | | | | | | |
| No. | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| 1 | | Gross Transmission Plant - Total | | Attach H, p 2, line 2 col 5 plus line 27 col 5 (Note A) | | | | - | | | | | | | | | | |
| 2 | | Net Transmission | | Attach H, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note B) | | | | - | | | | | | | | | | |

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| | | Plant - Total | | | | | | | | | | | | | | | | | |
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| | | O & M EXPENSE | | | | | | | | | | | | | | | | | |
| 3 | | Total O & M Allocated to Transmission | | Attach H, p 3, line 14 col 5 | | | | - | | | | | | | | | | | |
| 4 | | Annual Allocation Factor for O & M | | (line 3 divided by line 1 col 3) | | | | - | | | - | | | | | | | | |
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| | | GENERAL, INTANGIBLE AND COMM | | | | | | | | | | | | | | | | | |

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| | | ON (G&C) DEPRECIATION EXPENSE | | | | | | | | | | | | | | | | |
| 5 | | Total G, I & C Depreciation Expense | | Attach H, p 3, lines 17 & 18, col 5 (Note H) | | | | - | | | | | | | | | | |
| 6 | | Annual Allocation Factor for G, I & C Depreciation Expense | | (line 5 divided by line 1 col 3) | | | | - | | | - | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| | | TAXES OTHER | | | | | | | | | | | | | | | | |

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| | | THAN INCOME TAXES | | | | | | | | | | | | | | | | |
| 7 | | Total Other Taxes | | Attach H, p 3, line 30 col 5 | | | | - | | | | | | | | | | |
| 8 | | Annual Allocation Factor for Other Taxes | | (line 7 divided by line 1 col 3) | | | | - | | | - | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| 9 | | Less Revenue Credits | | Attach H, p 1, line 7 col 5 | | | | - | | | | | | | | | | |
| 1 | | An | | (line 9 | | | | | | | | | | | | | | |

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| 0 | | nual Allocation Factor Revenue Credits | | divided by line 1 col 3) | | | | - | | | - | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| **11** | | **Annual Allocation Factor for Expense** | | **Sum of line 4, 6, 8, and 10** | | | | | | | - | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| | | INCOME TAXES | | | | | | | | | | | | | | | | |
| 12 | | Total Income Taxes | | Attach H, p 3, line 44 col | | | | - | | | | | | | | | | |

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| | | | | 5 | | | | | | | | | | | | | | |
| 13 | | Annual Allocation Factor for Income Taxes | | (line 12 divided by line 2 col 3) | | | | - | | | - | | | | | | | |
| | | | | | | | | | | | | | | | | | | |
| | | RETURN | | | | | | | | | | | | | | | | |
| 14 | | Return on Rate Base | | Attach H, p 3, line 46 col 5 | | | | - | | | | | | | | | | |
| 15 | | Annual Allocation Factor for Return on Rate | | (line 14 divided by line 2 col 3) | | | | - | | | - | | | | | | | |

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| | | Base | | | | | | | | | | | | | | | | |
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| **16** | | **Annual Allocation Factor for Return** | | **Sum of line 13 and 15** | | | | **-** | | | **-** | | | | | | | |
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| | | | | | | Attachment 1 | | | | | | | | | | | | Page 2 of 2 |
| | | | | | | Project Revenue Requirement Work | | | | | | | | | | | | |

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| | | **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | **(6)** | **(7)** | **(8)** | **(9)** | **(10)** | **(11)** | **(12)** | **(12a)** | **(13)** | **(14)** | **(15)** | **(16)** |
| **Line No.** | | **Project Name (Notes M & N)** | **ITE PProject Number** | **Project Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Project Net Plant** | **Annual Allocation Factor for Return** | **Annual Return Charge** | **Project Depreciation/ Amortization Expense** | **Annual Revenue Requirement** | **Incentive Return in basis Points** | **Incentive Return** | **Ceiling Rate** | **Discount** | **Total Annual Revenue Requirement** | **True-Up Adjustment** | **Net RevReq** |
| | | | | (Note C) | (Page 1 line 11 | (Col. 3 * Col. 4) | (Notes D & I) | (Page 1 line 16) | (Col. 6 * C | (Notes E & I) | (Sum Col. 5, 8 & 9) | (Note K) | (Attachment 2, Line | (Sum Col. | (Note J) | (Sum Col. 10 & 12 Les | (Note F) | Sum Col. |

| | | | | | ) | | | | ol. 7) | | | | 28/100 * Col. 11) | 10 & 12) | | s Col. 13) | | 14 & 15 (Note G) |
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| 15a | | NIXA Example | | $ - | - | - | $ - | - | - | $ - | - | - | - | - | - | - | $ - | - |
| 15b | | | | $ - | - | - | $ - | - | - | $ - | - | - | - | - | - | - | $ - | - |
| 15c | | | | $ - | - | - | $ - | - | - | $ - | - | - | - | - | - | - | $ - | - |
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| 16 | | Annual Totals | | | | | | | | | | | | | - | | | - |
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| Note | | | | | | | | | | | | | | | | | | |
| Letter | | | | | | | | | | | | | | | | | | |
| A | | Gross Transmission Plant is that identified on page 2 line 2 of Attachment H | | | | | | | | | | | | | | | | |
| B | | Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable. | | | | | | | | | | | | | | | | |
| C | | Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities. | | | | | | | | | | | | | | | | |
| | | Gross plant does not include Unamortized Abando | | | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ned Plant. | | | | | | | | | | | | | | |
| D | | Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes any regulatory asset, which are to entered as a separate line item. | | | | | | | | | | | | | | |
| E | | Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 16. Project Depreciation Expense includes the amortization of Abandoned Plant | | | | | | | | | | | | | | |
| F | | True-Up Adjustment is calculated on the Project True-up Schedule for the Rate Year | | | | | | | | | | | | | | |
| G | | The Net Rev Req is the value to be used in the SPP's rate calculation under the applicable Schedule under the SPP OATT for each project. | | | | | | | | | | | | | | |
| H | | The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9. | | | | | | | | | | | | | | |
| I | | The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense. | | | | | | | | | | | | | | |
| J | | The discount is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate | | | | | | | | | | | | | | |
| K | | Requires approval by FERC of incentive return applicable to the specified project(s) | | | | | | | | | | | | | | |
| M | | All facilities other than those being recovered under Schedules 7, 8, 9 are to be | | | | | | | | | | | | | | |

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| | | included in Attachment 1. | | | | | | | | | | | | | | | |
| N | | Facilities that provide Wholesale Distribution Service are not to be listed as projects on lines 15, the revenue requirements associated with these facilities are calculated on Attachment 11 | | | | | | | | | | | | | | | |
| O | | When an updated projected net revenue requirement is posted due to an asset acquisition as provided for in the Protocols, the difference between the updated net revenue requirement in Col (16) and the revenues collected to date will be recovered | | | | | | | | | | | | | | | |
| | | over the remaining months of the Rate Year. | | | | | | | | | | | | | | | |

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| | | | | | Attachment 2 | | | | | Page 1 of 1 |
| | | | | | Incentive ROE | | | | | |
| | | | | | South Central MCN LLC | | | | | |
| | | | | | | | | | | |
| 1 | Rate Base | Attachment H, Page 2 line 37, Col.5 | | | | | | | | - |
| | | | | | | | | | | |
| 2 | 100 Basis Point Incentive Return | | | | | | | | $ | |
| | | | | | | | Cost | | | |
| | | | | $ | % | | | | Weighted | |
| 3 | Long Term Debt | (Attachment H, Notes Q and R) | | - | - | | - | | - | |
| 4 | Preferred Stock | (Attachment H, Notes Q and R) | | - | - | | - | | - | |
| 5 | Common Stock | (Attachment H, Notes K, Q and R) | Cost = Attachment H, Page 4 Line 22, Cost plus .01 | - | - | | 0.1130 | | - | |
| 6 | Total (sum lines 3-5) | | | - | | | | | - | |
| 7 | 100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6) | | | | | | | | | - |
| | | | | | | | | | | |
| | INCOME | | | | | | | | | |

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| 8 | TAXES | | | | | | | | | |
| 9 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | - | | | | | | |
| 10 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | | - | | | | | | |
| 11 | WCLTD = Line 3 | | | | | | | | | |
| 12 | and FIT, SIT & p are as given in footnote K. | | | | | | | | | |
| 13 | 1 / (1 - T) = (from line 9) | | | - | | | | | | |
| 14 | Amortized Investment Tax Credit (266.8f) (enter negative) | | Attachment H, Page 3, Line 37 | - | | | | | | |
| 15 | Excess Deferred Income Taxes (enter negative) | | Attachment H, Page 3, Line 38 | - | | | | | | |
| 16 | Tax Effect of Permanent Differences (Note B) | | Attachment H, Page 3, Line 39 | - | | | | | | |
| 17 | Income Tax Calculation = line 10 * line 7 | | | - | | NA | | | - | |
| 18 | ITC adjustment (line 13 * line 14) | | | - | | NP | - | | - | |
| 19 | Excess Deferred Income Tax Adjustment (line 13 * line 15) | | | - | | NP | - | | - | |
| 20 | Permanent Differences Tax Adjustment (line 13 * 16) | | | - | | NP | - | | - | |
| 21 | Total Income Taxes (sum lines 17 - 20) | | | - | | | | | - | - |
| | | | | | | | | | | |
| 22 | Return and Income Taxes with 100 basis point increase in ROE | | | | | | | | | - |

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|---|---|---|---|---|---|---|---|---|---|---|
| 23 | Return (Attach. H, page 3 line 46 col 5) | | | | | | | | | - |
| 24 | Income Tax (Attach. H, page 3 line 44 col 5) | | | | | | | | | - |
| 25 | Return and Income Taxes without 100 basis point increase in ROE | | | | | | | | | - |
| 26 | Incremental Return and Income Taxes for 100 basis point increase in ROE | | | | | | | | | - |
| 27 | Rate Base (line 1) | | | | | | | | | - |
| 28 | Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base | | | | | | | | | - |
| | | | | | | | | | | |
| Notes: | | | | | | | | | | |
| A | Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with | | | | | | | | | |
| | a 100 basis point increase in ROE. Any actual ROE incentive must be approved by the Commission. | | | | | | | | | |
| | For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point | | | | | | | | | |
| | increase in ROE would be multiplied by 1.37 on Attachment 1 column 12. | | | | | | | | | |
| B | The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated | | | | | | | | | |
| | in Attachment H that are not the result of a timing difference | | | | | | | | | |

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| | | | | | | | | | Page 1 of 1 | |
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| | | | | Attachment 3 | | | | | | |
| | | | | Project True-Up | | | | | | |
| | | | | South Central MCN LLC | | | | | | |
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| | | | | | | | | | | |
| | | | Revenue Requirement Projected | | | Actual Revenue | | | | |
| 1 | Rate Year being Trued-Up | | For Rate Year | | Revenue Received[3] | Requirement | Annual True-Up Calculation | | | |
| 2 | | | | | $ - | | | | | |
| | A | B | C | D | E | F | G | H | I | J |
| | | | | % of | | | | | | |
| | | | Projected | Total | Revenue | Actual | Net | | Interest | |
| | Project # | | Net Revenue | Revenue | Received | Net Revenue | Under/(Over) | Prior Period | Income | Total True-Up |
| | Or Other Identifier | Project Name | Requirement[1] | Requirement | (E, Line 2 ) x (D) | Requirement[2] | Collection (F)-(E) | Adjustment [5] | (Expense) [4] | (G) + (H) + (I) |
| 3 | Attachment H | | - | - | - | - | - | - | - | - |
| 3a | | | - | - | - | - | - | - | - | - |
| 3b | | | - | - | - | - | - | - | - | - |
| 3c | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |

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| | | | - | - | - | - | - | - | - | - |
| | | | | | | | | | | |
| 4 | Total Annual Revenue Requirements (Note A) | | - | - | - | - | - | | - | - |
| | | | | | | | | | | |
| | | | | | | Monthly Interest Rate | | | - | |
| | | | | | | Interest Income (Expense) | | | - | |

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| | Notes: | | | | | | | | | |
| | 1) From Attachment 1, line 15, col. 14 for the projection for the Rate Year. | | | | | | | | | |
| | 2) From Attachment 1, line 15, col. 14 for that project based on the actual costs for the Rate Year. | | | | | | | | | |
| | 3) The "Revenue Received" on line 2, Col. (E), is the total amount of revenue distributed to company in the year as shown on pages 328-330 of the Form No 1. The Revenue Received is input on line 2, Col. E excludes any True-Up revenues. | | | | | | | | | |
| | Column E, lines 3 are the dollar amounts of Revenue Received reflecting the % in Column D. This assigns to each project a percentage of the revenue received based on the percentage of the Projected Net Revenue Requirement in Column C. | | | | | | | | | |
| | 4) Interest from Attachment 6. | | | | | | | | | |
| | 5) Prior Period Adjustment from line 5 is pro rata to each project, unless the error was project specific. | | | | | | | | | |
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| **Prior Period Adjustment** | | | | | | | | | | |
| | (a) | (b) | (c) | (d) | | | | | | |
| | Prior Period Adjustment | Amount | Interest | Total | | | | | | |
| | (Note B) | In Dollars | Note B | Col. (b) + Col. (c) | | | | | | |
| 5 | - | - | - | - | | | | | | |
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| Notes: | A | For each project or Attachment H, the utility will populate the formula rate with the inputs for the True-Up Year. The revenue requirements, based on actual operating results for the True-Up Year, associated with the projects and Attachment H will then be entered in Col. (F) above. Column (E) above contains the actual revenues received associated with Attachment H and any Projects paid by SPP to the utility during the True-Up Year. Then in Col. (G), Col. (E) is subtracted from Col. (F) to calculate the True-up Adjustment. The Prior Period Adjustment from Line 5 below is input in Col. (H). Column (I) is the applicable interest rate from Attachment 6. Column (I) adds the interest on the sum of Col.(G) and (H). Col. (J) is the sum of Col. (G), (H), and (I). | | |
| | B | Prior Period Adjustment is the amount of an adjustment to correct an error in a prior period. The FERC Refund interest rate specified in CFR 35.19(a) for the period up to the date the projected rates that are subject to True Up here went into effect. | | |

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| | | | | | | Attachment 4 | | | Page 1 of 2 | |
| | | | | | | Rate Base Worksheet | | | | |
| | | | | | | South Central MCN LLC | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | **Gross Plant In Service** | | **CWIP** | **LHFU** | **Working Capital** | | **Accumulated Depreciation** | | |
| Line No | **Month** | **Transmission** | **General & Intangible** | **CWIP in Rate Base** | **Held for Future Use** | **Materials & Supplies** | **Prepayments** | **Transmission** | **General & Intangible** | |
| | **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)** | **(h)** | **(i)** | |
| | Attachment H, Page 2, Line No: | 2 | 4 | 27 | 31 | 34 | 35 | 9 | 11 | |
| | | 207.58.g for end of year, records for other months | 205.5.g & 207.99.g for end of year, records for other months | (Note C) | 214.x.d for end of year, records for other months | 227.8.c & 227.16.c for end of year, records for other months | 111.57.c for end of year, records for other months | 219.25.c for end of year, records for other months | 219.28.c & 200.21.c for end of year, records for other months | |
| 1 | December Prior Year | - | - | - | - | - | | - | - | |
| 2 | January | - | - | - | - | - | | - | - | |
| 3 | February | - | - | - | - | - | | - | - | |
| 4 | March | - | - | - | - | - | | - | - | |
| 5 | April | | | | | | | | | |

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| | | - | - | - | - | - | | - | - | |
| 6 | May | - | - | - | - | - | | - | - | |
| 7 | June | - | - | - | - | - | | - | - | |
| 8 | July | - | - | - | - | - | | - | - | |
| 9 | August | - | - | - | - | - | | - | - | |
| 10 | September | - | - | - | - | - | | - | - | |
| 11 | October | - | - | - | - | - | | - | - | |
| 12 | November | - | - | - | - | - | | - | - | |
| 13 | December | - | - | - | - | - | | - | - | |
| 14 | Average of the 13 Monthly Balances | - | - | - | - | - | - | - | - | |
| | | | | | | | | | | |
| | | **Adjustments to Rate Base** | | | | | | | | |
| Line No | **Month** | **Unamortized Regulatory Asset** | **Unamortized Abandoned Plant** | **Account No. 281 Accumulated Deferred Income Taxes (Note D)** | **Account No. 282 Accumulated Deferred Income Taxes (Note D)** | **Account No. 283 Accumulated Deferred Income Taxes (Note D)** | **Account No. 190 Accumulated Deferred Income Taxes (Note D)** | **Account No. 255 Accumulated Deferred Investment Credit** | | |
| | **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)** | **(h)** | | |
| | Attachment H, Page 2, Line No: | 28 | 29 | 22 | 23 | 24 | 25 | 26 | | |
| | | **Notes A & E** | **Notes B & F** | **272.8.b & 273.8** | **274.2.b & 275.2.** | **276.9.b & 277.9.k** | **234.8.b & c** | **Consistent with** | | |

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|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **.k** | **k** | | | **266.8.b & 267.8.h** | | |
| 15 | December Prior Year | - | - | - | - | - | - | - | | |
| 16 | January | - | - | | | | | - | | |
| 17 | February | - | - | | | | | - | | |
| 18 | March | - | - | | | | | - | | |
| 19 | April | - | - | | | | | - | | |
| 20 | May | - | - | | | | | - | | |
| 21 | June | - | - | | | | | - | | |
| 22 | July | - | - | | | | | - | | |
| 23 | August | - | - | | | | | - | | |
| 24 | Septembe r | - | - | | | | | - | | |
| 25 | October | - | - | | | | | - | | |
| 26 | Novembe r | - | - | | | | | - | | |
| 27 | December | - | - | - | - | - | - | - | | |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | - | - | - | | |
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| | | | | | Attac hment 4 | | | | | |
| | | | | | Rate Base Work sheet | | | | | |
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| | | | | | MCN LLC | | | | | |
| | Unfunded Reserves (Notes G & H) | | | | | | | | | |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | Page 2 of 2 | |
| 29 | List of all reserves: | | Amount | Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account | Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate | Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liability on the balance sheet | Allocation (Plant or Labor Allocator) | Amount Allocated, col. c x col. d x col. e x col. f x col. g | | |
| 30a | | Reserve 1 | - | - | | | | - | | |
| 30b | | Reserve 2 | - | - | | | | - | | |
| 30c | | Reserve 3 | | | | | | | | |
| 30 | | Reserve 4 | | | | | | | | |

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| d | | | | | | | | | | |
| 30e | | … | | | | | | | | |
| 30f | | … | - | - | | | | - | | |
| 31 | | Total | - | | | | | - | | |
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| Notes: | | | | | | | | | | |
| A | Recovery of regulatory asset is limited to any regulatory assets authorized by FERC. | | | | | | | | | |
| B | Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC. | | | | | | | | | |
| C | Includes only CWIP authorized by the Commission for inclusion in rate base. The annual report filed pursuant to Section 7 of the Protocols will include for each project under construction (i) the CWIP balance eligible for inclusion in rate base; (ii) the CWIP balance ineligible for inclusion in rate base; and | | | | | | | | | |
| | (iii) a demonstration that AFUDC is only applied to the CWIP balance that is not included in rate base. The annual report will reconcile the project-specific CWIP balances to the total Account 107 CWIP balance reported on p. 216.b of the FERC Form 1. | | | | | | | | | |
| D | ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances. | | | | | | | | | |
| E | Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rate year when costs are first recovered. | | | | | | | | | |
| F | Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. | | | | | | | | | |
| G | The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since | | | | | | | | | |

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| | reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account. | | | | | |
| H | Calculate using 13 month average balance, except ADIT which is calculated based on the average of the beginning of the year and the end of the year balances | | | | | |

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| | | | | | | Attachment 5 | | | | | | Page 1 of 2 |
| | | | | | | Attachment H, Pages 3 and 4, Worksheet | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | |
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| | | | | | | | | | | | | |
| Line No. | Month | Transmission O&M Expenses | Account No. 566 (Misc. Trans. Expense) | Account No. 565 | A&G Expenses | FERC Annual Fees | EPRI & Reg. Comm. Exp. & Non-safety Ad. | Transmission Related Reg. Comm. Exp. | Transmission Lease Payments | Amortization of Regulatory Asset | Miscellaneous Transmission Expense (less amortization of regulatory asset) | Depreciation Expense - Transmission |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| | Attachment H, Page 3, Line No.: | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 9 | 11 | 12 | 16 |
| | Form No. 1 | 321.112.b | 321.97.b | 321.96.b | 323.197.b | (Note E) | (Note E) | (Note E) | Portion of Transmis | Portion of Account | Balance of Account | 336.7.b, d & e |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | sion O&M | 566 | 566 | |
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| | | | | | | | | | | | | |
| 1 | January | | - | - | - | - | - | - | - | - | - | - |
| 2 | February | | - | - | - | - | - | - | - | - | - | - |
| 3 | March | | - | - | - | - | - | - | - | - | - | - |
| 4 | April | | - | - | - | - | - | - | - | - | - | - |
| 5 | May | | - | - | - | - | - | - | - | - | - | - |
| 6 | June | | - | - | - | - | - | - | - | - | - | - |
| 7 | July | | - | - | - | - | - | - | - | - | - | - |
| 8 | August | | - | - | - | - | - | - | - | - | - | - |
| 9 | September | | - | - | - | - | - | - | - | - | - | - |
| 10 | October | | - | - | - | - | - | - | - | - | - | - |
| 11 | November | | - | - | - | - | - | - | - | - | - | - |
| 12 | December | | - | - | - | - | - | - | - | - | - | - |
| 13 | Total | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | |
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| | | Depreciation Expense - General & Intangible | Amortization of Abandoned Plant | Payroll Taxes | Highway & Vehicle Taxes | Property Taxes | Gross Receipts Taxes | Other Taxes | Payments in lieu of Taxes | Amortized Investment Tax Credit (266.8f) | Excess Deferred Income Taxes | Tax Effect of Permanent Differences |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |

| | Attachment H, Page 3, Line Number | 17 | 19 | 23 | 24 | 26 | 27 | 28 | 29 | 37 | 38 | 39 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Form No. 1 | 336.10.b, d & e, 336.1.b, d & e | (Note S) | 263.i | 263.i | 263.i | 263.i | 263.i | 263.i | 266.8.f | (Note G) | (Note W) |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| 14 | January | - | - | - | - | | - | - | - | - | - | - |
| 15 | February | - | - | - | - | | - | - | - | - | - | - |
| 16 | March | - | - | - | - | | - | - | - | - | - | - |
| 17 | April | - | - | - | - | | - | - | - | - | - | - |
| 18 | May | - | - | - | - | | - | - | - | - | - | - |
| 19 | June | - | - | - | - | | - | - | - | - | - | - |
| 20 | July | - | - | - | - | | - | - | - | - | - | - |
| 21 | August | - | - | - | - | | - | - | - | - | - | - |
| 22 | September | - | - | - | - | | - | - | - | - | - | - |
| 23 | October | - | - | - | - | | - | - | - | - | - | - |
| 24 | November | - | - | - | - | | - | - | - | - | - | - |
| 25 | December | - | - | - | - | | - | - | - | - | - | - |
| 26 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | Attachment 5 | | | | | | Page 2 of 2 |
| | | | | | | Attachment H, | | | | | | |

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| | | | | | | Pages 3 and 4, Worksheet | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | |
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| | | **Bundled Sales for Resale included on page 4 of Attachment H** | **ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)** | **Transmission charges for all transmission transactions** | **Transmission charges associated with Project detailed on the Project RevReq Schedule Col. 10.** | **Account No. 457.1 Scheduling** | | | | | | |
| | | (a) | (b) | (c) | (d) | (e) | | | | | | |
| | Attachment H, Page 4, | 27 | 29 | 31 | 32 | Attach H, p 1 line 4 | | | | | | |

| | Line No: | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (Note L) | (Note M) | Portion of Account 456.1 | | | | | | | | |
| | | | | | | | | | | | | |
| 24 | January | - | - | - | - | - | | | | | | |
| 25 | February | - | - | - | - | - | | | | | | |
| 26 | March | - | - | - | - | - | | | | | | |
| 27 | April | - | - | - | - | - | | | | | | |
| 28 | May | - | - | - | - | - | | | | | | |
| 29 | June | - | - | - | - | - | | | | | | |
| 30 | July | - | - | - | - | - | | | | | | |
| 31 | August | - | - | - | - | - | | | | | | |
| 32 | September | - | - | - | - | - | | | | | | |
| 33 | October | - | - | - | - | - | | | | | | |
| 34 | November | - | - | - | - | - | | | | | | |
| 35 | December | - | - | - | - | - | | | | | | |
| 36 | Total | $ - | $ - | $ - | $ - | $ - | | | | | | |
| 37 | | | | | | | | | | | | |
| 38 | RETURN (R) | | | | | | | | | | | |
| | Notes K, Q & R from Attachment H | | | | | | | | | | | |

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| | | | | | | | | | $ | | | |
| 39 | | | Long Term Interest (117, sum of 62.c through 67.c) | | | | | | - | | | |
| | | | | | | | | | | | | |
| 40 | | | Preferred Dividends (118.29c) (positive number) | | | | | | - | | | |
| | | | | | | | | | | | | |
| 41 | | | Proprietary Capital (112.16.c) | | | | | | - | | | |
| 42 | | | Less Preferred Stock (line 49) | | | | | | - | | | |
| 43 | | | Less Account 216.1 (112.12.c) (enter negative) | | | | | | - | | | |
| 44 | | | Common Stock | (sum lines 41-43) | | | | | - | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | Cost | | | | |
| | | | | | $ | % | | | | Weighted | | |
| 45 | Long Term Debt | Note A | | | - | - | | - | | - | =WCLTD | |
| 46 | Preferred Stock (112.3.c) | Note B | | | - | - | | - | | - | | |
| 47 | Common Stock | Note C | | | - | - | | 10.30% | | - | | |
| 48 | Total | (Sum of Lines 45-47) | | | - | | | | | - | =R | |
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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Note: | | | | | | | | | | | | |
| A | Long Term Debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c & d to 21.c & d in the Form No. 1, the cost is calculated by dividing line 39 by the Long Term Debt balance in line 45. | | | | | | | | | | | |
| B | Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c & d in the Form No. 1 | | | | | | | | | | | |
| C | Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 3.c & d, 12.c & d, and 16.c & d in the Form No. 1 as shown on lines 41-44 above | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Attachment 6 | | | | | | | | Page 1 of 1 |
| | | | | | | | | True-Up Interest Rate | | | | | | | | |
| | | | | | | | | South Central MCN LLC | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| | | **Quarter (Note A)** | | **Interest rate for the Quarter pursuant to Section 35.19(a)** | | | | | | | | | | | | |
| 1 | | 1st Qtr | | - | | | | | | | | | | | | |
| 2 | | 2nd Qtr | | - | | | | | | | | | | | | |
| 3 | | 3rd Qtr | | - | | | | | | | | | | | | |
| 4 | | 4th Qtr | | - | | | | | | | | | | | | |
| 5 | | 1st Qtr | | - | | | | | | | | | | | | |
| 6 | | 2nd Qtr | | - | | | | | | | | | | | | |
| 7 | | 3rd Qtr | | - | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| 8 | Avg. Monthly FERC Rate | | | - | | | - | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| Note A: | | | | | | | | | | | | | | | | |
| Lines 1-7 are the FERC interest rate under section 35.19(a) of the regulations for the period shown. | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line 8 is the average of lines 1-7. | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
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| | | | | | | | | | | | | | | | | |
| 9 | Year | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | |
| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
| | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| | Project # | | Date Payments Received | | | | | | | | | | | | Interest | Interest |
| | Or Other Identifier | Project Name | January | February | March | April | May | June | July | August | September | October | November | December | Rate (line 8) | (Note B) |
| 11 | Attachment H | | | | | | | | | | | | | | | |
| 11a | | | | | | | | | | | | | | | - | - |
| 11b | | | | | | | | | | | | | | | - | - |
| 11c | | | | | | | | | | | | | | | - | - |
| … | | | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | | - | - |

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| | | | | | | | | | | | | | | | - | - |
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| | | | | | | | | | | | | | | | - | - |
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| | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| | Note B | | | | | | | | | | | | | | | |
| | Interest is calculated by taking the interest rate in line 8 and applying it monthly to the balances in Column C-N (i.e., for January 12/12* Column O, February 11/12* Column O, etc.) | | | | | | | | | | | | | | | |
| | plus the interest rate in line 8 times 1.5 times the sum of the balances for January through December. | | | | | | | | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Attachment 7 | | | | | | Page 1 of 1 |
| | | PBOPs | | | | | | |
| | | South Central MCN LLC | | | | | | |
| | | | | | | | | |
| | **Calculation of PBOP Expenses** | | | | | | | |
| | (a) | | (b) | (c) | (d) | (e) | (f) | (g) |
| | | | | | | | | |
| 1 | | | **SCMCN** | **Affiliate** | **Affiliate** | **Affiliate** | **Affiliate** | **Total** |
| 2 | Total PBOP expenses (Note A) | | - | - | - | - | - | |
| 3 | Labor dollars (total labor from budget) | | - | - | - | - | - | |
| 4 | Cost per labor dollar (line2 / line3) | | - | - | - | - | - | |
| 5 | labor expensed (labor not capitalized) by SCMCN in current year, 354.28.b. | | - | - | - | - | - | |
| 6 | PBOP Expense for current year | | - | - | - | - | - | - |
| 7 | Lines 2-3 cannot change absent approval or acceptance by FERC in a separate proceeding. | | | | | | | |
| | | | | | | | | |
| 8 | PBOP amount included in Company's O&M and A&G expenses included in FERC Account Nos. 500-935 | | | | | | | - |
| | | | | | | | | |
| Note | | | | | | | | |
| Letter | | | | | | | | |
| A | There will be zero PBOP expenses in the SCMCN rates until SCMCN files for recovery of its PBOP expenses. Line 8 removes all SCMCN or affiliate BPOP expenses in FERC Accounts 500-935. | | | | | | | |
| | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Page 1 of 1 |
| Attachment 8 | | | | | | | | | |
| Financing Costs for Long Term Debt using the Internal Rate of Return Methodology | | | | | | | | | |
| South Central MCN LLC | | | | | | | | | |
| | | | | | | | | | |
| | To be utilized until a project is placed in service | | | | | | | | |
| | Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of Return formula below. | | | | | | | | |
| | Each year, the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount will be updated on this attachment. | | | | | | | | |
| | | | | | | | | | |
| | Table 1 | | | | | | | | |
| | | | | | | | | | |
| 1 | **Total Loan Amount** | | | | **$ 50,000 ,000** | | | | |
| | Table 2 | | | | | | | | |
| 2 | **Internal Rate of Return (Note 1)** | | | | **4.85%** | | | | |
| 3 | **Based on following Financial Formula (Note 2):** | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | **NPV = 0 =** | | $\sum_{t=1}^{N} C_t / (1 + IRR)pwr(t)$ | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| | | | | | | | | | |
| | Table 3 | | | | | | | | |
| 9 | | | | | | | | | |
| 1 | **Origination** | | | R | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 0 | **Fees** | | | atesFees | Amount | | | | |
| 11 | Underwriting Discount | | | - | - | | | | |
| 12 | Arrangement Fee | | | 0.75 | 375,000 | | | | |
| 13 | Upfront Fee | | | - | 750,000 | | | | |
| 14 | Rating Agency Fee | | | - | - | | | | |
| 15 | Legal Fees | | | - | - | | | | |
| 15a | | | | - | - | | | | |
| 16 | Total Issuance Expense | | | | **1,125,000** | | | | |
| | | | | | | | | | |
| 17 | | | | | | | | | |
| 18 | **Annual Rating Agency Fee** | | | - | - | | | | |
| 19 | **Annual Bank Agency Fee** | | | - | - | | | | |
| 21 | **Revolving Credit Commitment Fee** | | | | - | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 21a | | | | | | | | | |
| | | | | | | | | | |
| | Table 4 | | | | | | | | |
| 22 | | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | |
| 23 | LIBOR Rate | 0.24% | 0.56% | 1.45% | 2.29% | 2.76% | 3.03% | 3.21% | |
| 24 | Spread | 1.75% | 1.75% | 1.75% | 1.75% | 1.75% | 1.75% | 1.75% | |
| 25 | **Interest Rate** | 1.99% | 2.31% | 3.20% | 4.04% | 4.51% | 4.78% | 4.96% | |
| | | | | | | | | | |
| | Table 5 | | | | | | | | |
| 26 | (A) | (B) | ( C) | (D) | (E) | (F) | (G) | (H) | (I) |
| 27 | **Year** | | **Quarterly Construction Expenditures ( $000's)** | **Principle Drawn In** | **Principle Drawn To Date ($000's)** | **Interest & Principal Payments ($000's)** | **Origination Fees ($000's)** | **Commitment, Utilization & Ratings Fees ($000's)** | **Net Cash Flows ($000's)** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | **Quarter ($0000's)** | | | | | |
| 28 | | | Estimated | Estimated | Cumulative Col. D | Interest Rate from Line 25 (Note 3) | Input in first Qtr of Loan | Lines 17 - 21x | (D-F-G-H) |
| 29 | | | | | | | | | |
| 30 | 1/1/2015 | | - | | | | | | |
| 31 | 3/31/2015 | Q1 | - | - | - | - | | | - |
| 32 | 6/30/2015 | Q2 | - | - | - | - | | | - |
| 33 | 9/30/2015 | Q3 | - | - | - | - | | | - |
| 34 | 12/31/2015 | Q4 | - | - | - | - | | | - |
| 35 | 3/31/2016 | Q1 | 25,000 | 10, | 10,000 | - | 1,125 | - | 8,875 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | 000 | | | | | |
| 36 | 6/30/2016 | Q2 | - | - | 10,000 | 57 | | - | (57) |
| 37 | 9/30/2016 | Q3 | 25,000 | 10,000 | 20,000 | 58 | | - | 9,942 |
| 38 | 12/31/2016 | Q4 | - | - | 20,000 | 116 | | - | (116) |
| 39 | 3/31/2017 | Q1 | - | - | 20,000 | 114 | | - | (114) |
| 40 | 6/30/2017 | Q2 | 25,000 | 10,000 | 30,000 | 160 | | - | 9,840 |
| 41 | 9/30/2017 | Q3 | - | - | 30,000 | 242 | | - | (242) |
| 42 | 12/31/2017 | Q4 | - | - | 30,000 | 242 | | - | (242) |
| 43 | 3/31/2018 | Q1 | 25,000 | 10,000 | 40,000 | 237 | | - | 9,763 |
| 44 | 6/30/2018 | Q2 | - | - | 40,000 | 403 | | - | (403) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 45 | 9/30/2018 | Q3 | 25,000 | 10,000 | 50,000 | 408 | | - | 9,592 |
| 46 | 12/31/2018 | Q4 | - | - | 50,000 | 510 | | - | (510) |
| 47 | 3/31/2019 | Q1 | - | - | 50,000 | 499 | | - | (499) |
| 48 | 6/30/2019 | Q2 | - | - | 50,000 | 562 | | - | (562) |
| 49 | 9/30/2019 | Q3 | - | - | 50,000 | 568 | | - | (568) |
| 50 | 12/31/2019 | Q4 | - | - | 50,000 | 568 | | - | (568) |
| 51 | 1/1/2020 | Q1 | - | - | 50,000 | 50,006 | | - | (50,006) |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | | | | | | | | |
| 58 | | | | | | | | | |
| | | | | | | | | | |
| Notes | | | | | | | | | |
| | 1 The IRR is the input to Debt Cost shown on Attachment H, Page 4, Line 20 during the construction period, after obtaining project financing, in accordance with Note Q of | | | | | | | | |

| | |
|---|---|
| | Attachment H. |
| | 2. The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation is shown on line 6. |
| | N is the last quarter the loan would be outstanding |
| | t is each quarter |
| | Ct is the cash flow (Table 5, Col. I in each quarter) |
| | Alternatively the equation can be written as 0 = C0 + C1/(1+IRR) + C2/(1+IRR)2 + C3/(1+IRR)3 + . . . +Cn/(1+IRR)n and solved for IRR |
| | The Excel ™ formula on line 2 is : (round(XIRR(first quarter of loan Col A of Table 5:last quarter of loan Col A of Table 5, first quarter of loan Col I of Table 5: last quarter of loan Col I of Table 5, 8%),4) |
| | The 8% in the above formula is a seed number to ensure the formula produces a positive number. |
| | 3. Line 1 reflects the loan amount, the maximum amount that can be drawn on |
| | 4. Lines 11-21a include the fees associated with the loan. They are estimated based on current bank condition and are updated with the actual fees |
| | once the actual fees are known. |
| | 5. The estimate of the average 3 month Libor forward rate for the year on line 23 is that published by Bloomberg Finance L.P. during August of the prior year and is trued-up to actual |
| | average 3 month Libor rate for the year under the loan. |
| | 6. Table 5, Col. C reflect the capital expenditures in each quarter |
| | 7. Table 5, Col. D reflect the amount of the loan that is drawn down in the quarter |
| | 8. Table 5, Col. E is the amount of principle drawn down |
| | 9. Table 5, Col F calculates the interest on the |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | principle drawn down to date based on the applicable interest on line 25 | | | | | | | |
| | 10. Table 5, Col. G is the total origination fees in line 16 and is input in the first quarter that a portion of the loan in drawn | | | | | | | |
| | 11. Table 5, Col. H is calculated as follows: | | | | | | | |
| | | A x (line 21, Col. (b)/4) + sum of line 17, Col. (c) through line 21x, Col. (c) | | | | | | |
| | Where A = | Loan amount in line 1 less the amount drawn down (Table 5, Col. (E)) in the prior quarter | | | | | | |
| | 12. The inputs shall be estimated based on the current market conditions and is subject to true up for all inputs , e.g., fees, interest rates, spread, and Table 3 once the | | | | | | | |
| | amounts are known | | | | | | | |
| | 13. Prior to obtaining long term debt, the cost of debt, will be 1.99%. If SCMCN obtains project financing, the long term debt rate will be determined using the methodology in Attachment 8 and Attachment 9 contains the internal rate of return methodology; the methodology will be applied to actual amounts for use in Attachment H. Once there is $100 million in rate base, SCMCN will use the its actual cost of long term debt determined in Attachment 5. The capital structure will be 60% equity and 40% debt during the construction period, after any asset is placed in service, it will be based on the actual capital structure. | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Attachment 9 | | | | | | | | Page 1 of 3 |
| | | | | | | Final True-Up of Interest Rates and Interest Calculations for the Construction Loan | | | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | | | |
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| **SUMMARY** | | | | | | | | | | | | | | |
| **(a)** | | **(b)** | | **(c)** | | **(d)** | | **(e)** | | **(f)** | | **(g)** | | **(h)** |
| **YEAR** | | **Cost of Debt Used in Determining the Actual Net Revenue Requirement in Attachment H, page 4, line 20** | | **Cost of Debt for the Construction Loan Calculated on Attachment 8 Once the Loan is Paid Off:** | | **Actual Net Revenue Requirement in Attachment 3, col. (G) for the year** | | **Actual Net Revenue Requirement if the Cost of Debt in Col. (c)** | | **Over (Under) Recovery Col. (d) less Col. (e)** | | **Refund/Surcharge Interest Rate Calculated on Attachment 6 for the Rate Year** | | **Total Amount of Construction Loan Related True-Up with Interest (Refund)/Owed (Total Amount of True-Up Adjustment below for the Rate Year)** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | **had been Used** | | | | | | |
| | | | | | | | | | | $ - | | | | $ - |
| | | | | | | | | | | $ - | | | | $ - |
| | | | | | | | | | | $ - | | | | $ - |
| | | | | | | | | | | $ - | | | | $ - |
| | * | | | | | | | | | $ - | | | | $ - |
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**Calculation of Applicable Interest Expense for each ATRR period**

| **Interest Rate on Amount of Refunds or Surcharges from 35.19a** | | | **Over (Under) Recovery** | | **Monthly Interest Rate** | | **Months** | | **Calculated Interest** | | **Amortization** | | **Surcharge (Refund) Owed** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | From Column (g) | | | | | | | | |
| | | | Column (f) above divided by 12 | | Above for the | | | | Col (c) x Col (d) x | | | | |
| | | | For the Months the Rate | | Rate Year | | Weigh | | Col (e) x -1 | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | was in Effect | | | | ting | | | | | | |
| **Calculation of Interest for 2015 True-Up Period** | | | | | | | | | | | | | | |
| | | | | | | | | | | **Monthly** | | | | |
| - | | | | | | | | | | | | | | |
| January | | Year 2015 | | - | | | | 12.00 | | - | | | | - |
| February | | Year 2015 | | - | | | | 11.00 | | - | | | | - |
| March | | Year 2015 | | - | | | | 10.00 | | - | | | | - |
| April | | Year 2015 | | - | | | | 9.00 | | - | | | | - |
| May | | Year 2015 | | - | | | | 8.00 | | - | | | | - |
| June | | Year 2015 | | - | | | | 7.00 | | - | | | | - |
| July | | Year 2015 | | - | | | | 6.00 | | - | | | | - |
| August | | Year 2015 | | - | | | | 5.00 | | - | | | | - |
| September | | Year 2015 | | - | | | | 4.00 | | - | | | | - |
| October | | Year 2015 | | - | | | | 3.00 | | - | | | | - |
| November | | Year 2015 | | - | | | | 2.00 | | - | | | | - |
| December | | Year 2015 | | - | | | | 1.00 | | - | | | | - |
| | | | | | | | | | | - | | | | - |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | **Annual** | | | | |
| | | | | | | | | | | | | | | |
| January through December | | Year 2016 | | - | | | | 12.00 | | - | | | | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| January through December | | Year 2017 | | - | | | | 12.00 | | - | | | | - |
| January through December | | Year 2018 | | - | | | | 12.00 | | - | | | | - |
| January through December | | Year 2019 | | - | | | | 12.00 | | - | | | | - |
| January through December | | Year 2020 | | - | | | | 12.00 | | - | | | | - |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | | | | | | **Monthly** | | | | |
| January | | Year 2021 | | - | | | | | | - | | - | | - |
| February | | Year 2021 | | - | | | | | | - | | - | | - |
| March | | Year 2021 | | - | | | | | | - | | - | | - |
| April | | Year 2021 | | - | | | | | | - | | - | | - |
| May | | Year 2021 | | - | | | | | | - | | - | | - |
| June | | Year 2021 | | - | | | | | | - | | - | | - |
| July | | Year 2021 | | - | | | | | | - | | - | | - |
| August | | Year 2021 | | - | | | | | | - | | - | | - |
| September | | Year 2021 | | - | | | | | | - | | - | | - |
| October | | Year 2021 | | - | | | | | | - | | - | | - |
| November | | Year 2021 | | - | | | | | | - | | - | | - |
| Decemb | | Year | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| er | | 2021 | | - | | | | | | - | | - | | - |
| | | | | | | | | | | - | | | | |
| | | | | | | | | | | | | | | |
| Total Amount of True-Up Adjustment for 2015 ATRR | | | | | | | | | | | | $ - | | |
| Less Over (Under) Recovery | | | | | | | | | | | | $ - | | |
| Total Interest | | | | | | | | | | | | $ - | | |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | Page 2 of 3 |

**Attachment 9 -Final True-Up of Interest Rates and Interest Calculations for the Construction Loan**

**South Central MCN LLC**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Calculation of Interest for 2016 True-Up Period** | | | | | | | | | | | | | | |
| | | | | | | | | | | **Monthly** | | | | |
| - | | | | | | | | | | | | | | |
| January | | Year 2016 | | - | | | | 12.00 | | - | | | | - |
| February | | Year 2016 | | - | | | | 11.00 | | - | | | | - |
| March | | Year 2016 | | - | | | | 10.00 | | - | | | | - |
| April | | Year 2016 | | - | | | | 9.00 | | - | | | | - |
| May | | Year 2016 | | - | | | | 8.00 | | - | | | | - |
| June | | Year 2016 | | - | | | | 7.00 | | - | | | | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| July | | Year 2016 | | - | | | | 6.00 | | - | | | | - |
| August | | Year 2016 | | - | | | | 5.00 | | - | | | | - |
| September | | Year 2016 | | - | | | | 4.00 | | - | | | | - |
| October | | Year 2016 | | - | | | | 3.00 | | - | | | | - |
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| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | | | | | | **Monthly** | | | | |
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| Total Amount of True-Up Adjustment for 2016 ATRR | | | | | | | | | | | | $ - | | |
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| **Calculation of Interest for 2017 True-Up Period** | | | | | | | | | | | | | | |
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| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | | | | | | **Monthly** | | | | |
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| Total Amount of True-Up Adjustment for 2017 ATRR | | | | | | | | | | | | $ - | | |
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| **Attachment 9 -Final True-Up of Interest Rates and Interest Calculations for the Construction Loan** | | | | | | | | | | | | | | |
| **South Central MCN LLC** | | | | | | | | | | | | | | |
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| **Calculation of Interest for 2018 True-Up Period** | | | | | | | | | | | | | | |
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| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | | | | | | **Monthly** | | | |
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| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | | | | | | **Monthly** | | | | |
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| True-Up Adjustment for 2019 ATRR | | | | | | | | | | | | | | |
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| FERC ACCOUNT | DESCRIPTION | RATE PERCENT |
|---|---|---|
| | | |
| TRANSMISSION | | |
| 350 | Land Rights | N/A |
| 352 | Structures and Improvements | 1.5397% |
| 353 | Station Equipment | 2.0285% |
| 354 | Towers and Fixtures | 1.8847% |
| 355 | Poles and Fixtures | 2.1496% |
| 356 | Overhead Conductors & Devices | 2.0973% |
| 357 | Underground Conduit | 1.3665% |
| 358 | Underground Conductors & Devices | 1.8416% |
| 359 | Roads and Trails | 0.0000% |
| | | |
| GENERAL AND INTANGIBLE | | |
| 302 | Franchises and Consents (Note 1) | N/A |
| 303 | Intangible Plant - 5 Year | 20.0000% |
| 390 | Structures and Improvements | 2.1194% |
| 391 | Office Furniture and Equipment | 5.0671% |
| 391 | Network Equipment | 25.0000% |
| 392 | Transportation Equipment - Auto | 10.9667% |
| 392 | Transportation Equipment - Light Truck | 8.4139% |
| 392 | Transportation Equipment - Trailers | 6.9486% |
| 392 | Transportation Equipment - Heavy Trucks | 7.2364% |
| 393 | Stores Equipment | 5.0000% |
| 394 | Tools, Shop and Garage Equipment | 6.6672% |
| 395 | Laboratory Equipment | 10.0000% |
| 396 | Power Operated Equipment | 8.4139% |
| 397 | Communication Equipment | 11.1110% |
| 398 | Miscellaneous Equipment | 6.6672% |
| | | |
| Note 1: | | |
| Electric Intangible Franchises and Transmission Land Rights are amortized | | |
| over the life of the franchise agreement or land right. | | |
| Note 2: | | |
| South Central’s depreciation and amortization rates may not be changed absent a section | | |
| 205 or 206 filing | | |

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| | | | | | | Attachment 11 | | | | | | | | | | |
| | | | | | | Wholesale Distribution Service | | | | | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | | | | | |
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| | | | | | | | | | | | | | | | | |
| | | To be completed in conjunction with Attachment H. | | | | | | | | | | | | | | |
| | | Pages 1-3 are to be filed out if the facilities providing Wholesale Distribution Service are booked to transmission. If the facilities are booked to Distribution, see pages 4-6 | | | | | | | | | | | | | | |
| | | Notes A-H refer to the notes at the bottom of page 2 of 6 of this Attachment | | | | | | | | | | | | | | |
| | | (1) | | (2) | | | | (3) | | | (4) | | | | | |
| | | | | **Attachment H** | | | | | | | | | | | | |
| Li | | | | **Page,** | | | | **Trans** | | | **Allocato** | | | | | |

| ne | | | | **Line, Col.** | | | | **mission** | | | **r** | | | | | |
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| No. | | | | **Notes are on Page 2** | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| 1 | | Gross Transmission Plant - Total | | Attach H, p 2, line 2 col 5 plus line 27 col 5 (Note A) | | | | - | | | | | | | | |
| 2 | | Net Transmission Plant - Total | | Attach H, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note B) | | | | - | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| | | O&M EXPENSE | | | | | | | | | | | | | | |
| 3 | | Total O&M Allocated to Transmission | | Attach H, p 3, line 14 col 5 | | | | - | | | | | | | | |
| 4 | | Annual Allocation Factor for O&M | | (line 3 divided by line 1 col 3) | | | | - | | | - | | | | | |
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| | | GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE | | | | | | | | | | | | | | |
| 5 | | Total G, I & C Depreciation Expense | | Attach H, p 3, lines 17 & 18, col 5 (Note H) | | | | - | | | | | | | | |
| 6 | | Annual Allocation Factor for G, I & C | | (line 5 divided by line 1 col 3) | | | | - | | | - | | | | | |

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| | | Depreciation Expense | | | | | | | | | | | | | |
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| | | TAXES OTHER THAN INCOME TAXES | | | | | | | | | | | | | |
| 7 | | Total Other Taxes | | Attach H, p 3, line 30 col 5 | | | | - | | | | | | | |
| 8 | | Annual Allocation Factor for Other Taxes | | (line 7 divided by line 1 col 3) | | | | - | | | - | | | | |
| | | | | | | | | | | | | | | | |
| 9 | | Less Revenue Credits | | Attach H, p 1, line 7 col 5 | | | | - | | | | | | | |
| 10 | | Annual Allocation Factor Revenue Credits | | (line 9 divided by line 1 col 3) | | | | - | | | - | | | | |
| | | | | | | | | | | | | | | | |
| **11** | | **Annual Allocation Factor for Expense** | | **Sum of line 4, 6, 8, and 10** | | | | | | | - | | | | |
| | | | | | | | | | | | | | | | |
| | | INCOME TAXES | | | | | | | | | | | | | |
| 12 | | Total Income Taxes | | Attach H, p 3, | | | | - | | | | | | | |

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| | | | | line 44 col 5 | | | | | | | | | | | | |
| 13 | | Annual Allocation Factor for Income Taxes | | (line 12 divided by line 2 col 3) | | | | - | | | - | | | | | |
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| | | RETURN | | | | | | | | | | | | | | |
| 14 | | Return on Rate Base | | Attach H, p 3, line 46 col 5 | | | | - | | | | | | | | |
| 15 | | Annual Allocation Factor for Return on Rate Base | | (line 14 divided by line 2 col 3) | | | | - | | | - | | | | | |
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| **16** | | **Annual Allocation Factor for Return** | | **Sum of line 13 and 15** | | | | - | | | **-** | | | | | |
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| | | | | | | Attachment 11 | | | | | | | | | | |
| | | | | | | Wholesale Distribution Servi | | | | | | | | | | |

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| | | **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | **(6)** | **(7)** | **(8)** | **(9)** | **(10)** | **(11)** | | | | |
| **Line No.** | | **Wholesale Distribution Service** | **Project Gross Plant** | **Annual Allocation Factor for Expense, Page 1 line 11** | **Annual Expense Charge** | **Project Net Plant (Note G)** | **Annual Allocation Factor for Return** | **Annual Return Charge** | **Project Depreciation/ Amortization Expense (Notes F & G)** | **Annual Revenue Requirement** | **Use % (Note H)** | **Total Annual Revenue Requirement (Col. 9 *10)** | | | | |
| | | | (Note C) | (Page 1 line 11) | (Col. 2 * Col. 3) | (Notes D & I) | (Page 1 line 16) | (Col. 5 * Col. 6) | (Notes E & I) | (Sum Col. 4, 7 & 8) | | (Sum Col. 9 & 10) | | | | |
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| 15a | | | - | - | - | - | - | - | - | - | - | - | | | | |
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| 16 | | Annual Totals | | | | | | | | | | - | | | | |
| Note | | | | | | | | | | | | | | | | |
| Letter | | | | | | | | | | | | | | | | |
| A | | Gross Transmission Plant is that identified on page 2 line 2 of Attachment H | | | | | | | | | | | | | | |
| B | | Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable. | | | | | | | | | | | | | | |
| C | | Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1. This value includes subsequent capital | | | | | | | | | | | | | | |

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|---|---|---|
| | | investments required to maintain the facilities to their original capabilities. |
| | | Gross plant does not include Unamortized Abandoned Plant. |
| D | | Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes any regulatory asset, which are to entered as a separate line item. |
| E | | Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 16. Project Depreciation Expense includes the amortization of Abandoned Plant |
| F | | The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9. |
| G | | The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense. |
| H | | The Use % is the customers NCP load divided by all of the NCP loads on the facilities |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | Page 3 of 6 |
| | | | | | | | | | | | | | | |
| | | | | | | Attachment 11 | | | | | | | | |
| | | | | | | Wholesale Distribution Service | | | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | | | |
| | | | | | | | | | | | | | | |
| | | **(1)** | **(2)** | **(3)** | | **(4)** | **(5)** | | **(6)** | **(7)** | **(8)** | **(9)** | **(10)** | **(11)** |
| **Line No.** | | **Wholesale Distribution Service** | **Project Gross Plant** | **Annual Allocation Factor for Expense, Page 6 line 18** | | **Annual Expense Charge** | **Project Net Plant** | | **Annual Allocation Factor for Return, Page 6 line 19** | **Annual Return Charge** | **Project Depreciation/Amortization Expense** | **Annual Revenue Requirement (Col. 6, 7 & 8)** | **Use % (Note A)** | **Total Annual Revenue Requirement (Col. 9 *10)** |
| a | | Example 1 | | | | | | | | | | | | |

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| c | | | | - | | - | - | | - | - | - | - | - | - |
| d | | | | - | | - | - | | - | - | - | - | - | - |
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| z | | Total | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | |
| | | Note A The Use % is the customers NCP load divided by all of the NCP loads on the facilities | | | | | | | | | | | | |
| | | Note B The Wholesale Distribution Revenue Requirement is projected using either pages 1-2 or 4-6. The same pages are populated with actual data and the difference with interest is calculated on Attachment 3 | | | | | | | | | | | | |
| | | | | | | Attachment 11 | | | | | | | | Page 4 of 6 |
| | | | | | | Wholesale Distribution Service | | | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | | | |
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| | | (1) | (2) | (3) | | | (4) | | (5) | | | | | |
| | | | | | | **Allocator** | | | **Transmissio** | | | | | |

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| | | | | | | | | | **n** | | | | | |
| Line | | | **Source** | **Company Total** | | The allocators are shown on | | | (Col 3 times Col 4) | | | | | |
| No. | | **RATE BASE:** | | | | Pages 4 and 6 (DA equals 1) | | | | | | | | |
| | | GROSS PLANT IN SERVICE | | | | | | | | | | | | |
| 1 | | Production | Attachment H, Page 2, Line 1 | - | | NA | | | - | | | | | |
| 2 | | Transmission | Attachment H, Page 2, Line 2 | - | | NA | | | - | | | | | |
| 3 | | Distribution | (Pagew 6, Line 33, Col. (b) | - | | DA | 1.00 | | - | | | | | |
| 4 | | General & Intangible | Attachment H, Page 2, Line 4 | - | | W/S | - | | - | | | | | |
| 5 | | Common | Attachment H, Page 2, Line 5 | - | | CE | - | | - | | | | | |
| 6 | | TOTAL GROSS PLANT | (Sum of Lines 1 through 5) | - | | GP= | - | | - | | | | | |
| | | | | | | | | | | | | | | |
| 7 | | ACCUMULATED DEPRECIATION | | | | | | | | | | | | |
| 8 | | Production | Attachment H, Page 2, Line 8 | - | | NA | | | - | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | Transmission | Attachment H, Page 2, Line 9 | - | | NA | | | - | | | | | |
| 10 | | Distribution | (Page 6, Line 33, Col. (c) | - | | DA | 1.00 | | - | | | | | |
| 11 | | General & Intangible | Attachment H, Page 2, Line 11 | - | | W/S | - | | - | | | | | |
| 12 | | Common | Attachment H, Page 2, Line 12 | - | | CE | - | | - | | | | | |
| 13 | | TOTAL ACCUM. DEPRECIATION | (Sum of Lines 8 through 12) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
| 14 | | NET PLANT IN SERVICE | | | | | | | | | | | | |
| 15 | | Production | (line 1 - line 8) | - | | | | | - | | | | | |
| 16 | | Transmission | (Line 2 minus Line 9) | - | | | | | - | | | | | |
| 17 | | Distribution | (line 3 - line 10) | - | | | | | - | | | | | |
| 18 | | General & Intangible | (Line 4 minus Line 11) | - | | | | | - | | | | | |
| 19 | | Common | (line 5 - line 12) | - | | | | | - | | | | | |
| 20 | | TOTAL NET PLANT | (Sum of Lines 15 through 19) | - | | NP= | - | | - | | | | | |
| | | | | | | | | | | | | | | |
| 21 | | ADJUSTMENTS TO RATE BASE | | | | | | | | | | | | |
| 22 | | Account No. 281 (enter negative) | Attachment H, Page 2, Line 22 | - | | NA | zero | | - | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | | Account No. 282 (enter negative) | Attachment H, Page 2, Line 23 | - | | NP | - | | - | | | | |
| 24 | | Account No. 283 (enter negative) | Attachment H, Page 2, Line 24 | - | | NP | - | | - | | | | |
| 25 | | Account No. 190 | Attachment H, Page 2, Line 25 | - | | NP | - | | - | | | | |
| 26 | | Account No. 255 (enter negative) | Attachment H, Page 2, Line 26 | - | | NP | - | | - | | | | |
| 26a | | Unfunded Reserves (enter negative) | (Page 6, Line 36, Col. (h) | - | | DA | 1.0000 | | - | | | | |
| 27 | | CWIP | Attachment H, Page 2, Line 27 | - | | NA | | | - | | | | |
| 28 | | Unamortized Regulatory Asset | Attachment H, Page 2, Line 28 | - | | DA | 1.0000 | | - | | | | |
| 29 | | Unamortized Abandoned Plant | Attachment H, Page 2, Line 29 | - | | DA | 1.0000 | | - | | | | |
| 30 | | TOTAL ADJUSTMENTS | (Sum of Lines 22 through 29) | - | | | | | - | | | | |
| | | | | | | | | | | | | | |
| 31 | | DISTRIBUTION LAND HELD FOR FUTURE USE | (Page 6, Line 33, Col. (d) | | | DA | 1.00 | | - | | | | |
| | | | | | | | | | | | | | |
| 32 | | WORKING CAPITAL | | | | | | | | | | | |
| 3 | | CWC | 1/8*(Pag | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | e 3, Line 14) | - | | | | | - | | | | | |
| 34 | | Distribution Materials & Supplies | (Page 6, Line 33, Col. (e) | - | | DA | 1.00 | | - | | | | | |
| 35 | | Prepayments (Account 165) | Attachment H, Page 2, Line 35 | - | | GP | - | | - | | | | | |
| 36 | | TOTAL WORKING CAPITAL | (Sum of Lines 33 through 35) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
| 37 | | RATE BASE | (Sum of Lines 20, 30, 31 & 36) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
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| | | | | | | | | | | | | | | Page 5 of 6 |
| | | | | | | | | | | | | | | |
| | | Formula Rate - Non-Levelized | | | | Attachment 11 | | | | | | | | |
| | | | | | | Wholesale Distribution Service | | | | | | | | |
| | | | | | | South Central MCN LLC | | | | | | | | |
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| | | (1) | (2) | (3) | | | (4) | | (5) | | | | | |
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| N o . | | | **Source** | **Co mpa ny Tot al** | | **Alloc ator** | | | (Co l 3 tim es Col 4) | | | | | |
| | | O&M | | | | | | | | | | | | |
| 1 | | Distribution | 322.156. b | | | DA | 1.0 0 | | - | | | | | |
| 2 | | A&G | Attachm ent H, Page 3, Line 4 | - | | W/S | - | | - | | | | | |
| 3 | | Less FERC Annual Fees | Attachm ent H, Page 3, Line 5 | - | | W/S | - | | - | | | | | |
| 4 | | Less EPRI & Reg. Comm. Exp. & Non-safety Ad. | Attachm ent H, Page 3, Line 6 | - | | W/S | - | | - | | | | | |
| 5 | | Less PBOP Expense in Year | Attachm ent H, Page 3, Line 6a | - | | W/S | - | | - | | | | | |
| 6 | | Plus PBOP Expense Allowed Amount | Attachm ent H, Page 3, Line 7a | - | | W/S | - | | - | | | | | |
| 7 | | Common | Attachm ent H, Page 3, Line 8 | - | | CE | - | | - | | | | | |
| 8 | | TOTAL O&M | (Sum of Lines 1, 2, 6, 7, less Lines 3, 4, 5) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
| 9 | | DEPRECIAT | | | | | | | | | | | | |

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| | | ION EXPENSE | | | | | | | | | | | |
| 10 | | Distribution | 336.8.b, d &e | | | DP | 1.00 | | - | | | | |
| 11 | | General & Intangible | Attachment H, Page 3, Line 17 | - | | W/S | - | | - | | | | |
| 12 | | Common | Attachment H, Page 3, Line 18 | - | | CE | - | | - | | | | |
| 13 | | TOTAL DEPRECIATION | (Sum of Lines 10 through 12) | - | | | | | - | | | | |
| | | | | | | | | | | | | | |
| 14 | | TAXES OTHER THAN INCOME TAXES | | | | | | | | | | | |
| 15 | | LABOR RELATED | | | | | | | | | | | |
| 16 | | Payroll | Attachment H, Page 3, Line 23 | - | | W/S | - | | - | | | | |
| 17 | | Highway and vehicle | Attachment H, Page 3, Line 24 | - | | W/S | - | | - | | | | |
| 18 | | PLANT RELATED | | | | | | | | | | | |
| 19 | | Property | Attachment H, Page 3, Line 26 | - | | GP | - | | - | | | | |
| 20 | | Gross Receipts | Attachment H, Page 3, Line 27 | - | | NA | zero | | - | | | | |
| 21 | | Other | Attachment H, Page 3, | - | | GP | - | | - | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Line 28 | | | | | | | | | | | |
| 22 | | Payments in lieu of taxes | Attachment H, Page 3, Line 29 | - | | GP | - | | - | | | | | |
| 23 | | TOTAL OTHER TAXES | (Sum of Lines 16 through 22) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
| 24 | | INCOME TAXES | | | | | | | | | | | | |
| 25 | | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} * (1-TEP) | Attachment H, Page 3, Line 32 | - | | | | | | | | | | |
| 26 | | CIT=(T/1-T) * (1-(WCLTD/R)) = | Attachment H, Page 3, Line 33 | - | | | | | | | | | | |
| 27 | | FIT & SIT & P | Attachment H, Page 3, Line 34 | | | | | | | | | | | |
| 28 | | | | | | | | | | | | | | |
| 29 | | 1 / (1 - T) = (T from line 25) | | - | | | | | | | | | | |
| 30 | | Amortized Investment Tax Credit | Attachment H, Page 3, Line 37 | - | | | | | | | | | | |
| 31 | | Excess Deferred Income Taxes | Attachment H, Page 3, Line 38 | - | | | | | | | | | | |
| 32 | | Tax Effect of Permanent Differences | Attachment H, Page 3, Line 39 | - | | | | | | | | | | |
| 33 | | Income Tax Calculation | (Line 26 times Line 39) | - | | NA | | | - | | | | | |
| 3 | | ITC | (Line 29 | | | NP | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | adjustment | times Line 30) | - | | | - | | - | | | | | |
| 35 | | Excess Deferred Income Tax Adjustment | (Line 29 times Line 31) | - | | NP | - | | - | | | | | |
| 36 | | Permanent Differences Tax Adjustment | (Line 29 times Line 32) | - | | NP | - | | - | | | | | |
| 37 | | Total Income Taxes | (Sum of Lines 33 through 36) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
| 38 | | RETURN | | | | | | | | | | | | |
| 39 | | Rate Base times Return | (Page 2, Line 37 times Page 4, Line 17) | - | | NA | | | - | | | | | |
| | | | | | | | | | | | | | | |
| 40 | | REV. REQUIREMENT | (Sum of Lines 18, 13, 23, 37 & 39) | - | | | | | - | | | | | |
| | | | | | | | | | | | | | | |
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| | | | | | | | | | | | | | | Page 6 of 6 |
| | | | | | | | | | | | | | | |
| | | Formula Rate - Non-Levelized | | | | Attachment 11 | | | | | | | | |
| | | | | | | Wholesale Distribution Service | | | | | | | | |

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| | | | | | | South Central MCN LLC | | | | | | | | |
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| | | (1) | (2) | (3) | | | (4) | | (5) | | | | | |
| | | | | | | | | | | | | | | |
| | | | **SUPPORTING CALCULATIONS AND NOTES** | | | | | | | | | | | |
| Line | | | | | | | | | | | | | | |
| No. | | | | | | | | | | | | | | |
| 1 | | WAGES & SALARY ALLOCATOR (W&S) | | | | | | | | | | | | |
| | | | Form 1 Reference | $ | Alloc | | Allocation | | | | | | | |
| 2 | | Production | Attachment H, Page 4, Line 7 | - | - | | - | | | | | | | |
| 3 | | Transmission | Attachment H, Page 4, Line 8 | - | - | | - | | | | | | | |
| 4 | | Distribution | Attachment H, Page 4, Line 9 | - | 1.000 | | - | | W&S Allocator | | | | | |
| 5 | | Other | Attachment H, Page 4, Line 10 | - | - | | - | | ($ / Allocation) | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | Total (W&S Allocator is 1 if lines 7-10 are zero) | (Sum of Lines 2 through 5) | - | | | - | = | - | = | WS | | |
| | | | | | | | | | | | | | |
| | | COMMON PLANT ALLOCATOR (CE) | | **$** | | | % Electric | | W&S Allocator | | | | |
| 7 | | Electric | Attachment H, Page 4, Line 13 | - | | | (line 7 / line 10) | | (line 6) | | CE | | |
| 8 | | Gas | Attachment H, Page 4, Line 14 | - | | | - | * | - | = | - | | |
| 9 | | Water | Attachment H, Page 4, Line 15 | - | | | | | | | | | |
| 10 | | Total | (Sum of Lines 7 through 9) | - | | | | | | | | | |
| 11 | | | | | | | | | | | | | |
| | | RETURN (R) | | | | | | | $ | | | | |
| 12 | | | | | | | | | | | | | |
| 13 | | | | $ | | % | Cost | | Weighted | | | | |
| 14 | | Long Term Debt | Attachment H, Page 4, Line 20 | - | | - | - | | - | =WCLTD | | | |
| 15 | | Preferred Stock (112.3.c) | Attachment H, Page 4, Line 21 | - | | - | - | | - | | | | |
| 16 | | Common Stock | Attachment H, Page 4, Line 22 | - | | - | 10.30 % | | - | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17 | | Total | (Sum of Lines 14 through 16) | - | | | | | - | =R | | | | |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | | | | | | Amount | | | Gross Plant | Allocation Factor | | | | |
| | | | | | | Page 5 lines 8 and 23, col 5 | | | Distribution | Amount / Gross Plant | | | | |
| 18 | | Annual Allocation Factor for Expense | | | | - | | | - | - | | | | |
| | | | | | | Amount | | | Net Plant | Allocation Factor | | | | |
| | | | | | | Page 5 lines 37 and 39, col 5 | | | Distribution | Amount / Gross Plant | | | | |
| 19 | | Annual Allocation Factor for Return | | | | - | | | - | - | | | | |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | | | | **Accumulated** | | | | | | | | | | |
| | | | **Gross Plant In Service** | **Depreciation** | | **LHFFU** | **Working Ca** | | | | | | | |

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| | | | | | | | **pital** | | | | | | | |
| Line No | | **Month** | **Distribution** | **Distribution** | | **Held for Future Use** | **Materials & Supplies** | | | | | | | |
| | | **(a)** | **(b)** | **(c)** | | **(d)** | **(e)** | | | | | | | |
| | | | | | | | | | | | | | | |
| | | | 206.75.g for end of year, records for other months | 219.26.b for end of year, records for other months | | 214.x.d for end of year, records for other months | 227.9.c for end of year, records for other months | | | | | | | |
| 20 | | December Prior Year | - | - | | - | - | | | | | | | |
| 21 | | January | - | - | | - | - | | | | | | | |
| 22 | | February | - | - | | - | - | | | | | | | |
| 23 | | March | - | - | | - | - | | | | | | | |
| 24 | | April | - | - | | - | - | | | | | | | |
| 25 | | May | - | - | | - | - | | | | | | | |
| 26 | | June | - | - | | - | - | | | | | | | |
| 27 | | July | - | - | | - | - | | | | | | | |
| 28 | | August | - | - | | - | - | | | | | | | |
| 29 | | September | - | - | | - | - | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | | October | - | - | | - | - | | | | | | | |
| 31 | | November | - | - | | - | - | | | | | | | |
| 32 | | December | - | - | | - | - | | | | | | | |
| 33 | | Average of the 13 Monthly Balances | - | - | | - | - | | | | | | | |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |
| | | Unfunded Reserves (Notes A & B) | | | | | | | | | | | | |
| | | (a) | (b) | (c) | | (d) | (e) | | (f) | (g) | (h) | | | |
| 34 | | List of all reserves: | | Amount | | Enter 1 if NOT in a trustor reserved account, enter zero (0) if included in a trustor reserved account | Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual acc oun | | Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liab | Allocation (Plant or Labor Allocator) | Amount Allocated, col. c x col. d x col. e x col. f x col. g | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | t is NOT included in the formula rate | | ility on the balance sheet | | | | | |
| 35a | | | Reserve 1 | - | | - | | | | | - | | | |
| 35b | | | Reserve 2 | - | | - | | | | | - | | | |
| 35c | | | Reserve 3 | | | | | | | | | | | |
| … | | | | | | | | | | | | | | |
| … | | | … | | | | | | | | | | | |
| … | | | … | - | | - | | | | | - | | | |
| 36 | | | Total | - | | | | | | | - | | | |
| | | | | | | | | | | | | | | |
| A | The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account. | | | | | | | | | | | | | |
| B | Calculate using 13 month average balance, except ADIT which is calculated based on the average of the beginning of the year and the end of the year balances | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |

## South Central MCN LLC (SCMCN)

## ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES

### Section I. Applicability

The following procedures shall apply to SCMCN's calculation of its actual net revenue requirement, True-Up Adjustment, and projected net revenue requirement. The project-specific annual revenue requirements determined under the SCMCN formula are "up to" rates, i.e., ceiling rates, and permit SCMCN to discount the revenue requirement to the extent necessary to reflect the result of any cost commitment to SPP. In the Formula Rate Template, the effect of any such discount is removed from the projected revenue requirement and the actual revenue requirement, which ensures that customers receive the benefits of any discount.

### Section II. Annual True-Up and Projected Net Revenue Requirement

A. Beginning on or before June 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent June 1, SCMCN shall determine the Annual True-Up under this Attachment H - SCMCN and Section VII of these protocols, to derive a True-Up Adjustment to be included in SCMCN's projected net revenue requirement for the subsequent calendar year (the "Rate Year").

B. On or before June 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent June 1, SCMCN shall provide the Annual True-Up, actual net revenue requirement, and True-Up Adjustment to SPP and cause such information to be posted on the SPP website. Within ten (10) days of such posting, SCMCN shall provide notice of such posting via the email exploder list. Interested Parties shall contact SCMCN at the following email address to be placed on the exploder list: regulatory@gridliance.com.

C. On or before October 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent October 1, SCMCN shall provide the projected net revenue requirement to SPP and cause such information to be posted on the

SPP website. Within ten (10) days of posting of the projected net revenue requirement, SCMCN shall provide notice of such posting to the email exploder list.

D. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the projected net revenue requirement will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

E. The Annual True-Up shall:

1. Include a workable populated Formula Rate Template and underlying workpapers in native format with fully functional spreadsheets showing the calculation of the net revenue requirement;

2. Be based on SCMCN's FERC Form No. 1 reports for the prior calendar year;

3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in the FERC Form No. 1 reports; [1]

---

1 It is the intent of the formula rate, including the supporting explanations and allocations described therein, that each input to the formula rate will be either taken directly from FERC Form No. 1 or reconcilable to FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

4. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the Annual True-Up results from the FERC Form No. 1 reports;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1 reports;

6. Identify all material adjustments made to the FERC Form No. 1 report data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 reports and any adjustments not shown in the FERC Form No. 1 reports;

7. Provide underlying data for formula rate inputs that provide greater granularity than is required for the FERC Form No. 1 reports;

8. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

    a. Identify any Accounting Changes, including:

        i. the initial implementation of an accounting standard or policy;

        ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

        iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

        iv. the implementation of new estimation methods or policies that change prior estimates; and

        v. changes to income tax elections;

    b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up;

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

F. The projected net revenue requirement shall:

1. Include a workable populated Formula Rate Template and underlying workpapers in native format with fully functional spreadsheets showing the calculation of the net revenue requirement;

2. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement;

3. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the projected net revenue requirement;

4. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

a. Identify any Accounting Changes, including:

i. the initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement;

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

G. SCMCN shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") with remote access between the Publication Date and September 1. No less than seven (7) days prior to such Annual True-Up Meeting, SCMCN shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual True-Up Meeting and SCMCN shall provide notice of such meeting to the email exploder list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall (i) permit SCMCN to explain and clarify its Annual True-Up and True-Up Adjustment and (ii) provide Interested Parties an opportunity to seek information and clarifications from SCMCN about the Annual True-Up and True-Up Adjustment.

H. SCMCN shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") with remote access between the date that the projected net revenue requirement is posted to the SPP website (as described in Section II.C of these protocols) and October 31. No less than seven (7) days prior to such Annual Projected Rate Meeting, SCMCN shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual Projected Rate Meeting and SCMCN shall provide

notice of such meeting to the email exploder list. The Annual Projected Rate Meeting shall (i) permit SCMCN to explain and clarify their projected net revenue requirement and (ii) provide Interested Parties an opportunity to seek information and clarifications from SCMCN about the projected net revenue requirement.

I. Each year SCMCN shall endeavor to coordinate with other Transmission Owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

**Section III. Information Exchange Procedures**

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until December 1 following the Publication Date (unless such period is extended with the written consent of SCMCN or by FERC order) to serve reasonable information and document requests on SCMCN ("Information Exchange Period"). If December 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) the extent or effect of an Accounting Change;

(2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(3) the proper application of the formula rate and procedures in these protocols;

(4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;

(5) the prudence of actual costs and expenditures;

(6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1 reports; or

(7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. SCMCN shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. SCMCN shall respond to all information and document requests by no later than January 10 following the Publication Date, unless the Information Exchange Period is extended by SCMCN or FERC.

C. SCMCN will cause to be posted on the SPP website all information requests from Interested Parties and SCMCN's response(s) to such requests; except, however, if responses to information and document requests include material deemed by SCMCN to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by SCMCN and the requesting party.

D. SCMCN shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing SCMCN's Annual True-Up or projected net revenue requirement.

**Section IV. Challenge Procedures**

A. Interested Parties shall have until January 31 following the Publication Date (unless such period is extended with the written consent of SCMCN or by FERC order) to review the

inputs, supporting explanations, allocations and calculations and to notify SCMCN in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or projected net revenue requirement. The period of time from the Publication Date until January 31 shall be referred to as the Review Period. If January 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that Annual True-Up or projected net revenue requirement, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement.

B. A party submitting an Informal Challenge to SCMCN must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. SCMCN shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. SCMCN, and where applicable, the Transmission Provider, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If SCMCN disagrees with such challenge, SCMCN will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31, and SCMCN must respond to all Informal Challenges by no later than February 28, unless the Review Period is extended by SCMCN or FERC.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

(1) A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

(b) Explain how the action or inaction violates the filed rate formula or protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) the extent or effect of an Accounting Change;

(ii) whether the Annual True-Up projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(iii) the proper application of the formula rate and procedures in these protocols;

(iv) the accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;

(v) the prudence of actual costs and expenditures;

(vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form 1; or

(vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(2) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on SCMCN. Service to SCMCN must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on SCMCN's Informational Filing required under Section VI of these protocols.

D. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1 reports; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

E. SCMCN will cause to be posted on the SPP website all Informal Challenges from Interested Parties and SCMCN's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by SCMCN to be confidential information, such information will not be publicly

posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by SCMCN and the requesting party.

F. Any changes or adjustments to the True-Up Adjustment or projected net revenue requirement resulting from the Information Exchange and Informal Challenge processes that are agreed to by SCMCN will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by SCMCN on or before December 1 will be reflected in the projected net revenue requirement for the upcoming Rate Year. Any changes or adjustments agreed to by SCMCN after December 1 will be reflected in the following year's Annual True-Up, as discussed in Section V of these protocols.

G. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of SCMCN to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on SCMCN on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as SCMCN's Informational Filing discussed in Section VI of these protocols. SCMCN shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

H. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, SCMCN shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in this Attachment H - SCMCN. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

I. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of SCMCN to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace

the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

J. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual True-Up or projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. SCMCN may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for (i) amortization and depreciation rates, (ii) Post-Employment Benefits Other Than Pensions rates, or (iii) the weighting of the ADIT balance in rate base to ensure SCMCN's compliance with the IRS regulations for normalization under IRS Section 1.167(l)-1(h)(6). The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

K. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with SCMCN in accordance with this Section IV before pursuing a Formal Challenge.

## Section V. Changes to True-Up Adjustment or Projected Net Revenue Requirement

Except as provided in Section IV.F of these protocols, any changes to the data inputs, including but not limited to revisions to SCMCN's FERC Form No. 1 reports, or as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

## Section VI. Informational Filings

A. By March 15 of each year, SCMCN shall submit to FERC an informational filing ("Informational Filing") of their projected net revenue requirement for the Rate Year, including their Annual True-Up and True-Up Adjustment. This Informational Filing must:

(1) Include the information that is reasonably necessary to determine: (i) that input data under the formula rate are properly recorded in any underlying workpapers; (ii) that SCMCN has properly applied the formula rate and these procedures; (iii) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement under review; (iv) the extent of accounting changes that affect formula rate inputs; and (v) the reasonableness of projected costs.

(2) Include for the applicable Rate Year the following information related to affiliate cost allocation: (i) a detailed description of the methodologies used to allocate and directly assign costs between SCMCN and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (ii) the magnitude of such costs that have been allocated or directly assigned between SCMCN and each affiliate by service category or function; and

(3) Describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, SCMCN shall provide notice of the Informational Filing via the email exploder list and shall cause SPP to post the docket number assigned to SCMCN's Informational Filing on the SPP website.

B. Any challenges to the implementation of the Attachment H - SCMCN formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

**Section VII. Calculation of True-Up Adjustment**

The True-Up Adjustment is developed on Attachment 3 and will be determined in the following manner:

(1) Actual transmission revenues for the previous year will be compared to Net Revenue Requirement not including any prior year True-Up Adjustment calculated in accordance with SCMCN's Attachment H of this Tariff for the previous year using SCMCN's FERC Form No. 1 for that same year to determine any over or under recovery ("True-Up Adjustment"). SCMCN shall cause the True-Up Adjustment and related calculations to be posted to the SPP website no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the FERC Form No. 1 for the previous year, as set forth in Section II of these protocols.

(2) Interest on any over recovery of the net revenue requirement shall be determined on Attachment 9 of the formula rate. Interest on any under recovery of the net revenue requirement or any under recovery due to volume changes, shall be determined using the interest rate equal to SCMCN's actual short-term debt costs capped at the applicable FERC refund interest rate. The interest rate to be applied to the over or under recovery amounts will be determined using the average interest rate for the twenty-one (21) months preceding October of the current year. In either case, the interest payable shall be calculated by applying the average interest rate to the over or under recovery in the revenue requirement or volume changes for the twenty-four (24) month period. The interest amount will be included in the projected costs made available on October 1 in accordance with Section II.C above.

(3) The Net Revenue Requirement for transmission services for the following Year shall be the sum of the projected revenue requirement for the following year, plus or minus the True-Up Adjustment from the previous year, if any, including interest, as explained above.

(4) The SCMCN may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

# Addendum 4 to Attachment H – Part 3

Reserved for Future Use

**ADDENDUM 42 TO ATTACHMENT H**

**Mountrail-Williams Electric Cooperative**

Index

## Mountrail-Williams Electric Cooperative

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| 3 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 4 | Worksheet C | Capital Structure & Rate of Return based on Return on Equity |
| 5 | Worksheet D | Network Demand |
| 6 | Worksheet E | Allocation Factors |
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| 8 | Worksheet G | Depreciation Rates |
| 9 | Worksheet H | SPP Upgrades |
| 10 | Worksheet I | O&M Input |
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Key Denotes input values

Summary ATRR

# Mountrail-Williams Electric Cooperative

## Summary of Total ATRR Revenue Requirement Rate Year Ending December 31,

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account Number | Description | Reference | Total Company | Adjustments | Adjusted Company | Allocation Factor | Allocation % | Transmission ATRR |
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 35, Column J | | | | | | |
| 3 | | Revenue Credits-Operating | | | | | | | |
| 4 | 412 | Electric Plant, Leased | Worksheet M, Line 16, Column E | $ - | | | Direct 100 | 100.0% | |
| 5 | 456 | Wheeling-SPP P2P | Worksheet M, Line 16 Column F | $ - | | | Direct Zero | 0.0 % | $ - |
| 6 | 454 | Rents | Worksheet M, Line 16 Column G | $ - | | | Direct 100 | 100.0% | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Worksheet | | | Dir | | |
| | | Other Electric | M, Line 16 | $ | | ect | 100 | $ |
| 7 | 456 | Revenue | Column H | - | | 100 | .0% | - |

| | | | | | |
|---|---|---|---|---|---|
| | | | 2 | Dir to-Point | Cost |
| 8 | 456 | Basin Facility Discount | 0 | ($/MW-Yr) | |
| 9 | 456 | Sch 7 & 8 P2P | | | |
| 10 | 456 | Sch 11 P2P | | | |
| 11 | 456 | Direct Assigned Revenues | | | |
| 12 | 459 | Renewable Energy Credits | | | |
| 13 | | Revenue Credits-Operating | | | |
| 14 | | Revenue Requirement before SPP Adj and Prior Yr corrections | | | |
| 15 | | True-Up Adjustment | | | |
| 16 | | SPP Upgrades | | | |
| 17 | | Sum | | | |
| 18 | | Network Transmission Load (MW) | | | |
| 19 | | **B. Point-To-Point Service** Annual Point- | | | |

| | | | |
|---|---|---|---|
| Worksheet M, Line 16 Column I | $ 0.0 - % | Direct Zero $ - | rksheet D, Line 14, Column C - |
| Worksheet M, Line 16 Column J | $ 100 - .0% | Direct 100 - | Line 17 / Line 18 |
| Worksheet M, Line 16 Column K | $ 100 - .0% | Direct 100 - | |
| Worksheet M, Line 16 Column L | $ 100 - .0% | Direct 100 - | |
| Worksheet M, Line 16 Column M | $ 0.0 - % | Direct Zero $ - | |
| Subtotal | $ - | | |
| Line 2 + Line 13 | | | |
| Worksheet S, Line 18, Column J -Worksheet H, Line 28, Column O | | $ - | |
| Sum Lines 14 thru 16 | | | |

W
o

| | | |
|---|---|---|
| 21 | Monthly Point-to-Point ($/MW-Mo) | Line 20 / 12 |
| 22 | Weekly Point-to-Point ($/MW-Week) | Line 20 / 52 |
| 23 | Daily On-Peak Point-to-Point ($/MW-Day) | Line 20 / 260 |
| 24 | Daily Off-Peak Point-to-Point ($/MW-Day) | Line 20 / 365 |
| 25 | Hourly On-Peak Point-to-Point ($/MWh) | Line 20 / 4160 |
| 26 | Hourly Off-Peak Point-to-Point ($/MWh) | Line 20 / 8760 |

Worksheet A

**Mountrail-Williams Electric Cooperative**

**Calculation of Rate Base**
**Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account Number** | | | | | | | **ATR** | |
| | | 5 | | 352 | | | **Description** | Intangible Plant | Worksheet F, Line 46, Columns E and F |
| | | | | | | | | | **Reference** |
| 1 | | | | | | | | Production Plant | Worksheet F, Lines 49 thru 53, Columns E and F |
| 2 | 301-303 | | | | | | **Plant in Service** | | |
| | | | | | | | | Land and Land Rights | Worksheet J, Line 134, Columns F and G |
| 3 | 310-340 | | | | | | | Structures and Improvements | Worksheet J, Line 134, Columns H and I |
| 4 | 350 | | | | | | | | |

| Beginning of Year | End of Year | Total Company | Allocation Factor | R Allocation % | Transmission |
|---|---|---|---|---|---|
| $ - | $ - | $ - | T-Wage | | |
| $ - | $ - | $ - | Direct Zero | 0.0 % | $ - |
| $ - | $ - | $ - | T-Trans Stations | | $ - |
| $ - | $ - | | T-Trans | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Stations | | | | |
| | | Station | | | Worksheet J, | | | | $ |
| | 35 | Equipment - | | Construction | Line 134, | | | | - |
| 6 | 3 | SCADA | | 10 Work in | Columns J and K | $ - | $ - | | |
| | | | 16 | 7 Progress | | | | | $ |
| | | | | | Worksheet | | | | J, |
| | 35 | Station | | | - | | | | |
| 7 | 3 | Equipment | | | Line 134, Columns L and M | $ - | $ - | | |
| | 35 | | | | | $ | $ | | $ |
| | 4- | Other | | | | - | - | | |
| | 35 | Transmission | | | Worksheet J, | | | | |
| 8 | 9 | Plant | | | | - | | | |
| | | Transmission | | | Line 134, | | | | |
| 9 | | Plant | | | Columns N and O | | | | |
| | | | | | Subtotal | $ - | $ - | | $ - |
| | | Distribution | | | | | | | |
| 10 | | Plant | | | Worksheet F, Line 43, | $ - | $ - | | $ |
| | 38 | | | | Columns D and E | | | | |
| | 9- | | | | | | | | |
| | 39 | General Plant | | | | | | | |
| 11 | | | | | | $ | $ | | $ |
| | 9.1 | Subtotal | | | Worksheet F, | - | - | | |
| | 38 | | | | | - | | | |
| | 9- | | | | Line 44, | | | | |
| | 39 | Headquarters | | | Columns D | | | | |
| 12 | 0 | Plant | | | and E | | | | |
| | | Gross Electric | | | | $ | $ | | $ |
| | | Plant in | | | Worksheet F, | - | - | | |
| 13 | | Service | | | | - | | | |
| | | | | | Line 45, Columns D and E | | | | |
| | | Electric Plant | | | | | | | |
| | 10 | Held For | | | Subtotal | $ | $ | | $ |
| 14 | 5 | Future Use | | | | - | - | | - |
| | | Completed | | | | | | | |
| | 10 | Construction | | | | | | | |
| 15 | 6 | Not Classified | | | Worksheet P, | $ | $ | | $ |
| | | | | | Line 6, | - | - | | |
| | | | | | | - | | | |
| | | | | | Columns E | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| thru H Worksheet O, Columns E, F, and K | $ - | $ - | $ - | Direct | 100.0% | $ - | |
| Worksheet F, Line 54, Columns D and E and Worksheet N, | $ - | $ - | $ - | T-Tran Stations | | | |
| | | | | T-Tran Lines | | | |
| | | | | Direct Zero | 0.0% | $ - | |
| | | | | T-Wage | | | |
| | | | | T-Wage | | | |
| | | | | Direct | WS-P | $ - | |
| | | | | Direct | WS-O | $ - | |
| | | | | Direct | WS-N | $ - | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Line 18, Column L | | | | | | | |
| 17 | | Utility Plant | Sum | $ - | $ - | $ - | | | | |
| 18 | | **Accumulated Depreciation** | | | | | | | | |
| 19 | 10 8.4 | 108.4 Depr Rsv of Other Prod Plant | Worksheet J, Line 176, Columns P and Q | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - | |
| 20 | 10 8.5 | Accumulated Depreciation of Transmission Stations | Worksheet J, Line 182, Columns D and E | $ - | $ - | $ - | T-Tran Stations | | | |
| 21 | 10 8.5 | Accumulated Depreciation of Transmission SCADA | Worksheet J, Line 184, Columns D and E | $ - | $ - | $ - | Direct 100 | 100.0 % | $ - | |
| 22 | 10 8.5 | Accumulated Depreciation of Transmission Lines | Worksheet J, Line 183, Columns D and E | $ - | $ - | $ - | T-Tran Lines | | | |
| 23 | 10 8.6 | Accumulated Depreciation of Distribution Plant | Worksheet J, Line 176, Columns R and S | $ - | $ - | $ - | Direct Zero | 0.0 % | $ - | |
| 24 | 10 8.7 | Accumulatd Depreciation of General Plant | Worksheet J, Line 176, Columns T and U | $ - | $ - | $ - | T-Wage | | | |
| 25 | 10 8.8 | Retirement Work in Progress | Worksheet J, Line 176, Columns V and W | $ - | $ - | $ - | T-Wage | | | |
| 26 | 11 1 | Amort of Electric Plant in Service | Worksheet J, Line 176, Columns X and Y | $ - | $ - | $ - | T-Wage | | | |
| 27 | | Total Accumulated Depreciation | Sum | $ - | $ - | $ - | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Total Net Plant in Service** | | | | | | | | |
| 28 | | Net Intangible Plant | Line 2 | $ - | $ - | $ - | | | | |
| 29 | | Net Production Plant | Line 3 - Line 19 | $ - | $ - | $ - | | | $ - | |
| 30 | | Net Transmission Plant | Line 9 - Line 20 thru 22 | $ - | $ - | $ - | | | | |
| 31 | | Net Distribution Plant | Line 10 - Line 23 | $ - | $ - | $ - | | | $ - | |
| 32 | | Net General Plant | Line 11 + Line 12 - Line 24 | $ - | $ - | $ - | | | | |
| 33 | | Net Completed Construction Not Classified | Line 15 | $ - | $ - | $ - | | | $ - | |
| 34 | | Retirement work in progress | - Line 25 | $ - | $ - | $ - | | | | |
| 35 | | Total Net Plant in Service | Sum | $ - | $ - | $ - | | | | |
| 36 | | | | | | | | | | |
| 37 | | **Adjustments to Rate Base** | | | | | | | | |
| 38 | | Plant Held for Future Use | Line 14 | $ - | $ - | $ - | | | $ - | |
| 39 | | Construction Work in Progress | Line 16 | $ - | $ - | $ - | Direct | WS-N | $ - | |
| 40 | | Working Capital | | | | | | | | |
| 41 | | Total Transmission O&M Costs | Worksheet B, Line 23, Columns G and J | | | $ - | | | | |
| 42 | | Billing Lag in Days | Worksheet F, Line 1 Col | | | | 0 | | | 0 |
| 43 | | Working Capital | Line 41 * Line 42 / 365 | | | $ - | | | | |
| 44 | 165 | Prepayments | Worksheet F, Line 38, Columns D and E | $ - | $ - | $ - | T-Plant | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 44 | Materials and Supplies | Worksheet F, Line 37, Columns D and E | - | - | $ - | T-Plant |
| 45 | Rate Base | Total | | | $ - | |

46 Note:
A. Acquisition adjustments will not be used in the calculation of ATRR absent Commission approval through a 205 or 206 filing.

Worksheet B

**Mountrail-Williams Electric Cooperative**

**O&M, Depreciation, and Return Expenses**
**Rate Year Ending December 31,**

| A<br>Line No | B | C | D<br>Account Number | E<br>Description | F | G | H | I<br>Total Company | J<br>Total Reference Company |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | Transmission Operation & Maintenance Expenses | | | | Lines | Stations |
| 2 | | | | **Transmission Expenses** | | | | | |
| 3 | | | 556 | System Control & Load Dispatching<br>Transmission of | | | Worksheet U, Column Worksheet | Line | 13, C |

I, Line 40 colum n J

| Total Company | Allocation Factor | Allocation % | Transmiss |
|---|---|---|---|
| Total Company | | | |
| $ - | | | |
| $ - | | | |
| | T-Plant Direct | | $ |
| | - Zero | 0.0% | |

| | | | | |
|---|---|---|---|---|
| | | by Others (Note B) | | |
| 5 | | Transmission Station Expenses (Note B) | Worksheet I, Line 40 columns G, N, and O | 911 Worksheet F, Line 24, Column E |
| 6 | | Transmission Line Expenses (Note B) | Worksheet I, Line 40 columns H, I, P, and Q | |
| 7 | | Other Transmission Expenses (Note B) | Worksheet I, Line 40 columns E, K, L, M, and R | |
| 8 | 575 - 576 | Regional Market Expenses (Note B) | Worksheet I, Line 40 columns S and T | 1 - F, Line 24, Column E |
| 9 | 561 | Load Dispatch Expense (Notes B and C) | Worksheet I, Line 40 column F | |
| 10 | | Distribution Expense - Operations | Worksheet F, Line 20, Column E | |
| 11 | | Distribution Expense - Maintenance | Worksheet F, Line 21, Column E | |
| 12 | | Transmission O&M | Subtotal | 916 Sales Column E - Line 14 |
| 13 | 901 - 905 | Customer Accounting | Worksheet F, Line 22, Column E - Line 14 | |
| 14 | 901 - 905 | Customer Accounting SPP Expenses | Worksheet T, Line 10, Column E | |
| 15 | 907 - 910 | Customer Services & Information | Worksheet F, Line 23, Column E | |

| | | | | | | |
|---|---|---|---|---|---|---|
| $ - | | | T-Tran Stations | Direct | WS-T | $ - |
| $ - | | | T-Tran Lines | Direct Zero | 0.0% | $ - |
| $ - | | | | Direct Zero | 0.0% | $ - |
| $ - | | | T-Tran Plant | | | |
| $ - | | | | Direct | WS-R | $ - |
| $ - | | | | Direct Zero | 0.0% | $ - |
| $ - | | | | Direct - | Zero | 0.0% |
| $ - | | | | Direct Zero | 0.0% | $ - |
| | $ - | | | | | |
| | $ - | | | | | |
| | $ - | | | | | |
| | | | | Direct Zero | 0.0% | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Q, Line 7, Col F | | $ - |
| 17 | | Customer Related Expense | | | Subtotal | | Worksheet Q, Line 7, Col E | $ - | $ - |
| 18 | | Administrative & General Expense | | | | | Subtotal | - | $ - |
| 19 | 920-931 | Admin and General Operations Expense | | | | | Line 12 + Line 17 + Line 22 | | $ - |
| 20 | 928 | SPP Commission and Regulatory Expenses | | | | | | | Total Company |
| 21 | 928 | Non-SPP Commission and Regulatory Expenses | | | | | Worksheet L, Line 8, Col E | | $ - |
| 22 | | Total A&G Expenses | | | | | Worksheet L, Line 8, Col F | | $ - |
| 23 | | Subtotal O&M | | | | | Worksheet L, Line 8, Col G | | $ - |
| | | | | | | | Worksheet L, Line 8, Col H | | $ - |
| 24 | | Depreciation Expense | | | | | | | |
| 25 | 403 | Depreciation Expense-Production | | | | | | | |
| 26 | 403 | Depreciation Expense-Transmission Plant | | | | | | | |
| 27 | 403 | Depreciation Expense-Distribution | | | | | | | |
| 28 | 403 | Depreciation Expense-General | | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 0.0% | $ - |
| | | $ - | | | | |
| | | | | | WS-F | $ - |
| | | | | | 0.0% | $ - |
| T-Wage | | | | | | |
| Direct 100 | | | | | | |
| Direct Zero | | | 100.0 % | $ - | | |
| | | | | $ 0.0% - | | |
| Direct Zero | | | | | | |
| Direct | | | | | | |
| Direct Zero | | | | | | |
| T-Wage | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 29 | 405 | Unrecovered Plant Expense (Note A) | Worksheet L, Line 8, Col K | $ | - | Direct 100 | 100.0 % | $ - |
| 30 | 411.1 | Accretion Expense - Plant Retirement | Worksheet L, Line 8, Col J | $ | - | Direct Zero | 0.0% | $ - |
| 31 | 407 | Amortization of Intangible Plant | Worksheet L, Line 8, Col I | $ | - | T-Wage | | |
| 32 | | Total Depreciation & Amortization | sum lines 25 thru 31 | $ | - | | | |
| 33 | | Tax - Gross Reciepts and Property Tax | Worksheet F, Line 28, Column E | $ | - | T-Tax | | |
| 34 | | Return | Worksheet C, Line 7 | | | | | |
| 35 | | Revenue Requirement | Line 23 + Line 32 + Line 33 + Line 34 | | | | | |

Notes:

A These unrecovered plant expense are associated with the contribution in aid of construction paid by Mountrail-Williams to Basin Electric for the Wheelock Substation. No other amounts should be included on this line absent specific FERC approval. Should Basin Electric purchase the Wheelock Substation or be granted approval by FERC to include its costs in its ATRR, this line item will be populated with a zero. No other contributions in aid of construction (either paid by Mountrail-Williams or paid to Mountrail-Williams) will be included in Mountrail-Williams' Zone 19 ATRR absent specific Commission approval.

The sum of the total company

amounts for lines 4 through 9 must match the amount shown on the B Form 7, Part A, Line 4, Column B.

C To the extent that Mountrail-Williams has amounts included in Account 561, it will recover those amounts through Schedule 1 of the SPP Tariff and provide a workpaper demonstrating the derivation of the amount recovered under Schedule 1 of the SPP Tariff in its annual update. Total company Account 561 expenses, to the extent that they are incurred, will be allocated to Mountrail-Williams' Zone 19 Schedule 1 Revenue Requirement using the T-Tran Plant Allocator.

Worksheet C

**Capital Structure & Rate of Return based on Return on Equity**
**Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line No** | **Description** | **Reference** | **Total Co EoY** | **Cap Str Weight** | **Target Capital Str (A), (B)** | **Interest, Margin or Annual Cost** | **Cost of Capital (A), (B), (C)** | **Weighted Rate of Return** |
| 1 | **Capital Structure & Return** | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Line 40, Column E and Line 30 | $ - | | | $ - | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Worksheet | | | | | 0. | |
| | Notes | F, Line 41, | $ | 0.00 | $ | 0 | 0.0 | |
| 3 | Payable | Col E | - | % | - | % | % | |

| | | | | | |
|---|---|---|---|---|---|
| | | and Line 32, Col E if balance is positive. | | | |
| 4 | Total Margins and Equities | Worksheet F, Line 39, Col E | $ - | | 10.1 % |
| 5 | Total Capitalization | Subtotal | $ - | $ - | |
| 6 | Rate Base | Worksheet A, Line 45, Column J Line 5 * | | | |
| 7 | Return | Line 6 | | | |

8 Notes:

A. The cost of capital for Total Margins and Equities is fixed through January 1, 2021 and no Settling Party may submit a filing under section 205 or 206 of the Federal Power Act prior to that date to change the base ROE or Mountrail-Williams's entitlement to the 50-basis point adder for RTO participation, nor may any Settling Party support such a request by another entity. After that date, the cost of capital for Total Margins and Equities cannot be changed absent Commission approval through a Section 205 or

9 206 filing.

B. The ROE and capital structure shall remain in effect through December 31, 2025, absent Commission action under Federal Power Act Section 205 or 206. Mountrail-Williams may submit a Section 205 filing prior to December 31, 2025 in order to establish rates to be effective no later than January 1, 2026. All parties, including Mountrail-Williams, retain all of their rights with respect to such a filing. Absent such a filing, Mountrail-Williams's ROE shall apply to the equity component of Mountrail-Williams's actual

10 capital structure, effective January 1, 2026.

C. The cost of capital for Total Margins and Equities reflects a 50 basis point incentive

11 adder for RTO participation.

Worksheet
D

**Mountrail-Williams Electric Cooperative**

**Network Demand**
**Rate Year Ending December 31,**

| A<br>Line No | B<br>Description | C<br>Load (MW) |
|---|---|---|
| 1 | January | |
| 2 | February | |
| 3 | March | |
| 4 | April | |
| 5 | May | |
| 6 | June | |
| 7 | July | |
| 8 | August | |
| 9 | September | |
| 10 | October | |
| 11 | November | |
| 12 | December | |
| 13 | Total (MW-Mo) | 0 |
| 14 | Average (MW-Mo) | **0** |

Work shee t E

**Mountrail-Williams Electric Cooperative**

**Allocation Factors Rate Year Ending December 31,**

Distribution Operations

| A | B | C | D | E |
|---|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Total** | **Allocation Factor Name** |
| 1 | Production Wages | NA | $ - | Direct Zero |
| 2 | Transmission Supervision | Worksheet K, Line 34, Column G | $ - | T-Tran Plant |
| 3 | Transmission Load Management | Worksheet K, Line 34, Column H | $ - | Direct Zero |
| 4 | Transmission Station Operations | Worksheet K, Line 34, Column I | $ - | T-Tran Stations |
| 5 | Transmission Line Operations | Worksheet K, Line 34, Column J | $ - | T-Tran Lines |
| 6 | Transmission Supervision Maintenance | Worksheet K, Line 34, Column K | $ - | T-Tran Plant |
| 7 | Transmission Station Maintenance | Worksheet K, Line 34, Column L | $ - | T-Tran Stations |
| 8 | Transmission Line Maintenance | Worksheet K, Line 34, Column M | $ - | T-Tran Lines |
| 9 | Transmission Maintenance - Misc | Worksheet K, Line 34, Column N | $ - | T-Tran Plant |
| 10 | | Worksheet K, | | |

| | | |

| | | | | | |
|---|---|---|---|---|---|
| 11 | 28 | Worksheet K, Distribution | | | |
| | 29 | Maintenance | Transmission Qualifying Plant<br>**T-Tran Plant** | | |
| 12 | | | | | |
| 13 | | Customer Accounts Less SPP Exp | | | |
| 14 | | Account 901-905 SPP Expenses | Plant in Service<br>**T-Plant** | | |
| 15 | | | **Direct** | | **Zero** |
| 16 | | Customer Service | **Direct 100** | | |
| 17 | | | | | |
| 18 | | Sales Total Wages, Excluding A&G<br>**T-Wage** | | | |
| 19 | | 350-353 Transmission | | | |
| 20 | | Stations Gross Plant (Less 353 | | | |
| 21 | | SCADA & Load Control) | | | |
| 22 | | 353 SCADA & Load Control Equipment | | | |
| 23 | | Sum | | | |
| 24 | | **T-Tran Stations** | | | |
| 25 | | | | | |
| 26 | | 354-359.1Transmission | | | |
| 27 | | Lines Gross Plant<br>**T-Tran Lines** | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Line 34, Column P | $ - | Direct | 0.0 | $ - | | |
| Worksheet K, Line 34, Column Q | | Zero | % | - | | |
| Worksheet T, Line 10, Col E | $ - | Direct | 0.0 | $ - | | |
| Worksheet K, Line 34, Column R | | Zero | % | - | | |
| Worksheet K, Line 34, Column S | $ - | Direct | | $ - | $ - | |
| Sum Lines 1 thru 15 | $ - | Direct | 0.0 | $ - | | |
| | | Zero | % | - | | |
| Worksheet J, Line 178, Column F and Worksheet F, Line 4, Column F | $ - | Direct | 0.0 | $ - | | |
| | | Zero | % | - | | |
| Worksheet J, Line 179, Column F | $ - | | | | $ - | |
| Sum Lines 18+19 | | | | | | |
| Worksheet J, Line 180, Column F and Worksheet F, Line 8, Column F | $ - | | | $ - | | **0.0%** |
| Worksheet A, Line 9 Col G and J | $ - | | | $ - | | **100.0%** |
| | $ - | | | $ - | | |
| Worksheet A, Line 13 Col G and J | | | | | | |
| Fixed allocation | | | | | | |
| Fixed allocation | $ - | | | $ - | | |

| | | | |
|---|---|---|---|
| 30 | SPP Trans. as % of Total Company Trans. + Dist. | Worksheet A, Lines 9 and 10, Col. G and J | $ - |

31 **T-Tax**

Work shee t F

**Mountrail-Williams Electric Cooperative**

**General Input Section**
**Rate Year Ending December 31,**

| **A** **Line No** | **B** **Description** | Qualified Transmission 1 Line Annual Depreciation 1 Expense | **C** **Reference** | **D** **E** **BoY EoY** |
|---|---|---|---|---|
| 1 | Billing Lag in days | | | |
| 2 | CWIP to included in Rate Base | | Indus try Stan dard | |
| 3 | Test Year | | Per ER17-1610 Settlement | |
| 4 | Qualified Substation Gross Plant | | | |
| 5 | Qualified Substation Accumulated Depreciation Reserve | | Worksheet V, Line 20, Column D and G | $ - |
| 6 | Qualified Substation Net Book Value | | Worksheet V, Line 20, Column E and H | $ - |
| 7 | Qualified Substation Annual Depreciation Expense | | Worksheet V, Line 20, Column F and I | $ - |
| 8 | Qualified Transmission Line Gross Plant | | Worksheet V, Line 20, Column J | |
| 9 | Qualified Transmission Line Accumulated Depreciation Reserve | | Worksheet W, Line 51, Column F and I | |
| 1 0 | Qualified Transmission Line Net Book Value | | Worksheet W, | $ - |

| | | |
|---|---|---|
| Line 51, Column G and J Worksheet W, Line 51, Column H and K Worksheet W, Line 51, Column L | $ - | $ - |

**F**

**End of Year Value or Amount**

$ -

$ -

$ -

$ -

$ -

$ -

$ -

$ -

1
2 **Form 7 Input**

1 Operating Revenue and 3
Patronage Capital

1 Power Production
4 Expense
1 Purchased Power
5 Commodity Expense
1 Purchased Power Load
6 Dispatching Expense

1
7 Cost of Purchased Power

1
8 Transmission Expense

1 Regional Market
9 Operations Expense

2 Distribution Expense-
0 Operation

2 Distribution Expense-
1 Maintenance

2 Customer Account
2 Expense

2 Customer Sales and
3 Informational Expense

2
4 Sales Expense

2 Administrative and
5 General Expense
2 Subtotal-Operations &
6 Maintenance Expense

2 Depreciation and
7 Amortization Expense

2 Tax - Gross Reciepts and 8 Property Tax

Form 7, Part A, Line 1, Column B Form 7, Part A, Line 2, Column B

| | |
|---|---|
| Cost of Purchased Power | $ - |
| Less Dispatching Worksheet U Line 13 Col C | $ - |
| Form 7, Part A, Line 3, Column B | |
| Form 7, Part A, Line 4, Column B | |
| Form 7, Part A, Line 5, Column B | |
| Form 7, Part A, Line 6, Column B | |
| Form 7, Part A, Line 7, Column B | |
| Form 7, Part A, Line 8, Column B | |
| Form 7, Part A, Line 9, Column B | |
| Form 7, Part A, Line 10, Column B | |
| Form 7, Part A, Line 11, Column B | |
| Sum Lines 14 thru 25 | $ - |
| Form 7, Part A, Line 13, Column B | |
| Form 7, Part A, Line 14, Column B | |

| | | | | | |
|---|---|---|---|---|---|
| 29 | Tax Expense - Other | Form 7, Part A, Line 15, Column B | | | |
| 30 | Interest on Long Term Debt | Form 7, Part A, Line 16, Column B | | | |
| 31 | Interest Charged to Construction (Credit) | Form 7, Part A, Line 17, Column B | | | |
| 32 | Other Interest Expense | Form 7, Part A, Line 18, Column B | | | |
| 33 | Other Deductions | Form 7, Part A, Line 19, Column B | | | |
| 34 | Subtotal Cost of Electric Service | Sum Lines 26 and 27 thru 33 | | | $ - |
| 35 | Patronage Capital and Operating Margins | Line 13 - Line 34 | | | $ - |
| 36 | | | | | |
| | | | BoY | EoY | Average |
| 37 | Materials and Supplies | Form 7, Part C, Line 23 | | | $ - |
| 38 | Prepayments | Form 7, Part C, Line 24 | | | $ - |
| | | | | EoY | |
| 39 | Total Margins and Equities | Form 7, Part C, Line 35 | | | |
| 40 | Total Long Term Debt | Form 7, Part C, Line 38 | | | |
| 41 | Notes Payable | Form 7, Part C, Line 42 | | | |
| 42 | | | | | |
| 42 | Plant in Service | | BoY | EoY | Average |
| 43 | Total Distribution Plant | Form 7, Part E, Line 1 | | | $ - |
| 44 | General Plant | Form 7, Part E, Line 2 | | | $ - |
| 45 | Headquarters Plant | Form 7, Part E, Line 3 | | | $ - |
| 46 | 301-303 Total Intangible Plant | Form 7, Part E, Line 4 | | | $ - |
| 47 | Transmission Plant | Form 7, Part E, Line 5 | | | $ - |
| 48 | | Form 7, Part E, | | | $ |

8 380-386 RTO/ISO Plant Line 6 -

| | | | | | |
|---|---|---|---|---|---|
| 4 | | Form 7, Part E, | | | $ |
| 9 | Production Plant-Steam | Line 7 | | | - |
| 5 | | Form 7, Part E, | | | $ |
| 0 | Production Plant-Nuclear | Line 8 | | | - |
| 5 | | Form 7, Part E, | | | $ |
| 1 | Production Plant-Hydro | Line 9 | | | - |
| 5 | | Form 7, Part E, | | | $ |
| 2 | Production Plant-Other | Line 10 | | | - |
| 5 | | Form 7, Part E, | | | $ |
| 3 | All Other Utility Plant | Line 11 | | | - |
| 5 | Construction Work in | Form 7, Part E, | | | $ |
| 4 | Progress | Line 13 | | | - |
| 5 | | Subtotal | $ | $ | $ |
| 5 | Plant in Service | | - | - | - |
| 5 | | | | | |
| 6 | | | | | |
| 5 | | | | | |

7 Notes:
A. Acquisition adjustments will not be used in the
5 calculation of ATRR absent Commission approval
8 through a 205 or 206 filing.
5 B. The addition of new lines and the removal of outdated
9 lines may be necessary in order to accurately provide
information, and populate or remove data in the
6 Worksheet with changes in future years. Where
0 appropriate, these
changes will provide detail and linkage to
6 updated Form 7 data requirements or other
1 similar supporting
documentation. Additional line items or line deletions
6 will not require FPA Section 205 or 206 filings. MWEC
2 will
describe such changes in the Annual Update, and
6 the changes will be subject to the review of Interested
3 Parties under
the procedures set forth in MWEC's Implementation
6 Protocols. MWEC may not change the columns or the
4 formulas
included in these
6 Worksheets during the
5 Annual Update.

Worksheet G

**Mountrail-Williams Electric Cooperative**

**Depreciation Rates**
**Rate Year Ending December 31,**

| A | B | C | D |
|---|---|---|---|
| Line No | Description | Plant Account Number | Annual Depr Rate |
| 1 | Land & Land Rights | 389.00 | N/A |
| 2 | Structures & Improvements | 390.00 | 2.40% |
| 3 | Office Furniture | 391.00 | 5.00% |
| 4 | Transportation Equip- LIGHT VEHICLE - 5 YEAR DEP | 392.1 | 20.00% |
| 5 | Transportation Equip-LIGHT VEHICLE - 6 YEAR DEP | 392.2 | 16.67% |
| 6 | Transportation Equip-HEAVY TRAILER - 15 YEAR DEP | 392.3 | 6.71% |
| 7 | Transportation Equip-LARGE TRUCK - 10 YEAR DEP | 392.4 | 10.00% |
| 8 | Transportation Equip-LARGE TRUCK - 8 YEAR DEP | 392.5 | 12.30% |
| 9 | Transportation Equip-LARGE TRUCK 7 YEAR DEP | 392.6 | 14.23% |
| 10 | Stores Equipment | 393.00 | 12.00% |
| 11 | Storage and Garage Equip-HEAVY/COMMERCIAL SHOP EQUIPMENT | 394.1 | 10.00% |
| 12 | Storage and Garage Equip-REGULAR SHOP EQUIPMENT | 394.2 | 20.00% |
| 13 | Storage and Garage Equip-SMALL TOOLS | 394.3 | 33.30% |
| 14 | Laboratory Equipment | 395. | 12.0 |

0

0

0

%

40

Power Operated Equip-LARGE TRUCK - BUCKET UNIT
Power Operated Equip-SMALL TRUCK - BUCKET UNIT
Power Operated Equip-HEAVY FORK LIFT/LOADER
Power Operated Equip-SMALL FORK LIFTS
Power Operated Equip-SMALL TRUCK - BUCKET UNIT
Power Operated Equip-CRANE UNIT
LARGE POWER OPERATED DIGGER UNIT
Communications Equip-TRUCK RADIO SYSTEM
Communications Equip-DESK
COMMUNICATION EQUIPMENT
Communications Equip-SMALL
TOWER
Communications Equip-LARGE TOWER
DISTRIBUTION PLANT

Land & Land Rights-Substations Station Equipment-

Substations Substation Equipment Belden Substation

Oilfield Specific

Pleasant Valley Switchyard Poles Towers fixtures

Overhead, Conductor and Services

Underground Conductor and Devices

Line Transformers Services

Services Meters

Installations on Customer Premises

Leased Property on Consumers Premises

Street Lighting and Signal Systems

| | |
|---|---|
| 373 | 3.23 % |
| 396.2 | 10.00% |
| 396.21 | 20.00% |
| 396.2 | 12.57% |
| 396.2 | 8.33 % |
| 396.2 | 16.67% |
| 396.2 | 14.30% |
| 396.2 | 17.30% |
| 397 | 10.24% |
| 397 | 2.04 % |
| 397 | 4.62 % |
| 397 | 3.45 % |
| 360.00 | N/A |
| 362.00 | 3.05 % |
| 362.10 | 14.28% |
| 362.20 | 10.00% |
| 362.30 | 2.54 % |
| 364.00 | 3.00 % |
| 365.00 | 2.30 % |
| 367.00 | 6.00 % |
| 368.00 | 3.10 % |
| 369.00 | 3.60 % |
| 370.00 | 3.40 % |
| 371.00 | 4.10 % |
| 372 | 4.10 % |

41 TRANSMISSION PLANT LAND AND LAND RIGHTS
42 TRANSMISSIO SUBSTATION EQUIPMENT-TRANSMISSION
43 TRANSMISSION SUBSTATION PLEAS VAL SWITCH
44 TRANSMISSION SUBSTATION - NESET
45 SCADA & LOAD CONTROL EQUIPMENT
POLES AND FIXTURES TRANSMISSION
46 POLES & FIXTURES PLSNT VAL - BEL
47 POLES & FIXTURES TRANS-OILFIELD
48 POLES-TRANSMISSION MONT TO N MISSR RIDGE
49 POLES-TRANSMISSION-BLAISDELL TO PALERMO
POLES-TRANSMISSION-MDU TO LOSTWOOD
50 POLES-TRANSMISSION-POWERS LAKE TO 3-WAY
51 POLES-TRANSMISSION-STANLEY 25 to BELDEN
52 POLES-TRANSMISSION-STANLEY 25 TO PALERMO POLES-TRANSMISSION-GRENORA TO BARR BUTTE
53 POLES-TRANSMISSION-ZAHL TO MDU 69KV
54 POLES-TRANSMISSION-PARSHALL TO HWY 8
POLES-TRANSMISSION-NEW TOWN TO HWY 8
55 POLES-TRANSMISSION-PARSHALL TO MAKOTI
56 POLES-TRANSMISSION-WHEELOCK TO 12 MILE
57 POLES-TRANSMISSION-WILLISTON TO JUDSON
58 POLES-TRANSMISSION-STANLEY TO BELDEN
59 POLES-TRANSMISSION-NESET TO PLEASANT VAL
POLES-TRANSMISSN-HESS RAIL TO WEST BANK
60 POLES-TRANSMISSION - NESET TO LINDAHL
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| | POLES-TRANSMISSION-NEW TOWN TO BIG BEND | 355.59 | 2.60 % | | | | |
| | POLES-TRNSMISSION-SE WILL TO 12 MILE | 355.6 | 2.60 % | | | | |
| | POLES-TRNSMISSION-WHEELOCK to ELLISVLL 2 | 355.61 | 2.60 % | | | | |
| POLES-TRANSMISSION - ROSS TRANS LINE | POLES-TRNSMISSION - STANLEY TO NE ROSS | 355.47 | 2.60 % | | | | |
| | POLES-TRANSMISSION-RAT LAKE TAP | 355.63 | 2.60 % | | | | |
| POLES-TRANSMISSION-AUSTIN SUB TRANS LINE | POLES-TRANSMISSION-JUDSON TO TANDE 345/1 | 355.48 | 2.60 % | | | | |
| | POLES-TRANSMISSION GRENORA to BARR BUTTE | 355.65 | 2.60 % | | | | |
| POLES-TRANSMISSION-LINDAHL TO SIMPSON | POLES-TRANSMISSION - HOFFLUND | 355.49 | 2.60 % | | | | |
| POLES-TRANSM N MISS RIDGE to N WILLISTON | POLES-TANSMISSION-ZAHL TO BLACKTAIL | 355.5 | 2.60 % | | | | |
| | POLES-TRANSMISSION-WHEELOCK - N 2 MILES | 355.68 | 2.60 % | | | | |
| POLES-TRANSMISSION-N WILL TO NE WILLISTO | POLES-TRANSMISSION STANLEY to NE ROSS | 355.51 | 2.60 % | | | | |
| | POLES-TRANSMISSION-BLACKTAIL TO TYRONE | 355.7 | 2.60 % | | | | |
| POLES-TRANSMSSN-NW WILLISTON TO 56TH ST | POLES-TRANSMISSION PLEASANT VAL - N TIOG | 355.71 | 2.60 % | | | | |
| POLES-TRANSMISSION-WILLISTON TO MONT | | 355.52 | 2.60 % | | | | |
| POLES-TRANSMISSION-WILL to NW WILLISTON | | 355.53 | 2.60 % | | | | |
| POLES-TRANSMISSION-NE WILL TO SE WILLIST | | 355.54 | 2.60 % | | | | |
| POLES-TRANSMISSION-WHEELOCK TO ELLISVILL | | 355.55 | 2.60 % | | | | |
| POLES-TRANSMISION-NEW TOWN TO FINSTAD | | 355.56 | 2.60 % | | | | |
| POLES-TRANSMISSION-ELLISVILLE TO ZAHL | | 355.57 | 2.60 % | | | | |
| | | 355.58 | 2.60 % | | | | |

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92 POLES-TRANSMSSN - PV SWITCH TO NESET 115
POLES-TRANSMSSN PV SWITCH to PV 115 TL
93 POLES - TRANSMISSION BROOKBANK TAP
POLES-TRANSMISSION TAP TO VAN HOOK
94 POLES-TRANS BLAISDELL SUB TO BLAISD TL
POLES-TRANSMISSION WHITE EARTH TAP
95 POLES-TRANSMISSION MOE TAP
96 POLES-TRANSMISSION NORTH 12 MILE TAP
97 POLES-TRANSMISSION STANLEY TO MDU 115
POLES-TRANSMISSION WILLISTON TAP
98 POLES - TRANSMISSION - FARMVALE TAP
99 POLES-TRANSMISSION TYRONE TO EAST FORK
POLES-TRANSMISSION - AUSTIN TAP
100 POLES - TRANSMISSION - LIBERTY TAP
101 POLES-TRANSMISSION-PALERMO TAP
102 POLES-TRANSMISSION-BASIN 345 TO EAST FRK
POLES-TRANSMISSION-NMR TO BASIN 345
103 POLES-TRANSMISSION - EPPING TAP
104 OVERHEAD CONDUCTORS & DEVICES TR
OHD CNDCTR & DEVICES PLSNT VAL -
105 OHD CONDUCTOR & DEVICES - OILFIE
106 CONDUCTOR TRANSMISSION MONT-N MISSR RDG
107 CONDUCTOR-TRANSMISSION-BLAISDELL TO PALR
108 CONDUCTOR-TRANSMISSION-MDU TO LOSTWOOD
109 CONDUCTOR-TRANSMISSION-POWERS LAKE TO 3-
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| | NESET TO LINDAHL | 46 | % |
| | CONDUCTOR-TRANSMISSION-ROSS TRANS LINE | 356. 47 | 2.45 % |
| | CONDUCTOR-TRANSMISSION-AUSTIN SUB LINE | 356. 48 | 2.45 % |
| CONDUCTOR-TRANSMISSION-STANLEY25 TO BELD | CONDUCTOR-TRANSMISSN-LINDAHL TO SIMPSON | 356. 49 | 2.45 % |
| CONDUCTOR-TRANSMISS-STANLEY TO PALERMO 3 | CONDUCTOR-TRANSM-N MISS RIDG to N WILLIS | 34 % | 356. 5 2.45 % |
| CONDUCTOR-TRANSMIS-GRENORA TO BARR BUTTE | CONDUCTOR TRANSMISSION-N WILL TO NE WILL | 356. 51 | 2.45 % |
| CONDUCTOR-TRANSMISSION-ZAHL TO MDU 69KV | CONDUCTOR-TRANSMSSN-NW WILL TO 56th ST | 35 % | 356. 52 2.45 % |
| CONDUCTOR-TRANSMISSION PARSHALL TO HWY 8 | CONDUCTOR-TRANSMISSION-WILLISTON TO MONT | 356. 53 | 2.45 % |
| CONDUCTOR-TRANSMISSION-NEW TOWN TO HWY 8 | CONDUCTOR-TRANSMISSION-WILL to NW WILLIS | 36 % | 356. 54 2.45 % |
| CONDUCTOR-TRANSMISSN-PARSHALL TO MAKOTI | CONDUCTOR-TRANSMSSION-NE WILL to SE WILL | 356. 55 | 2.45 % |
| CONDUCTOR-TRANSMISSN-WHEELOCK TO 12 MILE | CONDUCTOR-TRANSMISSN-WHEELOCK TO ELLISVI | 37 % | 356. 56 2.45 % |
| CONDUCTOR-TRANSMISSN-WILLISTON TO JUDSON | CONDUCTOR-TRANSMISSN-NEW TOWN TO FINSTAD | 356. 57 | 2.45 % |
| CONDUCTOR-TRANSMISSION-STANLEY TO BELDEN | CONDUCTOR-TRANSMISSN-ELLISVILLE TO ZAHL | 38 % | 356. 58 2.45 % |
| CONDUCTOR-TRANSMISSN-NESET TO PLEASANT V | 356. 39 | 2.45 % | |
| CONDUCTOR-TRANSM-HESS RAIL TO WEST BANK | 356. 4 | 2.45 % | |
| CONDUCTOR-TRANSMISSION- | 356. 41 | 2.45 % | |
| | 356. 42 | 2.45 % | |
| | 356. 43 | 2.45 % | |
| | 356. 44 | 2.45 % | |
| | 356. 45 | 2.45 % | |

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| | CONDUCTOR-TRANSMSSN-PV SWITCH to NESET 1 | 356. 72 | 2.45 % | | |
| | CONDUCTOR-TRANSMSSN PV SWITCH TO PV 115 | 356. 73 | 2.45 % | | |
| | CONDUCTOR-TRANSMISSION BROOKBANK TAP | 356. 74 | 2.45 % | | |
| CONDUCTOR-TRANSMISS-NEW TOWN TO BIG BEND | CONDUCTOR-TRANSMISSION TAP TO VAN HOOK | 356. 75 | 2.45 % | | |
| CONDUCTOR-TRNSMISSION-SE WILL TO 12 MILE | CONDUCTOR-TRANS BLAISDEL SUB TO BLAIS TL | 356. 76 | 2.45 % | | |
| CONDUCTOR-TRANSMSSN-WHEELOCK TO ELLISV 2 | CONDUCTOR - TRANSMISSION WHITE EARTH TAP | 356. 77 | 2.45 % | | |
| CONDUCTOR-TRNSMISSION STANLEY TO NE ROSS | CONDUCTOR-TRANSMISSION MOE TAP | 356. 78 | 2.45 % | | |
| CONDUCTOR-TRANSMISSION-RAT LAKE TAP | CONDUCTOR-TRANSMSSN NORTH 12 MILE TAP | 356. 79 | 2.45 % | | |
| CONDUCTOR-TRANSMISSION-JUDSON TO TANDE | CONDUCTOR-TRANSMISSION STANLEY TO MDU | 356. 8 | 2.45 % | | |
| CONDUCTOR-TRNSMSSN-GRENORA to BARR BUTTE | CONDUCTOR-TRANSMISSION WILLISTON TAP | 356. 81 | 2.45 % | | |
| CONDUCTOR-TRANSMISSION - HOFFLUND | CONDUCTOR - TRANSMISSION - FARMVALE TAP | 356. 82 | 2.45 % | | |
| CONDUCTUR-TRANSMISSION-ZAHL TO BLACKTAIL | CONDUCTOR-TRANSMISSION TYRONE-EAST FORK | 356. 83 | 2.45 % | | |
| CONDUCTOR-TRANSMSSN-WHEELOCK - N 2 MILES | 356. 68 | 2.45 % | | | |
| CONDUCTOR-TRANSMISSN-STANLEY TO NE ROSS | 356. 69 | 2.45 % | | | |
| CONDUCTOR-TRANSMSSN-BLACKTAIL TO TYRONE | 356. 7 | 2.45 % | | | |
| CONDUCTOR-TRANSMSSN-PLEAS VAL - N TIOGA | 356. 71 | 2.45 % | | | |

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|---|---|---|---|
| 167 | CONDUCTOR-TRANSMISSION - AUSTIN TAP | 356.84 | 2.45 % |
| 168 | CONDUCTOR-TRANSMISSION-LIBERTY TAP | 356.85 | 2.45 % |
| 169 | CONDUCTOR-TRANSMISSION-PALERMO TAP | 356.86 | 2.45 % |
| 170 | CONDUCTOR-TRANSMSSN-BASIN 345 - EAST FRK | 356.87 | 2.45 % |
| 171 | CONDUCTOR-TRANSMISSION-NMR TO BASIN 345 | 356.88 | 2.45 % |
| 172 | CONDUCTOR-TRANSMISSION - EPPING TAP | 356.89 | 2.45 % |
| 173 | UNDERGROUND CONDUCTORS & DEVICES | 358 | 5.00 % |
| 174 | | | |

175 Note:

176 A. Stated Values in Column D are fixed and cannot be changed absent Commission approval through a Section 205 or 206 filing.

Worksheet H

**Mountrail-Williams Electric Cooperative**

**SPP Upgrades Rate Year Ending December 31,**

| A | B | C | D |
|---|---|---|---|
| **Line No** | **Description** | **Reference** | **Company Total Transmission Amount** |
| 1 | Gross Qualified Transmission Plant | Worksheet A, Line 9, Column J | |
| 2 | Accumulated Qualified Transmission Depreciation | Worksheet A, Lines 20 thru 22, Column J | |
| 3 | Net Transmission Plant | Line 1 - Line 2 | |

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| 4 | Transmission O&M | Worksheet B, |

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|---|---|---|---|
| | | Line 12, Column J | |
| 5 | **Annual Allocation Factor for Transmission O&M** | Line 4 / Line 1 | |
| 6 | General Plant Depreciation Expense | | |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | Line 6 / Line 1 | |
| 8 | Return on Rate Base | Worksheet B, Line 34, Column J | |
| 9 | **Annual Allocation Factor for Return** | Line 8 / Line 3 | |
| 10 | **Depreciation Rates** | | |
| 11 | Line | Worksheet G, Line 1, Column D | 2.50% |
| 11 | | Worksheet G, | |

| | | | | |
|---|---|---|---|---|
| 2 | Sub | Line 2, | 2.45% | |

| | | | Column D | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
| Line No | Project Name and # | Type | Project Gross Plant | Project Accumulated Depreciation | Transmission O&M Annual Allocation Factor | Allocation for Transmission O&M | General Plant Depreciation Annual Allocation Factor | Allocation for General Plant Depreciation Charge | Annual Expense | Project Net Plant | Factor for Annual Return | Annual Return Charge | Project Annual Allocation Expense | Project Depreciation and Amortization Expense | Project ATRR |
| | | | | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | Col G + Col I | Col D - Col E (Note B) | Line 9, Col D | Col K * Col L | | Note C | Col J + Col M + Col N |
| | | | Note A | | | | | | | | | | | | |

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| 1 | | $ | $ |
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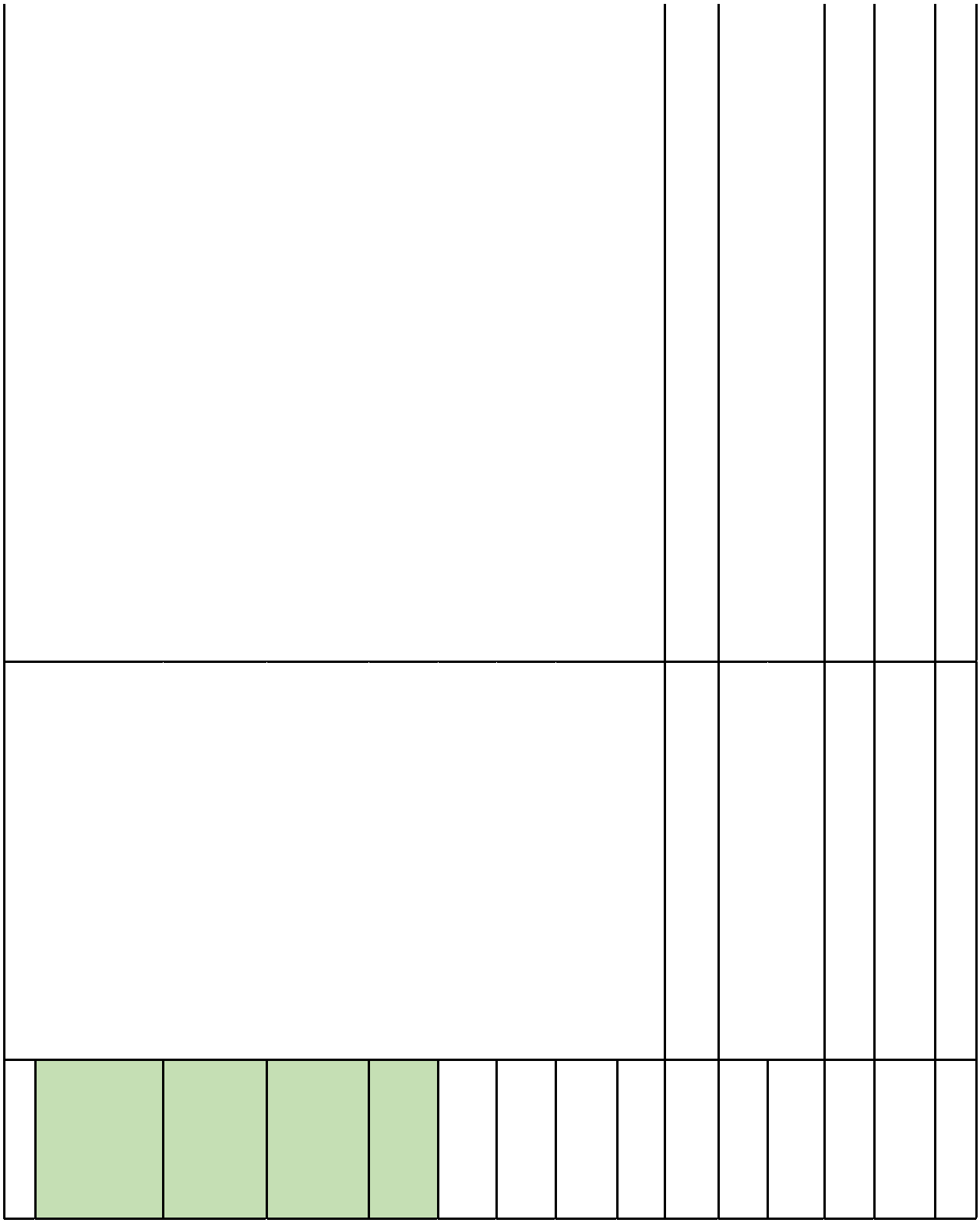

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| 26 | | | | | $ - | $ - |
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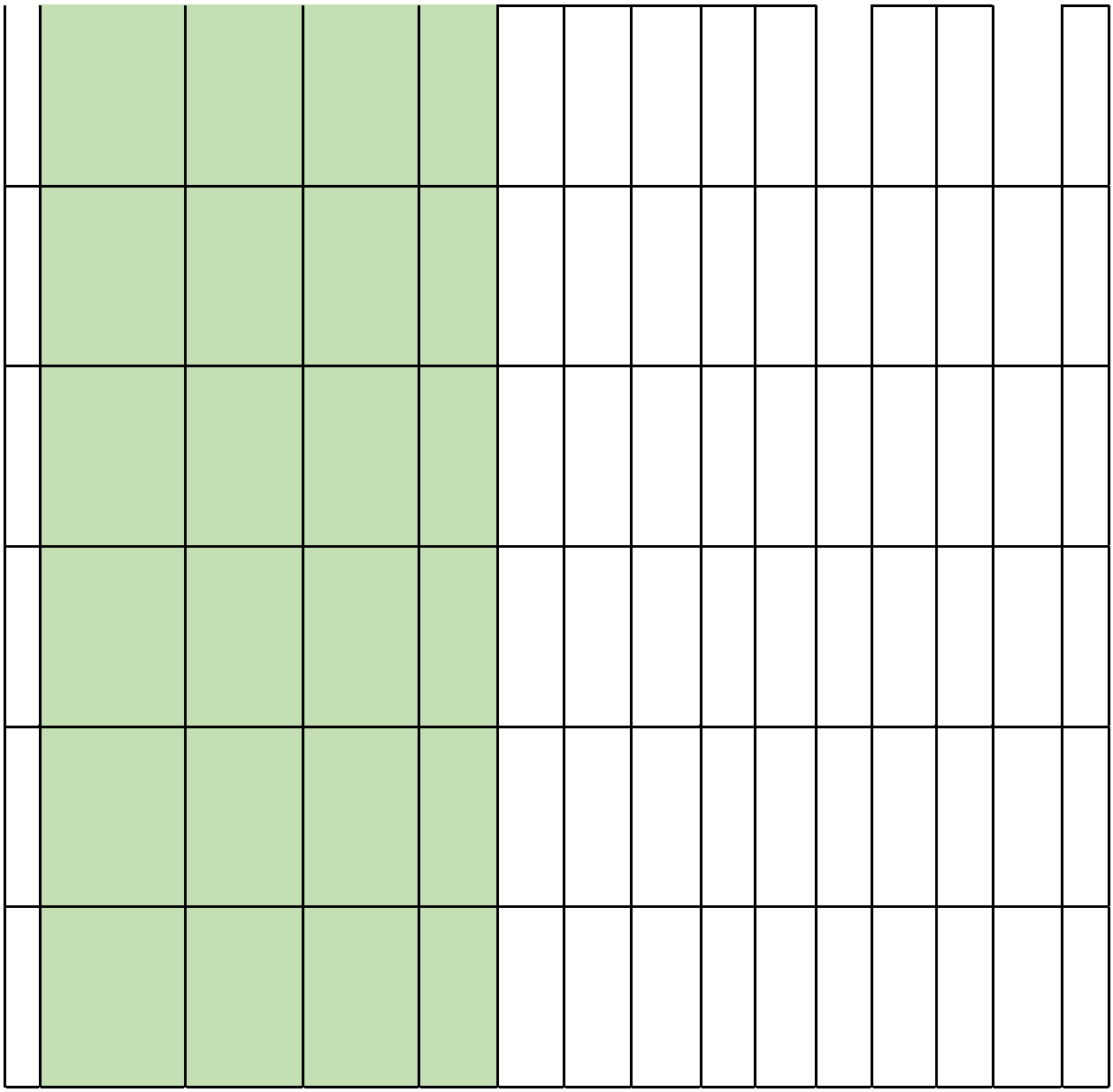
| 28 | Total | $ - | $ - | | $ - | $ - |

29 Notes

A. Project Gross Plant is the total capital investment for the

0 project calculated in the same



method as the gross plant value in line 1.

This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

B. Net Plant is the Gross Plant less the associated Accumulated Depreciation.

C. Depreciation Expense is the depreciation amount associated with the specified line or sub.

Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. MWEC will describe such changes in the Annual Update, and the changes will be subject to the

4 review of Interested Parties
0 under

the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas

included in these Workshee ts during the Annual Update.

Worksheet I

**Mountrail-Williams Electric Cooperative**

**O&M Input Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Account | Description | Balance | 560-Supervision & E | 561-Load Dispatchi | 562-Station Ex | 563-OH Line Exp | 564-UG Line Exp | 565-Transmiss | 566-Miscellaneou | 567-Rents | 568-Supervisi | 569-Structure | 570-Station Equ | 571-OH Lines | 572-UG Lines | 573-Misc Trans | 575 1-575 8 | 576 1-576 5 | 580-589 Distrib | 590-598 Distrib |

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**gr g e n n o E n p i ti ti**
**n s s n x a m s o o**

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| | | | **ses** | **es** | **es** | **of Elec By Others** | **penses** | **nd Engineering** | **ent** | **sion Plant** | **n Operations** | **n Maintenance** |
| 1 | 562.0 | OPERATIONS OF TRANS-SWITCHING ST | $- | | | | | | | | | |
| 2 | 562.1 | TRANSMISSION LINE INVEST/IR | $- | | | | | | | | | |
| 3 | 563.0 | OPERATIONS OF TRANSMISSION LINES | | $- | | | | | | | | |
| | 563.1 | Transmission Maintenance- | | | | | | | | | | |

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| 5 | 563.2 | Transmission Maintenance-Mountra | $ - | | | |
| 6 | 570.0 | MAINTENANCE OF TRANS SWITCHING | | $ - | | |
| 7 | 571.0 | MAINTENANCE OF TRANSMISSION LINE | | | $ - | |
| 8 | 571.1 | TRANSMISSION LINE REPAIR/IR | | | $ - | |
| 9 | 572.0 | MAINTENANCE OF TRANSM. UNDERGROU | | | | $ - |
| | 573.1 | TRANSMISSION EXP | | | | |

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| 10 | ENSE-COM | | $ - |

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| | 5 8 0. 0 | OPERATION, SUPERVISION, | |
| 1 1 | | ENGINEER | $ - |
| | 5 8 1. 1 0 | LOAD DISPATCHING STATION | $ - |
| | 5 8 2. 1 0 | EXPENSE | $ - |
| | 5 8 2. 1 4 | SUBSTATION INVESTIGATION/IR | $ - |
| | 5 8 3. 1 5 | OVERHEAD LINE EXPENSE | $ - |
| | 5 8 3. 1 6 | O.H. DISTRIBUTION LINE INVEST/I | $ - |
| | 5 8 4. 0 | UNDERGROUND ROUND LINE | |

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| | 8 | DIST | | |
| | 4. | RIBU | | |
| | 1 | TION | | |
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| 1 | | ST/I | $ | |
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| | 5 | STR | | |
| | 8 | EET | | |
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| | 0 | TING | | |
| | | EXP | | |
| 1 | | ENS | $ | |
| 9 | | ES | - | |
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| | 8 | ER | | |
| | 6. | EXP | | |
| 2 | 0 | ENS | $ | |
| 0 | | ES | - | |
| | 5 | CON | | |
| | 8 | SUM | | |
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| | 0 | INST | | |
| 2 | | ALLA | $ | |
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| | 5 | MISC | | |
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describe such changes
in the Annual Update, and
the changes will be

subject to the review of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet J

**Mountrail-Williams Electric Cooperative**

**Plant Input Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y |
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| Line No | Account | Description | Balance BOY | Balance EOY | 350 Tran Land BOY | Tran Land EOY | Tran Structure | Tran Structure | Transmission Station SCADA | Transmission Station SCADA | Transmission Station Conn | Transmission Station Conn | Tran Lines BOY | BOY | EOY | DABOY | DDAEOY | DDOY | GGOY | GGOY | Y | | | | EO |

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| | | PMENT | | | |
| | 353 | POLES | | | |
| | 355 | AND FIXTURES | | | |
| | 350 | TRANSMISSION | $ | - | $ - |
| | 353 | POLES & FIXTURES | | | |
| | 101 | PLSNT VAL - BEL | $ | - | $ - |
| | 353 | POLES & FIXTURES | | | |
| | 102 | TRANS-OILFIELD | $ | - | $ - |
| | 353 | POLES-TRANSMISSION | | | |
| | 303 | MONT TON MISSR RIDGE | $ | - | $ - |
| | 353 | POLES-TRANSMISSION- | | | |
| | 101 | BLAISDELL TO PALERMO | $ | - | $ - |
| | 353 | POLE | | | |

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| | 3 | SION-2 MDU TO LOST WOOD | | | | |
| | 3 | POLES-TRANSMIS | | | | |
| | 3 | SION-3 POWERS LAKE TO 3-WAY | | | $ - | $ - |
| | 3 | POLES-TRANSMIS | | | | |
| | 3 | SION-4 STANLEY 25 to BELDEN | | | $ - | $ - |
| | 3 | POLES-TRANSMIS | | | | |
| | 3 | SION-5 STANLEY 25 TO PALERMO | | | $ - | $ - |
| | 3 | POLES-TRANSMIS | | | | |
| | 3 | SION-6 GRENORA TO BARR BUTTE | | | $ - | $ - |
| | 3 | POLE | | | | |

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| | 3 5 5 | POLE S-TRANSMIS | | | | |
| | 3 8 | SION-PARSHALL TO | | $ | | |
| 1 8 | | HWY 8 | | - | $ - | |
| | 3 5 5 | POLE S-TRANSMIS | | | | |
| | 3 9 | SION-NEW TOWN TO | | $ | | |
| 1 9 | | HWY 8 | | - | $ - | |
| | 3 5 5 | POLE S-TRANSMIS | | | | |
| | 4 | SION-PARSHALL TO | | $ | | |
| 2 0 | | MAKOTI | | - | $ - | |
| | 3 5 5 | POLE S-TRANSMIS | | | | |
| | 4 1 | SION-WHEELOCK TO | | $ | | |
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| | 3 5 5 | POLE S-TRAN | | | | |

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| | 8 | SN-ELLISVILLE TO ZAHL | $ | $ |
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| | 9 | S-NEW TOWN TO BIG BEND | $ | $ |
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| | 6 | OR-TRAN | | | |
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| | 8 | SMISSION- | | | |
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| 170 | FOR AMORT ELECTRIC UT | | | | | | | | | | | | | | | | | | | | | | | - |
| 175 | | | | | | | | | | | | | | | | | | | | | | | | |
| 176 | Total Accumulated Depreciation Reserves | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 177 | **Transmission Plant Functionalization** | Balance - BOY | Balance - EOY | Balance - Average | | | | | | | | | | | | | | | | | | | | |
| 178 | 350-353 Transmission Stations | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |
| 1 | 352-353 Transmission Stations | | | | | | | | | | | | | | | | | | | | | | | |

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| 180 | 354-359.1 Other Transmission Plant | $ - | $ - | $ - |
| | **Transmission Depreciation** | | | |
| 181 | **Functionalization** | | | |
| 182 | 108.5 Accumulated Depreciation Reserves Transmission Stations | $ - | $ - | $ - |
| 183 | 108.5 Accumulated Depreciation Reserves Transmission Lines | $ - | $ - | |
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9 the changes will be
0 subject to the review

of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet K

**Mountrail-Williams Electric Cooperative**

**Wage Input & Functionalization Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Account | Account Description | Labor Amount | Overhead Amount | Actual | 560 Trans Ops Super & 566 Misc-Wage | 561 Load Dispatc | 562 Transtion | 563 OH Line Expens | 568 Maint-Supervision and Engineerin | 569-570 Str Maint-Wage | 571 Maint-OH Line | 573 Maint-Misc Tran Plan | 580-589 Dist Operatio | 590-598 Dist Maint | 901-905 Cust Act-Wage | 907-910 Cust Service-Wage | 911-916 Cust Sales-Wage | Admin & General |

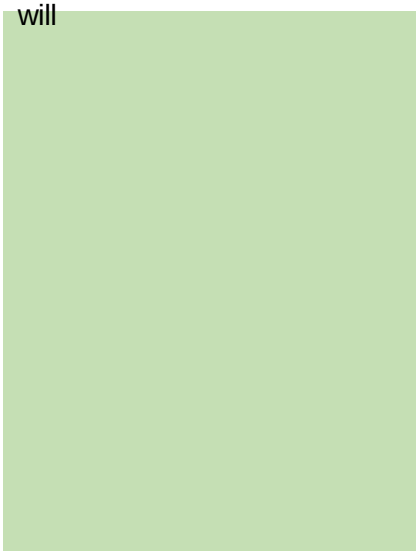
**nt on nt t l s h s e g s s t n nt s s s al**



| | | |
|---|---|---|
| 2 | | $ |
| 5 | | - |

| | | |

4 or 206 filings. MWEC
0 will



describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet L

**Mountrail-Williams Electric Cooperative**

**Annual Depreciation Expense Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line No** | | | **Year Account** | **Production** | **Transmission** | **Distribution** | **General Reti** | **Amort vere** | **Plant** | **Unreco** |
| | | 7 | | **Description** | | | | RETIREMENT | | |
| 1 | | | 403.40 | DEPRECIATION EXP / OTHER PRODUCT | | | | | | |
| 2 | | | 403.50 | DEPRECIATION OF TRANSMISSION PLA | | | | | | |
| 3 | | | 403.60 | DEPRECIATION OF DISTRIBUTION PLA | | | | | | |
| 4 | | | 403.70 | DEPRECIATION OF GENERAL PLANT | | | | | | |
| 5 | | | 405.00 | AMORTIZATION OF OTHER ELEC. PLAN | | | | | | |
| 6 | | | 407.00 | AMORTIZATION OF UNRECOVERED PLANT COSTS | | | | | | |
| | | | 411.10 | ACCRETION EXPENSE - PLANT | | | | | | |

| xp End ns Bala nce | E e e | rem ent | d Plan t E x p e n s e |
|---|---|---|---|
| $ - | | | |
| $ - | | | |
| | $ - | | |
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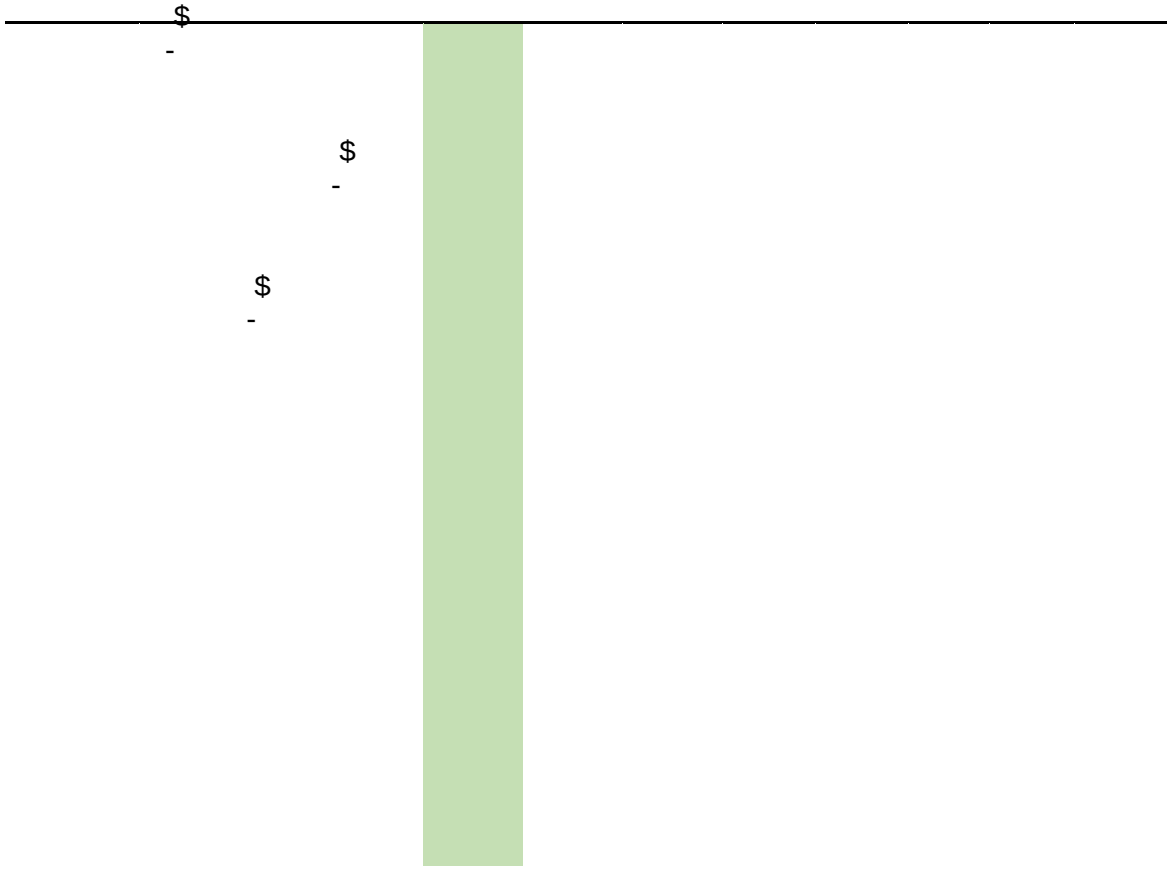
| | | $ - | |



| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Totals | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | | - | - | - | - | - | - | - | - |
| 9 | | | | | | | | | |

10 Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. MWEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet M

**Mountrail-Williams Electric Cooperative**

**Other Operating Revenue**
**Rate Year Ending December 31,**

| Line No. | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Account No | Account Description | Total Company | Electric Plant, Leased | Wheeling - SPP | Rents | Other Electric Revenue | Basin Facility Discount | Sch 7 & 8 P2p | Sch 11 P2p | Direct Assigned Revenues | Renewable Energy Credits |
| 1 | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | |
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| 14 | | | | | | | | | | | |
| 15 | | | | | | | | | | | |
| 16 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

17

18 Note:

A. The addition of new lines and the removal of outdated lines may be
19 necessary in order to accurately provide
information, and populate or remove data
20 in the Worksheet with changes in future years. Where appropriate, these
changes will provide detail and linkage to updated Form 7 data
21 requirements or other similar supporting
documentation. Additional line items or line deletions will not require
22 FPA Section 205 or 206 filings.
22 MWEC will describe such changes in the Annual
23 Update, and the changes will be subject to the review of Interested Parties under
the procedures set forth in MWEC's
24 Implementation Protocols. MWEC may not change the columns or the formulas
included in these
25 Worksheets during the Annual Update.

Worksheet N

# Mountrail-Williams Electric Cooperative

## Construction Work in Process Rate Year Ending December 31,

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Project ID | 3 | | | | Description | | Approver | Docket No. pro | Re co | Ap 1610-000 Settlement ER17-1610-000 |
| 1 | | | | | Project | | | | ER17- | Settlem 50 nt % | ve d |
| 2 | | | | | | | | al | | y | E |

| Pricing Zone | Approximate Construction Start Date | Close-out Date (Estimated) | BoY Balance | EoY Balance | Balance (Col I + Col J) / 2 Col | Incl $ - $ - | Rate Base ( E * K ) | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | $ $ | | | | |
| | | | | | - - | | | | |
| | | | | | $ $ | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 4 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 5 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 6 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 7 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 8 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 9 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 10 | Settlement ER17-1610-000 | 50 % | | $ - | $ - |
| 11 | Settlement ER17-1610-000 | 50 % | | | |
| 12 | Settlement ER17- | 50 % | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | | | 1610-000 | 50 % | | | | | | | | | |
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|---|---|---|---|---|---|---|---|---|
| | | Settlement ER17-1610-000 | | | | | | |
| 14 | | Settlement ER17-1610-000 | 50 % | | | | | |
| 15 | | Settlement ER17-1610-000 | 50 % | | | | | |
| 16 | | Settlement ER17-1610-000 | 50 % | | | | | |
| 17 | | Settlement | 50 % | | | | $ - | $ - |
| 18 | **Totals** | | | **$ -** | **$ -** | | **$ -** | **$ -** |

19 Notes:

A. Percentage recovery cannot be added or changed 20 absent approval from FERC.

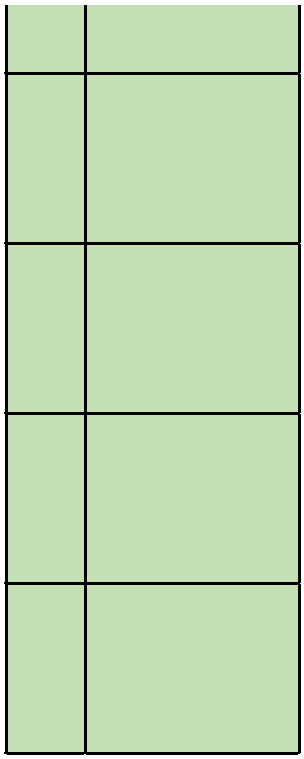
B. CWIP amounts should be directly assigned to pricing 21 zone on Summary.

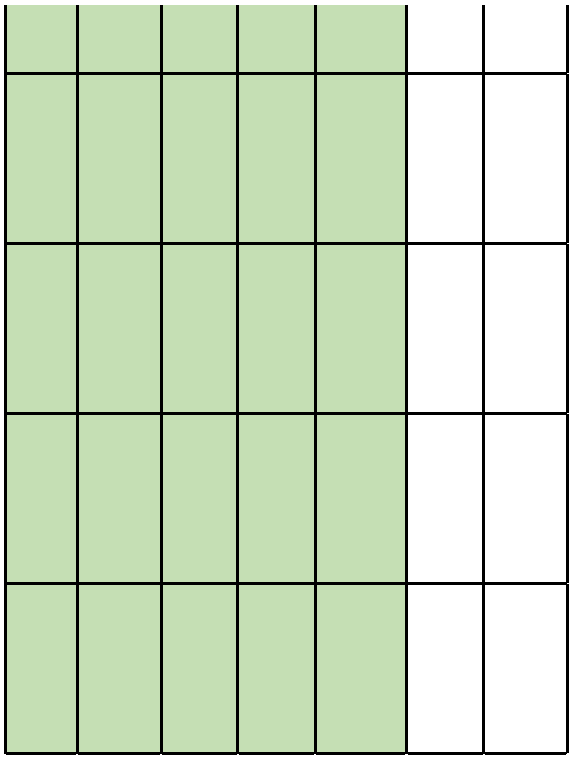
C. AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate 22 base absent FERC authorization.

Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery 23 of CWIP and corresponding AFUDC capitalized. Projects 24 are transmission related only.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and

25 populate or remove data in the Worksheet with





changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation.

Additional line items will not require FPA Section 205 or 206 filings. MWEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheet during the Annual Update.

Worksheet O

# Mountrail-Williams Electric Cooperative

## Construction Completed Not Classified Rate Year Ending December 31,

| A Line No | B Fac ID | C Work Order | D Project | E BoY Balance | F EoY Balance | G Facility | H % SPP Eligible | I BoY Amount | J EoY Amount | K Average | L Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | $ - | $ - | $ - | |
| 2 | | | | | | | | $ - | $ - | $ - | |
| 3 | | | | | | | | $ - | $ - | $ - | |
| 4 | | | | | | | | $ - | $ - | $ - | |
| 5 | | | | | | | | $ - | $ - | $ - | |
| 6 | | | | | | | | $ - | $ - | $ - | |
| 7 | | | | | | | | $ - | $ - | $ - | |
| 8 | | | | | | | | $ - | $ - | $ - | |
| 9 | | | | | | | | $ - | $ - | $ - | |

| | | | | |
|---|---|---|---|---|
| 1 | | $ | $ | $ |
| 0 | | - | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | $ | $ | $ |
| 1 | | | | | | - | - | - |
| 1 | | | $ | $ | | $ | $ | $ |
| 2 | | Total | - | - | | - | - | - |

Notes

1. A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.
2. with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting
3. documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA
4. Section 205 or 206 filings. MWEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures
5. set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Work sheet P

# Mountrail-Williams Electric Cooperative

## Plant Held for Future Use
## Rate Year Ending December 31,

| Line No | B Facility No. | C Asset No. | D Description | E BoY Investment | F EOY Investment | G Average Investment | H Qualified |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | Transmission Qualified Future Use Assets | | | | |
| 3 | | 105.000 | Land Held for Future Use | | | $ - | |
| 4 | | 105.000 | Land Held for Future Use | | | $ - | |
| 5 | | 105.000 | Land Held for Future Use | | | $ - | |
| | | | | | | $ - | |
| 6 | | | Total Plant Held for Future Use | $ - | $ - | $ - | $ - |

Notes

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.

with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. MWEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

Works
heet Q

**Mountrail-Williams Electric Cooperative**

**Regulatory and Commission Expenses**
**Rate Year Ending December 31,**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line No.** | **Account 928** | **Description** | **Total Company** | **Non-Qualifying SPP Expenses** | **SPP Expenses** |
| 1 | 928.00 | | | | |
| 2 | 928.10 | | | | |
| 3 | 928.20 | | | | |
| 4 | 928.21 | | | | |
| 5 | 928.31 | | | | |
| 6 | | Total | $ - | $ - | $ - |

8 Note:
A. The addition of new lines and the removal of outdated lines
9 may be necessary in order to accurately provide
information, and populate or remove data in the Worksheet with 10
changes in future years. Where appropriate, these
changes will provide detail and linkage to updated Form 7
11 data requirements or other similar supporting
documentation. Additional line items or line deletions will not require
12 FPA Section 205 or 206 filings. MWEC will
describe such changes in the Annual Update, and the changes will be
13 subject to the review of Interested Parties under
the procedures set forth in MWEC's Implementation Protocols.
14 MWEC may not change the columns or the formulas
included in these Worksheets

15 during the Annual Update.

Work shee t R

# Mountrail-Williams Electric Cooperative

**Account 575/576 Expenses**
**Rate Year Ending December 31,**

| A<br>Line | B<br>Account No. | C<br>Description | D<br>Annual Expense Amount | E<br>% Included in SPP | F<br>SPP Amount |
|---|---|---|---|---|---|
| | **575.1-575.8 RTO/ISO Expense - Operation** | | | | |
| 1a<br>1b<br>… | | | | | |
| 2 | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)** | | | | |
| | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | | |
| 3a<br>3b<br>… | | | | | |
| 4 | **576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)** | | | | |

5 Notes
A. The total on line 2, column D must reconcile to the amounts shown on Form 7.
6

B. The total on line 4, column D must reconcile to the amounts shown on Form 7 7.

$0.00

$0.00

$0.00

$0.00

$0.00

$0.00

$0.00

$0.00

$0.00

$0.00





C. Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for inclusion in SPP Zone 19 ATRR following a change in accounting procedures to the Form 7 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that this occurs, MWEC may file a single-issue Section 205 filing with the Commission to seek recovery of these amounts in Zone 19 rates. MWEC may not include any costs absent authroization from FERC via a Section 205 or 206 filing.

D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Work sheet S

**Mountrail-Williams Electric Cooperative**
**Calculation of Interest Applied to True-Up Calculations**
**Rate Year Ending December 31,**

| | Calculation | | Annual Amount | Quarterly Amount |
|---|---|---|---|---|
| 1 | | | | |
| 2 | ATRR Actual | | | |
| 3 | ATRR Estimated | | | |
| 4 | Difference | | $ - | $ - |

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| | Period Start | Period Ending | Year description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance | True-Up Adjustment |
| 5 | | | | | | | | | |
| 6 | | | Rate Year | | $ - | | $ - | $ - | |
| 7 | | | Rate Year | $ - | $ - | | $ - | $ - | |
| 8 | | | Rate Year | $ - | $ - | | $ - | $ - | |
| 9 | | | Rate Year | $ - | $ - | | $ - | $ - | |
| 10 | | | | $ - | | | $ - | $ - | |
| 11 | | | | $ - | | | $ - | $ - | |

12 - - -

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 13 | | | $ - | | | $ - | $ - | |
| 14 | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 15 | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 16 | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 17 | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 18 | **True-up Adjustment** | | | | | | | $ - |

Notes:

19 A. Rate Year in which the error occurred and
20 affected the ATRR and rates paid by customers.
B. Each ATRR adjustment shall include interest based on
21 Section 35.19a of the Commission Regulations.
C. The interest calculation may need to be modified
22 to recognize the implementation partial year.

Worksheet T

# Mountrail-Williams Electric Cooperative

## Customer Accounting Input Rate Year Ending December 31,

| A | B | C | D | E |
|---|---|---|---|---|
| Line No | Account 901-905 | Description | Total Company | 901-905 SPP Expenses |
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | Total Customer Accounting | $ - | $ - |

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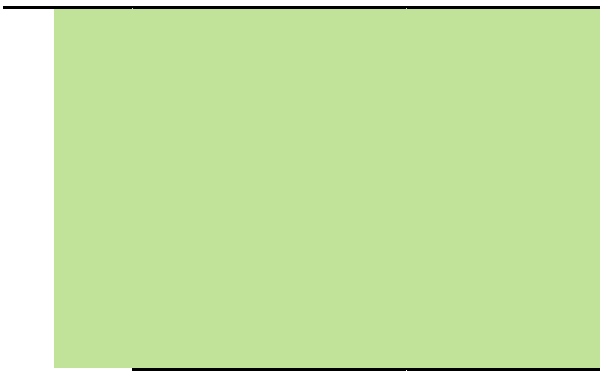

1 Not
2 es
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FPA Section 205 or 206 filings. MWEC will describe such changes in
1 the Annual Update, and the changes will be subject to the review of
6 Interested Parties under the
procedures set forth in MWEC's Implementation Protocols. MWEC may
1 not change the columns or the formulas included in these Worksheets
7 during the Annual Update.

Works
heet U

**Mountrail-Williams Electric Cooperative**

**Account 556 System Control & Load Dispatching**
**Rate Year Ending December 31,**

| | A | B | C |
|---|---|---|---|
| Line No. | Month | | Total Company Expenses |
| 1 | January | | |
| 2 | February | | |
| 3 | March | | |
| 4 | April | | |
| 5 | May | | |
| 6 | June | | |
| 7 | July | | |
| 8 | August | | |
| 9 | September | | |
| 10 | October | | |
| 11 | November | | |
| 12 | December | | |
| 13 | Total | | $ - |
| 14 | Note | | |
| 15 | A. Source: Upper Missouri Power Cooperative Metering & Load Monitoring Shared Cost Allocations Report. | | |

Work sheet V

**Mountrail-Williams Electric Cooperative**
**Qualified Transmission Substations**
**Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line No | Description | Year in service | BOY Qualified Gross Plant | BOY Qualified Accum Depreciation | BOY Qualified Net Plant | EOY Qualified Gross Plant | EOY Qualified Accum. Depreciation | EOY Qualified Net Plant | Qualified Depr. Exp. |
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
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| 18 | | | | | | | | | |
| 19 | | | | | | | | | |
| 20 | Total | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

21

22 Note:

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Worksheet W

**Mountrail-Williams Electric Cooperative**

**Qualified Transmission Lines Rate Year Ending December 31,**

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Account Minor (355.xx or 356.xx) | Line Length (Miles) | Year in service | BOY Qualified Gross Plant | BOY Qualified Accum Depr | BOY Qualified Net Plant | EOY Qualified Gross Plant | EOY Qualified Accum Depr | EOY Qualified Net Plant | Qualified Annual DepR |
| 1 | | | | | | | | | | | |
| 2 | | | | | | | | | | | |
| 3 | | | | | | | | | | | |
| 4 | | | | | | | | | | | |
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| 46 | Total | | 0.00 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 47 | | | | | | | | | | | |
| 48 | Note: | | | | | | | | | | |
| 49 | A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. | | | | | | | | | | |
| 50 | Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section | | | | | | | | | | |
| 51 | other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. MWEC will describe such changes in the Annual Update, and the changes will be | | | | | | | | | | |
| 52 | subject to the review of Interested Parties under the procedures set forth in MWEC's Implementation Protocols. MWEC may not change the columns or the formulas included in these Worksheets during Annual Update. | | | | | | | | | | |

# Mountrail-Williams Electric Cooperative
# Transmission Formula Rate Implementation Protocols

The formula rate template ("Formula Rate Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Mountrail-Williams Electric Cooperative ("Mountrail-Williams") for transmission revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("Tariff"). Mountrail-Williams shall follow annually the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement ("ATRR"). Recovery of costs associated with existing facilities and new facilities shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the Tariff.

The initial ATRR will be in effect for a partial year from the effective date of transfer of functional control of Mountrail-Williams's transmission facilities to SPP through December 31, 2017. The Formula Rate shall be recalculated each year with the resulting rates to become effective on and after January 1 of each year through December 31 of such year ("Rate Year"). The resulting rates implemented each January 1 will be subject to review and true-up as further provided in the Protocols. The Formula Rate shall become effective for recovery of MountrailWilliam's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC") under Section 205 of the Federal Power Act ("FPA").

## Section I Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

A. "Accounting Change" means any change in Mountrail-Williams's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

   1. Revisions to Rural Utilities Service's ("RUS") Uniform System of Accounts ("USoA");

   2. Revisions to the National Rural Utilities Cooperative Finance Corporation ("CFC") Form No. 7 data and the requirement to report certain values within it;

3. correction of errors and prior period adjustments that impact the ATRR;

4. the implementation of new estimation methods or policies;

5. changes to income tax elections;

6. changes in accounting practices or policies mandated by a state regulatory authority with jurisdiction over Mountrail-Williams that could impact the Formula Rate or calculations under the Formula;

7. implementation of accounting practices for unusual or unconventional items where the RUS has not provided specific accounting direction;

8. a change in Mountrail-Williams's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor);

9. Mountrail-Williams's own accounting changes (which constitute a change to the ATRR greater than or equal to $15,000) such as the addition or deletion of a subaccount not specified by the RUS's USoA; or

10. a change in Mountrail-Williams's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

B. "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by Mountrail-Williams for informational purposes with FERC and posted on the SPP OASIS on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

C. "Annual Meeting" means the meeting hosted by Mountrail-Williams for the purpose of exchanging information with Interested Parties regarding the formula rate.

D. "Annual Update" means Mountrail-Williams's annual posting of its Formula Rate, in a working Excel™ format.

E. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

F. "Calendar Year" means January 1 through December 31 of a given year.

G. "CFC" means National Rural Utilities Cooperative Finance Corporation.

H. "CFC Form" means the independently-audited CFC Form No.7 prepared by Mountrail-Williams's accounting staff.

I. "Current Calendar Year" means the Calendar Year in which the Annual Update is posted

(e.g., if the Annual Update is posted on July 1, 2018, the Current Calendar Year is 2018).

J. "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and which Mountrail-Williams has filed with FERC (e.g., if the Annual Update is posted on July 1, 2018 and the Informational Filing is submitted to FERC on December 15, 2018 , the Current Rate Year is January 1, 2019 through December 31, 2019).

K. "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS service, service under Grandfathered Agreements, or PTP service.

L. "FERC" or "Commission" means the Federal Energy Regulatory Commission.

M. "Final Posting" means the annual update information posted to the SPP OASIS with changes agreed to during the informal review process.

N. "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with FERC, and served on Mountrail-Williams by electronic service on the date of such filing.

O. "Formula Rate Template" means the Mountrail-Williams transmission formula rate template set forth herein.

P. "Formula" means the Formula Rate Template set forth in Addendum 37 to Attachment H of the SPP Tariff.

Q. "Formula Rate" means the Mountrail-Williams Implementation Protocols together with the Formula Rate Template.

R. "FPA" means Federal Power Act.

S. "Informal Challenge" means written notification by an Interested Party to Mountrail-Williams, during the Review Period, of any specific challenge to the Annual Update.

T. "Information Request" means a written request submitted by an Interested Party to Mountrail-Williams.

U. "Informational Filing" means Mountrail-Williams's annual filing at FERC with the information stipulated in these Protocols.

V. "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a) (2) (iii), or any successor regulation.

W. "Interested Party" includes but is not limited to, customers under the SPP Tariff, state

utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

X. "Information Request Period" means a period of ninety (90) calendar days after each annual Publication Date (unless such period is extended with the written agreement of Mountrail-Williams) during which Interested Parties may serve reasonable information requests on Mountrail-Williams.

Y. "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

Z. "OASIS" means SPP's Open Access Same-Time Information System.

AA. "OATT" or "SPP Tariff" means SPP's Open Access Transmission Tariff.

BB. "Prior Calendar Year" means the year preceding the Current Calendar Year (*e.g.*, if the Annual Update is posted on July 1, 2018 and the Informational Filing is submitted on December 15, 2018, the Prior Calendar Year is 2017).

CC. "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is January 1, 2018 through December 31, 2018, then the Prior Rate Year is January 1, 2017 through December 31, 2017).

DD. "PTP Rates" means the point-to-point rates derived from the Formula Rate.

EE. "Publication Date" means the date on which Mountrail-Williams posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2017 shall be no later than July 1, provided, however, that if July 1 should fall on a weekend or a holiday recognized by FERC, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

FF. "Rate Year" means January 1 of a given Calendar Year through December 31 of the same Calendar Year.

GG. "Review Period" means, unless otherwise extended in writing by Mountrail-Williams, one-hundred and twenty (120) calendar days after the Publication Date.

HH. "RUS" means Rural Utilities Service.

II. "SPP" means Southwest Power Pool, Inc. or its successor organization.

JJ. "SPP Tariff" or "OATT" means SPP's Open Access Transmission Tariff.

KK. "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity ("ROE"); (ii) Depreciation and amortization rates; and (iii) and other similar fixed values. Stated Values may be changed only pursuant to FPA Section 205 or 206.

LL. "True-up Adjustment" means the calculated difference between the projected and actual ATRR for a Rate Year.

MM. "USoA" means RUS Uniform System of Accounts.

## Section II Annual Update

A. On or before July 1 of each calendar year, Mountrail-Williams shall:

1. Calculate the projected ATRR for the following Rate Year in accordance with the Formula Rate and using the Formula Rate Template;

2. Calculate the True-up Adjustment for the preceding Rate Year as described and defined in Section III below, if applicable, beginning in 2018;

3. Sum the projected ATRR for the following Rate Year and the True-up Adjustment for the Prior Rate Year, including interest, as explained in Section III below.

4. Provide its Annual Update to SPP and cause such information to be accessible on SPP's OASIS; and

5. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next Business Day. The date on which such posting occurs shall be that year's Publication Date. Any delay in Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

B. Concurrent with the Annual Update postings, Mountrail-Williams shall provide a notice concerning that posting to SPP to serve electronically upon the Service List.[1]

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[1] As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP OASIS. As of January 2016, the Exploder List was titled "Formula Rate Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/.

C. The Annual Update shall:

1. Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

2. Be based on the independently-audited books and records of Mountrail-Williams for the most recent fiscal year including its CFC Form No. 7 or successor reports;

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

4. Identify any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, including:

   a. Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

   b. Any items included in the Formula Rate at an amount other than a historic cost basis.

   c. Individual impact of any Accounting Changes in Section II.C.4.a above on charges billed under the Formula Rate.

   d. Any Accounting Changes related to a reorganization or merger transaction;

5. Not seek to modify the Formula Rate; and

6. With each Annual Update, Mountrail-Williams will include a list of any new transmission facilities included in the Formula Rate Template that were not included in the prior Annual Update. New transmission facilities include but are not limited to additional substations, breakers, other major substation equipment, and additional transmission line miles. The list will indicate the Zone 19 Attachment AI Guidance Document criteria that Mountrail-Williams believes supports each facility's inclusion in Mountrail-Williams's annual transmission revenue requirement as well as the beginning-of-year and end-of-year balances

associated with that facility. This provision in no way limits the rights of any party to challenge inclusion of new facilities.

## Section III Annual True-Up Adjustment

A. Mountrail-Williams will calculate the amount of under- or over-collection of its actual ATRR during the preceding Rate Year ("True-up Adjustment"). The True-up Adjustment shall be the sum of components 1 and 2, determined in the following manner:

1. *Difference between the projected ATRR and the actual ATRR*: Mountrail-Williams's actual revenues collected during the previous Rate Year[2] will be compared to Mountrail-Williams's actual ATRR for the previous Rate Year calculated in accordance with Mountrail-Williams's Formula Rate and based upon (i) Mountrail-Williams's CFC Form No. 7 for that same Rate Year, (ii) any Commission orders specifically applicable to Mountrail-Williams's calculation of its ATRR, (iii) the books and records of Mountrail-Williams (which shall be maintained consistent with the USoA), (iv) RUS accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the Tariff or SPP Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates,[3] to determine any over- or under-recovery ("True-up Adjustment"). Mountrail-Williams will include a variance analysis of, at minimum, actual revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected ATRR that was calculated for the previous Rate Year with an explanation of material changes; and

2. *Interest*: Interest on any over-or under-recovery shall be calculated in accordance with 18 C.F.R. § 35.19a, and shall be accrued from the date on which the over- or under-recovery occurs to the date on which the refunds or surcharges are applied;

B. Mountrail-Williams will reflect the True-up Adjustment as a line item in its Formula Rate Template included with the Annual Update.

C. An affidavit from the Manager of Finance and Accounting of Mountrail-Williams (or a similar successor position, if applicable) attesting to the accuracy of the cost and revenue data will also be provided.

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[2] Because the initial year of this rate schedule is a partial year, the actual revenues collected and the Net Revenue Requirement will be converted to monthly amounts. The difference between the monthly actual revenues collected and the monthly Net Revenue Requirement will be multiplied by the number of months the Formula Rate was in effect to calculate the True-up Adjustment.

[3] SPP Governing Documents include the Tariff, Bylaws, Criteria, and Membership Agreements.

## Section IV Review of Annual Update

Within twenty (20) calendar days of the Publication Date of Mountrail-Williams's Annual Update and with at least ten (10) calendar days' notice, Mountrail-Williams will host a meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). Mountrail-Williams shall provide notice of this meeting concurrent with the posting of the Formula Rate Update accessible on SPP's OASIS. The notice shall include the date, time and location of the Annual Meeting and also shall be provided to Interested Parties via the Service List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the OASIS.

A. Information Exchange

1. Interested Parties may begin submitting information requests immediately following the Publication Date of the Annual Rate Update and will have until ninety (90) calendar days after the date of the Publication Date to serve reasonable information requests on Mountrail-Williams for information and work papers supporting the Annual Rate Update. Such information requests shall be limited to those that are necessary to determine:

    a. The extent or effect of an accounting change;

    b. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

    c. The proper application of the Formula Rate and procedures in these Protocols;

    d. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

    e. The effect of any change to the underlying USoA or Formula Rate Template; or

    f. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The Information Requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. Mountrail-Williams will not claim that responses to information and document request pursuant to the Protocols are subject to any settlement confidentiality provision however, Mountrail-Williams may require that Interested Parties execute a non-disclosure agreement to obtain access to material that Mountrail-Williams deems commercially

sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 C.F.R. § 388.113(c)(1).

2. Mountrail-Williams shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) Business Days of receipt.

3. Mountrail-Williams shall request that SPP post on a publicly accessible portion of the SPP OASIS all information requests from Interested Parties and Mountrail-Williams' response(s) to such requests. If responses to information requests contain information deemed by Mountrail-Williams to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Mountrail-Williams.

4. If the deadline for Interested Parties to submit Information Requests falls on a weekend or holiday recognized by FERC, the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until November 1 (or the first Business Day after November 1 if November 1 falls on a weekend or holiday recognized by FERC) to notify Mountrail-Williams in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. Mountrail-Williams will make a good faith effort to respond to any Informal Challenge within twenty (20) calendar days of notification of such Informal Challenge. Mountrail-Williams, and if appropriate SPP, shall appoint representatives to work with the Interested Party to resolve the Informal Challenge.

2. Mountrail-Williams will request that SPP post on a publicly accessible portion of the SPP OASIS all Informal Challenges from Interested Parties and Mountrail-Williams's responses to the Informal Challenges. If responses to Informal Challenges contain information deemed by Mountrail-Williams to be confidential, such information will not be publicly posted but will be made available to Interested Parties pursuant to a confidentiality agreement executed by the requesting Interested Party and Mountrail-Williams.

3. Mountrail-Williams will request that SPP post on the SPP OASIS, the final True-up Adjustment no later than November 30 of each year.

4. Any changes or adjustments to the Annual Update resulting from the Information

Exchange and Informal Challenge procedures that are agreed to by Mountrail-Williams and resolved prior to the end of the Review Period shall be reported in the Final Posting. Any changes or adjustments agreed to by Mountrail-Williams after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Rate Update for the following Rate Year.

C. Formal Challenges

1. Interested Parties shall have until January 15 (or the first Business Day after January 15 if January 15 falls on a weekend or holiday recognized by FERC) to file a Formal Challenge. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues. Regardless of whether an Interested Party pursues or fails to pursue Informal or Formal Challenges, an Interested Party may file a complaint under section 206 of the Federal Power Act at any time.

2. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

b. Explain how the action or inaction violates the filed Formula Rate or Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. Any other information that may reasonably have a substantive

effect on the calculation of the charges pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

3. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the FPA, and shall be served upon Mountrail-Williams contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in Mountrail-Williams's Informational Filing.

4. Mountrail-Williams will provide a response to the Formal Challenge within thirty (30) calendar days.

5. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Mountrail-Williams shall bear the burden, consistent with section 205 of the FPA, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols in that year's Annual Update. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

Modifications to the Formula Rate may be made only pursuant to Federal Power Act section 205 or section 206.

2. A change to the Formula Rate's fixed inputs related to ROE, depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA Sections 205 or 206, provided, however, that Mountrail-Williams may make a limited Section 205 filing to change depreciation rates, amortization periods, Post-Employment Benefits other than Pensions recovery, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed changes(s) are just and reasonable, and not unduly discriminatory.

3. If Mountrail-Williams makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the SPP Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the SPP Tariff.

E. FERC Informational Filing

1. By December 15 of each year, Mountrail-Williams shall submit to FERC an informational filing ("Informational Filing") of its Annual Update.

2. This Informational Filing must include the information that is reasonably necessary to determine:

a. That input data under the Formula Rate is properly recorded in any underlying work papers;

b. That Mountrail-Williams has properly applied the Formula Rate and these procedures;

c. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

d. The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its

inputs that are subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Mountrail-Williams shall request that SPP provide notice of the Informational Filing to Interested Parties via the Service List and by posting the docket number assigned to the Informational filing on SPP's OASIS.

## Section V Joint SPP Transmission Owners' Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, Mountrail-Williams intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to Interested Parties via the Service List maintained by SPP no less than seven (7) calendar days prior to such meetings.

## Section VI Mountrail-Williams Example Schedule (Nominal Last Dates)

| Action | Date |
|---|---|
| Rate Year | January 1 - December 31 |
| Publication Date | July 1 |
| Annual Meeting of Interested Parties | July 11 - July 24 |
| Information Request Due Date | October 1 |
| Informal Challenges Due Date | November 1 |
| Final Posting | November 30 |
| Informational Filing | December 15 |
| Formal Challenge Due Date | January 15 |

**ADDENDUM 45 TO ATTACHMENT H**

**Mor-Gran-Sou Electric Cooperative, Inc.**

## Mor-Gran-Sou Electric Cooperative, Inc

Index

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| **Line No.** | **Worksheet** | **Description** |
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| 3 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 4 | Worksheet C | Capital Structure & Rate of Return based on Return on Equity |
| 5 | Worksheet D | Network Demand |
| 6 | Worksheet E | Allocation Factors |
| 7 | Worksheet F | General Input Section |
| 8 | Worksheet G | Depreciation Rates |
| 9 | Worksheet H | Other Operating Revenue (A454-456) |
| 10 | Worksheet I | O&M Input (A560-598) |
| 11 | Worksheet J | Wage Input & Functionalization |
| 12 | Worksheet K | Annual Depreciation Expense (A403) |
| 13 | Worksheet L | RTO / ISO Expenses (A575-576) |
| 14 | Worksheet M | Regulatory and Commission Expenses (A928) |
| 15 | Worksheet N | Customer Accounting Input (A901-905) |
| 16 | Worksheet O | Plant Input (A350-358), Accum Depr (A108), Amortization (A111) |
| 17 | Worksheet P | Plant Held for Future Use (A105) |

| | | |
|---|---|---|
| 18 | Worksheet Q | Construction Completed Not Classified (A106) |
| 19 | Worksheet R | Construction Work in Process (A107) |
| 20 | Worksheet S | SPP Upgrades |
| 21 | Worksheet T | Calculation of Interest Applied to True-Up Calculations |
| 22 | Worksheet U | Qualified Transmission Substations |
| 23 | Worksheet V | Qualified Transmission Lines |

24 Notes:
25 A. Green Shading denotes input values.
B. If not already provided for in automatic updates of the cell text references and line references
26 describing the
27 source of the values should be updated accordingly.

**Mor-Gran-Sou Electric Cooperative, Inc**

Summary ATRR

## Summary of Total ATRR Revenue Requirement

| A | B | C | D | | E | F | G | H |
|---|---|---|---|---|---|---|---|---|
| Line No. | Account Number | Description | Reference | | Total Company | Allocation Factor | Allocation % | Transmission ATRR |
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 36, Column H | | | | | #DIV/0! |
| 3 | | Revenue Credits- Operating | | | | | | |
| 4 | 412 | Electric Plant, Leased | Worksheet H, Line 16, Column F | $ | - | Direct 100 | 100.0 % | $ - |
| 5 | 450-451 | Retail Related | Worksheet H, Line 17, Column G | $ | - | Direct Zero | 0.0% | $ - |
| 6 | 456 | Wheeling- SPP P2P | Worksheet H, Line | $ | - | Direct Zero | 0.0% | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 7 | 454 | Rents | 16 Column H Worksheet H, Line 16 Column I | $ | - | Direct 100 | 100.0% | $ - |
| 8 | 456 | Other Electric Revenue | Worksheet H, Line 16 Column J | $ | - | Direct 100 | 100.0% | $ - |
| 9 | 456 | Basin Facility Discount | Worksheet H, Line 16 Column K | $ | - | Direct Zero | 0.0% | $ - |
| 10 | 456 | Sch 7 & 8 P2P | Worksheet H, Line 16 Column L | $ | - | Direct 100 | 100.0% | $ - |
| 11 | 456 | Direct Assigned Revenues | Worksheet H, Line 16 Column N | $ | - | Direct 100 | 100.0% | $ - |
| 12 | 459 | Renewable Energy Credits | Worksheet H, Line 16 Column O | $ | - | Direct Zero | 0.0% | $ - |
| 13 | | Revenue Credits-Operating | Subtotal | $ | - | | | $ - |
| 14 | | Revenue Requirement before SPP Adj and Prior Yr | Line 2 - Line 13 | | | | | #DIV/0! |

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|---|---|---|---|---|
| | | corrections | | |
| 15 | | True-Up Adjustment ATRR - | Worksheet T, Line 6, Column L | $ - |
| 16 | | True-Up Adjustment SPP Upgrades - | Worksheet T, Line 12, Column L | $ - |
| 17 | | SPP Upgrades - | Worksheet S, Line 28, Column P | $ - |
| 18 | 456 | Sch 11 P2P Revenue Credits | Worksheet H, Line 16 Column M | $ - |
| 19 | | Sum | Sum Lines 14 thru 18 | #DIV/0! |
| 20 | | Network Transmission Load (MW) | Worksheet D, Line 14, Column C | - |
| 21 | | **B. Point-** | | |

| | | | |
|---|---|---|---|
| | **To-Point Service** | | |
| 22 | Annual Point-to-Point Cost ($/MW-Yr) | Line 19 / Line 20 | #DIV/0! |
| 23 | Monthly Point-to-Point ($/MW-Mo) | Line 22 / 12 | #DIV/0! |
| 24 | Weekly Point-to-Point ($/MW-Week) | Line 22 / 52 | #DIV/0! |
| 25 | Daily On-Peak Point-to-Point ($/MW-Day) | Line 22 / 260 | #DIV/0! |
| 26 | Daily Off-Peak Point-to-Point ($/MW-Day) | Line 22 / 365 | #DIV/0! |
| 27 | Hourly On-Peak Point-to-Point ($/MWh) | Line 22 / 4160 | #DIV/0! |
| 28 | Hourly Off-Peak Point-to-Point ($/MWh) | Line 22 / 8760 | #DIV/0! |

## Mor-Gran-Sou Electric Cooperative, Inc

Work sheet A

## Calculation of Rate Base

| A<br>Line No. | B<br>Account Number | C<br>Description | D<br>Reference | E<br>Beginning of Year | F<br>End of Year | G<br>Total Company | H<br>Allocation Factor | I<br>ATRR Allocation % | J<br>Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Plant in Service** | | | | | | | |
| 2 | 301 - 303 | Intangible Plant | Worksheet F, Line 43, Columns E and F | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! |
| 3 | 310 - 340 | Production Plant | N/A | | | $ - | Direct Zero | 0.0% | $ - |
| 4 | 350 | Land and Land Rights | Worksheet O, Line 24, Columns F and G | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 5 | 352 | Structures and Improvements | Worksheet O, Line 24, Columns H and I | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 6 | 353 | Station Equipment - SCADA | Worksheet O, Line 24, Columns J and K | $ - | $ - | $ - | Direct 100 | 100.0% | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 7 | 353 | Station Equipment | Worksheet O, Line 24, Columns L and M | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 8 | 354 - 359 | Other Transmission Plant | Line 9 Less Lines 4 thru 7 | $ - | $ - | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 9 | | Transmission Plant | Worksheet F, Line 44, Columns D and E | $ - | $ - | $ - | | | #DIV/0! |
| 10 | 360 .00 | Land and Land Rights | Worksheet O, Line 24, Columns P and Q | $ - | $ - | $ - | T-Distb Plant | #DIV/0! | #DIV/0! |
| 11 | 361 .00 | Structures and Improvements | Worksheet O, Line 24, Columns R and S | $ - | $ - | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |
| 12 | 362 .00 | Station Equipment | Worksheet O, Line 24, Columns T and U | $ - | $ - | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |
| 13 | 364 - 373 | Other Distribution Plant | Line 14 Less Lines 10 thru 12 | $ - | $ - | $ - | Direct Zero | 0.0% | $ - |
| 14 | | Distribution Plant | Worksheet F, Line 40, Columns D and E | $ - | $ - | $ - | | | #DIV/0! |
| 15 | 389 - 399 .1 | General Plant Subtotal | Worksheet F, Line 41, Columns D and E | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! |
| 16 | 389 - | Headquarters Plant | Worksheet F, Line 42, Columns D and E | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 390 | | | | | | | | |
| 17 | | Gross Electric Plant in Service | Subtotal | $ - | $ - | $ - | | | #DIV/0! |
| 18 | 105 | Electric Plant Held For Future Use | Worksheet P, Line 7, Columns E, F and H | $ - | $ - | $ - | Direct | | $ - |
| 19 | 106 | Completed Construction Not Classified | Worksheet Q, Line 12, Columns E, F, and K | $ - | $ - | $ - | Direct | | $ - |
| 20 | 107 | Construction Work in Progress | Worksheet F, Line 47, Columns D and E and Worksheet R, Line 18, Column K | $ - | $ - | $ - | Direct | | $ - |
| 21 | | Utility Plant | Sum | $ - | $ - | $ - | | | #DIV/0! |
| 22 | | **Accumulated Depreciation** | | | | | | | |
| 23 | 108.4 | Depr Rsv of Other Prod Plant | Worksheet O, Line 66, Columns X and Y | $ - | $ - | $ - | Direct Zero | 0.0% | $ - |
| 24 | 108.5 | Accumulated Depreciation of Transmission Stations | Worksheet O, Line 75, Columns D and E | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 25 | 108.5 | Accumulated Depreciation of Transmission SCADA | Worksheet O, Line 76, Columns D and E | $ - | $ - | $ - | Direct 100 | 100.0% | $ - |
| 26 | 108.5 | Accumulated Depreciation of Transmission Lines | Worksheet O, Line 77, Columns D and E | $ - | $ - | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 27 | 108 | Accumulated Depreciation of | Worksheet O, Line 79, Columns D and | $ - | $ - | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | .6 | Distribution Stations | E | | | | | | | |
| 28 | 108 | Accumulated Depreciation of Distribution Plant | Worksheet O, Line 80, Columns D and E | $ - | $ - | $ - | Direct Zero | | $ - | |
| 29 | 108 .6 | Accumulated Depreciation of Other | Worksheet O, Line 66, Columns Z and AA | $ - | $ - | $ - | T-Wage | 0.0% #DIV/0! | #DIV/0! | |
| 30 | 108 .7 | General Plant Retirement Work in Progress | Worksheet O, Line 66, Columns AB and AC | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | |
| 31 | 111 | Amort of Electric Plant in Service | Worksheet O, Line 66, Columns AD and AG | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | |
| 32 | | Total Accumulated Depreciation | Sum | $ - | $ - | $ - | | | #DIV/0! | |
| 33 | | **Total Net Plant in Service** | | | | | | | | |
| 34 | | Net Intangible Plant | Line 2 | $ - | $ - | $ - | | | #DIV/0! | |
| 35 | | Net Production Plant | Line 3 - Line 23 | $ - | $ - | $ - | | | $ - | |
| 36 | | Net Transmission Plant | Line 9 - Line 24 thru 26 | $ - | $ - | $ - | | | #DIV/0! | |
| 37 | | Net Distribution Plant | Line 14 - Line 27 thru 28 | $ - | $ - | $ - | | | #DIV/0! | |
| 38 | | Net General Plant | Line 15 + Line 16 - Line 29 | $ - | $ - | $ - | | | #DIV/0! | |
| 39 | | Net Completed Construction Not Classified | Line 19 | $ - | $ - | $ - | | | $ - | |
| 40 | | Retirement work in progress | - Line 30 | $ - | $ - | $ - | | | #DIV/0! | |
| 41 | | Total Net Plant in Service | Sum | $ - | $ - | $ - | | | #DIV/0! | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 42 | | **Adjustments to Rate Base** | | | | | | | | | |
| 43 | | Plant Held for Future Use | Line 18 | $ - | $ - | $ - | | | | $ - | |
| 44 | | Construction Work in Progress | Line 20 | $ - | $ - | $ - | | Direct | | $ - | |
| 45 | | Working Capital | | | | | | | | | |
| 46 | | Total Transmission O&M Costs | Worksheet B, Line 24, Columns E and H | | | $ - | | | | #DIV/0! | |
| 47 | | Billing Lag in Days | Worksheet F, Line 1 Col F | | | | 45 | | | 45 | |
| 48 | | Working Capital | Line 46 * Line 47 / 365 | | | $ - | | | | #DIV/0! | |
| 49 | 165 | Prepayments | Worksheet F, Line 35, Columns D and E | $ - | $ - | $ - | | T-Plant | #DIV/0! | #DIV/0! | |
| 49 | | Materials and Supplies | Worksheet F, Line 34, Columns D and E | - | - | $ - | | T-Plant | #DIV/0! | #DIV/0! | |
| 50 | | Rate Base | Total | | | $ - | | | | #DIV/0! | |

## Mor-Gran-Sou Electric Cooperative, Inc

Worksheet B

## O&M, Depreciation, and Return Expenses

| A Line No. | B Account Number | C Description | D Reference | E Total Company | F Allocation Factor | G Allocation % | H Transmission |
|---|---|---|---|---|---|---|---|
| 1 | | **Transmission Expenses** | | | | | |
| 2 | 561 | Load Dispatch Expense | Worksheet I, Line 108 column F | $ - | Direct Zero | 0.0% | $ - |
| 3 | 562 | Transmission Station Expenses | Worksheet I, Line 108 columns G, N, and O | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 4 | 563-564, 571-572 | Transmission Line Expenses | Worksheet I, Line 108 columns H, I, P, and Q | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 5 | 565 | Transmission of Electricity by Others | Worksheet I, Line 108 column J | $ - | Direct Zero | 0.0% | $ - |
| 6 | 560, 566-567 | Super, Misc & Rents Transmission Expenses | Worksheet I, Line 108 columns E, K, L, M, and R | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 7 | 575-576 | Regional Market Expenses | Worksheet I, Line 108 columns S and T | $ - | Direct | | $ - |
| 8 | | Transmission O&M | Subtotal | $ - | | | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 9 | 582 | Distribution Expense - Stations Operations | Worksheet I, Line 108 Column U | $ - | | T-Distb Stations | #DIV/0! | #DIV/0! |
| 10 | 580-589 | Distribution Expense - Operations All Other | Worksheet F, Line 17, Column E Less Line 9 | $ - | | Direct Zero | 0.0% | $ - |
| 11 | 591-592 | Distribution Expense - Stations Maintenance | Worksheet I, Line 108 Column W | $ - | | T-Distb Stations | #DIV/0! | #DIV/0! |
| 12 | 590-598 | Distribution Expense - Maintenance All Other | Worksheet F, Line 18, Column E Less Line 11 | $ - | | Direct Zero | 0.0% | $ - |
| 13 | | Distribution O&M | Subtotal | $ - | | | | #DIV/0! |
| 14 | 901-905 | Customer Accounting | Worksheet F, Line 19, Column E - Line 15 | | $ - | Direct Zero | 0.0% | $ - |
| 15 | 901-905 | Customer Accounting SPP Expenses | Worksheet N, Line 22, Column E | | $ - | Direct | | $ - |
| 16 | 907-910 | Customer Services & Information | Worksheet F, Line 20, Column E | | $ - | Direct Zero | 0.0% | $ - |
| 17 | 911-916 | Sales | Worksheet F, Line 21, Column E | | $ - | Direct Zero | 0.0% | $ - |
| 18 | | Customer Related Expense | Subtotal | | $ - | | | $ - |
| 19 | | <u>Administrative & General Expense</u> | | | | | | |
| 20 | 920-931 | Admin and General Operations Expense | Worksheet F, Line 22, Column E - lines 21 and 22 | $ - | | T-Wage | #DIV/0! | #DIV/0! |
| 21 | 928 | SPP Commission and Regulatory Expenses | Worksheet M, Line 7, Column F | | $ - | Direct 100 | 100.0% | $ - |
| 22 | 928 | Non-SPP Commission and Regulatory Expenses | Worksheet M, Line 7, Column E | | $ - | Direct Zero | 0.0% | $ - |
| 23 | | Total A&G Expenses | Subtotal | $ - | | | | #DIV/0! |
| 24 | | Subtotal O&M | Line 13 + Line 18 + Line 23 | $ - | | | | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 25 | | Depreciation Expense | | | | | | |
| 26 | 403 | Depreciation Expense-Production | Worksheet K, Line 8, Col E | $ - | Direct Zero | 0.0% | $ - | |
| 27 | 403 | Depreciation Expense-Transmission Plant | Worksheet K, Line 8, Col F | $ - | T-Tran Plant | #DIV/0! | #DIV/0! | |
| 28 | 403 | Depreciation Expense-Distribution | Worksheet K, Line 8, Col G | $ - | Direct Zero | 0.0% | $ - | |
| 29 | 403 | Depreciation Expense-General | Worksheet K, Line 8, Col H | $ - | T-Wage | #DIV/0! | #DIV/0! | |
| 30 | 405 | Unrecovered Plant Expense (Note A) | Worksheet K, Line 8, Col K | $ - | Direct 100 | 100.0% | $ - | |
| 31 | 411.1 | Accretion Expense - Plant Retirement | Worksheet K, Line 8, Col J | $ - | Direct Zero | 0.0% | $ - | |
| 32 | 407 | Amortization of Intangible Plant | Worksheet K, Line 8, Col I | $ - | T-Wage | #DIV/0! | #DIV/0! | |
| 33 | | Total Depreciation & Amortization | sum lines 26 thru 32 | $ - | | | #DIV/0! | |
| 34 | | Electric Generation, Distribution, and Transmission Taxes | Worksheet F, Line 25, Column E | $ - | T-Tax | #DIV/0! | #DIV/0! | |
| 35 | | Return | Worksheet C, Line 7, Column I | | | | #DIV/0! | |
| 36 | | Revenue Requirement | Line 24 + Line 33 + Line 34 + Line 35 | | | | #DIV/0! | |

37 Notes:

38 A. Any unrecovered plant expense are associated with the contribution in aid of construction. No amounts should be included on this line absent specific FERC approval.

## Mor-Gran-Sou Electric Cooperative, Inc

Worksheet C

## Capital Structure & Rate of Return based on Return on Equity

| A<br>Line No | B<br>Description | C<br>Reference | D<br>Total Co EoY | E<br>Cap Str Weight | F<br>Target Capital Str (A), (B) | G<br>Interest, Margin or Annual Cost | H<br>Cost of Capital (A), (B), (C) | I<br>Weighted Rate of Return |
|---|---|---|---|---|---|---|---|---|
| 1 | **Capital Structure & Return** | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Line 37, Col E and Worksheet F, Line 27 + Line 28, Col E | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | Notes Payable | Worksheet F, Line 38, Col E (if balance is positive). | $ - | #DIV/0! | 0.00% | $ - | 0.0% | 0.0% |
| 4 | Total Margins and Equities | Worksheet F, Line 36, Col E | $ - | #DIV/0! | #DIV/0! | | 10.1% | #DIV/0! |
| 5 | Total Capitalization | Subtotal | $ - | #DIV/0! | | $ - | | #DIV/0! |
| 6 | Rate Base | Worksheet A, Line 50, Column J | | | | | | #DIV/0! |

| | | | |
|---|---|---|---|
| 7 | Return | Line 5 * Line 6 | #DIV/0! |

8 Notes:

A. Mor-Gran-Sou shall apply its base ROE and the 50-basis point adder to its actual capital structure except that for any four Rate Years, Mor-Gran-Sou, at its own discretion, may elect to
9 apply its base ROE plus any applicable adders to a hypothetical capital structure with an equity component of 35.24 percent and a debt component of 64.76 percent (“Capital Structure Option”). The four Rates Years may be consecutive or non-consecutive.

B. The base ROE of 9.6% and the incentive adder of 0.5% are fixed. The ROE shall remain in effect
10 absent Commission action under Federal Power Act Section 205 or 206.

C. The cost of capital for Total Margins and Equities reflects a 50
11 basis point incentive adder for RTO participation.

## Mor-Gran-Sou Electric Cooperative, Inc

Worksheet D

## Network Demand

| A<br>Line No | B<br>Description | C<br>Load (MW) |
|---|---|---|
| 1 | January | |
| 2 | February | |
| 3 | March | |
| 4 | April | |
| 5 | May | |
| 6 | June | |
| 7 | July | |
| 8 | August | |
| 9 | September | |
| 10 | October | |
| 11 | November | |
| 12 | December | |
| 13 | Total (MW-Mo) | 0.0 |
| 14 | Average (MW-Mo) | **0.0** |

# Mor-Gran-Sou Electric Cooperative, Inc

Worksheet E

## Allocation Factors

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total | E<br>Allocation Factor Name | F<br>Allocation Factor % | G<br>ATRR Allocated |
|---|---|---|---|---|---|---|
| 1 | Production Wages | Worksheet J, Line 225, Column E | $ - | Direct Zero | 0.0% | $ - |
| 2 | Transmission Supervision Operations | Worksheet J, Line 225, Column F | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 3 | Transmission Load Dispatch and Scheduling | Worksheet J, Line 225, Column G | $ - | Direct Zero | 0.0% | $ - |
| 4 | Transmission Station Operations | Worksheet J, Line 225, Column H | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 5 | Transmission Line Operations | Worksheet J, Line 225, Column I | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 6 | Transmission of Elect by Others | Worksheet J, Line 225, Column J | $ - | Direct Zero | 0.0% | $ - |
| 7 | Transmission Misc | Worksheet J, Line 225, Column K | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 8 | Transmission Supervision Maintenance | Worksheet J, Line 225, Column L | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 9 | Transmission Station Maintenance | Worksheet J, Line 225, Column M | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 10 | Transmission Line Maintenance | Worksheet J, Line 225, Column N | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 11 | Transmission Maintenance – Misc | Worksheet J, Line 225, Column O | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 12 | Distribution Operations-Stations | Worksheet J, Line 225, Column P | $ - | T-Distb Stations | #DIV/0! | | #DIV/0! |
| 13 | Distribution Operations-All Other | Worksheet J, Line 225, Column Q | $ - | Direct Zero | 0.0% | $ - | |
| 14 | Distribution Maintenance-Stations | Worksheet J, Line 225, Column R | $ - | T-Distb Stations | #DIV/0! | | #DIV/0! |
| 15 | Distribution Maintenance-All Other | Worksheet J, Line 225, Column S | $ - | Direct Zero | 0.0% | $ - | |
| 16 | Customer Accounts Less meter reading | Worksheet J, Line 225, Column U | $ - | Direct Zero | 0.0% | $ - | |
| 17 | Customer Accounts Meter Reading | Worksheet J, Line 225, Column T | $ - | Direct 100 | 100.0% | $ - | |
| 18 | Customer Service | Worksheet J, Line 225, Column V | $ - | Direct Zero | 0.0% | $ - | |
| 19 | Sales | Worksheet J, Line 225, Column W | $ - | Direct Zero | 0.0% | $ - | |
| 20 | Total Wages, Excluding A&G | Sum Lines 1 thru 19 | $ - | | | | #DIV/0! |
| 21 | **T-Wage** | | | | | | **#DIV/0!** |
| 22 | 353 Transmission Stations Gross Plant | Worksheet A Line 7, Column G | $ - | Direct WS-U | | $ - | |
| 23 | **T-Tran Stations** | | | | | | **#DIV/0!** |
| 24 | 362 Distribution Stations Gross Plant | Worksheet A Line 12, Column G | $ - | Direct WS-U | | $ - | |
| 25 | **T-Distb Stations** | | | | | | **#DIV/0!** |
| 26 | 354-359.1 Transmission Lines Gross Plant | Worksheet A Line 8, Column G | $ - | Direct WS-V | | $ - | |
| 27 | **T-Tran Lines** | | | | | | **#DIV/0!** |
| 28 | Transmission Qualifying Plant | Worksheet A, Lines 5 thru 8, Column G | $ - | | | | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 29 | **T-Tran Plant** | | | #DIV/0! |
| 30 | Distribution Qualifying Plant | Worksheet A, Lines 11 thru 13, Column G | $ - | #DIV/0! |
| 31 | **T-Distb Plant** | | | #DIV/0! |
| 30 | Plant in Service | Worksheet A Line 17, Column G | $ - | #DIV/0! |
| 31 | **T-Plant** | | | #DIV/0! |
| 32 | **Direct Zero** | Fixed allocation | | **0.0%** |
| 33 | **Direct 100** | Fixed allocation | | **100.0%** |
| 34 | SPP Trans. as % of Total Company Trans. + Dist. | Worksheet A, Lines 9 and 14, Col. G and J | $ - | #DIV/0! |
| 35 | **T-Tax** | | | #DIV/0! |

# Mor-Gran-Sou Electric Cooperative, Inc

Workshee
t F

## General Input Section

| A<br>Line<br>No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>End of Year Value or Amount |
|---|---|---|---|---|---|
| 1 | Billing Lag in days | Industry Standard | | | 45 |
| 2 | CWIP included in Rate Base | Per ER19-456 Settlement | | | 50% |
| 3 | Test Year | | | | |
| 4 | Capital Structure Option (Yes or No) | Worksheet C, Note A, line 9 | | | |
| 5 | Capital Structure Option Rate Year 1 | Worksheet C, Note A, line 9 | | | |
| 6 | Capital Structure Option Rate Year 2 | Worksheet C, Note A, line 9 | | | |
| 7 | Capital Structure Option Rate Year 3 | Worksheet C, Note A, line 9 | | | |
| 8 | Capital Structure Option Rate Year 4 | Worksheet C, Note A, line 9 | | | |
| 9 | Typical construction cost of 69 kV ($/Mile) | | | | |
| 10 | Typical construction cost of 115 kV ($/Mile) | | | | |
| 11 | Typical construction cost of 230 kV ($/Mile) | | | | |
| 12 | Operating Revenue and Patronage Capital | Form 7, Part A, Line 1, Column B | | | |
| 13 | Power Production Expense | Form 7, Part A, Line 2, | | | |

| | | | |
|---|---|---|---|
| | | Column B | |
| 14 | Cost of Purchased Power | Form 7, Part A, Line 3, Column B | |
| 15 | Transmission Expense | Form 7, Part A, Line 4, Column B | |
| 16 | Regional Market Operations Expense | Form 7, Part A, Line 5, Column B | |
| 17 | Distribution Expense-Operation | Form 7, Part A, Line 6, Column B | |
| 18 | Distribution Expense-Maintenance | Form 7, Part A, Line 7, Column B | |
| 19 | Customer Account Expense | Form 7, Part A, Line 8, Column B | |
| 20 | Customer Sales and Informational Expense | Form 7, Part A, Line 9, Column B | |
| 21 | Sales Expense | Form 7, Part A, Line 10, Column B | |
| 22 | Administrative and General Expense | Form 7, Part A, Line 11, Column B | |
| 23 | Subtotal-Operations & Maintenance Expense | Sum Lines 13 thru 22 | $ - |
| 24 | Depreciation and Amortization Expense | Form 7, Part A, Line 13, Column B | |
| 25 | Electric Generation, Dist., and Trans. Taxes | Form 7, Part A, Line 14, Column B | |
| 26 | Tax Expense - Other | Form 7, Part A, Line 15, Column B | |
| 27 | Interest on Long Term Debt | Form 7, Part A, Line 16, Column B | |
| 28 | Interest Charged to Construction (Credit) | Form 7, Part A, Line 17, Column B | |
| 29 | Other Interest Expense | Form 7, Part A, Line 18, Column B | |
| 30 | Other Deductions | Form 7, Part A, Line 19, Column B | |

| | | | |
|---|---|---|---|
| | Subtotal Cost of Electric | Sum Lines 23 and 24 thru | $ |
| 31 | Service | 30 | - |
| | Patronage Capital and | Line 12 - Line 31 | $ |
| 32 | Operating Margins | | - |

| | | | BoY | EoY | Average | |
|---|---|---|---|---|---|---|
| 33 | | | | | | |
| | | Form 7, Part C, Line 23 | | | | $ |
| 34 | Materials and Supplies | (Prior year & current) | | | | - |
| | | Form 7, Part C, Line 24 | | | | $ |
| 35 | Prepayments | (Prior year & current) | | | | - |

| | | | EoY | |
|---|---|---|---|---|
| 36 | Total Margins and Equities | Form 7, Part C, Line 36 | | |
| 37 | Total Long Term Debt | Form 7, Part C, Line 43 | | |
| 38 | Notes Payable | Form 7, Part C, Line 47 | | |

| | | | BoY | EoY | Average | |
|---|---|---|---|---|---|---|
| 39 | Plant in Service | | | | | |
| | | Form 7, Part E, Line 1, Cols | | | | $ |
| 40 | Total Distribution Plant | A and E | | | | - |
| | | Form 7, Part E, Line 2, Cols | | | | $ |
| 41 | General Plant | A and E | | | | - |
| | | Form 7, Part E, Line 3, Cols | | | | $ |
| 42 | Headquarters Plant | A and E | | | | - |
| | | Form 7, Part E, Line 4, Cols | | | | $ |
| 43 | 301-303 Total Intangible Plant | A and E | | | | - |
| | | Form 7, Part E, Line 5, Cols | | | | $ |
| 44 | Transmission Plant | A and E | | | | - |
| | | Form 7, Part E, Line 6, Cols | | | | $ |
| 45 | 380-386 RTO/ISO Plant | A and E | | | | - |
| | | Form 7, Part E, Line 7, Cols | | | | $ |
| 46 | All Other Utility Plant | A and E | | | | - |
| | | Form 7, Part E, Line 9, Cols | | | | $ |
| 47 | Construction Work in Progress | A and E | | | | - |
| | | Subtotal | $ | $ | | $ |
| 48 | Plant in Service | | - | - | | - |

Notes:
A. Acquisition adjustments will not be used in the calculation of ATRR absent Commission approval through a 205 or 206 filing.
B. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the Annual Update.

## Mor-Gran-Sou Electric Cooperative, Inc

Worksheet G

## Depreciation Rates

| A | B | C | D |
|---|---|---|---|
| Line No | Description | Plant Account Number | Annual Depr Rate |
| 1 | Transmission: | | |
| 2 | Land and Land rights | 350.00 | 0.00% |
| 3 | Structures & Improvements | 352.00 | 2.75% |
| 4 | Transmission Station Equipment | 353.00 | 2.75% |
| 5 | Poles and Fixtures | 355.00 | 2.75% |
| 6 | Overhead Conductors and devices | 356.00 | 2.75% |
| 7 | Underground Conductors and Devices | 358.00 | 2.75% |
| 8 | | | |
| 9 | Distribution: | | |
| 10 | Land and Land rights | 360 | 0.00% |
| 11 | Structures & Improvements | 361 | |
| 12 | Distribution Station Equipment | 362 | 2.95% |
| 13 | Poles, Towers & Fixtures | 364 | 3.03% |
| 14 | Overhead Conductor & Devices | 365 | 2.31% |
| 15 | Underground Conduit | 366 | 2.00% |
| 16 | UG Conductor & Devices Post 1987 | 367 | 2.75% |
| 17 | UG Conductor & Devices Pre 1988 | 367.1 | 5.03% |
| 18 | Line Transformers | 368 | 2.61% |
| 19 | Services | 369 | 3.21% |
| 20 | Meters | 370 | 3.40% |
| 21 | Instal on Cust Premises | 371 | 4.40% |
| 22 | Leased Property on Cust Premises | 372 | 4.10% |

| | | | |
|---|---|---|---|
| 23 | Street Lighting and Signal | 373 | 3.80% |
| 24 | | | |
| 25 | General: | | |
| 26 | Structures & Improvements | 390 | 2.00% |
| 27 | Transportation Equip | 392 | 15.00% |
| 28 | Power Operated Equip | 396 | 11.00% |
| 29 | Other Tangible SCADA | 399 | 20.00% |
| 30 | | | |
| 31 | Note: | | |
| 32 | A. Stated Values in Column D are fixed and cannot be changed absent Commission approval through | | |
| 33 | a Section 205 or 206 filing. | | |

Wo
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## Mor-Gran-Sou Electric Cooperative, Inc

## Other Operating Revenue (A454-456)

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account No | Account Description | Total Company | % Allocated to SPP | Electric Plant, Leased | Retail Related | Wheeling - SPP | Rents | Other Electric Revenue | Basin Facility Discount | Sch 7 & 8 P2P | Sch 11 P2P | Direct Assigned Revenues | Renewable Energy Credits |
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| 15 | | | | | | | | | | | | |
| | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 16 | Total | - | - | - | - | - | - | - | - | - | - | - |
| 17 | | | | | | | | | | | | |

18 Note:
A. The addition of new lines and the removal of outdated
19 lines may be necessary in order to accurately provide
information, and populate or remove data in the
Worksheet with changes in future years. Where
20 appropriate, these
changes will provide detail and linkage to
updated Form 7 data requirements or other similar
21 supporting
documentation. Additional line items or line deletions
will not require FPA Section 205 or 206 filings. Mor-Gran-
22 Sou will
describe such changes in the Annual Update, and the
changes will be subject to the review of Interested Parties
23 under
the procedures set forth in Mor-Gran-Sou's Implementation
Protocols. Mor-Gran-Sou may not change the columns or the
24 formulas
included in these Worksheets
25 during the Annual Update.
B. The total amount shown for Column D must match the
amount shown in Mor-Gran-Sou's RUS Form No. 7 for Other
26 Revenues.

**Mor-Gran-Sou Electric Cooperative, Inc**

**O&M Input (A560-598)**

Worksheet I

| A Line No. | B Account | C Description | D Balance | E 560 - Supervision & Engr. | F 561 - Load Dispatching | G 562- Station Expenses | H 563- OH Line Expenses | I 564- UG Line Expenses | J 565 - Transmission of Elec. By Others | K 566- Miscellaneous Expenses | L 567 - Rents | M 568 - Supervision and Engineering | N 569- Structures | O 570- Station Equipment | P 571 - OH Lines | Q 572 - UG Lines | R 573 - Misc Transmission Plant | S 575.1 - 575.8 | T 576.1 - 576.5 | U 582 Distb Station Ops Exp | V 580- 589 Distribution Operations All Other | W 591- 592 Distb Station Maint E | X 590 - 598 Distribution Maintenance All Other |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

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| 108 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

109 Note:
110 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures

5 set forth in Mor-Gran-Sou's Implementation Protocols.

**Mor-Gran-Sou Electric Cooperative, Inc**

Worksheet J

**Wage Input & Functionalization**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 560 | | | | | | | 569-570 | | 573 | | | 591-592 | | | 901, 903-905 | 907-910 | 911-916 | |
| Line No. | Account | Account Description | Labor Total Company | 555 Purchased Power | Trans Ops Super-Wages | 561 Load Dispatch | 562 Trans Stations | 563-564 OH & UG Line Expense | 565 Trans of Elect by Others | 566 Misc-Wages | 568 Maint - Supervision and Engineering | Maint-Wages | 571 Maint-OH Lines | Maint-Misc Trans Plan | 582 Dist Stat Op Exp | 580-589 Dist Operation | Dist Stat Maint Exp | 590-598 Dist Maint | 902 Meter Reading-Wages | Cust Acct-Wa | Cust Service-Wages | 911-916 Cust Sales-Wages | Admin & General |

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2 te:
6
A. The addition of new lines and the removal of outdated
2 lines may be
2 necessary in order
7 to accurately provide information, and populate or remove data
2 in the Worksheet with
2 changes in future years.
8 Where appropriate, these changes will provide detail and linkage to updated Form 7 data
2 requirements or
2 other similar
9 supporting documentation. Additional line items or line deletions will not
2 require FPA Section 205
3 or 206 filings. Mor-Gran-
0 Sou will describe such changes in the Annual Update, and the changes
2 will be subject to the
3 review of Interested
1 Parties under the procedures set forth in
2 Mor-Gran-Sou's
3 Implementation Protocols.
2 Mor-Gran-Sou may not

change the columns or the formulas

included in these Workshe ets during 2 the 3 Annual 3 Update.

# Mor-Gran-Sou Electric Cooperative, Inc

Worksheet K

## Annual Depreciation Expense (A403)

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Account | Description | Year End Balance | Production | Transmission | Distribution Expense | General | Amort | Plant Retirement | Unrecovered Plant Expense |
| 1 | | | | | | | | | | |
| 2 | | | | | | | | | | |
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| | | Totals | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | | | - | - | - | - | - | - | - | - |
| 9 | | | | | | | | | | |

10 Note:
A. The addition of new lines and the removal of outdated lines may
11 be necessary in order to accurately provide
information, and populate or remove data in the Worksheet with
12 changes in future years. Where appropriate, these
changes will provide detail and linkage to updated Form 7 data
13 requirements or other similar supporting
documentation. Additional line items or line deletions will not require FPA
14 Section 205 or 206 filings. Mor-Gran-Sou will
15 describe such changes in the Annual Update, and the changes will be

subject to the review of Interested Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the Annual Update.

Work sheet L

## Mor-Gran-Sou Electric Cooperative, Inc

## RTO / ISO Expenses (A575-576)

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Line | Account No. | Description | Annual Expense Amount | % Included in SPP | SPP Amount |
| | **575.1-575.8 RTO/ISO Expense - Operation** | | | | |
| 1a | | | $0.00 | 100% | $0.00 |
| 1b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 2 | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)** | | $0.00 | | $0.00 |
| | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | | |
| 3a | | | $0.00 | 100% | $0.00 |
| 3b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 4 | **576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)** | | $0.00 | | $0.00 |
| 5 | Notes | | | | |
| 6 | A. The total on line 2, column D must reconcile to the amounts shown on Form 7. | | | | |
| 7 | B. The total on line 4, column D must reconcile to the amounts shown on Form 7. | | | | |

C. Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for inclusion in SPP Zone 19 ATRR following a change in accounting procedures to the Form 7 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that this occurs, Mor-Gran-Sou may file a single-issue Section 205 filing with the Commission to seek recovery of these amounts in Zone 19 rates. Mor-Gran-Sou may not include any costs absent authorization from FERC via a Section 205 or 206 filing.

D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

## Mor-Gran-Sou Electric Cooperative, Inc

Works heet M

## Regulatory and Commission Expenses (A928)

| A<br>Line No. | B<br>Account 928 | C<br>Description | D<br>Total Company | E<br>Non-Qualifying SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
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| 6 | | | | | |
| 7 | Total | | $ - | $ - | $ - |

8 Note:
A. The addition of new lines and the removal of outdated lines may be
9 necessary in order to accurately provide
information, and populate or remove data in the Worksheet with changes in future
10 years. Where appropriate, these
changes will provide detail and linkage to updated Form 7 data
11 requirements or other similar supporting
12 documentation. Additional line items or line deletions will not require FPA Section

205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the Annual Update.

# Mor-Gran-Sou Electric Cooperative, Inc

Works
heet N

## Customer Accounting Input (A901-905)

| A<br>Line No. | B<br>Account | C<br>Description | D<br>Total Company | E<br>901-905 SPP Expenses |
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| 21 | | | |
| | Total Customer Accounting | $ | $ |
| 22 | | - | - |
| 23 | | | |

24 Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide
25 information, and populate or remove data in the Worksheet.
with changes in future years. Where appropriate, these changes will provide detail and linkage to
26 updated Form 7 data requirements or other similar supporting
documentation. Additional linkage to updated Form 7 data requirements or other similar supporting
27 documentation. Additional line items or line deletions will not require
FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the
28 changes will be subject to the review of Interested Parties under the
procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the
29 columns or the formulas included in these Worksheets during the
30 Annual Update.

**Mor-Gran-Sou Electric Cooperative, Inc**

Worksheet O

**Plant Input (A350-358), Accum Depr (A108), Amortization (A111)**

| A<br>Line No. | B<br>Account | C<br>Description | D<br>Balance BO | E<br>Balance EO | F<br>350 Tran La | G<br>350 Tran | H<br>352 Tran Str | I<br>352 Tran Str | J<br>353 Tran St | K<br>353 Tran St | L<br>353 Tran St | M<br>353 Tran St | N<br>355-358 Tr | O<br>355-358 T | P<br>360 Dist bL | Q<br>360 Dist bL | R<br>361 Structures & Impr | S<br>361 Structures & Impr | T<br>362 Distrib Stat | U<br>362 Distrib Stat | V<br>364-373 Other | W<br>364-373 Other | X<br>108 Generators | Y<br>108 Generators | Z<br>108 Gener a | AA<br>108 Gener a | AB<br>108.8 RWl | AC<br>108.8 RWl | AD<br>111 Amort o | AG<br>111 Amort o |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | Y | Y | ndBOY | LandEOY | ucturBOY | uctureEOY | ationSCADABOY | ationSCADAEOY | ationBOY | ationEOY | anLinesBOY | ranLinesEOY | and&RightsBOY | and&RightsEOY | ovementsBOY | ovementsEOY | ionEquipmentBOY | ionEquipmentEOY | DistributionBOY | DistributionEOY | BOY | EOY | lPlantBOY | lPlantEOY | PBOY | PEOY | felec.PlantInServBOY | felec.PlantInServEOY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | **Gross Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
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| 12 | Total Gross Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | **Accu** | | | | | | | | | | | | | | | | | | | | |

| | mulated Depreciation Reserves |
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| 656 | Total Accumulated Depreciation Reserves | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 657 | **Trans** | Bal | Bal | Av | | | | | | | | | | | | | | | | | | | | | | | | | | | |

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| | **mission Plant Functionalization** | ance-BOY | ance-EOY | erage |
| 68 | 350-353 Transmission Stations | $ - | $ - | $ - |
| 69 | 352-353 Transmission Stations SCADA | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 70 | 354 - 359.1 Other Transmission Plant (Lines) | $ - | $ - | $ - |
| 71 | **Distribution Plant Functionalization** | | | |
| 72 | 360 - 362 Distribution Sta | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | tions 364 - 373 Distribution All | | | |
| 73 | Other | $ - | $ - | $ - |
| | **Transmission Depreciation Functionalization** | | | |
| 74 | 108.5 Accumulated | | | |
| 75 | De | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | preciation Reserves - Transmission Stations 108.5 Accumulated Depreciation Reserves - Transmission | | | |
| 76 | SCAD | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | A 108 .5 Accumulated Depreciation Reserves - Transmission | | | |
| 7 7 | Lines | $ - | $ - | $ - |
| | **Distribution Depreciation Functionaliz** | | | |
| 7 8 | | | | |

| | | | | |
|---|---|---|---|---|
| | **ation** 108.5 Accumulated Depreciation Reserves - Distibution Station | | | |
| 79 | s | $ - | $ - | $ - |
| | 108.5 Accumulated Depreciation Reserves | | | |
| 80 | - | $ - | $ - | $ - |

Dis
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N
8 ot
1 e:
A. The addition of new lines and the removal of outdated lines may be necessary in order to
8 accurately
2 provide information, and populate or remove data in the Worksheet with changes in future
8 years. Where
3 appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or
8 other similar
4 supporting
8 documentation.

5 Additional line items or line deletions will not require FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the
8 review of Interested
6 Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the
8 columns or the
7 formulas included in these Worksheets during the
8 Annual
8 Update.

**Mor-Gran-Sou Electric Cooperative, Inc**

Work sheet P

## Plant Held for Future Use (A105)

| A Line No | B Facility No. | C Asset No. | D Description | E BoY Investment | F EOY Investment | G Average Investment | H Qualified |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | Transmission Qualified Future Use Assets | | | | |
| 3 | | | | | | $ - | $ - |
| 4 | | | | | | $ - | |
| 5 | | | | | | $ - | |
| 6 | | | | | | $ - | |
| 7 | | | Total Plant Held for Future Use | $ - | $ - | $ - | $ - |

8 Note:

9 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide

information, and populate or remove data in the Worksheet.

with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet Q

## Mor-Gran-Sou Electric Cooperative, Inc

## Construction Completed Not Classified (A106)

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Fac ID | Work Order | Project | BoY Balance | EoY Balance | Facility | % SPP Eligible | BoY Amount | EoY Amount | Average | Comments |
| 1 | | | | | | | | $ - | $ - | $ - | |
| 2 | | | | | | | | $ - | $ - | $ - | |
| 3 | | | | | | | | $ - | $ - | $ - | |
| 4 | | | | | | | | $ - | $ - | $ - | |
| 5 | | | | | | | | $ - | $ - | $ - | |
| 6 | | | | | | | | $ - | $ - | $ - | |
| 7 | | | | | | | | $ - | $ - | $ - | |
| 8 | | | | | | | | $ - | $ - | $ - | |
| 9 | | | | | | | | $ - | $ - | $ - | |
| 10 | | | | | | | | $ | $ | $ | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | - | - | - | |
| | | | | | $ | $ | $ | |
| 11 | | | | | - | - | - | |
| | | | $ | $ | | $ | $ | $ |
| 12 | | Total | - | - | | - | - | - |

13 Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the
14 Worksheet.
with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other
15 similar supporting
documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will
16 not require FPA
Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the
17 procedures
set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the
18 Annual Update.

## Mor-Gran-Sou Electric Cooperative, Inc

Work sheet R

## Construction Work in Process (A107)

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project ID | Project Description | Approval Docket No. | Recovery Approved | Approximate Construction Start Date | Close-out Date (Estimated) | BoY Balance | EoY Balance | Average Balance (Col H + I) /2 | Includable in Rate Base (Col E * Col J) |
| 1 | | | Per ER19-456 Settlement | 50% | | | | | $ - | $ - |
| 2 | | | Per ER19-456 Settlement | 50% | | | | | $ - | $ - |
| 3 | | | Per ER19-456 Settlement | 50% | | | | | $ - | $ - |
| 4 | | | Per ER19-456 Settlement | 50% | | | | | $ - | $ - |
| 5 | | | Per ER19-456 Settlement | 50% | | | | | $ - | $ - |
| 6 | | | Per ER19-456 Settlement | 50% | | | | | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 8 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 9 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 10 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 11 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 12 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 13 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 14 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 15 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 16 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 17 | | Per ER19-456 Settlement | 50% | | $ - | $ - |
| 18 | **Total** | | | | **$ -** | **$ -** | **$ -** | **$ -** |

**s**

19

Note
20 s:
A. Percentage of "Recovery Approved" cannot be
21 added or changed absent approval from FERC.
B. AFUDC ceases when CWIP is recovered in rate base corresponding to the amount of CWIP included
22 in Rate Base. No CWIP will be included in rate base absent FERC authorization.
Accounting procedures must be provided during the annual update
23 to ensure that there is no duplicate recovery of
CWIP and corresponding AFUDC capitalized.
24 Projects are transmission related only.
C. The addition of new lines and the removal of outdated lines may be necessary in order to
25 accurately provide information, and populate or remove data in the Worksheet with
changes in future years. Where appropriate, these changes will provide detail and linkage to
26 updated Form 7 data requirements or other similar supporting documentation.
Additional line items will not require FPA Section 205 or 206 filings.
27 Mor-Gran-Sou will describe such changes in the Annual
Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in
28 Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns
or the formulas included in these Worksheet
29 during the Annual Update.

# Mor-Gran-Sou Electric Cooperative, Inc

Work
shee
t S

## SPP Upgrades

| A | B | C | D |
|---|---|---|---|
| Line No. | Description | Reference | Company Total Transmission Amount |
| 1 | Gross Qualified Transmission Plant | Worksheet A, Line 9, Column J | $ - |
| 2 | Accumulated Qualifi | Worksheet A, | $ - |

| | | | |
|---|---|---|---|
| | ed Transmission Depreciation | Lines 24 thru 26, Column J | |
| | Net Transmission Plant | Line 1 - Line 2 | $ - |
| | Transmission O&M | Worksheet B, Line 8, Column H | $ - |
| | **Annual Allocation Factor for Transmission O&M** | Line 4 / Line 1 | 0.00% |
| | General Plant Depreciation | Worksheet B, Line 29, | $ - |

| | Expense | Column H | |
|---|---|---|---|
| 7 | **Annual Allocation Factor for General Plant Depreciation** | Line 6 / Line 1 | 0.00% |
| 8 | Return on Rate Base | Worksheet B, Line 35, Column H | $ - |
| 9 | **Annual Allocation Factor for Return** | Line 8 / Line 3 | 0.00% |

1 **Depre**

| | | | |
|---|---|---|---|
| 0 | **ciation Rates** | | |
| 1 1 | Sub | Worksheet G, Line 4 Col D | 2.75% |
| 1 2 | Line | Worksheet G, Line 5 Col D | 2.75% |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project Name and #** | **Type** | **Project Gross Plant** | **Project Accumulated Depreciation** | **Transmission O&M Annual Allocation Factor** | **Allocation for Transmission O&M** | **General Plant Depreciation Annual Allocation Factor** | **Allocation for General Plant Depreciation** | **Annual Expense Charge** | **Project Net Plant** | **Annual Allocation Factor for Return** | **Annual Return Charge** | **Project Depreciation and Amortization Expense** | **Revenue Credits** | **Project ATRR** |
| | | | | | | | | | | | | | | | |

| | | | Note A | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | Col G + Col I | Col D - Col E (Note B) | Line 9, Col D | Col K * Col L | Note C | | Col J + Col M + Col N - Col O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 14 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 15 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 16 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 17 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 18 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 19 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 20 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 21 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 22 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 23 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 24 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 25 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 2 | | | | | 0.00% | $ | 0.00% | $ | $ | $ | 0.00 | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26 | | | | | | - | | - | - | - | % | - | - | - | - |
| 27 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - |
| 28 | Total | | $ - | $ - | | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |

29 Notes:

30 A. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1.

31 This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

32 Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

33 B. Net Plant is the Gross Plant less the associated Accumulated

Depreciation.
C. Depreciation Expense is the depreciation amount associated with the specified line or sub. Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.
D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation.
Additional line items or line deletions will not

require FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the Annual Update.

# Mor-Gran-Sou Electric Cooperative, Inc

Works heet T

## Calculation of Interest Applied to True-Up Calculations

A B C D E F G H I J K L

**Adjustments To ATRR Due To Error Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | $ - | $ - | $ - | $ - |
| 2 | | | | | | | | | $ - |
| 3 | | | | | | | | | $ - |
| 4 | | | | | | | | | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | $ - |

| | | |
|---|---|---|
| 6 | **Total Adjustment to Gross ATRR:** | $ - |

**Adjustments To SPP Regional Projects' ATRR Due To Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | | | | $ - |
| 8 | | | | | | | | | $ - |
| 9 | | | | | | | | | $ - |
| 10 | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | $ - |
| 11 | | | | | | | | | $ - |

| | | |
|---|---|---|
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | $ - |

13 Notes:
A. Rate Year in which the error occurred and affected the
14 ATRR and rates paid by customers.
B. Each ATRR adjustment shall include interest based on Section
15 35.19a of the Commission Regulations.

| | Period Start | Period Ending | Year description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance |
|---|---|---|---|---|---|---|---|---|
| 16 | | | | | | | | |
| **Interest calculation for Item #1** | | | | | | | | |
| | | | Rate | | $ | | $ | $ |
| 17 | | | Year | | - | | - | - |
| | | | Rate | $ | $ | | $ | $ |
| 18 | | | Year | - | - | | - | - |
| 19 | | | Rate | $ | $ | | $ | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Year | - | - | | | - | - |
| | | Rate | $ | $ | | | $ | $ |
| 20 | | Year | - | - | | | - | - |
| | | | $ | | | | $ | $ |
| 21 | | | - | | | | - | - |
| | | | $ | | | | $ | $ |
| 22 | | | - | | | | - | - |
| | | | $ | | | | $ | $ |
| 23 | | | - | | | | - | - |
| | | | $ | | | | $ | $ |
| 24 | | | - | | | | - | - |
| | | True-Up | $ | $ | | | $ | $ |
| 25 | | Year | - | - | | | - | - |
| | | True-Up | $ | $ | | | $ | $ |
| 26 | | Year | - | - | | | - | - |
| | | True-Up | $ | $ | | | $ | $ |
| 27 | | Year | - | - | | | - | - |
| | | True-Up | $ | $ | | | $ | $ |
| 28 | | Year | - | - | | | - | - |
| | | | | | | | $ | |
| 29 | Total | | | | | | - | |

**Interest calculation**
30 **for Item #2…**
(Repeat interest calculation for other
31 items as necessary.)

C. Interest Note: The interest calculation may need to be modified to
32 recognize the implementation partial year.
D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work
33 paper with the changes in future years does not require a Federal
34 Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns

cannot be changed absent a Federal Power Act section 205 or 206
35 filing.

Worksheet U

## Mor-Gran-Sou Electric Cooperative, Inc

## Qualified Transmission Substations

| A | B | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|
| Line No. | Description | BOY Gross Plant | EOY Gross Plant | Percent High Side | Network | BOY Qualified Gross Plant | EOY Qualified Gross Plant | Average Qualified Gross Plant |
| 1 | **353 Transmission Stations** | | | | | | | |
| 2 | | | | | | $ - | $ - | $ - |
| 3 | | | | | | $ - | $ - | $ - |
| 4 | | | | | | $ - | $ - | $ - |
| 5 | | | | | | $ - | $ - | $ - |
| 6 | | | | | | $ - | $ - | $ - |
| 7 | | | | | | $ - | $ - | $ - |
| 8 | | | | | | $ - | $ - | $ - |
| 9 | | | | | | $ - | $ - | $ - |
| 10 | | | | | | $ - | $ - | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 11 | | | | | | $ - | $ - | $ - |
| 12 | | | | | | $ - | $ - | $ - |
| 13 | | | | | | $ - | $ - | $ - |
| 14 | | | | | | $ - | $ - | $ - |
| 15 | | | | | | $ - | $ - | $ - |
| 16 | | | | | | $ - | $ - | $ - |
| 17 | | | | | | $ - | $ - | $ - |
| 18 | | | | | | $ - | $ - | $ - |
| 19 | | | | | | $ - | $ - | $ - |
| 20 | | | | | | $ - | $ - | $ - |
| 21 | | | | | | $ - | $ - | $ - |
| 22 | | | | | | $ - | $ - | $ - |
| 23 | | | | | | $ - | $ - | $ - |
| 24 | | | | | | $ - | $ - | $ - |
| 25 | | | | | | $ - | $ - | $ - |
| 26 | | | | | | $ - | $ - | $ - |
| 27 | | | | | | $ - | $ - | $ - |
| 27 | | | | | | $ - | $ - | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 28 | | | | | | | | |
| 29 | Total 353 | $ - | $ - | | | $ - | $ - | $ - |
| 30 | **362 Distribution Stations** | | | | | | | |
| 31 | | | | | | $ - | $ - | $ - |
| 32 | | | | | | $ - | $ - | $ - |
| 33 | | | | | | $ - | $ - | $ - |
| 34 | | | | | | $ - | $ - | $ - |
| 35 | | | | | | $ - | $ - | $ - |
| 36 | | | | | | $ - | $ - | $ - |
| 37 | | | | | | $ - | $ - | $ - |
| 38 | | | | | | $ - | $ - | $ - |
| 39 | | | | | | $ - | $ - | $ - |
| 40 | | | | | | $ - | $ - | $ - |
| 41 | | | | | | $ - | $ - | $ - |
| 42 | | | | | | $ - | $ - | $ - |
| 43 | | | | | | $ - | $ - | $ - |
| 44 | | | | | | $ - | $ - | $ - |
| 45 | | | | | | $ | $ | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | - | - | - |
| 46 | | | | | | $ - | $ - | $ - |
| 47 | | | | | | $ - | $ - | $ - |
| 48 | | | | | | $ - | $ - | $ - |
| 49 | | | | | | $ - | $ - | $ - |
| 50 | | | | | | $ - | $ - | $ - |
| 51 | | | | | | $ - | $ - | $ - |
| 52 | | | | | | $ - | $ - | $ - |
| 53 | | | | | | $ - | $ - | $ - |
| 54 | | | | | | $ - | $ - | $ - |
| 55 | | | | | | $ - | $ - | $ - |
| 56 | | | | | | $ - | $ - | $ - |
| 56 | | | | | | $ - | $ - | $ - |
| 57 | | | | | | | | |
| 58 | Total 362 | | | | | $ - | $ - | $ - |

58 Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order
59 to accurately
provide information, and populate or remove data in the Worksheet with changes in
60 future years.

Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Mor-Gran-Sou will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Mor-Gran-Sou's Implementation Protocols. Mor-Gran-Sou may not change the columns or the formulas included in these Worksheets during the Annual Update.

# Mor-Gran-Sou Electric Cooperative, Inc

Worksheet V

## Qualified Transmission Lines

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | Description | kV Voltage | Line Length (Miles) | BOY Gross Plant | EOY Gross Plant | Network | BOY Qualified Gross Plant | EOY Qualified Gross Plant | Average Qualified Gross Plant |
| 1 | | | | | | | $ - | $ - | $ - |
| 2 | | | | | | | $ - | $ - | $ - |
| 3 | | | | | | | $ - | $ - | $ - |
| 4 | | | | | | | $ - | $ - | $ - |
| 5 | | | | | | | $ - | $ - | $ - |
| 6 | | | | | | | $ - | $ - | $ - |
| 7 | | | | | | | $ - | $ - | $ - |
| 8 | | | | | | | $ - | $ - | $ - |
| 9 | | | | | | | $ - | $ - | $ - |
| 10 | | | | | | | $ | $ | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | - | - | - |
| 11 | | | | | | | $ - | $ - | $ - |
| 12 | | | | | | | $ - | $ - | $ - |
| 13 | | | | | | | $ - | $ - | $ - |
| 14 | | | | | | | $ - | $ - | $ - |
| 15 | | | | | | | $ - | $ - | $ - |
| 16 | | | | | | | $ - | $ - | $ - |
| 17 | | | | | | | $ - | $ - | $ - |
| 18 | | | | | | | $ - | $ - | $ - |
| 19 | | | | | | | $ - | $ - | $ - |
| 20 | | | | | | | $ - | $ - | $ - |
| 21 | | | | | | | $ - | $ - | $ - |
| 22 | | | | | | | $ - | $ - | $ - |
| 23 | | | | | | | $ - | $ - | $ - |
| 24 | | | | | | | $ - | $ - | $ - |
| 25 | | | | | | | | | $ - |
| 26 | | | | | | | | | $ - |
| 27 | Total | | 0.00 | $ - | $ - | | $ - | $ - | $ - |

| | Calculation of Ratioed Miles | Voltage | Gross Miles | Cost Per Mile | Ratio to 69 KV | Ratioed Miles |
|---|---|---|---|---|---|---|
| 28 | | | | | | |
| 29 | 69 kV Miles | 69 | 0.00 | $ - | #DIV/0! | #DIV/0! |
| 30 | 115 kV Miles | 115 | 0.00 | $ - | #DIV/0! | #DIV/0! |
| 31 | 230 kV Miles | 230 | 0.00 | $ - | #DIV/0! | #DIV/0! |
| 32 | Total | | 0.00 | | | #DIV/0! |
| 33 | Derivation of Cost Per Ratioed Miles | | | BoY | EoY | |
| 34 | Gross Plant (From Worksheet A, Line 8) | | | $ - | $ - | |
| 35 | Cost of 69 kV ($/Ratioed Mile) | | | #DIV/0! | #DIV/0! | |

36 Note:
A. The addition of new lines and the removal of outdated
37 lines may be necessary in order to accurately
provide information, and populate or remove data in
38 the Worksheet with changes in future years.
Annual changes may also include the addition of additional line
39 voltages in the "Calculation of Ratioed Miles" section.
Where appropriate, these changes will provide detail and
40 linkage to updated Form 7 data requirements or
other similar supporting documentation. Additional line items or
41 line deletions will not require FPA Section
205 or 206 filings. Mor-Gran-Sou will describe such changes in
42 the Annual Update, and the changes will be
43 subject to the review of Interested Parties under the procedures

set forth in Mor-Gran-Sou's Implementation
Protocols. Mor-Gran-Sou may not change the columns or the
44 formulas included in these Worksheets during
45 the Annual Update.

# Mor-Gran-Sou Electric Cooperative, Inc. Transmission Formula Rate Implementation Protocols

The transmission formula rate template ("Formula Rate Template") of Mor-Gran-Sou Electric Cooperative, Inc. ("Mor-Gran-Sou") and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Mor-Gran-Sou for transmission revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("SPP Tariff"). Mor-Gran-Sou must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point ("PTP") Transmission Service in Zone 19.

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the SPP Tariff. The ATRR shall be determined for January 1 to December 31 of a given calendar year. The Formula Rate shall become effective for recovery of Mor-Gran-Sou's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC") under section 205 of the Federal Power Act ("FPA").

The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein. These Protocols specify the dates applicable to the activities described herein. Should any due date fall on a weekend or a holiday recognized by FERC, then the due date shall be no later than the next Business Day.

## Section I Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

A. "Accounting Change" means any change in Mor-Gran-Sou's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

1. revisions to Rural Utilities Service's ("RUS") Uniform System of Accounts ("USoA");

2. revisions to the RUS Financial and Operating Report - Electric Distribution ("Form No. 7") data and the requirement to report certain values within it;

3. correction of errors and prior period adjustments that impact the ATRR;

4. the implementation of new estimation methods or policies;

5. changes to income tax elections;

6. changes in accounting practices or policies mandated by a state regulatory authority with jurisdiction over Mor-Gran-Sou that could impact the Formula Rate or calculations under the Formula;

7. implementation of accounting practices for unusual or unconventional items where RUS has not provided specific accounting direction;

8. a change in Mor-Gran-Sou's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor);

9. Mor-Gran-Sou's own accounting changes (which constitute a change to the ATRR greater than or equal to $15,000) such as the addition or deletion of a subaccount not specified by FERC's USoA; or

10. a change in Mor-Gran-Sou's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

B. "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by Mor-Gran-Sou for informational purposes with FERC and posted on the SPP Open Access Same-Time Information System ("OASIS") on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

C. "Annual Meeting" means the meeting hosted by Mor-Gran-Sou for exchanging information with Interested Parties regarding the Formula Rate.

D. "Annual Update" means Mor-Gran-Sou's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

E. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

F. "Calendar Year" means January 1 through December 31 of a given year.

G. "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and which Mor-Gran-Sou has filed with FERC (*e.g.*, if the Annual Update is posted on June 30, 2019, and the Informational Filing is submitted to FERC on December 15, 2019, the Current Rate Year is January 1, 2020 through December 31, 2020).

H. "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS, service under Grandfathered Agreements, or PTP Transmission Service.

I. "FERC" or "Commission" means the Federal Energy Regulatory Commission.

J. "Final Posting" means the Annual Update information that SPP posts to the SPP OASIS with changes agreed to during the informal review process.

K. "Form No. 7" means the RUS Financial and Operating Report - Electric Distribution, formerly RUS Form No. 7.

L. "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with FERC, and served on Mor-Gran-Sou by electronic service on the date of such filing.

M. "Formula Rate Template" means the Mor-Gran-Sou transmission formula rate template set forth herein.

N. "Formula" means the Formula Rate Template set forth in Addendum 45 to Attachment H of the SPP Tariff.

O. "Formula Rate" has the meaning defined herein and means the Mor-Gran-Sou Implementation Protocols together with the Formula Rate Template.

P. "FPA" means the Federal Power Act.

Q. "Informal Challenge" means written notification by an Interested Party to Mor-Gran-Sou, during the Review Period, of any specific challenge to the Annual Update.

R. "Information Request" means a written request submitted by an Interested Party to Mor-Gran-Sou.

S. "Informational Filing" means Mor-Gran-Sou's annual filing at the Commission with the information stipulated in these Protocols.

T. "Initial Posting" means the date on which SPP posts Mor-Gran-Sou's Annual Update to the SPP OASIS.

U. "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a) (2) (iii), or successor regulation.

V. "Interested Party" includes (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

W. "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

X. "OASIS" means Open Access Same-Time Information System.

Y. "OATT" or "SPP Tariff "means SPP's Open Access Transmission Tariff.

Z. "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is January 1, 2019 through December 31, 2019, then the Prior Rate Year is January 1, 2018 through December 31, 2018).

AA. "PTP Rates" means the point-to-point rates derived from the Formula Rate.

BB. "Publication Date" means the date on which Mor-Gran-Sou posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2019 shall be no later than June 30, provided, however, that if June 30 should fall on a weekend or a holiday recognized by FERC, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

CC. "Rate Year" means January 1 of a given year through December 31 of the same Calendar year.

DD. "Review Period" means, unless otherwise extended in writing by Mor-Gran-Sou, the period extending from the Publication Date through October 28, which includes a period for submission of Information Requests and a period for preparation of Informal Challenges.

EE. "RUS" means Rural Utilities Service.

FF. "SPP" means Southwest Power Pool, Inc. or its successor organization.

GG. "SPP Tariff" or "OATT" means SPP's Open Access Transmission Tariff.

HH. "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity ("ROE"); (ii) depreciation and amortization rates; and (iii) other similar fixed values. Stated Values may be changed only pursuant to FPA section 205 or 206.

II. "USoA" means FERC's Uniform System of Accounts.

## Section II Annual Update

A. On or before June 30 of each calendar year (the Publication Date), Mor-Gran-Sou shall:

1. Recalculate the ATRR and the rates for zonal NITS service for the new Rate Year in accordance with the Formula Rate and using the Formula Rate Template; and

2. Provide its Annual Update to SPP and request that SPP post such information to the SPP OASIS (the Initial Posting); and

3. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the Initial Posting shall be due on the next Business Day. The date on which the Initial Posting occurs shall be that year's Publication

Date. Any delay in the Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

B. Concurrent with the Initial Posting, Mor-Gran-Sou shall provide the Annual Update to SPP to serve electronically upon the Service List.[i]

C. The Annual Update shall:

1. Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

2. Be based on the independently-audited books and records of Mor-Gran-Sou for the most recent fiscal year including its certified Form No. 7 or successor reports, including the Financial and Operating Report Electric Power Supply (Op. Report – Power Supply), (January 1 through December 31);

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

4. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, Mor-Gran-Sou shall identify:

   a. Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

   b. Any items included in the Formula Rate at an amount other than a historic cost basis.

   c. Individual impact of any changes in Section I.C (4)(a) above on charges billed under the Formula Rate.

   d. Accounting Changes related to any reorganization or merger transaction.

5. Not seek to modify the Formula Rate.

6. With each Annual Update, Mor-Gran-Sou will include a list of any new transmission facilities included in the Formula Rate Template that were not included in the prior Annual Update. New transmission facilities include but are not limited to additional substations, breakers, other major substation equipment, and additional transmission line miles. The list will indicate the Zone 19 Attachment AI Guidance Document criteria that Mor-Gran-Sou believes supports each facility's inclusion in Mor-Gran-Sou's ATRR as well as the beginning-of-year and end-of-year balances associated with that facility. This provision in no way limits the rights of any Interested Party to challenge inclusion of new facilities.

## Section III Review of Annual Update

Within twenty (20) calendar days of the posting of Mor-Gran-Sou's Annual Update, and with at least seven (7) calendar days' notice, Mor-Gran-Sou will host a meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). Mor-Gran-Sou shall provide notice of this meeting concurrent with the posting of the Annual Update accessible on the SPP OASIS. The notice shall include the date, time and location of the Annual Meeting and shall be provided to Interested Parties through the Service List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the SPP OASIS.

A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Update and will have until September 28 to serve reasonable Information Requests on Mor-Gran-Sou for information and work papers supporting the Annual Update. Such Information Requests shall be limited to that which is necessary to determine:

   a. The extent or effect of an Accounting Change;

   b. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

c. The proper application of the Formula Rate and procedures in these Protocols;

d. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

e. The effect of any change to the underlying USoA or Formula Rate Template; or

f. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. Mor-Gran-Sou will not claim that responses to information and document requests pursuant the Protocols are subject to any settlement confidentiality provision; however, Mor-Gran-Sou may require that Interested Parties execute a non-disclosure agreement to obtain access to material that Mor-Gran-Sou deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR § 388.113(c)(1).

2. Mor-Gran-Sou shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within fifteen (15) Business Days of receipt.

3. Mor-Gran-Sou shall request that SPP post on a publically accessible portion of the SPP OASIS all Information Requests from Interested Parties and Mor-Gran-Sou's response(s) to such requests, and a link to the posting will be electronically served on all Interested Parties via the Service List. If responses to Information Requests contain information deemed by Mor-Gran-Sou to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Mor-Gran-Sou.

4. If the deadline for Interested Parties falls on a weekend or holiday recognized by the FERC, the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until October 28 (or the first Business Day after October 28 if October 28 falls on a weekend or holiday) to notify Mor-Gran-Sou in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. Mor-Gran-Sou will make a good faith effort to respond to any Informal Challenge within twenty (20) calendar days of notification of such Informal Challenge. Mor-Gran-Sou, and, if appropriate, SPP, shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. Mor-Gran-Sou will request that SPP post on the SPP OASIS all Informal Challenges from Interested Parties and Mor-Gran-Sou's responses to the Informal Challenges, and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Informal Challenges contain information are deemed by Mor-Gran-Sou to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Mor-Gran-Sou.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by Mor-Gran-Sou and resolved prior to the end of the Review Period shall be reported in the Final Posting on the SPP OASIS. Any changes or adjustments agreed to by Mor-Gran-Sou after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges.

1. An Interested Party shall have until January 15 (or the first Business Day after January 15 if January 15 falls on a weekend or holiday recognized by FERC) to file a Formal Challenge. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues. Regardless of whether an Interested Party pursues or fails to pursue Informal or Formal Challenges, an Interested Party may file a complaint under section 206 of the FPA at any time.

2. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

b. Explain how the action or inaction violates the filed Formula Rate or Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

3. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via section 206 of the FPA, and shall be served upon Mor-Gran-Sou contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f) (3), or by facsimile, express delivery or messenger to the individual listed as the contact person in Mor-Gran-Sou's Informational Filing.

4. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Mor-Gran-Sou shall bear the burden, consistent with section 205 of the FPA, of proving that it has correctly applied the Formula Rate consistent with these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for modifying the Formula Rate. Modifications to the Formula Rate may be made only pursuant to Federal Power Act section 205 or section 206.

2. A change to the Formula Rate fixed inputs related to ROE, depreciation rates, capital structure, amortization periods, or any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA, sections 205 or 206, provided, however, that Mor-Gran-Sou may make a limited section 205 filing to change depreciation rates, amortization periods, Post-Employment Benefits other than Pensions recovery, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed changes(s) are just and reasonable, and not unduly discriminatory. Any modification to the Formula Rate will require a filing under section 205 or 206 of the FPA.

3. If Mor-Gran-Sou makes a correction to a Mistake in its financial information during the Current Rate Year that would affect the Formula Rate for the Current Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with 18 C.F.R. § 35.19a. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a.

E. Informational Filing

1. By December 15 of each year, Mor-Gran-Sou shall submit to FERC an informational filing ("Informational Filing") of its Annual Update under a separate docket number.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   a. That input data under the Formula Rate is properly recorded in any underlying work papers;

   b. That Mor-Gran-Sou has properly applied the Formula Rate and these procedures;

   c. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   d. The extent of Accounting Changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Mor-Gran-Sou shall provide notice of the Informational Filing to Interested Parties via the Service List and request that SPP post the notice and the docket number assigned to the Informational filing on the SPP OASIS.

## Section IV Joint SPP Transmission Owners' Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, Mor-Gran-Sou intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to Interested Parties via the Formula Rate Posting Information Notification List no less than seven (7) days prior to such meetings.

## Section V Mor-Gran-Sou Example Schedule

| Line No. | Action | Begin | End | Calendar Days from Publication Date |
|---|---|---|---|---|
| 1 | Rate Year | January 1, 2020 | December 31, 2020 | |
| 2 | Publication Date | | July 1, 2019 | |
| 3 | Annual Meeting of Interested Parties | | July 22, 2019 | 7-20 |
| 4 | Information Request Due Date | July 1, 2019 | September 30, 2019 | 90 |
| 5 | Informal Challenges Due Date | | October 30, 2019 | 120 |
| 6 | Final Posting | | December 1, 2019 | |
| 7 | Informational Filing | | December 15, 2019 | |
| 8 | Formal Challenge Due Date | | January 15, 2020 | |

[i] As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP website. As of June 2017, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/.

**ADDENDUM 46 TO ATTACHMENT H**

**Kansas City Board of Public Utilities**

# Calculation of Rates for Point-to-Point Transmission Service Kansas City, Kansas Board of Public Utilities Period ending December 31, 2018

| Line No. | | | |
|---|---|---|---|
| 1 | Kansas City, Kansas BPU ATRR | | $0 |
| 2 | Kansas City, Kansas BPU 12 CP Load (Worksheet 11) | | 0.0 |
| 3 | Firm Yearly Point-to-Point Rate in $/MW - Year | (Line 1 / Line 2) | **$0.000** |
| 4 | Firm and Non-Firm Monthly Point-to-Point Rate in $/MW - Month | (Line 3 / 12) | **$0.000** |
| 5 | Firm and Non-Firm Weekly Point-to-Point Rate in $/MW - Weekly | (Line 3 / 52) | **$0.000** |
| 6 | Firm and Non-Firm Daily On-Peak Point-to-Point Rate in $/MW - Day | (Line 3 / 260) | **$0.000** |
| 7 | Firm and Non-Firm Daily Off-Peak Point-to-Point Rate in $/MW - Day | (Line 3 / 365) | **$0.000** |
| 8 | Firm Hourly On-Peak Point-to-Point Rate in $/MW - Hour | (Line 3 / 4160) | **$0.000** |
| 9 | Firm Hourly Off-Peak Point-to-Point Rate in $/MW - Hour | (Line 3 / 8760) | **$0.000** |

Annual Transmission Revenue Requirement
Kansas City, Kansas Board of Public Utilities

Period ending December 31, 2018

## Annual Transmission Revenue Requirement (ATRR)

| Acco | Description | Tot | Allocator | Alloc | Transmi | Reference |
|---|---|---|---|---|---|---|

| Line No. | unt (A) | (B) | al (C) | (D) | ator (E) | ssion (F) | (G) |
|---|---|---|---|---|---|---|---|
| 1 | | Zonal Gross ATRR | | | | $0 | Line 65, Column (F) |
| 2 | | | | | | | |
| 3 | | Revenue Credits | | | | | |
| 4 | 456 | Rev from SPP for Point-to-Point | $0 | | | | Input |
| 5 | 456 | Other Short-term Point-to-Point Revenue | $0 | | | | Input |
| 6 | 454 | Transmission Related Rents | $0 | | | | Input |
| 7 | | Total Transmission Revenue Credits | | | | $0 | -(Sum(Lines 4c(F), 5c(F), 6c(F)) |
| 8 | | | | | | | |
| 9 | | Zonal Revenue Requirement | | | | $0 | Line 1(F) + Line 7(F) |
| 10 | | | | | | | |
| 11 | | Less: Base Plan Upgrades Revenues | | | | $0 | - (Line 20, Col(F)) |
| 12 | | | | | | | |
| 13 | | **Zonal Net ATRR** | | | | **$0** | Line 9(F) + Line 11(F) |
| 14 | | | | | | | |
| 15 | | Point-to-Point Transmission Service Rates ($/MW-month) | | | | $ - | Rate Calc Worksheet |
| 16 | | | | | | | |
| 17 | | Base Plan Upgrade ATRR | | | | | |
| 18 | | Base Plan Upgrade ATRR without Incentives | | | | $0 | Input |
| 19 | | Additional ATRR for Incentives on Base Plan Upgrades | | | | $0 | Input |
| 20 | | Base Plan Upgrade ATRR for SPP OATT Schedule 11 | | | | $0 | Line 18(F) + Line 19(F) |
| 21 | | | | | | | |
| 22 | | Schedule 1 Annual Revenue Requirements | | | | | |
| 23 | | Scheduling, System Control, and Dispatch Costs | | | | $0 | Acct 561 (excl SPP charges in 561) |
| 24 | | Less PTP Service Credit | | | | $0 | Input |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 25 | | Subtotal | | | | $ - | Line 23 - Line 24 |
| 26 | | Payment in Lieu of Taxes | | | | - | =Line 25 x (1/(1-PILOT %)) - Line 25 |
| 27 | | Total | | | | $ - | Line 25 + Line 26 |

| Line No. | Account | Description | Total | Allocator | Allocator | Transmission | Reference |
|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| 28 | | **Operating & Maintenance (O&M)** | | | | | |
| 29 | 500-557 | Production | $0 | N/A | 0% | $0 | Worksheet 1 |
| 30 | 580-598 | Distribution | $0 | N/A | 0% | $0 | Worksheet 1 |
| 31 | 901-917 | Customer | $0 | N/A | 0% | $0 | Worksheet 1 |
| 32 | 560-574 | Transmission | $0 | | | | Worksheet 3 |
| 33 | 565 | Less: Transmission of Electricity by Others | $0 | | | | Worksheet 1 (Enter as Negative) |
| 34 | 561 | Less: Load Dispatch | $0 | | | | Worksheet 1 (Enter as Negative) |
| 35 | | Net Transmission O&M | $0 | TP | 100% | $0 | Col(C) * Col(E) |
| 36 | | Subtotal | $0 | | | $0 | Sum (Lines 28, 29, 30 and 33) |
| 37 | | | | | | | |
| 38 | | **Administrative & General (A&G) O&M** | | | | | |
| 39 | 920-935 | A&G | $0 | W/S | 0.00% | $0 | Worksheet 1 |
| 40 | 921.00 | Less: Gen Advertising | $0 | W/S | 0.00% | $0 | Worksheet 2 (Enter as negative) |
| 41 | | Less: Misc General Exp | $0 | W/S | 0.00% | $0 | Worksheet 2 (Enter as negative) |
| 42 | | Total A&G | $0 | | | $0 | Sum(Lines 39-41) |
| 43 | | | | | | | |
| 44 | | Total O&M and A&G | $0 | | | $0 | Line 36 + Line 44 |

| Line No. | Account | Description | Total | Allocator | Allocator | Transmission | Reference |
|---|---|---|---|---|---|---|---|
| 45 | | | | | | | |
| 46 | | **Depreciation & Amortization Expense** | | | | | |
| 47 | 310-348 | Production | $0 | N/A | 0% | $0 | Worksheet 1 |
| 48 | 350-359 | Transmission | $0 | TP | 100% | $0 | Worksheet 1 & 3 |
| 49 | 360-374 | Distribution | $0 | N/A | 0% | $0 | Worksheet 1 |
| 50 | 389-399 | General | $0 | W/S | 0.00 % | $0 | Worksheet 1 |
| 51 | | Total Depreciation & Amortization | $0 | | | $0 | Sum (Lines 47-50) |
| 52 | | | | | | | |
| 53 | | **Margin Requirement** | | | | | |
| 54 | | Return on Rate Base | $0 | | | $0 | Line 106 * Line 128 |
| 55 | | Base & Non Base Plan Upgrades | $0 | N/A | 0% | $0 | Inputs, Col(E)*Col(G) |
| 56 | | | | | | | |
| 57 | | **Rate Case Expenses** | $0 | Trans | 100% | $0 | Worksheet 4 |
| 58 | | | | | | | |
| 59 | 408.1 | **Taxes** | | | | | |
| 60 | | PILOT - Gross Receipts | $0 | | | $0 | Worksheet 1 & 5 |
| 61 | | PILOT - Property Tax | $0 | NP | 0.00 % | $0 | Worksheet 1 |
| 62 | | Payroll Tax | $0 | W/S | 0.00 % | $0 | Worksheet 1 |
| 63 | | Total Taxes | $0 | | | $0 | Sum(Lines 60-62) |
| 64 | | | | | | | |
| 65 | | **Zonal Gross ATRR** | **$0** | | | **$0** | Sum(Lines 44,51,54,57,63) |
| 66 | | **Rate Base** | | | | | |
| 67 | | **Gross Plant in Service** | | | | | |
| 68 | 310-348 | Production | $0 | NA | 0% | $0 | Worksheet 6, Line 3(G) |
| 69 | 350-359 | Transmission | $0 | Trans | 100% | $0 | Worksheet 6, Line 38(G) |
| 70 | 360-374 | Distribution | $0 | N/A | 0% | $0 | Worksheet 6, Line 4(G) |
| 71 | 389-399 | General | $0 | W/S | 0.00 % | $0 | Worksheet 6, Line 5(G) |
| 72 | | Total Gross Plant | $0 | GP= | 0.00 | $0 | Sum (Lines 68- |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | % | | 71) |
| 73 | | | | | | | |
| 74 | | **Gross Plant Allocator** | | **GP =** | **0.00 %** | | Line 72(F) / Line 72(C) |
| 75 | | | | | | | |
| 76 | | **Accumulated Depreciation** | | | | | |
| 77 | 310-348 | Production | $0 | NA | 0.00 % | $0 | Worksheet 6, Line 43(G) |
| 78 | 350-359 | Transmission | $0 | Trans | 100.00% | $0 | Worksheet 6, Line 78(G) |
| 79 | 360-374 | Distribution | $0 | N/A | 0.00 % | $0 | Worksheet 6, Line 44(G) |
| 80 | 389-399 | General | $0 | W/S | 0.00 % | $0 | Worksheet 6, Line 45(G) |
| 81 | | Total Accumulated Depreciation | $0 | | | $0 | Sum (Lines 77-80) |
| 82 | | | | | | | |
| 83 | | **Net Plant In Service** | | | | | |
| 84 | 310-348 | Production | $0 | NA | 0.00 % | $0 | Line 68 - Line 77 |
| 85 | 350-359 | Transmission | $0 | Trans | 0.00 % | $0 | Line 69 - Line 78 |
| 86 | 360-374 | Distribution | $0 | N/A | 0.00 % | $0 | Line 70 - Line 79 |
| 87 | 389-399 | General | $0 | W/S | 0.00 % | $0 | Line 71 - Line 80 |
| 88 | | Total Net Plant in Service | $0 | NP= | 0.00 % | $0 | Sum (Lines 84-87) |
| 89 | | | | | | | |
| 90 | | **Net Plant Allocator** | | **NP =** | **0.00 %** | | Line 88(F) / Line 88(C) |
| 91 | | | | | | | |
| 92 | | **Adjustments to Rate Base** | | | | | |
| 93 | N/A | Adjustment | $0 | | | $0 | Worksheet 1 |
| 94 | | Total Adjustments | $0 | | | $0 | Sum (Line 93) |
| 95 | | | | | | | |
| 96 | 105 | **Land Held for Future Use** | $0 | Trans | 100.00% | $0 | Worksheet 1 |
| 97 | | | | | | | |
| 98 | | **Working Capital** | | | | | |
| 99 | | Working Capital | $0 | 1/8th Rule, 45 days | | $0 | Worksheet 10 |
| 100 | | Materials & Supplies | | | | $0 | Worksheet 1 & 7 |
| 101 | 165 | Prepayments | | GP | 0.00 % | $0 | Worksheet 1 |
| 102 | | Total Working Capital | $0 | | | $0 | Sum (Lines 112- |

114)

| Line No. | Account | Description | Total | Allocator | Allocator | | Reference |
|---|---|---|---|---|---|---|---|
| | | | (C) | (D) | (E) | (F) | (G) |
| 103 | | | | | | | |
| 104 | 107 | **Construction Work In Progress** | | | | $0 | Worksheet 1 & 8 |
| 105 | | | | | | | |
| 106 | | **Total Rate Base** | | | | **$0** | |
| 107 | | **Wages & Salaries** | | | | | |
| 108 | 500-555, 557 | Production | $0 | | 0.00 % | | Worksheet 9 |
| 109 | 556 | System Control | $0 | | 0.00 % | | Worksheet 9 |
| 110 | 560-575 | Transmission | $0 | | 0.00 % | | Worksheet 9 |
| 111 | 580-598 | Distribution | $0 | | 0.00 % | | Worksheet 9 |
| 112 | 800-899 | Other Direct Electric | $0 | | 0.00 % | | Worksheet 9 |
| 113 | 901-917 | Customer/Other | $0 | | 0.00 % | | Worksheet 9 |
| 114 | | Wages & Salaries | $0 | | 0.00 % | | |
| 115 | | | | | | | |
| 116 | | **Wages & Salaries Allocator** | | **W/S =** | **0.00 %** | | Line 110, col(E) |
| 117 | | | | | | | |
| 118 | | | | | | | |
| 119 | | | | | | | |

| Line No. | Account | Description | Capital Structure | Capital Structure Ratio | Cost Components | WACC | Reference |
|---|---|---|---|---|---|---|---|
| | | | (C) | (D) | (E) | (F) | (G) |
| 120 | | **Weighted Average Cost of Capital (WACC)** | | | | | |
| 121 | 221-226 | Long Term Debt | $0 | 0% | 0.0% | 0.0% | Worksheet 1 |
| 122 | | Equity (Retained Earnings) | $0 | 0% | 11.1 % | 0.0% | ROE pending FERC approval |
| 123 | | Tot | $0 | 0% | | 0.0% | Sum (Lines 121-122) |

| | | | | | |
|---|---|---|---|---|---|
| | al | | | | |
| 124 | | | | | |
| 125 | Long Term Interest | $0 | 0.0% | | Worksheet 1 |
| 126 | Long Term Debt | $0 | | | Worksheet 1 |
| 127 | | | | | |
| 128 | **Return on Rate Base** | | | **0.0%** | Line 123 col(F) |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 1: Kansas City, Kansas Board of Public Utilities Annual Financial Statements

Please see attached

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 2: Advertising Expense Excluded

| Line No. | Account (A) | Description (B) | Total Utility (C) |
|---|---|---|---|
| 1 | | | |
| 2 | 921.00 - 2140 | General Advertising - General Manager's Office | $0 |
| 3 | 921.00 - 2140 | General Advertising - Marketing and Communication | $0 |
| 4 | 921.00 - 2140 | General Advertising - Utility Services | $0 |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 3: Depreciation Expense Adjustment

| Line No. | FERC Account No (A) | Description (B) | | Amount (C) |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | **Transmission Plant Accounts** | | |
| 3 | 350-359 | Transmission Gross Plant (Worksheet 6, Line 16(G)) | | $0 |
| 4 | 350-359 | Adjustment to Trans Gross Plant (Worksheet 6, Line 26(G)) | | $0 |
| 5 | | Adjustment as a percent of Gross Plant | | 0.0% |
| 6 | | **Trans Plant Allocator (TP) =** | | 100.0% |
| 7 | | **Depreciation Expense** | | |
| 8 | 350 | Land & Land Rights | - | |
| 9 | 352 | Structures & Improvements | - | |
| 10 | 353 | Station Equipment | - | |
| 11 | 354 | Towers & Fixtures | - | |
| 12 | 355 | Poles & Fixtures | - | |
| 13 | 356 | Overhead Conductors & Devices | - | |
| 14 | 357 | Underground Conduits | - | |
| 15 | 358 | Underground Conductors & Devices | - | |
| 16 | 350-359 | Transmission | - | |
| 17 | | Adjustment as a percent of Gross Plant | | 0.0% |
| 18 | | Adjustment to Depreciation Expense | | $0 |
| 19 | | | | |
| 20 | | **Total Adjusted Transmission Depreciation Expense** | | $0 |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 4: Rate Case Expenses

| Line No. | Item (A) | Transmission Related (B) |
|---|---|---|
| 1 | | |
| 2 | Estimated Rate Case Expenses | $0 |
| 3 | | |
| 4 | Amortize over 3 years | $0 |
| 5 | | |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 5: Payment in Lieu of Taxes Calculation (PILOT)

| Line No. | Item (A) | Transmission (B) | Reference Schedule (C) |
|---|---|---|---|
| 1 | | | |
| 2 | | | |
| 3 | **Subtotal ATRR** | | |
| 4 | Total O&M and A&G | $0 | ATRR, Line 44 |
| 5 | Total Depreciation & Amortization | $0 | ATRR, Line 51 |
| 6 | Margin Requirement | $0 | ATRR, Line 54-55 |
| 7 | Rate Case Expenses | $0 | ATRR, Line 57 |
| 8 | Subtotal ATRR | $0 | |
| 9 | | | |
| 10 | Gross Receipts Calculation | =ATRR x (1/(1-PILOT %)) - ATRR | |
| 11 | | | |
| 12 | PILOT Percentage | 11.9% | Input |
| 13 | | | |

| | | | |
|---|---|---|---|
| 14 | PILOT - Gross Receipts | $0 | Line 10 x (1/(1-Line 12)) - Line 10 |

# Annual Transmission Revenue Requirement Kansas City, Kansas Board of Public Utilities Period ending December 31, 2018

## Worksheet 6: Plant in Service Adjustment

| Line No. | FERC Account No (A) | Description (B) | Asset Life (C) | Depreciation Rate (D) | Gross Plant in Service 2017 (E) | Gross Plant in Service 2018 (F) | Average Balance - 2018 (G) |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | **Non-Transmission Accounts** | | | | | |
| 3 | 310-348 | Production Plant In Service | | | $0 | $0 | $0 |
| 4 | 360-374 | Distribution Plant in Service | | | $0 | $0 | $0 |
| 5 | 389-399 | General Plant in Service | | | $0 | $0 | $0 |
| 6 | | | | | | | |
| 7 | | **Transmission Plant Accounts** | | | | | |
| 8 | 350 | Land & Land Rights | | 0.00% | $0 | $0 | $0 |
| 9 | 352 | Structures & Improvements | 40 | 2.50% | $0 | $0 | $0 |
| 10 | 353 | Station Equipment | 46 | 2.19% | $0 | $0 | $0 |
| 11 | 354 | Towers & Fixtures | 47 | 2.11% | $0 | $0 | $0 |
| 12 | 355 | Poles & Fixtures | 36 | 2.80% | $0 | $0 | $0 |
| 13 | 356 | Overhead Conductors & Devices | 40 | 2.49% | $0 | $0 | $0 |
| 14 | 357 | Underground Conduits | 57 | 1.75% | $0 | $0 | $0 |
| 15 | 358 | Underground Conductors & Devices | 45 | 2.24% | $0 | $0 | $0 |
| 16 | | | | | $0 | $0 | $0 |
| 17 | | **Adjustments** | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 18 | 350 | Land & Land Rights | | | $0 | $0 | $0 |
| 19 | 352 | Structures & Improvements | | | $0 | $0 | $0 |
| 20 | 353 | Station Equipment (1) | | | $0 | $0 | $0 |
| 21 | 354 | Towers & Fixtures | | | $0 | $0 | $0 |
| 22 | 355 | Poles & Fixtures | | | $0 | $0 | $0 |
| 23 | 356 | Overhead Conductors & Devices | | | $0 | $0 | $0 |
| 24 | 357 | Underground Conduits | | | $0 | $0 | $0 |
| 25 | 358 | Underground Conductors & Devices | | | $0 | $0 | $0 |
| 26 | | | | | $0 | $0 | $0 |
| 27 | | **Adjusted Plant in Service** | | | | | |
| 28 | 350 | Land & Land Rights | | | $0 | $0 | $0 |
| 29 | 352 | Structures & Improvements | | | $0 | $0 | $0 |
| 30 | 353 | Station Equipment | | | $0 | $0 | $0 |
| 31 | 354 | Towers & Fixtures | | | $0 | $0 | $0 |
| 32 | 355 | Poles & Fixtures | | | $0 | $0 | $0 |
| 33 | 356 | Overhead Conductors & Devices | | | $0 | $0 | $0 |
| 34 | 357 | Underground Conduits | | | $0 | $0 | $0 |
| 35 | 358 | Underground Conductors & Devices | | | $0 | $0 | $0 |
| 36 | | | | | $0 | $0 | $0 |
| 37 | | | | | | | |
| 38 | | **Total Adjusted Transmission Plant** | | | $0 | $0 | $0 |

| | FERC Account No | Description | Asset Life | Depreciation Rate | Accumulated Depreciation - 2017 | Accumulated Depreciation - 2018 | Average Balance - 2018 |
|---|---|---|---|---|---|---|---|
| 39 | | | | | | | |
| 40 | (A) | (B) | (C) | (D) | (E) | (F) | (G) |
| 41 | | | | | | | |
| 42 | | **Non-Transmission Accounts** | | | | | |
| 43 | 310-348 | Production Accum Depreciation | | | $0 | $0 | $0 |
| 44 | 360-374 | Distribution Accum Depreciation | | | $0 | $0 | $0 |
| 45 | 389-399 | General Accum Depreciation | | | $0 | $0 | $0 |
| 46 | | | | | | | |
| 47 | | **Transmission Plant Accounts** | | | | | |
| 48 | 350 | Land & Land Rights | | 0.00% | $0 | $0 | $0 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 49 | 352 | Structures & Improvements | 40 | 2.50% | $0 | $0 | $0 |
| 50 | 353 | Station Equipment | 46 | 2.19% | $0 | $0 | $0 |
| 51 | 354 | Towers & Fixtures | 47 | 2.11% | $0 | $0 | $0 |
| 52 | 355 | Poles & Fixtures | 36 | 2.80% | $0 | $0 | $0 |
| 53 | 356 | Overhead Conductors & Devices | 40 | 2.49% | $0 | $0 | $0 |
| 54 | 357 | Underground Conduits | 57 | 1.75% | $0 | $0 | $0 |
| 55 | 358 | Underground Conductors & Devices | 45 | 2.24% | $0 | $0 | $0 |
| 56 | | | | | $0 | $0 | $0 |
| 57 | | **Adjustments** | | | | | |
| 58 | 350 | Land & Land Rights | | | $0 | $0 | $0 |
| 59 | 352 | Structures & Improvements | | | $0 | $0 | $0 |
| 60 | 353 | Station Equipment (1) | | | $0 | $0 | $0 |
| 61 | 354 | Towers & Fixtures | | | $0 | $0 | $0 |
| 62 | 355 | Poles & Fixtures | | | $0 | $0 | $0 |
| 63 | 356 | Overhead Conductors & Devices | | | $0 | $0 | $0 |
| 64 | 357 | Underground Conduits | | | $0 | $0 | $0 |
| 65 | 358 | Underground Conductors & Devices | | | $0 | $0 | $0 |
| 66 | | | | | $0 | $0 | $0 |
| 67 | | **Adjusted Transmission Accumulated Depreciation** | | | | | |
| 68 | 350 | Land & Land Rights | | | $0 | $0 | $0 |
| 69 | 352 | Structures & Improvements | | | $0 | $0 | $0 |
| 70 | 353 | Station Equipment | | | $0 | $0 | $0 |
| 71 | 354 | Towers & Fixtures | | | $0 | $0 | $0 |
| 72 | 355 | Poles & Fixtures | | | $0 | $0 | $0 |
| 73 | 356 | Overhead Conductors & Devices | | | $0 | $0 | $0 |
| 74 | 357 | Underground Conduits | | | $0 | $0 | $0 |
| 75 | 358 | Underground Conductors & Devices | | | $0 | $0 | $0 |
| 76 | | | | | $0 | $0 | $0 |
| 77 | | | | | | | |
| 78 | | **Total Adjusted Transmission Accum Depreciation** | | | $0 | $0 | $0 |
| 79 | | | | | | | |
| 80 | Notes: | | | | | | |
| 81 | (1) | Reclassified assets based on line item review per Exhibit SPP-001 (Pat Morrill testimony) | | | | | |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 7: Materials & Supplies

| Line No. | Item (A) | Total Utility (B) | Transmission Related (1) (C) |
|---|---|---|---|
| 1 | | | |
| 2 | Materials & Supplies | $0 | $0 |
| 3 | | | |
| 4 | | | |
| 5 | | | |
| 6 | (1) Includes: | | |
| 7 | * Insulators | | |
| 8 | * Cables | | |
| 9 | * Other miscellaneous inventory items | | |
| 10 | | | |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 8: Construction Work in Progress (CWIP)

| Line No. | Item (A) | Transmission Related (B) | Allocable to ATRR (2) (C) | Transmission (D) |
|---|---|---|---|---|
| 1 | | | | |
| 2 | CWIP (1) | $0 | 50% | $0 |
| 3 | | | | |
| 4 | | | | |
| 5 | (1) Includes current transmission-related CWIP. | | | |
| 6 | | | | |
| 7 | (2) In accordance with the Code of Federal Regulations: 18 CFR Section 35.25(c)(3) | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |

# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 9: Functionalized Labor Expense

| Line No. | Account (A) | Description (B) | Total Utility (C) | Allocation of Account 556 (D) | Adjusted Total Utility (E) |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | **O&M Accounts:** | | | |
| 3 | 500-557 | Production-O&M | $ - | $0 | $0 |
| 4 | 556 | System Control & Load Dispatch | - | - | - |
| 5 | 560-575 | Transmission-O&M | - | - | - |
| 6 | 580-598 | Distribution-O&M | - | | - |
| 7 | 800-899 | Other Electric | - | | - |
| 8 | 901-917 | Customer Accounts | - | | - |
| 9 | 920-935 | Administrative & General | - | | - |
| 10 | | Subtotal | $0 | | $0 |
| 11 | | | | | |
| 12 | | **Allocation of System Control & Load Dispatch** | | | |
| 13 | | Allocation to Production | 100% | $0 | |
| 14 | | Allocation to Transmission | 0% | $0 | |
| 15 | 556 | Total 556 | | - | |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 10: Working Capital Calculation

| Line No. | Item (A) | Total (B) | Transmission (C) |
|---|---|---|---|
| 1 | | | |
| 2 | | | |
| 3 | **Working Capital Components** | | |
| 4 | Total O&M and A&G | $0 | $0 |
| 5 | Rate Case Expenses | $0 | $0 |
| 6 | Subtotal O&M | $0 | $0 |
| 7 | | | |
| 8 | Working Capital 1/8th rule (45 days of O&M) | $0 | $0 |

# Annual Transmission Revenue Requirement
# Kansas City, Kansas Board of Public Utilities
# Period ending December 31, 2018

## Worksheet 11: BPU Peak Demand

| Date | Hour Ending | BPU Transmission System Peak Demand | Percentage of Maximum Transmission Network Load During Year |
|---|---|---|---|
| (a) | (b) | (c) | (l) |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |

| | | | |
|---|---|---|---|
| | | | 0.00% |
| | | | 0.00% |
| | | | 0.00% |
| Total | | - | |
| 12-CP | | - | |

**Kansas City Board of Public Utilities**
**Transmission Formula Rate Implementation Protocols**

## I. ANNUAL UPDATE

1. The transmission formula rate template of Kansas City Board of Public Utilities ("BPU") and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of BPU for transmission service in the BPU zone of the Southwest Power Pool, Inc. ("SPP") footprint. BPU must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point ("PTP") Transmission Service, as well as rates for Scheduling, System Control and Dispatch Service ("Schedule 1 Service") in the BPU zone of the SPP footprint.

2. The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the following calendar year ("Rate Year"), subject to review, challenge, and refunds or surcharges with interest, to the extent provided herein.

3. On or before August 15th of each calendar year, BPU shall:

(a) Recalculate the ATRR and the rates for zonal NITS, zonal PTP and Schedule 1 service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

(b) Provide its Annual Update to SPP and cause such information to be accessible on SPP's website; and

(c) Post its Annual Update to the BPU website; and

(d) If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Posting Date." Any delay in the Posting Date shall result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these Protocols.

4. Concurrent with the Annual Update postings, BPU shall provide a notice of such posting via an email distribution list to all Interested Parties.

(a) Interested Parties shall include:

i. Customers under the SPP Tariff;

ii. the Kansas Corporation Commission; and

iii. any person or entity who communicates to BPU an interest in participating in the Annual Update process.

5. The Annual Update shall:

(a) Include a workable populated rate formula template with fully functional spreadsheets showing the calculation of the Annual Update and underlying workpapers in native format with links and formulas intact, including sufficiently detailed workpapers and supporting documentation for data;

(b) Be based on the independently-audited books and records of BPU for the most recent calendar year January 1 through December 31;

(c) Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

(d) With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, BPU shall identify:

i. Any accounting changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

ii. Any items included in the Formula Rate at an amount other than a historic cost basis.

iii. The individual impact of any changes in i. or ii. above on charges billed under the Formula Rate.

(e) Not seek to modify the Formula Rate.

## II. REVIEW OF ANNUAL UPDATE

Within twenty (20) but not less than 10 days after the posting of BPU's Annual Update, BPU will host a Meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). BPU shall provide notice of this meeting concurrent with the posting of the Formula Rate Update accessible on SPP's website and BPU's website. The notice shall include the date, time, and location of the Annual Meeting and shall be provided via email distribution list of Interested Parties identified in Section I.4(a) above. The Annual Meeting shall also be available by telephone and web access with all meeting materials provided electronically.

## III. INFORMATION EXCHANGE

1. Interested Parties may begin submitting information requests immediately following the

Posting Date of the Annual Rate Update and will have until sixty (60) days of the date of the posting to serve reasonable information requests on BPU for information and work papers supporting the Annual Rate Update. Such information requests shall be limited to that what is necessary to determine:

(a) The extent or effect of an accounting change;

(b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

(c) The proper application of the Formula Rate and procedures in these Protocols;

(d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

(e) The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

(f) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable.

2. BPU shall make a good faith effort to respond to information requests pertaining to the Annual Update within seven (7) business days.

3. BPU shall post on its website and cause to be accessible on SPP's website all information requests from Interested Parties and BPU's response(s) to such requests. If responses to information requests contain information deemed by BPU to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and BPU.

## IV. INFORMAL CHALLENGE PROCEDURES

1. Interested Parties shall have until November 1 (or the first Business Day after November 1 if November 1 falls on a weekend or holiday) to notify BPU in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its

Informal Challenge. BPU will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. BPU, and, if appropriate, SPP, shall appoint representatives to work with the Interested Party to resolve the Informal Challenge.

2. BPU will post on its website and cause to be accessible on SPP's website all Informal Challenges from Interested Parties and BPU's response(s) to the Informal Challenges. If responses to information requests contain information deemed by BPU to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and BPU.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by BPU and resolved prior to the Informational Filing shall be reported in the Informational Filing made with FERC and will be reflected in the Annual Rate Update for the following Rate Year.

4. The notification for the Informal Challenges should contain sufficient information to present the issue in question, as well as sufficient contact information.

(a) Any written notification should be addressed to:
ECC Regulatory Affairs
Kansas City Board of Public Utilities
312 N 65$^{th}$ St.
Kansas City, KS 66102

(b) E-mail notifications can be made to:
RegulatoryAffairs@bpu.com

## V. FORMAL CHALLENGES

1. A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the Federal Power Act, and shall be served upon BPU contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in BPU's Informational Filing.

3. The notification for the Formal Challenges should contain sufficient information to present the issue in question, as well as sufficient contact information.

(a) Any written notification should be addressed to:
ECC Regulatory Affairs

Kansas City Board of Public Utilities
312 N. 65th St.
Kansas City, KS 66102

(b) E-mail notifications can be made to:
RegulatoryAffairs@bpu.com

## VI. MODIFICATION OF FORMULA RATE OR ANNUAL UPDATE

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of return on equity ("ROE"), depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the Federal Power Act ("FPA"), Sections 205 or 206.

3. If BPU makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the SPP Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the SPP Tariff.

## VII. INFORMATIONAL FILING

1. By December 1 of each year, BPU shall submit to FERC an informational filing ("Informational Filing") of its Annual Update.

2. This Informational Filing must include the information that is reasonably necessary to determine:

(a) That input data under the Formula Rate is properly recorded in any underlying workpapers;

(b) That BPU has properly applied the Formula Rate and these procedures;

(c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

(d) The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, BPU shall provide notice of the Informational Filing via the mail distribution list and by posting the docket number assigned to the Informational filing on BPU's website and accessible on SPP's website.

## VIII. JOINT SPP TRANSMISSION OWNERS' MEETING

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, BPU will participate in that process.

**ADDENDUM 47 TO ATTACHMENT H**

**Roughrider Electric Cooperative, Inc.**

## Roughrider Electric Cooperative, Inc

Index

## INDEX
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX


| A<br>Line<br>No. | B<br>Worksheet | C<br>Description |
|---|---|---|
| 1 | Summary ATRR | Summary of Total ATRR Revenue Requirement |
| 2 | Worksheet A | Calculation of Rate Base |
| 3 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 4 | Worksheet C | Capital Structure & Rate of Return based on Return on Equity |
| 5 | Worksheet D | Network Demand |
| 6 | Worksheet E | Allocation Factors |
| 7 | Worksheet F | General Input Section |
| 8 | Worksheet G | Depreciation Rates |
| 9 | Worksheet H | Other Operating Revenue (A450-456) |
| 10 | Worksheet I | O&M Input (A560-598) |
| 11 | Worksheet J | Wage Input & Functionalization |
| 12 | Worksheet K | Annual Depreciation Expense (A403) |
| 13 | Worksheet L | RTO / ISO Expenses (A575-576) |
| 14 | Worksheet M | Regulatory and Commission Expenses (A928) |
| 15 | Worksheet N | Customer Accounting Input (A901-905) |
| 16 | Worksheet O | Plant Input (A350-373), Accum Depr (A108), Amortization (A111) |
| 17 | Worksheet P | Plant Held for Future Use (A105) |
| 18 | Worksheet Q | Construction Completed Not Classified (A106) |
| 19 | Worksheet R | Construction Work in Process (A107) |
| 20 | Worksheet S | SPP Upgrades |
| 21 | Worksheet T | Calculation of Interest Applied to True-Up Calculations |
| 22 | Worksheet U | Qualified Transmission Substations |
| 23 | Worksheet V | Qualified Transmission Lines |
| 24 | Notes: | |

A. Green Shading denotes input values.
B. If not already provided for in automatic updates of the cell text references and line references describing the source of the values should be updated accordingly.

**Roughrider Electric Cooperative, Inc**

Summary ATRR

**Summary of Total ATRR Revenue Requirement**
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Account Number | C Description | D Reference | E Total Company | F Allocation Factor | G Allocation % | H Transmission ATRR |
|---|---|---|---|---|---|---|---|
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 36, Column H | | | | #DIV/0! |
| 3 | | Revenue Credits- Operating | | | | | |
| 4 | 412 | Electric Plant, Leased | Worksheet H, Line 13, Column F | $ - | Direct 100 | 100.0% | $ - |
| 5 | 450-451 | Retail Related | Worksheet H, Line 14, Column G | $ - | Direct Zero | 0.0 % | $ - |
| 6 | 454 | Rents | Worksheet H, Line 13 Column I | $ - | Direct 100 | 100.0% | $ - |
| 7 | 456 | Other Electric Revenue | Worksheet H, Line 13 Column J | $ - | Direct 100 | 100.0% | $ - |
| 8 | 456 | Basin Facility Discount | Worksheet H, Line 13 Column K | $ - | Direct Zero | 0.0 % | $ - |
| 9 | 456 | SPP Wheeling, Sch 7 & 8 | Worksheet H, Line 13, Column H | $ - | Direct 100 | 100.0% | $ - |
| 10 | 456 | Direct Assigned Revenues | Worksheet H, Line 13 Column N | $ - | Direct 100 | 100.0% | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 11 | 459 | Renewable Energy Credits | Worksheet H, Line 13 Column O | $ - | Direct Zero | 0.0 % | $ - |
| 12 | | Revenue Credits-Operating | Subtotal | $ - | | | $ - |
| 13 | | Revenue Requirement before SPP Adj and Prior Yr corrections | Line 2 - Line 12 | | | | #DIV/0! |
| 14 | | Reconciliation Adjustment for Prior Period Errors (Gross ATRR) | Worksheet T, Line 6, Column L | | | | $ - |
| 15 | | Reconciliation Adjustment for Prior Period Errors (SPP Upgrades) | -Worksheet T, Line 12, Column L | | | | $ - |
| 16 | | SPP Upgrades | -Worksheet S, Line 28, Column P | | | | $ - |
| 17 | 456 | Sch 11 P2P Revenue Credits | -Worksheet H, Line 13 Column M | | | | $ - |
| 18 | | Sum | Sum Lines 13 thru 17 | | | | #DIV/0! |
| 19 | | Network Transmission Load (MW) | Worksheet D, Line 14, Column C | | | | - |
| 20 | | **B. Point-To-Point Service** | | | | | |
| 21 | | Annual Point-to-Point Cost ($/MW-Yr) | Line 18 / Line 19 | | | | #DIV/0! |
| 22 | | Monthly Point-to-Point ($/MW-Mo) | Line 21 / 12 | | | | #DIV/0! |
| 23 | | Weekly Point-to-Point ($/MW-Week) | Line 21 / 52 | | | | #DIV/0! |
| 24 | | Daily On-Peak Point-to-Point ($/MW-Day) | Line 21 / 260 | | | | #DIV/0! |
| 25 | | Daily Off-Peak Point-to-Point ($/MW-Day) | Line 21 / 365 | | | | #DIV/0! |
| 26 | | Hourly On-Peak Point-to-Point | Line 21 / 4160 | | | | #DIV/0! |

| | | | |
|---|---|---|---|
| 27 | ($/MWh) Hourly Off-Peak Point-to-Point ($/MWh) | Line 21 / 8760 | #DIV/0! |

## Roughrider Electric Cooperative, Inc

Worksheet A

## Calculation of Rate Base

| A Line No. | B Account Number | C Description | D Reference | E Beginning of Year | F End of Year | G Total Company | H Allocation Factor | I ATRR Allocation % | J Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Plant in Service** | | | | | | | |
| 2 | 301-303 | Intangible Plant | Worksheet F, Line 48, Columns D and E | $ - | $ - | $ - | T-Wage | | |
| 3 | 310-340 | Production Plant | N/A | | | $ - | Direct Zero | 0.0% | $ - |
| 4 | 350 | Land and Land Rights | Worksheet O, Line 23, Columns F and G | $ - | $ - | $ - | T-Tran Plant | | |
| 5 | 352 | Structures and Improvements | Worksheet O, Line 23, Columns H and I | $ - | $ - | $ - | T-Tran Stations | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 6 | 353 | Station Equipment - SCADA | Worksheet O, Line 23, Columns J and K | $ - | $ - | $ - | Direct 100 | 100.0% | $ - |
| 7 | 353 | Station Equipment | Worksheet O, Line 23, Columns L and M | $ - | $ - | $ - | T-Tran Stations | | |
| 8 | 354-359 | Other Transmission Plant | Line 9 Less Lines 4 thru 7 | $ - | $ - | $ - | T-Tran Lines | | |
| 9 | | Transmission Plant | Worksheet F, Line 49, Columns D and E | $ - | $ - | | | | |
| 10 | 360.00 | Land and Land Rights | Worksheet O, Line 23, Columns P and Q | $ - | $ - | $ - | T-Distb Plant | | |
| 11 | 361.00 | Structures and Improvements | Worksheet O, Line 23, Columns R and S | $ - | $ - | $ - | T-Distb Stations | | |
| 12 | 362.00 | Station Equipment | Worksheet O, Line 23, Columns T and U | $ - | $ - | $ - | T-Distb Stations | | |
| 13 | 364-373 | Other Distribution Plant | Line 14 Less Lines 10 thru 12 | $ - | $ - | $ - | Direct Zero | 0.0% | $ - |
| 14 | | Distribution Plant | Worksheet F, Line 45, Columns D and E | $ - | $ - | $ - | | | |
| 15 | 389-391.1 | General Plant Subtotal | Worksheet F, Line 46, Columns D and E | $ - | $ - | $ - | T-Wage | | |
| 16 | 389-390 | Headquarters Plant | Worksheet F, Line 47, Columns D and E | $ - | $ - | $ - | T-Wage | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 17 | | Gross Electric Plant in Service | Subtotal | $ - | $ - | | | | |
| 18 | 105 | Electric Plant Held For Future Use | Worksheet P, Line 7, Columns E, F and H | $ - | $ - | Direct | | | $ - |
| 19 | 106 | Completed Construction Not Classified | Worksheet Q, Line 12, Columns E, F, and K | $ - | $ - | Direct | | | $ - |
| 20 | 107 | Construction Work in Progress | Worksheet F, Line 52, Columns D and E and Worksheet R, Line 18, Column K | $ - | $ - | $ - | Direct | | $ - |
| 21 | | Utility Plant | Sum | $ - | $ - | $ - | | | |
| 22 | | **Accumulated Depreciation** | | | | | | | |
| 23 | 108.4 | Depr Rsv of Other Prod Plant | Worksheet O, Line 52, Columns X and Y | $ - | $ - | $ - | Direct Zero | 0.0% | $ - |
| 24 | 108.5 | Accumulated Depreciation of Transmission Stations | Worksheet O, Line 61, Columns D and E | $ - | $ - | $ - | T-Tran Stations | | |
| 25 | 108.5 | Accumulated Depreciation of Transmission SCADA | Worksheet O, Line 62, Columns D and E | $ - | $ - | $ - | Direct 100 | 100.0% | $ - |
| 26 | 108.5 | Accumulated Depreciation of Transmission Lines | Worksheet O, Line 63, Columns D and E | $ - | $ - | $ - | T-Tran Lines | | |
| 27 | 108.6 | Accumulated Depreciation of Distribution Stations | Worksheet O, Line 65, Columns D and E | $ - | $ - | $ - | T-Distb Stations | | |
| 28 | 108.6 | Accumulated Depreciation of Distribution | Worksheet O, Line 66, Columns D | $ - | $ - | $ - | Direct Zero | 0.0% | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Plant Other | and E | | | | | |
| 29 | 108.7 | Accumulated Depreciation of General Plant | Worksheet O, Line 52, Columns Z and AA | $ - | $ - | T-Wage | | |
| 30 | 108.8 | Retirement Work in Progress | Worksheet O, Line 52, Columns AB and AC | $ - | $ - | T-Wage | | |
| 31 | 111 | Amort of Electric Plant in Service | Worksheet O, Line 52, Columns AD and AG | $ - | $ - | T-Wage | | |
| 32 | | Total Accumulated Depreciation | Sum | $ - | $ - | $ - | | |
| 33 | | **Total Net Plant in Service** | | | | | | |
| 34 | | Net Intangible Plant | Line 2 | $ - | $ - | $ - | | |
| 35 | | Net Production Plant | Line 3 - Line 23 | $ - | $ - | $ - | | $ - |
| 36 | | Net Transmission Plant | Line 9 - Line 24 thru 26 | $ - | $ - | $ - | | |
| 37 | | Net Distribution Plant | Line 14 - Line 27 thru 28 | $ - | $ - | $ - | | |
| 38 | | Net General Plant | Line 15 + Line 16 - Line 29 | $ - | $ - | $ - | | |
| 39 | | Net Completed Construction Not Classified | Line 19 | $ - | $ - | $ - | | $ - |
| 40 | | Retirement work in progress | - Line 30 | $ - | $ - | $ - | | |
| 41 | | Total Net Plant in Service | Sum | $ - | $ - | $ - | | |
| 42 | | **Adjustments to Rate Base** | | | | | | |
| 43 | | Plant Held for Future Use | Line 18 | $ - | $ - | $ - | | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 44 | | Construction Work in Progress | Line 20 | $ - | $ - | $ - | Direct | | $ - |
| 45 | | Working Capital | | | | | | | |
| 46 | | Total Transmission O&M Costs | Worksheet B, Line 24, Columns E and H | | | $ - | | | |
| 47 | | Billing Lag in Days | Worksheet F, Line 1 Col F | | | 45 | | | 45 |
| 48 | | Working Capital | Line 46 * Line 47 / 365 | | | $ - | | | |
| 49 | 165 | Prepayments | Worksheet F, Line 36, Columns D and E | $ - | $ - | $ - | T-Plant | | |
| 49 | | Materials and Supplies | Worksheet F, Line 35, Columns D and E | | - - | $ - | T-Plant | | |
| 50 | | Rate Base | Total | | | $ - | | | |

## Roughrider Electric Cooperative, Inc

Worksheet B

## O&M, Depreciation, and Return Expenses Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Account Number | C Description | D Reference | E Total Company | F Allocation Factor | G Allocation % | H Transmission |
|---|---|---|---|---|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | | **Transmission Expenses** | | | | | |
| 2 | 561 | Load Dispatch Expense | Worksheet I, Line 108 column F | $ - | Direct Zero | 0.0 % | $ - |
| 3 | 562 | Transmission Station Expenses | Worksheet I, Line 108 columns G, N, and O | $ - | T-Tran Stations | 0.0 % | $ - |
| 4 | 563-564, 571-572 | Transmission Line Expenses | Worksheet I, Line 108 columns H, I, P, and Q | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 5 | 565 | Transmission of Electricity by Others | Worksheet I, Line 108 column J | $ - | Direct Zero | 0.0 % | $ - |
| 6 | 560, 566-567 | Super, Misc & Rents Transmission Expenses | Worksheet I, Line 108 columns E, K, L, M, and R | $ - | T-Tran Plant | 0.0 % | $ - |
| 7 | 575-576 | Regional Market Expenses | Worksheet L, Line 2 and 4 columns F | $ - | Direct | | $ - |
| 8 | | Transmission O&M | Subtotal | $ - | | | #DIV/0! |
| 9 | 582 | Distribution Expense - Stations Operations | Worksheet I, Line 108 Column U | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |
| 10 | 580-589 | Distribution Expense - Operations All Other | Worksheet F, Line 13, Column E Less Line 9 | $ - | Direct Zero | 0.0 % | $ - |
| 11 | 591-592 | Distribution Expense - Stations Maintenance | Worksheet I, Line 108 Column W | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |
| 12 | 590-598 | Distribution Expense - Maintenance All Other | Worksheet F, Line 14, Column E Less Line 11 | $ - | Direct Zero | 0.0 % | $ - |
| 13 | | Distribution O&M | Subtotal | $ - | | | #DIV/0! |
| 14 | 901-905 | Customer Accounting | Worksheet F, Line 15, Column E - Line 15 | $ - | Direct Zero | 0.0 % | $ - |
| 15 | 901-905 | Customer Accounting SPP Expenses | Worksheet N, Line 21, Column E | $ - | Direct | | $ - |
| 16 | 907-910 | Customer Services & Information | Worksheet F, Line 16, Column E | $ - | Direct Zero | 0.0 % | $ - |
| 17 | 911-916 | Sales | Worksheet F, Line 17, Column | $ - | Direct Zero | 0.0 % | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | E | | | | |
| 1 | | Customer Related | Subtotal | $ | | | $ |
| 8 | | Expense | | - | | | - |
| | | | | | | | |
| 1 | | Administrative & | | | | | |
| 9 | | General Expense | | | | | |
| 2 | 920- | Admin and General | Worksheet F, | $ | T-Wage | #DI | #DIV/0 |
| 0 | 931 | Operations | Line 18, Column | - | | V/0 | ! |
| | | Expense | E - lines 21 and | | | ! | |
| | | | 22 | | | | |
| 2 | | SPP Commission | Worksheet M, | $ | Direct | 100 | $ |
| 1 | 928 | and Regulatory | Line 7, Column F | - | 100 | .0 | - |
| | | Expenses | | | | % | |
| 2 | | Non-SPP | Worksheet M, | $ | Direct | 0.0 | $ |
| 2 | 928 | Commission and | Line 7, Column E | - | Zero | % | - |
| | | Regulatory | | | | | |
| | | Expenses | | | | | |
| 2 | | Total A&G | Subtotal | $ | | | #DIV/0 |
| 3 | | Expenses | | - | | | ! |
| | | | | | | | |
| 2 | | Subtotal O&M | Line 8 + Line 13 | $ | | | #DIV/0 |
| 4 | | | + Line 18 + Line | - | | | ! |
| | | | 23 | | | | |
| | | | | | | | |
| 2 | | Depreciation | | | | | |
| 5 | | Expense | | | | | |
| 2 | | Depreciation | Worksheet K, | $ | Direct | 0.0 | $ |
| 6 | 403 | Expense-Production | Line 13, Col E | - | Zero | % | - |
| 2 | | Depreciation | Worksheet K, | $ | T-Tran | 0.0 | $ |
| 7 | 403 | Expense- | Line 13, Col F | - | Plant | % | - |
| | | Transmission Plant | | | | | |
| 2 | | Depreciation | Worksheet K, | $ | Direct | 0.0 | $ |
| 8 | 403 | Expense- | Line 13, Col G | - | Zero | % | - |
| | | Distribution | | | | | |
| 2 | | Depreciation | Worksheet K, | $ | T-Wage | #DI | #DIV/0 |
| 9 | 403 | Expense-General | Line 13, Col H | - | | V/0 | ! |
| | | | | | | ! | |
| 3 | | Unrecovered Plant | Worksheet K, | $ | Direct | 100 | $ |
| 0 | 405 | Expense (Note A) | Line 13, Col K | - | 100 | .0 | - |
| | | | | | | % | |
| 3 | | Accretion Expense - | Worksheet K, | $ | Direct | 0.0 | $ |
| 1 | 411.1 | Plant Retirement | Line 13, Col J | - | Zero | % | - |
| 3 | | Amortization of | Worksheet K, | $ | T-Wage | #DI | #DIV/0 |
| 2 | 407 | Intangible Plant | Line 13, Col I | - | | V/0 | ! |
| | | | | | | ! | |
| 3 | | Total Depreciation | sum lines 26 thru | $ | | | #DIV/0 |
| 3 | | & Amortization | 32 | - | | | ! |
| | | | | | | | |
| 3 | | Electric Generation, | Worksheet F, | $ | T-Tax | 0.0 | $ |

| | | | | | |
|---|---|---|---|---|---|
| 4 | Distribution, and Transmission Taxes | Line 21, Column E | - | % | - |
| 35 | Return | Worksheet C, Line 6, Column J | | | #DIV/0! |
| 36 | Revenue Requirement | Line 24 + Line 33 + Line 34 + Line 35 | | | #DIV/0! |

37 Notes:

38 A. Any unrecovered plant expense are associated with the contribution in aid of construction. No amounts should be included on this line absent specific FERC approval.

## Roughrider Electric Cooperative, Inc

Worksheet C

## Capital Structure & Rate of Return based on Return on Equity
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No | B Description | C Reference | D Total Co EoY | E Actual Cap Str Weight (A) | F Target Cap Str (B) | ) | G Interest Expense | H Cost of Capital (C) | I Weighted Rate of Return (D) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Capital Structure & Return** | | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Lines 39 thru | $ - | #DIV/ | #DIV/0! | | $ - | #DIV/ | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | 43 and line 28 columns E | | 0! | | | | 0! | |
| 3 | Total Margins and Equities | Worksheet F, line 38, Column E | $ - | #DIV/0! | #DIV/0! | | | 10.1 % | #DIV/0! |
| 4 | Total Capitalization | Subtotal | $ - | #DIV/0! | #DIV/0! | ! | $ - | | #DIV/0! |
| 5 | Rate Base | Worksheet A, Line 50, Column | | | | | | | #DIV/0! |
| 6 | Return | Line 4 * Line 5 | | | | | | | #DIV/0! |

7 Notes:
8 A.) The capital structure listed in Column (E) is calculated based on total capitalization amounts listed in Column (D).
9 B.) Roughrider shall apply its base ROE and the 50-basis point adder to its actual capital structure except that for any four Rate Years, Roughrider, at its own discretion, may elect to apply its base ROE plus any applicable adders to a proxy capital structure with an equity component of 35.24 percent and a debt component of 64.76 percent ("Capital Structure Option"). The four Rates Years may be consecutive or non-consecutive.
10 C.) The Cost of Capital for Total Margins and Equities (ROE) is fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing. The Cost of Capital for Total Margins and Equities reflects a 50 basis point incentive adder for RTO participation. The Cost of Capital for Long Term Debt is calculated by dividing the interest expense in Column (G) by the total amount of LTD in Column (D).
11 D.) Column (I) values for lines 2-3 equal Column (H) values multiplied by Column (F) values.

## Roughrider Electric Cooperative, Inc

Worksheet D

## Network Demand
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A<br>Line No | B<br>Description | C<br>Load (MW) |
|---|---|---|
| 1 | January | |
| 2 | February | |
| 3 | March | |
| 4 | April | |
| 5 | May | |
| 6 | June | |
| 7 | July | |

| | | |
|---|---|---|
| 8 | August | |
| 9 | September | |
| 10 | October | |
| 11 | November | |
| 12 | December | |
| 13 | Total (MW-Mo) | 0.0 |
| 14 | Average (MW-Mo) | **0.0** |

## Roughrider Electric Cooperative, Inc

Work sheet E

## Allocation Factors Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Description | C Reference | D Total | E Allocation Factor Name | F Allocation Factor % | G ATRR Allocated |
|---|---|---|---|---|---|---|
| 1 | Production Wages | Worksheet J, Line 55, Column E | $ - | Direct Zero | 0.0 % | $ - |
| 2 | Transmission Supervision Operations | Worksheet J, Line 55, Column F | $ - | T-Tran Plant | 0.0 % | $ - |
| 3 | Transmission Load Dispatch and Scheduling | Worksheet J, Line 55, Column G | $ - | Direct Zero | 0.0 % | $ - |
| 4 | Transmission Station Operations | Worksheet J, Line 55, Column H | $ - | T-Tran Stations | 0.0 % | $ - |
| 5 | Transmission Line Operations | Worksheet J, Line 55, Column I | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 6 | Transmission of Elect by Others | Worksheet J, Line 55, Column J | $ - | Direct Zero | 0.0 % | $ - |
| 7 | Transmission Misc | Worksheet J, Line 55, Column K | $ - | T-Tran Plant | 0.0 % | $ - |
| 8 | Transmission Supervision Maintenance | Worksheet J, Line 55, Column L | $ - | T-Tran Plant | 0.0 % | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | Transmission Station Maintenance | Worksheet J, Line 55, Column M | $ - | T-Tran Stations | 0.0 % | $ - |
| 10 | Transmission Line Maintenance | Worksheet J, Line 55, Column N | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 11 | Transmission Maintenance - Misc | Worksheet J, Line 55, Column O | $ - | T-Tran Plant | 0.0 % | $ - |
| 12 | Distribution Operations-Stations | Worksheet J, Line 55, Column P | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |
| 13 | Distribution Operations-All Other | Worksheet J, Line 55, Column Q | $ - | Direct Zero | 0.0 % | $ - |
| 14 | Distribution Maintenance-Stations | Worksheet J, Line 55, Column R | $ - | T-Distb Stations | #DIV/0! | #DIV/0! |
| 15 | Distribution Maintenance-All Other | Worksheet J, Line 55, Column S | $ - | Direct Zero | 0.0 % | $ - |
| 16 | Customer Accounts Less meter reading | Worksheet J, Line 55, Column U | $ - | Direct Zero | 0.0 % | $ - |
| 17 | Customer Accounts Meter Reading | Worksheet J, Line 55, Column T | $ - | Direct 100 | 100.0% | $ - |
| 18 | Customer Service | Worksheet J, Line 55, Column V | $ - | Direct Zero | 0.0 % | $ - |
| 19 | Sales | Worksheet J, Line 55, Column W | $ - | Direct Zero | 0.0 % | $ - |
| 20 | Total Wages, Excluding A&G | Sum Lines 1 thru 19 | $ - | | | #DIV/0! |
| 21 | **T-Wage** | | | | | **#DIV/0!** |
| 22 | 353 Transmission Stations Gross Plant | Worksheet A Line 7, Column G | $ 1 | Direct WS-U | | $ - |
| 23 | **T-Tran Stations** | | | | | **0.0%** |
| 24 | 362 Distribution Stations Gross Plant | Worksheet A Line , Column G | $ - | Direct WS-U | | $ - |
| 25 | **T-Distb Stations** | | | | | **#DIV/0!** |
| 26 | 354-359.1Transmission Lines Gross Plant | Worksheet A Line 8, Column G | $ - | Direct WS-V | | $ - |
| 27 | **T-Tran Lines** | | | | | **#DIV/0!** |
| 28 | Transmission | Worksheet A, | $ | | | $ |

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|---|---|---|---|---|
| | Qualifying Plant | Lines 5 thru 8, Col. G and J | 2 | - |
| 29 | **T-Tran Plant** | | | **0.0%** |
| 30 | Distribution | Worksheet A, | $ | $ |
| | Qualifying Plant | Lines 11 thru 13, Col. G and J | - | - |
| 31 | **T-Distb Plant** | | | **#DIV/0!** |
| 32 | Plant in Service | Worksheet A Line 17, Col. G and J | | $ - |
| 33 | **T-Plant** | | | **#VALUE!** |
| 34 | **Direct Zero** | Fixed allocation | | **0.0%** |
| 35 | **Direct 100** | Fixed allocation | | **100.0%** |
| 36 | SPP Trans. as % of Total Company Trans. + Dist. | Worksheet A, Lines 9 and , Col. G and | $ 1 | $ - |
| 37 | **T-Tax** | | | **0.0%** |

# Roughrider Electric Cooperative, Inc

Work shee t F

## General Input Section
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Description | C Reference | D BoY | E EoY | F End of Year Value or Amount |
|---|---|---|---|---|---|
| 1 | Billing Lag in days | Industry Standard | | | 45 |
| 2 | CWIP included in Rate Base | Per ER20-1750 | | | 50% |
| 3 | Fixed Ratio 41.6 kV | Per ER20-1750 | | | 100% |
| 4 | Fixed Ratio 60 kV | Per ER20-1750 | | | 100% |
| 5 | Fixed Ratio of 69 kV | Per ER20-1750 | | | 100% |
| 6 | Fixed Ratio of 115 kV | Per ER20-1750 | | | 125% |
| 7 | Fixed Ratio of 230 kV | Per ER20-1750 | | | 188% |
| 8 | Capital Structure Option (Yes or No) | Worksheet C, Note B, line 9 | | | No |
| 9 | Capital Structure Option Rate Year 1 | Worksheet C, Note B, line 9 | | | Insert Rate Year 1 [20xx] |
| 10 | Capital Structure Option Rate Year 2 | Worksheet C, Note B, line 9 | | | Insert Rate Year 2 [20xx] |
| 11 | Capital Structure Option Rate Year 3 | Worksheet C, Note B, line 9 | | | Insert Rate Year 3 [20xx] |
| 12 | Capital Structure Option Rate Year 4 | Worksheet C, Note B, line 9 | | | Insert Rate Year 4 [20xx] |
| 13 | Operating Revenue and Patronage Capital | Form 7, Part A, Line 1, Column B | | | |
| 14 | Power Production Expense | Form 7, Part A, Line 2, Column B | | | |
| 15 | Cost of Purchased Power | Form 7, Part A, Line 3, Column B | | | |
| 16 | Transmission Expense | Form 7, Part A, Line 4, Column B | | | |
| 17 | Regional Market | Form 7, Part A, | | | |

| | | | | | |
|---|---|---|---|---|---|
| 177 | Operations Expense | Line 5, Column B | | | |
| 181 | Distribution Expense-Operation | Form 7, Part A, Line 6, Column B | | | |
| 191 | Distribution Expense-Maintenance | Form 7, Part A, Line 7, Column B | | | |
| 201 | Customer Account Expense | Form 7, Part A, Line 8, Column B | | | |
| 212 | Customer Sales and Informational Expense | Form 7, Part A, Line 9, Column B | | | |
| 222 | Sales Expense | Form 7, Part A, Line 10, Column B | | | |
| 232 | Administrative and General Expense | Form 7, Part A, Line 11, Column B | | | |
| 244 | Subtotal-Operations & Maintenance Expense | Sum Lines 9 thru 18 | | $ - | |
| 255 | Depreciation and Amortization Expense | Form 7, Part A, Line 13, Column B | | | |
| 266 | Electric Generation, Dist., and Trans. Taxes | Form 7, Part A, Line 14, Column B | | | |
| 277 | Tax Expense - Other | Form 7, Part A, Line 15, Column B | | | |
| 288 | Interest on Long Term Debt | Form 7, Part A, Line 16, Column B | | | |
| 299 | Interest Charged to Construction (Credit) | Form 7, Part A, Line 17, Column B | | | |
| 310 | Other Interest Expense | Form 7, Part A, Line 18, Column B | | | |
| 321 | Other Deductions | Form 7, Part A, Line 19, Column B | | | |
| 332 | Subtotal Cost of Electric Service | Sum Lines 19 and 20 thru 26 | | $ - | |
| 343 | Patronage Capital and Operating Margins | Line 8 - Line 27 | | $ - | |
| 354 | | | BoY | EoY | Average |
| 365 | Materials and Supplies | Form 7, Part C, Line 23 (Prior year & current) | | | $ - |
| 376 | Prepayments | Form 7, Part C, Line 24 (Prior year & current) | | | $ - |
| 387 | | | | EoY | |
| 398 | Total Margins and Equities | Form 7, Part C, Line 36 | | | |
| 399 | Total Long Term Debt | Form 7, Part C, Line 43 | | | |
| 4010 | Obligations Under Capital | Form 7, Part C, | | | |

| | | | | | |
|---|---|---|---|---|---|
| 40 | Leases - Noncurrent | Line 44 | | | |
| 41 | Current Maturities Long-Term Debt | Form 7, Part C, Line 50 | | | |
| 42 | Current Maturities Long-Term Debt - Economic Development | Form 7, Part C, Line 51 | | | |
| 43 | Current Maturities Capital Leases | Form 7, Part C, Line 52 | | | |
| | | | | | |
| 44 | Plant in Service | | BoY | EoY | Average |
| 44 | | | | | |
| 45 | Total Distribution Plant | Form 7, Part E, Line 1, Cols A and E | | | $ - |
| 46 | General Plant | Form 7, Part E, Line 2, Cols A and E | | | $ - |
| 47 | Headquarters Plant | Form 7, Part E, Line 3, Cols A and E | | | $ - |
| 48 | 301-303 Total Intangible Plant | Form 7, Part E, Line 4, Cols A and E | | | $ - |
| 49 | Transmission Plant | Form 7, Part E, Line 5, Cols A and E | | | $ - |
| 50 | 380-386 RTO/ISO Plant | Form 7, Part E, Line 6, Cols A and E | | | $ - |
| 51 | All Other Utility Plant | Form 7, Part E, Line 7, Cols A and E | | | $ - |
| 52 | Construction Work in Progress | Form 7, Part E, Line 9, Cols A and E | | | $ - |
| 53 | Plant in Service | Subtotal | $ - | $ - | $ - |

54 Notes:

55 A. Acquisition adjustments will not be used in the calculation of ATRR absent Commission approval through a 205 or 206 filing.

56 B. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Roughrider will

6 describe such changes in the Annual Update, and the changes will
0 be subject to the review of Interested Parties under
6 the procedures set forth in Roughrider's Implementation Protocols.
1 Roughrider may not change the columns or the formulas
6 included in these Worksheets during the
2 Annual Update.
6 C. Stated Values in Column F Lines 3-7 are fixed and cannot be
3 changed absent Commission approval through
6 a Section 205 or 206 filing.
4

## Roughrider Electric Cooperative, Inc

Workshe et G

## Depreciation Rates
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A<br>Line No | B<br>Description | C<br>Plant Account Number | D<br>Annual Depr Rate |
|---|---|---|---|
| 1 | Transmission: | | |
| 2 | Land and Land rights | 350.00 | N/A |
| 3 | Structures & Improvements | 352.00 | 2.75% |
| 4 | Transmission Station Equipment | 353.00 | 2.75% |
| 5 | Poles and Fixtures | 355.00 | 2.75% |
| 6 | Overhead Conductors and devices | 356.00 | 2.75% |
| 7 | Underground Conductors and Devices | 358.00 | 2.75% |
| 8 | | | |
| 9 | Distribution: | | |
| 10 | Land and Land rights | 360 | 0.00% |
| 11 | Structures & Improvements | 361 | 2.62% |
| 12 | Distribution Station Equipment | 362 | 2.95% |
| 13 | Poles, Towers & Fixtures | 364 | 3.03% |
| 14 | Overhead Conductor & Devices | 365 | 2.31% |
| 15 | Underground Conduit | 366 | 2.00% |
| 16 | UG Conductor & Devices Post 1987 | 367 | 2.75% |
| 17 | UG Conductor & Devices Pre 1988 | 367.1 | N/A |
| 18 | Line Transformers | 368 | 2.61% |
| 19 | Services | 369 | 3.21% |
| 20 | Meters | 370 | 3.40% |
| 21 | Install on Cust Premises | 371 | 4.40% |
| 22 | Leased Property on Cust Premises | 372 | 4.10% |
| 23 | Street Lighting and Signal | 373 | 3.80% |
| 24 | | | |
| 25 | General: | | |

| | | | |
|---|---|---|---|
| 26 | Structures & Improvements | 390 | 2.00% |
| 27 | Transportation Equip | 392 | 15.00% |
| 28 | Power Operated Equip | 396 | 11.00% |
| 29 | Other Tangible SCADA | 399 | 20.00% |
| 30 | | | |

31 Note:
32 A. Stated Values in Column D are fixed and cannot be changed absent Commission approval through
33 a Section 205 or 206 filing.
34 Account 373.0 (Street Lighting and Signals) is fully depreciated and no depreciation expense will be collected until additions are made to this account.

## Roughrider Electric Cooperative, Inc

Worksheet H

## Other Operating Revenue (A450-456)
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account No | Account Description | Total Company | % Allocated to SPP | Electric Plant, Lea | Retail Related | Wheeling - SPP | Rents | Other Electric Revenue | Basin Facility Discount | Sch 7 & 8 P2P | Sch 11 P2P | Direct Assigned Revenues | Renewable Energy Credits |

| | | |

**Roughrider Electric Cooperative, Inc**

Worksheet

**O&M Input (A560-598) Rate Year Data Ending 12/31/2XXX ; FY Ending 12/31/2XXX**

| A<br>Line No. | B<br>Account | C<br>Description | D<br>Balance | E<br>560 - Supervision & Engr. | F<br>561- Load Dispatching | G<br>562 - Station Expenses | H<br>563 - OH Line Expenses | I<br>564 - UG Line Expenses | J<br>565 - Transmission of Elec. | K<br>566 - Miscellaneous Expense | L<br>567 - Rents | M<br>568 - Supervision and Engin | N<br>569 - Structures | O<br>570 - Station Equipment | P<br>571 - OH Lines | Q<br>572 - UG Lines | R<br>573 - Misc Trans Sys Plan | S<br>575.1 - 575.8 | T<br>576.1 - 576.5 | U<br>582 - Station Ops | V<br>580 - 589 Distr Op & Maint | W<br>591 - 592 Distr Station Maint | X<br>590 - 598 Distribution Maint |
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| 108 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation.
Additional line items or line deletions will not

require FPA Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Roughrider's Implementation Protocols.

**Roughrider Electric Cooperative, Inc**

Worksheet J

**Wage Input & Functionalization Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Account Description | Labor Total Company | 555 Purchased Power | 560 Tran Ops Super | 561 Load Dispatch | 562 Trans Station | 563-564 OH & UG L | 565 Tran of Electb | 566 Misc-Wages | 568 Maint-Supervi | 569-570 Str Maint-W | 571 Maint-OH Line | 573 Maint-Misc Tr | 582 Distb Station | 580-589 Dist Opera | 591-592 Distb Sta | 590-598 Dist Maint | 902 Meter Reading-W | 901,903-905 Cust Ac | 907-910 Cust Servic | 911-916 Cust Sales- | Admin & General |

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| 9 | provide detail | | | | | | | | | | | | | | | | | | | | |
| | and linkage to | | | | | | | | | | | | | | | | | | | | |

updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas included in these Worksheets during the Annual Update.

## Roughrider Electric Cooperative, Inc

Worksheet K

## Annual Depreciation Expense (A403) Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No | B Account | C Description | D Year End Balance | E Production | F Transmission | G Distribution Expense | H General | I Amort | J Plant Retirement | K Unrecovered Plant Expense |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | |
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| 13 | | Totals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | | | | | | | | | | |
| 15 | | Note: | | | | | | | | |
| 16 | | A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide | | | | | | | | |
| 17 | | information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these | | | | | | | | |
| 18 | | changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting | | | | | | | | |
| 19 | | documentation. Additional line items or line deletions will not require FPA Section 205 or 206 | | | | | | | | |

filings. Roughrider will
20 describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under
21 the procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas
22 included in these Worksheets during the Annual Update.

## Roughrider Electric Cooperative, Inc

Worksheet L

## RTO / ISO Expenses (A575-576) Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A<br>Line | B<br>Account No. | C<br>Description | D<br>Annual Expense Amount | E<br>% Included in SPP | F<br>SPP Amount |
|---|---|---|---|---|---|
| | | **575.1-575.8 RTO/ISO Expense - Operation** | | | |
| 1a | | | $0.00 | 100% | $0.00 |
| 1b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 2 | | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)** | $0.00 | | $0.00 |
| | | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | |
| 3a | | | $0.00 | 100% | $0.00 |
| 3b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 4 | | **576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)** | $0.00 | | $0.00 |

5 Notes
6 A. The total on line 2, column D must reconcile to the amounts shown on Form 7.
7 B. The total on line 4, column D must

reconcile to the amounts shown on Form 7.

C. Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for inclusion in SPP Zone 19 ATRR following a change in accounting procedures to the Form 7 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that this occurs, Roughrider may file a single-issue Section 205 filing with the Commission to seek recovery of these amounts in Zone 19 rates. Roughrider may not include any costs absent authroization from FERC via a Section 205 or 206 filing.

D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

## Roughrider Electric Cooperative, Inc

Works heet M

## Regulatory and Commission Expenses (A928)
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A<br>Line No. | B<br>Account 928 | C<br>Description | D<br>Total Company | E<br>Non-Qualifying SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
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| 6 | | | | | |
| 7 | | Total | $ - | $ - | $ - |

8 Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas included in these Worksheets during the Annual Update.

**Roughrider Electric Cooperative, Inc**

Works heet N

**Customer Accounting Input (A901-905) Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX**

| A<br>Line No. | B<br>Account | C<br>Description | D<br>Total Company | E<br>901-905 SPP Expenses |
|---|---|---|---|---|
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|---|---|---|---|
| 21 | Total Customer Accounting | $ - | $ - |

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23 Note:

24 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.

25 with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting

26 documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require

27 FPA Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the

28 procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas included in these Worksheets during the

29 Annual Update.

**Roughrider Electric Cooperative, Inc**

Worksheet C

**Plant Input (A350-373),**

# Accum Depr (A108), Amortization (A111) Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AG |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Description | Balance BOY | Balance EOY | 350 Tran Land BOY | 350 Tran Land EOY | 352 Tran Structure BOY | 352 Tran Structure EOY | 353 Tran Station SCADA BOY | 353 Tran Station SCADA | 353 Tran Station BOY | 353 Tran Station EOY | 355-358 Tran Lines BOY | 355-358 Tran Lines EOY | 360 Distb Land & Right | 360 Distb Land & Right | 361 Structures & Improvements | 361 Structures & Impro | 362 Distrib Station Equipment BOY | 362 Distrib Station Eq | 363-373 Other Distribution BOY | 363-373 Other Distribt | 108 Generators BOY | 108 Generators EOY | 108 General Plant BOY | 108 General Plant EOY | 108.8 RWIP BOY | 108.8 RWIP EOY | 111 Amort of Elec. Plant in Serv BOY | 111 Amort of Elec. Pla |

| | | EOY | ss BOY | ss EOY | BOY | vements EOY | uipment EOY | ion EOY | nt in Serv EOY |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Gross Plant** | | | | | | | | |
| 2 | | | | | | | | | |
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|---|---|---|---|---|---|
| | | issio n Stati ons SC AD A | | | |
| 5 6 | | 354-359. 1 Oth er Tra nsm issio n Plan t (Lin es) | $ - | $ - | $ - |
| 5 7 | **Dist ribu tion Pla nt Fun ctio nali zati on** | | | | |
| 5 8 | | 360-362 Dist ribut ion Stati ons | $ - | $ - | $ - |
| 5 9 | | 364-373 Dist ribut ion All Oth er | $ - | $ - | $ - |
| 6 0 | **Tra ns mis sio** | | | | |

| | | | | |
|---|---|---|---|---|
| | **n Depreciation Functionalization** | | | |
| 61 | 108.5 Accumulated Depreciation Reserves - Transmission Stations | $ - | $ - | $ - |
| 62 | 108.5 Accumulated Depreciation Reserves - Transmission SCADA | $ - | $ - | $ - |
| 63 | 108.5 | $ | $ | $ |

| | | | | | |
|---|---|---|---|---|---|
| | Accumulated Depreciation Reserves - Transmission Lines | | - | - | - |
| 64 | **Distribution Depreciation Functionalization** | | | | |
| 65 | 108.5 | Accumulated Depreciation Reserves - Distribution Stations | $ - | $ - | $ - |
| 66 | 108.5 | Acc | $ | $ | $ |

umulated Depreciation Reserves - Distribution All Other - - -

Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and

linkage to updated Form 7 data requirements or other similar supporting
71 documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Roughrider will
72 describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under
73 the procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas
74 included in these Worksheets during the

Annual Update.

# Roughrider Electric Cooperative, Inc

Worksheet P

## Plant Held for Future Use (A105)
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No | B Facility No. | C Asset No. | D Description | E BoY Investment | F EOY Investment | G Average Investment | H Qualified |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | Transmission Qualified Future Use Assets | | | | |
| 3 | | | | | | $ - | $ - |
| 4 | | | | | | $ - | |
| 5 | | | | | | $ - | |
| 6 | | | | | | $ - | |
| 7 | | | Total Plant Held for Future Use | $ - | $ - | $ - | $ - |

8 Note:

9 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.

10 with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting

11 documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA

12 Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures

1 set forth in Roughrider's Implementation Protocols. Roughrider may not change
3 the columns or the formulas included in these Worksheets during the Annual Update.

## Roughrider Electric Cooperative, Inc

Worksheet Q

## Construction Completed Not Classified (A106) Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Fac ID | C Work Order | D Project | E BoY Balance | F EoY Balance | G Facility | H % SPP Eligible | I BoY Amount | J EoY Amount | K Average | L Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | $ - | $ - | $ - | |
| 2 | | | | | | | | $ - | $ - | $ - | |
| 3 | | | | | | | | $ - | $ - | $ - | |
| 4 | | | | | | | | $ - | $ - | $ - | |
| 5 | | | | | | | | $ - | $ - | $ - | |
| 6 | | | | | | | | $ - | $ - | $ - | |
| 7 | | | | | | | | $ - | $ - | $ - | |
| 8 | | | | | | | | $ - | $ - | $ - | |
| 9 | | | | | | | | $ - | $ - | $ - | |
| 10 | | | | | | | | $ - | $ - | $ - | |
| 11 | | | | | | | | $ - | $ - | $ - | |
| 12 | | | Total | $ - | $ - | | | $ - | $ - | $ - | |

13 Note :
14 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.
15 with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting
16 documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA
17 Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures
18 set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas included in these Worksheets during the Annual Update.

## Roughrider Electric Cooperative, Inc

Worksheet R

## Construction Work in Process (A107) Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Project ID | C Project Description | D Approval Docket No. | E Recovery Approved | F Approximate Construction Start Date | G Close-out Date (Estimated) | H BoY Balance | I EoY Balance | J Average Balance (Col H + I) /2 | K Includable in SPP ATRR Rate Base (Col E * Col J) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | Per | 50 | | | | | $ | $ |

| | | | | | |
|---|---|---|---|---|---|
| | ER20-1750 | % | | - | - |
| 2 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 3 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 4 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 5 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 6 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 7 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 8 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 9 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 10 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 11 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 12 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 13 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 14 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 15 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 16 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |
| 17 | Per | 50 | | $ | $ |
| | ER20-1750 | % | | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 18 | **Totals** | **$ -** | **$ -** | **$ -** | **$ -** |

19

20 Notes:

21 A. Percentage of "Recovery Approved" cannot be added or changed absent approval from FERC.

22 B. AFUDC ceases when CWIP is recovered in rate base corresponding to the amount of CWIP included in Rate Base. No CWIP will be included in rate base absent FERC authorization.

23 Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of

24 CWIP and corresponding AFUDC capitalized. Projects are transmission related only.

25 C. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with

26 changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation.

27 Additional line items will not require FPA Section 205 or 206 filings. Roughrider will describe such changes in the Annual

28 Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns

29 or the formulas included in these Worksheet during the Annual Update.

**Roughrider Electric Cooperative, Inc**

Worksheets

**SPP Upgrades**
**Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX**

| A Line No. | B Description | C Reference | D Company Total Transmission Amount |
|---|---|---|---|
| 1 | Gross Qualified Transmission Plant | Worksheet A, Line 9, Column | $ - |
| 2 | Accumulated Qualified Transmission Depreciation | Worksheet A, Lines 24 thru 26, Column | $ - |
| 3 | Net Transmi | Line 1 - Line | $ - |

| | | | | |
|---|---|---|---|---|
| | ssion Plant | 2 | | |
| 4 | Transmission O&M | Worksheet B, Line 8, Column H | $ - | |
| 5 | **Annual Allocation Factor for Transmission O&M** | Line 4 / Line 1 | | 0.00 % |
| 6 | General Plant Depreciation Expense | Worksheet B, Line 29, Column H | $ - | |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | Line 6 / Line 1 | | 0.00 % |
| 8 | Return on Rate Base | Worksheet B, Line 35, Column H | $ - | |
| 9 | **Annual Allocation Factor for** | Line 8 / Line 3 | | 0.00 % |

| | | | |
|---|---|---|---|
| | **Return** | | |
| 10 | **Depreciation Rates** | | |
| 11 | Sub | Worksheet G, Line 4 Col D | 2.75 % |
| 12 | Line | Worksheet G, Line 5 Col D | 2.75 % |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | | | | **Project Accumulated** | **Transmission O&M Annual Allocation** | **Allocation for** | **Depreciation Annual** | **General Plant** | **Annual Expense** | **Project** | **Annual Allocation Factor for** | **Annual Return** | **and Amortization** | **Revenue** | **Prior Year** | **Project** |
| **No.** | **Project Name and #** | **Type** | **Project Gross Plant** | **Depreciation** | **Factor** | **Transmission O&M** | **Allocation Factor** | **Depreciation** | **Charge** | **Net Plant** | **Return** | **Charge** | **Expense** | **Credits** | **Adjustments** | **ATRR** |
| | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Note A | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | Col G + Col I | Col D - Col E (Note B) | Line 9, Col D | Col K * Col L | Note C | | | Col J + Col M + Col N - Col O |
| 13 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 14 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 15 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 16 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 17 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 18 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 19 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 20 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 21 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 22 | | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 2 | | | | | | 0. | $ | 0. | $ | $ | $ | 0. | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | | 00% | - | 00% | - | - | - | 00% | - | - | - | - | - |
| 24 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 25 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 26 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 27 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - |
| 28 | Total | | $ - | $ - | | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - |

29 Notes:

30 A. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1.

31 This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

32 Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

33 B. Net Plant is the Gross Plant less the associated Accumulated Depreciation.

34 C. Depreciation Expense is the depreciation amount associated with the specified line

or sub.

Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Roughrider's Implementation Protocols. Roughrider may not change the columns or the formulas included in these Worksheets during the Annual Update.

# Roughrider Electric Cooperative, Inc

Worksheet T

## Calculation of Interest Applied to True-Up Calculations
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

**A B C D E F G H I J K L**

**Adjustments To ATRR Due To Error Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred) /Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | $ - |
| 2 | | | | | | | | | $ - |
| 3 | | | | | | | | | $ - |
| 4 | | | | | | | | | $ - |
| 5 | | | | | | | | | $ - |
| 6 | **Total Adjustment to Gross ATRR:** | | | | | | | | $ - |

**Adjustments To SPP Regional**

**Projects' ATRR Due To Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred) /Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | | | | $ - |
| 8 | | | | | | | | | $ - |
| 9 | | | | | | | | | $ - |
| 10 | | | | | | | | | $ - |
| 11 | | | | | | | | | $ - |
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | | | | | | | | $ - |

13 Notes:

14 A. Rate Year in which the error occurred and affected the ATRR and rates paid by customers.

15 B. Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.

| 16 | Period Start | Period Ending | Year description | Beginning Balance or Payb | Accumulation | FERC Annual Inter | Quarterly Interest | Ending Balance |
|---|---|---|---|---|---|---|---|---|

| | | | e | ack | est Rate | Amo unt | |
|---|---|---|---|---|---|---|---|
| **Interest calculation for Item #1** | | | | | | | |
| 17 | | Rate Year | $ - | $ - | | $ - | $ - |
| 18 | | Rate Year | $ - | $ - | | $ - | $ - |
| 19 | | Rate Year | $ - | $ - | | $ - | $ - |
| 20 | | Rate Year | $ - | $ - | | $ - | $ - |
| 21 | | | $ - | | | $ - | $ - |
| 22 | | | $ - | | | $ - | $ - |
| 23 | | | $ - | | | $ - | $ - |
| 24 | | | $ - | | | $ - | $ - |
| 25 | | True-Up Year | $ - | $ - | | $ - | $ - |
| 26 | | True-Up Year | $ - | $ - | | $ - | $ - |
| 27 | | True-Up Year | $ - | $ - | | $ - | $ - |
| 28 | | True-Up Year | $ - | $ - | | $ - | $ - |
| 29 | Tot al | | | | | $ - | |

30 **Interest calculation for Item #2…**

31 (Repeat interest calculation for other items as necessary.)

32 C. Interest Note: The interest calculation may need to be modified to recognize the implementation partial year.

33 D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a

34 Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal

35 Power Act section 205 or 206 filing.

## Roughrider Electric Cooperative, Inc

Worksheet U

## Qualified Transmission Substations
## Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A Line No. | B Sub No. | C Description | D BOY Gross Plant | E EOY Gross Plant | F Percent High Side | G Network | H BOY Qualified Gross Plant | I EOY Qualified Gross Plant | J Average Qualified Gross Plant |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **353 Transmission Stations** | | | | | | | |
| 2 | | | | | | | $ - | $ - | $ - |
| 3 | | | | | | | $ - | $ - | $ - |
| 4 | | | | | | | $ - | $ - | $ - |
| 5 | | | | | | | $ - | $ - | $ - |
| 6 | | | | | | | $ - | $ - | $ - |
| 7 | | | | | | | $ - | $ - | $ - |
| 8 | | | | | | | $ - | $ - | $ - |
| 9 | | | | | | | $ - | $ - | $ - |
| 10 | | | | | | | $ - | $ - | $ - |
| 11 | | | | | | | $ - | $ - | $ - |
| 12 | | | | | | | $ - | $ - | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 13 | | | | | | | $ - | $ - | $ - |
| 14 | | | | | | | $ - | $ - | $ - |
| 15 | | | | | | | $ - | $ - | $ - |
| 16 | | | | | | | $ - | $ - | $ - |
| 17 | | | | | | | $ - | $ - | $ - |
| 18 | | | | | | | $ - | $ - | $ - |
| 19 | | | | | | | $ - | $ - | $ - |
| 20 | | | | | | | $ - | $ - | $ - |
| 21 | | | | | | | $ - | $ - | $ - |
| 22 | | | | | | | $ - | $ - | $ - |
| 23 | | | | | | | $ - | $ - | $ - |
| 24 | | | | | | | $ - | $ - | $ - |
| 25 | | | | | | | $ - | $ - | $ - |
| 26 | | | | | | | $ - | $ - | $ - |
| 27 | | | | | | | $ - | $ - | $ - |
| 28 | | | | | | | $ - | $ - | $ - |
| 29 | | | | | | | $ - | $ - | $ - |
| 30 | | | | | | | $ - | $ - | $ - |
| 31 | | | | | | | $ - | $ - | $ - |
| 32 | | | | | | | $ - | $ - | $ - |
| 33 | | | | | | | $ - | $ - | $ - |
| 34 | | | | | | | $ - | $ - | $ - |
| 35 | | | | | | | $ - | $ - | $ - |
| 36 | | | | | | | $ - | $ - | $ - |
| 37 | | | | | | | $ | $ | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | - | - | - |
| 38 | | | | | | | $ - | $ - | $ - |
| 39 | | | | | | | $ - | $ - | $ - |
| | | | | | | | $ - | $ - | $ - |
| 40 | | | | | | | $ - | $ - | $ - |
| 41 | | | | | | | $ - | $ - | $ - |
| 42 | | | | | | | $ - | $ - | $ - |
| 43 | | | | | | | $ - | $ - | $ - |
| 44 | | | | | | | $ - | $ - | $ - |
| 45 | | | | | | | $ - | $ - | $ - |
| 46 | | | | | | | $ - | $ - | $ - |
| 47 | | | | | | | $ - | $ - | $ - |
| 48 | | | | | | | $ - | $ - | $ - |
| 49 | | | | | | | $ - | $ - | $ - |
| 50 | | | | | | | $ - | $ - | $ - |
| 51 | | | | | | | $ - | $ - | $ - |
| 52 | | Total 353 | $ - | $ - | | | $ - | $ - | $ - |
| 53 | | **362 Distribution Stations** | | | | | | | |
| 54 | | | | | | | $ - | $ - | $ - |
| 55 | | | | | | | $ - | $ - | $ - |
| 56 | | | | | | | $ - | $ - | $ - |
| 57 | | | | | | | $ - | $ - | $ - |
| 58 | | | | | | | $ - | $ - | $ - |
| 59 | | | | | | | $ - | $ - | $ - |
| 60 | | | | | | | $ | $ | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | - | - | - |
| 61 | | | | | | $ - | $ - | $ - |
| 62 | | | | | | $ - | $ - | $ - |
| 63 | | | | | | $ - | $ - | $ - |
| 64 | | | | | | $ - | $ - | $ - |
| 65 | | | | | | $ - | $ - | $ - |
| 66 | | | | | | $ - | $ - | $ - |
| 67 | | | | | | $ - | $ - | $ - |
| 68 | | | | | | $ - | $ - | $ - |
| 69 | | | | | | $ - | $ - | $ - |
| 70 | | | | | | $ - | $ - | $ - |
| 71 | | | | | | $ - | $ - | $ - |
| 72 | | | | | | $ - | $ - | $ - |
| 73 | | | | | | $ - | $ - | $ - |
| 74 | | | | | | $ - | $ - | $ - |
| 75 | | | | | | $ - | $ - | $ - |
| 76 | | | | | | $ - | $ - | $ - |
| 77 | | | | | | $ - | $ - | $ - |
| 78 | | | | | | $ - | $ - | $ - |
| 79 | | | | | | $ - | $ - | $ - |
| 80 | | | | | | $ - | $ - | $ - |
| 81 | | | | | | $ - | $ - | $ - |
| 82 | | | | | | $ - | $ - | $ - |
| 83 | | | | | | $ - | $ - | $ - |
| 84 | | | | | | $ - | $ - | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 85 | | | | | | | $ - | $ - | $ - |
| 86 | | | | | | | $ - | $ - | $ - |
| 87 | | | | | | | $ - | $ - | $ - |
| 88 | | | | | | | $ - | $ - | $ - |
| 89 | | | | | | | $ - | $ - | $ - |
| 90 | | | | | | | $ - | $ - | $ - |
| 91 | | | | | | | $ - | $ - | $ - |
| 92 | | | | | | | $ - | $ - | $ - |
| 93 | | | | | | | $ - | $ - | $ - |
| 94 | | | | | | | $ - | $ - | $ - |
| 95 | | | | | | | $ - | $ - | $ - |
| 96 | | | | | | | $ - | $ - | $ - |
| 97 | | | | | | | $ - | $ - | $ - |
| 98 | | | | | | | $ - | $ - | $ - |
| 99 | | | | | | | $ - | $ - | $ - |
| 100 | | | | | | | $ - | $ - | $ - |
| 101 | | | | | | | $ - | $ - | $ - |
| 102 | | | | | | | $ - | $ - | $ - |
| 103 | | Total 362.0 | $ - | $ - | | | $ - | $ - | $ - |

104 Note:

105 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately
106 provide information, and populate or remove data in the Worksheet with changes in future years.
107 Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or
108 other similar supporting documentation. Additional line items or line deletions will not require FPA Section
109 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be

110 subject to the review of Interested Parties under the
111 procedures set forth in Roughrider's Implementation
112 Protocols. Roughrider may not change the columns or the
113 formulas included in these Worksheets during
114 the Annual Update.
115
116 B. The percent of qualified plant is based on company
117 records.

## Roughrider Electric Cooperative, Inc

Worksheet V

## Qualified Transmission Lines Rate Year Data Ending 12/31/2XXX; FY Ending 12/31/2XXX

| A<br>Line No. | B<br>Table 1: Existing Assets Prior to January 1, 2020 | C<br>kV Voltage | D<br>Line Length (Miles) | E<br>BOY Gross Plant | F<br>EOY Gross Plant | G<br>Network | H<br>BOY Qualified Gross Plant | I<br>EOY Qualified Gross Plant | J<br>Average Qualified Gross Plant |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | $ - | $ - | $ - |
| 2 | | | | | | | $ - | $ - | $ - |
| 3 | | | | | | | $ - | $ - | $ - |
| 4 | | | | | | | $ - | $ - | $ - |
| 5 | | | | | | | $ - | $ - | $ - |
| 6 | | | | | | | $ - | $ - | $ - |
| 7 | | | | | | | $ - | $ - | $ - |
| 8 | | | | | | | $ - | $ - | $ - |
| 9 | | | | | | | $ - | $ - | $ - |
| 10 | | | | | | | $ | $ | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | - | - | - |
| 11 | | | | | | | $ - | $ - | $ - |
| 12 | | | | | | | $ - | $ - | $ - |
| 13 | | | | | | | $ - | $ - | $ - |
| 14 | | | | | | | $ - | $ - | $ - |
| 15 | | | | | | | $ - | $ - | $ - |
| 16 | | | | | | | $ - | $ - | $ - |
| 17 | | | | | | | $ - | $ - | $ - |
| 18 | | | | | | | $ - | $ - | $ - |
| 19 | | | | | | | $ - | $ - | $ - |
| 20 | | | | | | | $ - | $ - | $ - |
| 21 | | | | | | | $ - | $ - | $ - |
| 22 | | | | | | | $ - | $ - | $ - |
| 23 | | | | | | | $ - | $ - | $ - |
| 24 | | | | | | | $ - | $ - | $ - |
| 25 | | | | | | | $ - | $ - | $ - |
| 26 | | | | | | | $ - | $ - | $ - |
| 27 | | | | | | | $ - | $ - | $ - |
| 28 | | | | | | | $ - | $ - | $ - |
| 29 | | | | | | | $ - | $ - | $ - |
| 30 | | | | | | | $ - | $ - | $ - |
| 31 | | | | | | | $ - | $ - | $ - |
| 32 | | | | | | | $ - | $ - | $ - |
| 33 | | | | | | | $ - | $ - | $ - |
| 34 | | | | | | | $ - | $ - | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 35 | | | | | | | $ - | $ - | $ - |
| 36 | | | | | | | $ - | $ - | $ - |
| 37 | | | | | | | $ - | $ - | $ - |
| 38 | | | | | | | $ - | $ - | $ - |
| 39 | | | | | | | $ - | $ - | $ - |
| 40 | | | | | | | $ - | $ - | $ - |
| 41 | | | | | | | $ - | $ - | $ - |
| 42 | | | | | | | $ - | $ - | $ - |
| 43 | | | | | | | $ - | $ - | $ - |
| 44 | | | | | | | $ - | $ - | $ - |
| 45 | | | | | | | $ - | $ - | $ - |
| 46 | | | | | | | $ - | $ - | $ - |
| 47 | | | | | | | $ - | $ - | $ - |
| 48 | | | | | | | $ - | $ - | $ - |
| 49 | | | | | | | $ - | $ - | $ - |
| 50 | | | | | | | $ - | $ - | $ - |
| 51 | | | | | | | $ - | $ - | $ - |
| 52 | | | | | | | $ - | $ - | $ - |
| 53 | | | | | | | $ - | $ - | $ - |
| 54 | | | | | | | $ - | $ - | $ - |
| 55 | | | | | | | $ - | $ - | $ - |
| 56 | | | | | | | $ - | $ - | $ - |
| 57 | | | | | | | $ - | $ - | $ - |
| 58 | | | | | | | $ - | $ - | $ - |
| 59 | | | | | | | $ | $ | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | - | - | - |
| 60 | | | | | | | $ - | $ - | $ - |
| 61 | | | | | | | $ - | $ - | $ - |
| 62 | | | | | | | $ - | $ - | $ - |
| 63 | | | | | | | $ - | $ - | $ - |
| 64 | | | | | | | $ - | $ - | $ - |
| 65 | | | | | | | $ - | $ - | $ - |
| 66 | | | | | | | $ - | $ - | $ - |
| 67 | | | | | | | $ - | $ - | $ - |
| 68 | | | | | | | $ - | $ - | $ - |
| 69 | | | | | | | $ - | $ - | $ - |
| 70 | | | | | | | $ - | $ - | $ - |
| 71 | | | | | | | $ - | $ - | $ - |
| 72 | | | | | | | $ - | $ - | $ - |
| 73 | | | | | | | $ - | $ - | $ - |
| 74 | | | | | | | $ - | $ - | $ - |
| 75 | | | | | | | $ - | $ - | $ - |
| 76 | | | | | | | $ - | $ - | $ - |
| 77 | | | | | | | $ - | $ - | $ - |
| 78 | | | | | | | $ - | $ - | $ - |
| 79 | Total | | 0.00 | $ - | $ - | | $ - | $ - | $ - |
| 80 | | | | | | | | | |
| | **Table 2: All Transmission Plant In Service Beginning on January 1, 2020** | **kV Voltage** | **Line Length (Miles)** | **Network** | **BOY** | **EOY** | **Average Qualified Gross Plant** | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 81 | | | | $ - | $ - | $ - |
| 82 | | | | $ - | $ - | $ - |
| 83 | | | | $ - | $ - | $ - |
| 84 | Total | 0.00 | | $ - | $ - | $ - |
| 85 | | | | | | |
| 86 | **Table 3: Combined Summary** | **Line Length (Miles)** | **BOY** | **EOY** | **Average** | **Average Per Mile** |
| 87 | All Transmission Plant | 0.00 | $ - | $ - | $ - | |
| 88 | Existing Assets Before January 1, 2020 | 0.00 | $ - | $ - | $ - | |
| 89 | All Transmission Plant In Service Beginning on January 1, 2020 | 0.00 | $ - | $ - | $ - | N/A |
| 90 | | | | | | |
| 91 | | | | | | |
| 92 | Note: | | | | | |
| 93 | A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately | | | | | |
| 94 | provide information, and populate or remove data in the Worksheet with changes in future years. | | | | | |
| 95 | Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or | | | | | |
| 96 | other similar supporting documentation. Additional line items or line deletions will not require FPA Section | | | | | |
| 97 | 205 or 206 filings. Roughrider will describe such changes in the Annual Update, and the changes will be | | | | | |
| 98 | subject to the review of Interested Parties under the procedures set forth in Roughrider's Implementation | | | | | |
| 99 | Protocols. Roughrider may not change the columns or the formulas included in these Worksheets during | | | | | |
| 100 | the Annual Update. | | | | | |

# Roughrider Electric Cooperative, Inc. Transmission Formula Rate Implementation Protocols

The transmission formula rate template ("Formula Rate Template") of Roughrider Electric Cooperative, Inc. ("Roughrider") and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Roughrider for transmission revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("SPP Tariff"). Roughrider must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point ("PTP") Transmission Service in Zone 19.

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the SPP Tariff. The ATRR shall be determined for January 1 to December 31 of a given calendar year. The Formula Rate shall become effective for recovery of Roughrider's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC") under section 205 of the Federal Power Act ("FPA").

The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein. These Protocols specify the dates applicable to the activities described herein. Should any due date fall on a weekend or a holiday recognized by FERC, then the due date shall be no later than the next Business Day.

## Section I Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

A. "Accounting Change" means any change in Roughrider's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

1. revisions to Rural Utilities Service's ("RUS") Uniform System of Accounts ("USoA");

2. revisions to the RUS Financial and Operating Report - Electric Distribution ("Form No. 7") data and the requirement to report certain values within it;

3. correction of errors and prior period adjustments that impact the ATRR;

4. the implementation of new estimation methods or policies;

5. changes to income tax elections;

6. changes in accounting practices or policies mandated by a state regulatory authority with jurisdiction over Roughrider that could impact the Formula Rate or calculations under the Formula;

7. implementation of accounting practices for unusual or unconventional items where RUS has not provided specific accounting direction;

8. a change in Roughrider's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor);

9. Roughrider's own accounting changes (which constitute a change to the ATRR greater than or equal to $15,000) such as the addition or deletion of a subaccount not specified by FERC's USoA; or

10. a change in Roughrider's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

B. "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by Roughrider for informational purposes with FERC and posted on the SPP Open Access Same-Time Information System ("OASIS") on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

C. "Annual Meeting" means the meeting hosted by Roughrider for exchanging information with Interested Parties regarding the Formula Rate.

D. "Annual Update" means Roughrider's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

E. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

F. "Calendar Year" means January 1 through December 31 of a given year.

G. "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and which Roughrider has filed with FERC (*e.g.,* if the Annual Update is posted on June 30, 2020, and the Informational Filing is submitted to FERC on December 15, 2020, the Current Rate Year is January 1, 2021 through December 31, 2021).

H. "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS, service under Grandfathered Agreements, or PTP Transmission Service.

I. "FERC" or "Commission" means the Federal Energy Regulatory Commission.

J. "Final Posting" means the Annual Update information that SPP posts to the SPP OASIS with changes agreed to during the informal review process.

K. "Form No. 7" means the RUS Financial and Operating Report - Electric Distribution, formerly RUS Form No. 7.

L. "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with FERC and served on Roughrider by electronic service on the date of such filing.

M. "Formula Rate Template" means the Roughrider transmission formula rate template set forth herein.

N. "Formula" means the Formula Rate Template set forth in Addendum 45 to Attachment H of the SPP Tariff.

O. "Formula Rate" has the meaning defined herein and means the Roughrider Implementation Protocols together with the Formula Rate Template.

P. "FPA" means the Federal Power Act.

Q. "Informal Challenge" means written notification by an Interested Party to Roughrider, during the Review Period, of any specific challenge to the Annual Update.

R. "Information Request" means a written request submitted by an Interested Party to Roughrider.

S. "Informational Filing" means Roughrider's annual filing at the Commission with the information stipulated in these Protocols.

T. "Initial Posting" means the date on which SPP posts Roughrider's Annual Update to the SPP OASIS.

U. "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a) (2) (iii), or successor regulation.

V. "Interested Party" includes (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

W. "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

X. "OASIS" means Open Access Same-Time Information System.

Y. "OATT" or "SPP Tariff" means SPP's Open Access Transmission Tariff.

Z. "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is January 1, 2020 through December 31, 2020, then the Prior Rate Year is January 1, 2019 through December 31, 2019).

AA. "PTP Rates" means the point-to-point rates derived from the Formula Rate.

BB. "Publication Date" means the date on which Roughrider posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2020 shall be no later than June 30, provided, however, that if June 30 should fall on a weekend or a holiday recognized by FERC, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

CC. "Rate Year" means January 1 of a given year through December 31 of the same Calendar year.

DD. "Review Period" means, unless otherwise extended in writing by Roughrider, the period extending from the Publication Date through October 28, which includes a period for submission of Information Requests and a period for preparation of Informal Challenges.

EE. "RUS" means Rural Utilities Service.

FF. "SPP" means Southwest Power Pool, Inc. or its successor organization.

GG. "SPP Tariff" or "OATT" means SPP's Open Access Transmission Tariff.

HH. "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity ("ROE"); (ii) depreciation and amortization rates; and (iii) other similar fixed values. Stated Values may be changed only pursuant to FPA section 205 or 206.

II. "USoA" means FERC's Uniform System of Accounts.

## Section II Annual Update

A. On or before June 30 of each calendar year (the Publication Date), Roughrider shall:

1. Recalculate the ATRR and the rates for zonal NITS service for the new Rate Year in accordance with the Formula Rate and using the Formula Rate Template; and

2. Provide its Annual Update to SPP and request that SPP post such information to the SPP OASIS (the Initial Posting); and

3. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the Initial Posting shall be due on the next Business Day. The date on which the Initial Posting occurs shall be that year's Publication

Date. Any delay in the Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

B. Concurrent with the Initial Posting, Roughrider shall provide the Annual Update to SPP to serve electronically upon the Service List.[i]

C. The Annual Update shall:

1. Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

2. Be based on the independently-audited books and records of Roughrider for the most recent fiscal year including its certified Form No. 7 or successor reports, including the Financial and Operating Report Electric Power Supply (Op. Report - Power Supply), (January 1 through December 31);

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

4. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, Roughrider shall identify:

   a. Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

   b. Any items included in the Formula Rate at an amount other than a historic cost basis.

   c. Individual impact of any changes in Section I.C (4)(a) above on charges billed under the Formula Rate.

   d. Accounting Changes related to any reorganization or merger transaction.

5. Not seek to modify the Formula Rate.

6. With each Annual Update, Roughrider will include a list of any new transmission facilities included in the Formula Rate Template that were not included in the prior Annual Update. New transmission facilities include but are not limited to additional substations, breakers, other major substation equipment, and additional transmission line miles. The list will indicate the Zone 19 Attachment AI

Guidance Document criteria that Roughrider believes supports each facility's inclusion in Roughrider's ATRR as well as the beginning-of-year and end-of-year balances associated with that facility. This provision in no way limits the rights of any Interested Party to challenge inclusion of new facilities.

## Section III Review of Annual Update

Within twenty (20) calendar days of the posting of Roughrider's Annual Update, and with at least seven (7) calendar days' notice, Roughrider will host a meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). Roughrider shall provide notice of this meeting concurrent with the posting of the Annual Update accessible on the SPP OASIS. The notice shall include the date, time and location of the Annual Meeting and shall be provided to Interested Parties through the Service List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the SPP OASIS.

A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Update and will have until September 28 to serve reasonable Information Requests on Roughrider for information and work papers supporting the Annual Update. Such Information Requests shall be limited to that which is necessary to determine:

    a. The extent or effect of an Accounting Change;

    b. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

    c. The proper application of the Formula Rate and procedures in these Protocols;

    d. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

    e. The effect of any change to the underlying USoA or Formula Rate Template; or

    f. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

    The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. Roughrider will not claim that responses to information and document requests pursuant the Protocols are subject to any settlement confidentiality provision; however, Roughrider may require that Interested Parties execute a non-disclosure agreement to obtain access to material that Roughrider deems commercially sensitive or that contains Critical

Energy Infrastructure Information as that term is defined in 18 CFR § 388.113(c)(1).

2. Roughrider shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within fifteen (15) Business Days of receipt.

3. Roughrider shall request that SPP post on a publically accessible portion of the SPP OASIS all Information Requests from Interested Parties and Roughrider's response(s) to such requests, and a link to the posting will be electronically served on all Interested Parties via the Service List. If responses to Information Requests contain information deemed by Roughrider to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Roughrider.

4. If the deadline for Interested Parties falls on a weekend or holiday recognized by the FERC, the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until October 28 (or the first Business Day after October 28 if October 28 falls on a weekend or holiday) to notify Roughrider in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. Roughrider will make a good faith effort to respond to any Informal Challenge within twenty (20) calendar days of notification of such Informal Challenge. Roughrider, and, if appropriate, SPP, shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. Roughrider will request that SPP post on the SPP OASIS all Informal Challenges from Interested Parties and Roughrider's responses to the Informal Challenges, and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Informal Challenges contain information are deemed by Roughrider to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Roughrider.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by Roughrider and resolved prior to the end of the Review Period shall be reported in the Final Posting on the SPP OASIS. Any changes or adjustments agreed to by Roughrider after this date will be reported in the Informational Filing made with FERC and

will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges

1. An Interested Party shall have until January 15 (or the first Business Day after January 15 if January 15 falls on a weekend or holiday recognized by FERC) to file a Formal Challenge. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues. Regardless of whether an Interested Party pursues or fails to pursue Informal or Formal Challenges, an Interested Party may file a complaint under section 206 of the FPA at any time.

2. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

b. Explain how the action or inaction violates the filed Formula Rate or Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

3. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via section 206 of the FPA and shall be served upon Roughrider contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f) (3), or by facsimile, express delivery or messenger to the individual listed as the contact person in Roughrider's Informational Filing.

4. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Roughrider shall bear the burden, consistent with section 205 of the FPA, of proving that it has correctly applied the Formula Rate consistent with these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols, and the Annual Update shall not be subject to challenge for modifying the Formula Rate. Modifications to the Formula Rate may be made only pursuant to Federal Power Act section 205 or section 206.

2. A change to the Formula Rate fixed inputs related to ROE, depreciation rates, capital structure, amortization periods, or any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA, sections 205 or 206, provided, however, that Roughrider may make a limited section 205 filing to change depreciation rates, amortization periods, Post-Employment Benefits other than Pensions recovery, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed changes(s) are just and reasonable, and not unduly discriminatory. Any modification to the Formula Rate will require a filing under section 205 or 206 of the FPA.

3. If Roughrider makes a correction to a Mistake in its financial information during the Current Rate Year that would affect the Formula Rate for the Current Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with 18 C.F.R. § 35.19a. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a.

E. Informational Filing

1. By December 15 of each year, Roughrider shall submit to FERC an informational filing ("Informational Filing") of its Annual Update under a separate docket number.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   a. That input data under the Formula Rate is properly recorded in any underlying work papers;

   b. That Roughrider has properly applied the Formula Rate and these procedures;

   c. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   d. The extent of Accounting Changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Roughrider shall provide notice of the Informational Filing to Interested Parties via the Service List and request that SPP post the notice and the docket number assigned to the Informational filing on the SPP OASIS.

## Section IV Joint SPP Transmission Owners' Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, Roughrider intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to Interested Parties via the Formula Rate Posting Information Notification List no less than seven (7) days prior to such meetings.

## Section V Roughrider Example Schedule

| Line No. | Action | Begin | End |
|---|---|---|---|
| 1 | Rate Year | January 1, 2021 | December 31, 2021 |
| 2 | Publication Date | | June 30, 2020 |
| 3 | Annual Meeting of Interested Parties | | July 20, 2020 |
| 4 | Information Request Due Date | June 30, 2020 | September 28, 2020 |
| 5 | Informal Challenges Due Date | | October 28, 2020 |
| 6 | Final Posting | | December 1, 2020 |
| 7 | Informational Filing | | December 15, 2020 |
| 8 | Formal Challenge Due Date | | January 15, 2021 |

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i. As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP website. As of June 2017, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at <http://www.spp.org/stakeholder-center/exploder-lists/>.

# ADDENDUM 48 TO ATTACHMENT H

## Transource SPP Entities

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
Transource SPP Entity
Company Name Here

For the 12 months ended 12/31/____

| Line No. | (1) | (2) | (3) Total | (4) Allocator | | (5) Allocated Amount |
|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | (page 3, line 47) | | | | $ - |
| | REVENUE CREDITS | (Note O) | | | | |
| 2 | Account No. 454 | (page 4, line 29) | - | TP | - | - |
| 3 | Account No. 456.1 | (page 4, line 33) | - | TP | - | - |
| 4 | Account No. 457.1 Scheduling | Attachment 5, line 39, col e | - | TP | - | - |
| 5 | Revenues from Grandfathered Interzonal Transactions | (Note N) | - | TP | - | - |
| 6 | Revenues from service provided by the ISO at a discount | | - | TP | - | - |
| 7 | TOTAL REVENUE CREDITS | (Sum of Lines 2 through 6) | - | | | - |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus line 7) | | | | $ - |
| 9 | True-up Adjustment with Interest | Attachment 3, Col. K | - | DA | 1.00000 | - |
| 10 | NET REVENUE REQUIREMENT | (line 8 plus line 9) | | | | $ - |

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data Transource SPP Entity Company Name Here

For the 12 months ended 12/31/____

| Line No. | (1) | (2) Source | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE: (Note R)** | | | | | |
| | GROSS PLANT IN SERVICE (Note U) | | | | | |
| 1 | Production | 205.46.g for end of year, records for other months | - | NA | | - |
| 2 | Transmission | Attachment 4, Line 14, Col. (b) | - | TP | - | - |
| 3 | Distribution | 207.75.g for end of year, records for other months | - | NA | - | - |
| 4 | General & Intangible | Attachment 4, Line 14, Col. (c) | - | W/S | - | - |
| 5 | Common | 356.1 for end of year, records for other months | - | CE | - | - |
| 6 | TOTAL GROSS PLANT | (Sum of Lines 1 through 5) | - | GP= | - | - |
| | ACCUMULATED DEPRECIATION (Note U) | | | | | |
| 8 | Production | 219.20-24.c for end of year, records for other months | - | NA | | - |
| 9 | Transmission | Attachment 4, Line 14, Col. (h) | - | TP | - | - |
| 10 | Distribution | 219.26.c for end of year, records for other months | - | NA | - | - |
| 11 | General & Intangible | Attachment 4, Line 14, Col. (i) | - | W/S | - | - |
| 12 | Common | 356.1 for end of year, records for other months | - | CE | - | - |
| 13 | TOTAL ACCUM. DEPRECIATION | (Sum of Lines 8 through 12) | - | | | - |
| 14 | NET PLANT IN SERVICE | | | | | |
| 15 | Production | (line 1 - line 8) | - | | | - |
| 16 | Transmission | (Line 2 minus Line 9) | - | | | - |
| 17 | Distribution | (line 3 - line 10) | - | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 18 | General & Intangible | (Line 4 minus Line 11) | - | | | - |
| 19 | Common | (line 5 - line 12) | - | | | - |
| 20 | TOTAL NET PLANT | (Sum of Lines 15 through 19) | - | NP= | - | - |
| 21 | ADJUSTMENTS TO RATE BASE | | | | | |
| 22 | Account No. 281 (enter negative) | Attachment 4, Line 28, Col. (d) (Note B) | - | NA | zero | - |
| 23 | Account No. 282 (enter negative) | Attachment 4, Line 28, Col. (e) (Note B) | - | NP | - | - |
| 24 | Account No. 283 (enter negative) | Attachment 4, Line 28, Col. (f) (Note B) | - | NP | - | - |
| 25 | Account No. 190 | Attachment 4, Line 28, Col. (g) (Note B) | - | NP | - | - |
| 26 | Account No. 255 (enter negative) | Attachment 4, Line 28, Col. (h) (Note B) | - | NP | - | - |
| 27 | | | | | | |
| 28 | Unfunded Reserves (enter negative) | Attachment 4, Line 31, Col. (h) | - | DA | 1.00000 | - |
| 27 | CWIP | Attachment 4, Line 14, Col. (d) | - | DA | 1.00000 | - |
| 28 | Unamortized Regulatory Asset | Attachment 4, Line 28, Col. (b) (Note T) | - | DA | 1.00000 | - |
| 29 | Unamortized Abandoned Plant | Attachment 4, Line 28, Col. (c) (Note S) | - | DA | 1.00000 | - |
| 30 | TOTAL ADJUSTMENTS | (Sum of Lines 22 through 29) | - | | | - |
| 31 | LAND HELD FOR FUTURE USE | Attachment 4, Line 14, Col. (e) (Note C) | - | TP | - | - |
| 32 | WORKING CAPITAL | (Note D) | | | | |
| 33 | CWC | 1/8*(Page 3, Line 14 minus Page 3, Line 11) | - | | | - |
| 34 | Materials & Supplies | Attachment 4, Line 14, Col. (f) (Note C) | - | TP | - | - |
| 35 | Prepayments (Account 165) | Attachment 4, Line 14, Col. (g) | - | GP | - | - |
| 36 | TOTAL WORKING CAPITAL | (Sum of Lines 33 through 35) | - | | | - |
| 37 | RATE BASE | (Sum of Lines 20, 30, 31 & 36) | - | | | - |

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data

Transource SPP Entity

Company Name Here

For the 12 months ended 12/31/____

| Line No. | (1) | (2) Source | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | O&M | | | | | |
| 1 | Transmission | 321.112.b Attach. 5, Line 13, Col. (a) | - | TP | - | - |
| 2 | Less Account 566 (Misc Trans Expense) | 321.97.b Attach. 5, Line 13, Col. (b) | - | TP | - | - |
| 3 | Less Account 565 | 321.96.b Attach. 5, Line 13, Col. (c) | - | TP | - | - |
| 4 | A&G | 323.197.b Attach. 5, Line 13, Col. (d) | - | W/S | - | - |
| 5 | Less FERC Annual Fees | Attach. 5, Line 13, Col. (e) | - | W/S | - | - |
| 6 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad. | (Note E) Attach. 5, Line 13, Col. (f) | - | W/S | - | - |
| 6a | Less PBOP Expense in Year | Attachment 7, Line 8, Col. (c) | - | W/S | - | - |
| 7 | Plus Transmission Related Reg. Comm. Exp. | (Note E) Attach. 5, Line 13, Col. (g) | - | TP | - | - |
| 7a | Plus PBOP Expense Allowed Amount | Attachment 7, Line 6, Col. (c) | - | W/S | - | - |
| 8 | Common | 356.1 | - | CE | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | Transmission Lease Payments | Attach. 5, Line 13, Col (h) | - | DA | 1.0000 | - |
| 10 | Account 566 | | | | | |
| 11 | Amortization of Regulatory Asset | (Note T) Attach. 5, Line 13, Col. (i) | - | DA | 1.0000 | - |
| 12 | Miscellaneous Transmission Expense (less amortization of regulatory asset) | Attach. 5, Line 13, Col .(j) | - | TP | - | - |
| 13 | Total Account 566 | (Line 11 plus Line 12) Ties to 321.97.b" | - | | | - |
| 14 | TOTAL O&M | (Sum of Lines 1, 4, 7, 7a, 8, 9, 13 less Lines 2, 3, 5, 6, 6a) | - | | | - |
| 15 | DEPRECIATION EXPENSE (Note U) | | | | | |
| 16 | Transmission | 336.7.b&d Attach. 5, Line 13, Col. (k) | - | TP | - | - |
| 17 | General & Intangible | 336.10.b&d, 336.1.b&d Attach. 5, Line 26, Col. (a) | - | W/S | - | - |
| 18 | Common | 336.11.b&d | - | CE | - | - |
| 19 | Amortization of Abandoned Plant | (Note S) Attach. 5, Line 26, Col. (b) | - | DA | 1.0000 | - |
| 20 | TOTAL DEPRECIATION | (Sum of Lines 16 through 19) | - | | | - |
| 21 | TAXES OTHER THAN INCOME TAXES | (Note F) | | | | |
| 22 | LABOR RELATED | | | | | |
| 23 | Payroll | Attach. 5, Line 26, Col. (c) | - | W/S | - | - |
| 24 | Highway and vehicle | Attach. 5, Line 26, Col. (d) | - | W/S | - | - |
| 25 | PLANT RELATED | | | | | |
| 26 | Property | Attach. 5, Line 26, Co.l (e) | - | GP | - | - |
| 27 | Gross Receipts | Attach. 5, Line 26, Col. (f) | - | NA | zero | - |
| 28 | Other | Attach. 5, Line 26, Col. (g) | - | GP | - | - |
| 29 | Payments in lieu of taxes | Attach. 5, Line 26, Col. (h) | - | GP | - | - |
| 30 | TOTAL OTHER | (Sum of Lines | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 0 | TAXES | 23 through 29) | - | | | | - |
| 31 | INCOME TAXES | (Note G) | | | | | |
| 32 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} * (1-TEP) | WCLTD = Page 4, Line 20 | | - | | | |
| 33 | CIT=(T/1-T) * (1-(WCLTD/R)) = | R = Page 4, Line 23 | | - | | | |
| 34 | FIT & SIT & P | (Note G) | | | | | |
| 35 | | | | | | | |
| 36 | 1 / (1 - T) = (from line 32) | 1 / (1 - T), T from Line 32 | | - | | | |
| 37 | Amortized Investment Tax Credit | 266.8f (enter negative) Attach. 5, Line 26, Col. (i) (enter negative) | - | | | | |
| 38 | Excess Deferred Income Taxes | Attach. 5, Line 26, Col. (j) | - | | | | |
| 39 | Tax Effect of Permanent Differences | Attach. 5, Line 26, Col. (k) (Note W) | - | | | | |
| 40 | Income Tax Calculation | (Line 33 times Line 46) | | - | NA | | - |
| 41 | ITC adjustment | (Line 36 times Line 37) | | - | NP | - | - |
| 42 | Excess Deferred Income Tax Adjustment | (Line 36 times Line 38) | | - | NP | - | - |
| 43 | Permanent Differences Tax Adjustment | (Line 36 times Line 39) | | - | NP | - | - |
| 44 | Total Income Taxes | (Sum of Lines 40 through 43) | | - | | | - |
| 45 | RETURN | | | | | | |
| 46 | Rate Base times Return | (Page 2, Line 37 times Page 4, Line 23) | - | | NA | | - |
| 47 | REV. REQUIREMENT | (Sum of Lines 14, 20, 30, 44 & 46) | - | | | | - |

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data Transource SPP Entity Company Name Here

For the 12 months ended 12/31/____

| Line No. | (1) | (2) SUPPORTING CALCULATIONS AND NOTES | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | |
| 1 | Total Transmission plant | (Page 2, Line 2, Column 3) | | | - |
| 2 | Less Transmission plant excluded from ISO rates | (Note H) | | | - |
| 3 | Less Transmission plant included in OATT Ancillary Services | (Note I) | | | - |
| 4 | Transmission plant included in ISO rates | (Line 1 minus Lines 2 & 3) | | | - |
| 5 | Percentage of Transmission plant included in ISO Rates | (Line 4 divided by Line 1) | | TP = | - |
| 6 | WAGES & SALARY ALLOCATOR (W&S) | | | | |
| | | Form 1 Reference | $ | TP | Allocation |
| 7 | Production | 354.20.b | - | - | - |
| 8 | Transmission | 354.21.b | - | - | - |
| 9 | Distribution | 354.23.b | - | - | - |
| 10 | Other | 354.24,25,26.b | - | - | - |
| 11 | Total (W& S Allocator is 1 if lines 7-10 are zero) | (Sum of Lines 7 through 10) | - | - | = - = WS |
| 12 | COMMON PLANT ALLOCATOR (CE) (Note J and X) | | $ | % Electric | W&S Allocator |
| 13 | Electric | 200.3.c | - | (line 13 / line 16) | (line 11) = - CE |
| 14 | Gas | 201.3.d | - | - * | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 15 | Water | 201.3.e | - | | | | |
| 16 | Total | (Sum of Lines 13 through 15) | - | | | | |
| 17 | RETURN (R) | (Note V) | | | | $ | |
| 18 | | | | | | | |
| 19 | | | $ | % | Cost Attachment 5, see Notes K, Q, & R | Weighted | |
| 20 | Long Term Debt | Attachment 5, line 48 (Notes Q & R) | - | - | - | 0.00 | =WCLTD |
| 21 | Preferred Stock (112.3.c) | Attachment 5, line 49 (Notes Q & R) | - | - | - | 0.00 | |
| 22 | Common Stock | Attachment 5, line 50 (Notes K, Q & R) | - | - | 0.1030 | 0.00 | |
| 23 | Total | (Sum of Lines 20 through 22) | - | | | 0.00 | = R |
| 24 | REVENUE CREDITS | | | | | | |
| 25 | ACCOUNT 447 (SALES FOR RESALE) (Note L) | 310 -311 | | | | | |
| 26 | a. Bundled Non-RQ Sales for Resale | 311.x.h | | | | - | |
| 27 | b. Bundled Sales for Resale | Attach 5, line 39, col (a) | | | | - | |
| 28 | Total of (a)-(b) | | | | | - | |
| 29 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | (Note M) Attach 5, line 39, col (b) | | | | - | |
| 30 | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | 330.x.n (Note P) | | | | | |
| 31 | a. Transmission charges for all transmission transactions | Attach 5, line 39, col (c) | | | | - | |
| 32 | b. Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10. | Attach 5, line 39, col (d) | | | | - | |
| 33 | Total of (a)-(b) | | | | | - | |

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data Transource SPP Entity Company Name Here

For the 12 months ended 12/31/____

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

| Note Letter | |
|---|---|
| A | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff. |
| B | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated. |
| C | Identified in Form 1 as being only transmission related. |
| D | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1. |
| E | Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h. |
| F | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| G | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes" and TEP = "the tax exempt ownership interest". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T). |

Inputs Required:

| | | |
|---|---|---|
| FIT = | - | (Federal Income Tax Rate) |
| SIT= | - | (State Income Tax Rate or Composite SIT) |
| p = | - | (percent of federal income tax deductible for state purposes) |
| TEP = | - | (percent of the tax exempt ownership) |

| | |
|---|---|
| H | Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test). |
| I | Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| J | Enter dollar amounts |
| K | ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC. |

L Page 4, Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1.

M Includes only income related to transmission facilities, such as pole attachments, rentals and special use.

N Company will not have any grandfathered agreements. Therefore, this line shall remain zero.

O The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

P Account 456.1 entry shall be the annual total of the quarterly values reported at Form 1, page 300.22.b.

Q Prior to issuing any debt, the cost of debt on Attachment 8, Line 25 for the relevant year will be used. If Construction Financing (where an amount is borrowed but the funds are drawn down over the construction period) is obtained, the cost of debt is determined using the internal rate of return methodology shown on Attachment 8 until a project is placed in service, subject to true-up pursuant to Attachment 9, and the cost of debt is determined using the methodology in Attachment 5 after a project is placed in service. Attachment 8 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Attachment H. If non-construction financing is obtained, the cost of debt is determined using the methodology in Attachment 5 and Attachments 8 and 9 are not used. The capital structure will be 60% equity and 40% debt during the construction period; after the construction period, the actual capital structure will be used.

R Calculate using 13 month average balance, except ADIT which is calculated based on the average of the beginning of the year and the end of the year balances

S Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.

T Recovery of Regulatory Asset permitted only for pre-commercial and formation expenses as authorized by the Commission. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.

U Excludes Asset Retirement Obligation balances

V Company shall be allowed recovery of costs related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.

W The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

X Calculate using a simple average of beginning of year and end of year balances reconciling to FERC Form No. 1 by Page, Line and Column as shown in Column 2.

Attachment 1
Project Revenue Requirement Worksheet
Transource SPP Entity

Company Name Here

To be completed in conjunction with Attachment H.

| Line No. | (1) | (2) Attachment H Page, Line, Col. | (3) Transmission | (4) Allocator |
|---|---|---|---|---|
| 1 | Gross Transmission Plant - Total | Attach H, p 2, line 2 col 5 plus line 27 col 5 (Note A) | - | |
| 2 | Net Transmission Plant - Total | Attach H, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note B) | - | |
| | O&M EXPENSE | | | |
| 3 | Total O&M Allocated to Transmission | Attach H, p 3, line 14 col 5 | - | |
| 4 | Annual Allocation Factor for O&M | (line 3 divided by line 1 col 3) | - | - |
| | GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE | | | |
| 5 | Total G, I & C Depreciation Expense | Attach H, p 3, lines 17 & 18, col 5 (Note H) | - | |
| 6 | Annual Allocation Factor for G, I & C Depreciation Expense | (line 5 divided by line 1 col 3) | - | - |
| | TAXES OTHER THAN INCOME TAXES | | | |
| 7 | Total Other Taxes | Attach H, p 3, line 30 col 5 | - | |
| 8 | Annual Allocation Factor for Other Taxes | (line 7 divided by line 1 col 3) | - | - |
| 9 | Less Revenue Credits | Attach H, p 1, line 7 col 5 | - | |
| 10 | Annual Allocation Factor for Revenue Credits | (line 9 divided by line 1 col 3) | - | - |
| **11** | **Annual Allocation Factor for Expense** | **Sum of line 4, 6, 8, and 10** | | **-** |
| | INCOME TAXES | | | |
| 12 | Total Income Taxes | Attach H, p 3, line 44 col 5 | - | |
| 13 | Annual Allocation Factor for Income Taxes | (line 12 divided by line 2 col 3) | - | - |

| | | | | |
|---|---|---|---|---|
| | RETURN | | | |
| 14 | Return on Rate Base | Attach H, p 3, line 46 col 5 | - | |
| 15 | Annual Allocation Factor for Return on Rate Base | (line 14 divided by line 2 col 3) | - | - |
| **16** | **Annual Allocation Factor for Return** | **Sum of line 13 and 15** | - | - |

Attachment 1
Project Revenue Requirement Worksheet
Transource SPP Entity Company Name Here

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project Name (Note M)** | **STEP Project Number** | **Project Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Project Net Plant** | **Annual Allocation Factor for Return** | **Annual Return Charge** |
| | | | (Note C) | (Page 1 line 11) | (Col. 3 * Col. 4) | (Notes D & I) | (Page 1 line 16) | (Col. 6 * Col. 7) |
| 15a | | | $ - | - | - | $ - | - | - |
| 15b | | | $ - | - | - | $ - | - | - |
| 15c | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |
| | | | $ - | - | - | $ - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | $ - | - | - | $ - | - |
| 16 | Annual Totals | - | | | - | |
| 17 | Rev. Req. Adj For Attachment H | | | | | |

| Note Letter | |
|---|---|
| A | Gross Transmission Plant is that identified on page 2 line 2 of Attachment H |
| B | Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable. |
| C | Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include Unamortized Abandoned Plant. |
| D | Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes the regulatory asset. |
| E | Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 16. Project Depreciation Expense includes the amortization of Abandoned Plant |
| F | True-Up Adjustment is calculated on the Project True-up Schedule (Attachment 3) for the preceding calendar year. |
| G | The Network Upgrade Charge is the value to be used in the SPP's rate calculation under the applicable Schedule under the SPP OATT for each project. |
| H | The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9. |
| I | The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense. |
| J | The Competitive Bid Adjustment is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate |
| K | Requires approval by FERC of incentive return applicable to the specified project(s) |
| M | All facilities other than those being recovered under Schedules 7, 8, 9 are to be included in Attachment 1. |

| (9) | (10) | (11) | (12) | (12a) | (13) | (14) | (15) | (16) |
|---|---|---|---|---|---|---|---|---|
| **Project Depreciation/Amortization Expense** | **Annual Revenue Requirement** | **Incentive Return in basis Points** | **Incentive Return** | **Ceiling Rate** | **Competitive Bid Concession** | **Total Annual Revenue Requirement** | **True-Up Adjustment** | **Net Rev Req** |
| (Notes E & I) | (Sum Col. 5, 8 & 9) | (Note K) | (Attachment 2, Line 28 Incentive Return * Col. 6) | (Sum Col. 10 & 12) | (Note J) | (Sum Col. 10 & 12 Less Col. 13) | (Note F) | Sum Col. 14 & 15 (Note G) |
| $ - | - | - | - | - | - | - | $ - | - |
| $ - | - | - | - | - | - | - | $ - | - |
| $ - | - | - | - | - | - | - | $ - | -

- - - - - - -

-

| | | | | Attachment 2 Incentive ROE Transource SPP Entity Company Name Here | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | Rate Base | Attachment H, line 37, Col.5, Page 2 | | | | | | - |
| 2 | 100 Basis Point Incentive Return | | | | | | | $ |
| | | | | $ | % | Cost | Weighted | |
| 3 | Long Term Debt | (Notes Q & R from Attachment H) | | - | - | - | - | |
| 4 | Preferred Stock | (Notes Q & R from Attachment H) | | - | - | - | - | |
| 5 | Common Stock | (Notes K, Q & R from Attachment H) | Cost = Attachment H, Line 23, Cost plus .01 | - | - | 0.1130 | - | |
| 6 | Total (sum lines 3-5) | | | - | | | - | |
| 7 | 100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6) | | | | | | | - |
| 8 | INCOME TAXES | | | | | | | |
| 9 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | - | | | | |
| 10 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | | - | | | | |
| 11 | WCLTD = Line 3 | | | | | | | |
| 12 | and FIT, SIT & p are as given in footnote K. | | | | | | | |
| 13 | 1 / (1 - T) = (from line 9) | | | - | | | | |
| 14 | Amortized Investment Tax Credit (266.8f) (enter negative) | | Attachment H, Page 3, Line 37 | - | | | | |
| 15 | Excess Deferred Income Taxes (enter negative) | | Attachment H, Page 3, Line 38 | - | | | | |
| 16 | Tax Effect of Permanent Differences (Note B) | | Attachment H, Page 3, Line 39 | - | | | | |
| 17 | Income Tax Calculation = line 10 * line 22 | | | - | | NA | | - |
| 18 | ITC adjustment (line 13 * line 14) | | | - | | NP | - | - |
| 19 | Excess Deferred Income Tax Adjustment (line 13 * line 15) | | | - | | NP | - | - |
| 20 | Permanent Differences Tax Adjustment (line 13 * 16) | | | - | | NP | - | - |
| 21 | Total Income Taxes (sum lines 17 - 20) | | | - | | | | - - |
| 22 | Return and Income Taxes with 100 basis point increase in ROE | | | | | | | - |
| 23 | Return (Attach. H, page 3 line 46 col 5) | | | | | | | - |

| | | |
|---|---|---|
| 24 | Income Tax (Attach. H, page 3 line 44 col 5) | - |
| 25 | Return and Income Taxes without 100 basis point increase in ROE | - |
| 26 | Incremental Return and Income Taxes for 100 basis point increase in ROE | - |
| 27 | Rate Base (line 1) | - |
| 28 | Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base | - |

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any ROE actual incentive must be approved by the Commission. For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 1.37 on Attachment 1 column 12.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

Attachment 3
Project True-Up
Transource SPP Entity Company Name Here

| | | | Projected Revenue Requirement Calculation | | Revenue Received[3] | | Actual Revenue Requirement | Annual True-Up Calculation | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Year | | | | | | | | | | |
| 2 | | | | | $ - | | | | | | |
| | A | B | C | D | E | F | G | H | I | J | K |
| | Project # Or Other Identifier | Project Name | Net Revenue Requirement[1] | % of Total Revenue Requirement | Revenue Received (E, Line 2 ) x (F) | % of Revenue Received (D) | Adjusted Net Revenue Requirement[2] | Net Under/(Over) Collection (E )-(G) | Prior Period Adjustment or Construction Loan True-up[5] | Interest Income (Expense)[4] | Total True-Up (H) + (I) + (J) |
| 3 | Attachment H | | - | - | - | - | - | - | - | - | - |
| 3a | | | - | - | - | - | - | - | - | - | - |
| 3b | | | - | - | - | - | - | - | - | - | - |
| 3c | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | |
| 4 | Total Annual Revenue Requirements (Note A) | | - | - | - | - | - | - | | - | - |

| | | |
|---|---|---|
| | Monthly Interest Rate | - |
| | Interest Income (Expense) | - |

Notes:
1) From Attachment 1, line 15, col. 14 for that project.
2) From Attachment 1, line 15, col. 16, from the version of the template populated with actual calendar year data for the preceding calendar year.
3) The "revenue received" is the total amount of revenue distributed to company in the year as shown on pages 328-330 of the Form No 1. The Revenue Received is input on line 2, Col. E
Column F is equal to Column D. Column E is the dollar amount of Revenue Received reflecting the % in Column D. This assigns to each project a percentage of the revenue received based on the percentage of the Projected Revenue Requirement in Column C.
4) Interest Rate from Attachment 6, line 9.
5) Construction Loan True-Up from Attachment 9, col (h) and Prior Period Adjustment from Attachment 3, line 5.

**Prior Period Adjustment**

| | (a) Prior Period Adjustment (Note B) | (b) Amount In Dollars | (c) Interest Note B | (d) Total Col. (b) + Col. (c) |
|---|---|---|---|---|
| 5 | - | - | - | - |

Notes:
A For each project or Attachment H, the utility will populate the formula rate with the inputs for the True-Up Year. The revenue requirements, based on actual operating results for the True-Up Year, associated with the projects and Attachment H will then be entered in Col. (E) above. Column (E) above contains the actual revenues received associated with Attachment H and any Projects paid by SPP to the utility during the True-Up Year. Then in Col. (H), Col. (F) is subtracted from Col. (G) to calculate the True-up Adjustment. The Construction Loan True-up form Attachment 9 is input in Col. (I). Column (J) is the applicable interest rate from Attachment 6. Column (J) adds the interest on the sum of Col.(H) and (I). Col. (K) is the sum of Col. (H), (I) and (J).

| | |
|---|---|
| B | Prior Period Adjustment is the amount of an adjustment to correct an error in a prior period. The FERC Refund interest rate specified in CFR 35.19(a) for the period up to the date the projected rates that are subject to True Up here went into effect. |

Attachment 4 Rate Base Worksheet

Transource SPP Entity Company Name Here



| Line No | Month (a) | Gross Plant In Service: Transmission (b) | Gross Plant In Service: General & Intangible (c) | CWIP: CWIP in Rate Base (d) | LHFFU: Held for Future Use (e) | Working Capital: Materials & Supplies (f) | Working Capital: Prepayments (g) | Accumulated Depreciation: Transmission (h) | Accumulated Depreciation: General & Intangible (i) |
|---|---|---|---|---|---|---|---|---|---|
| | | 207.58.g for end of year, records for other months | 205.5.g & 207.99.g for end of year, records for other months | | 214.x.d for end of year, records for other months | 227.8.c & 227.16.c for end of year, records for other months | 111.57.c for end of year, records for other months | 219.25.c for end of year, records for other months | 219.28.c & 200.21.c for end of year, records for other months |
| | (Note H) | | | Note C | | | | | |
| 1 | December Prior Year | - | - | - | - | - | - | - | - |
| 2 | January | - | - | - | - | - | - | - | - |
| 3 | February | - | - | - | - | - | - | - | - |
| 4 | March | - | - | - | - | - | - | - | - |
| 5 | April | - | - | - | - | - | - | - | - |
| 6 | May | - | - | - | - | - | - | - | - |
| 7 | June | - | - | - | - | - | - | - | - |
| 8 | July | - | - | - | - | - | - | - | - |
| 9 | August | - | - | - | - | - | - | - | - |
| 10 | September | - | - | - | - | - | - | - | - |
| 11 | October | - | - | - | - | - | - | - | - |
| 12 | November | - | - | - | - | - | - | - | - |
| 13 | December | - | - | - | - | - | - | - | - |
| 14 | Average of the 13 | - | - | - | - | - | - | - | - |

Monthly Balances

| Line No | Month (a) | Adjustments to Rate Base: Unamortized Regulatory Asset (b) | Unamortized Abandoned Plant (c) | Account No. 281 Accumulated Deferred Income Taxes (Note D) (d) | Account No. 282 Accumulated Deferred Income Taxes (Note D) (e) | Account No. 283 Accumulated Deferred Income Taxes (Note D) (f) | Account No. 190 Accumulated Deferred Income Taxes (Notes B & D) (g) | Account No. 255 Accumulated Deferred Investment Credit (h) |
|---|---|---|---|---|---|---|---|---|
| | (Note H) | Notes A & E | Notes B & F | 272.8.b & 273.8.k | 274.2.b & 275.2.k | 276.9.b & 277.9.k | 234.8.b & c | Consistent with 266.8.b & 267.8.h |
| 15 | December Prior Year | - | - | - | - | - | - | - |
| 16 | January | - | - | [redacted] | | | | - |
| 17 | February | - | - | | | | | - |
| 18 | March | - | - | | | | | - |
| 19 | April | - | - | | | | | - |
| 20 | May | - | - | | | | | - |
| 21 | June | - | - | | | | | - |
| 22 | July | - | - | | | | | - |
| 23 | August | - | - | | | | | - |
| 24 | September | - | - | | | | | - |
| 25 | October | - | - | | | | | - |
| 26 | November | - | - | | | | | - |
| 27 | December | - | - | - | - | - | - | - |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | - | - | - |

Unfunded Reserves (Notes G and H)



| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| 29 | List of all reserves: | | Amount | Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account | Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate | Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liability on the balance sheet (Note I) | Allocation (Plant or Labor Allocator) | Amount Allocated, col. c x col. d x col. e x col. f x col. g |
| 30a | | Reserve 1 | - | - | - | - | - | - |
| 30b | | Reserve 2 | - | - | - | - | - | - |
| 30c | | Reserve 3 | - | - | - | - | - | - |
| 30d | | Reserve 4 | - | - | - | - | - | - |
| 30e | | … | | | | | | - |
| 30f | | | | | | | | |
| 31 | | Total | - | | | | | - |

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.

B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.

C Includes only CWIP authorized by the Commission for inclusion in rate base. The annual report filed pursuant to Section 7 of the Protocols will include for each project under construction (i) the CWIP balance eligible for inclusion in rate base; (ii) the CWIP balance ineligible for inclusion in rate base; and (iii) a demonstration that AFUDC is only applied to the CWIP balance that is not included in rate base. The annual report will reconcile the project-specific CWIP balances to the total Account 107 CWIP balance reported on p. 216.b of the FERC Form 1.

D ADIT is computed using the average of the beginning of the year and the end of the year balances.

E Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.

F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.

G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account (see Note I)). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by creating an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account.

H Calculate using 13 month average balance, except ADIT which is calculated based on the average of the beginning of the year and the end of the year balances

I Not all unfunded reserves are created only from contributions from customers. Many are created by creating an offsetting liability in whole or in part. Column (f) ensures only the portion of the unfunded reserve contributed by the customer (and not created by an off setting liability) is a reduction to rate base. The inputs in Column (f) are 1 - (the percentage of the unfunded reserve that was created by an off setting liability). The percentage shown in Column (f) is then equal to the percentage that customers have contributed to the unfunded reserve.

| Line No. | Month | Transmission O&M Expenses | Account No. 566 (Misc. Trans. Expense) | Account No. 565 | A&G Expenses | FERC Annual Fees | EPRI & Reg. Comm. Exp. & Non-safety Ad. | Attachment 5 Attachment H, Pages 1 and 4, Worksheet Transource SPP Entity Company Name Here<br>Transmission Related Reg. Comm. Exp. | Transmission Lease Payments | Amortization of Regulatory Asset | Miscellaneous Transmission Expense (less Amortization of Regulatory Asset) | Depreciation Expense - Transmission |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Attachment H, Page 3, Line No.: | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 9 | 11 | 12 | 16 |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| 1 | January | - | - | - | - | - | - | - | - | - | - | - |
| 2 | February | - | - | - | - | - | - | - | - | - | - | - |
| 3 | March | - | - | - | - | - | - | - | - | - | - | - |
| 4 | April | - | - | - | - | - | - | - | - | - | - | - |
| 5 | May | - | - | - | - | - | - | - | - | - | - | - |
| 6 | June | - | - | - | - | - | - | - | - | - | - | - |
| 7 | July | - | - | - | - | - | - | - | - | - | - | - |
| 8 | August | - | - | - | - | - | - | - | - | - | - | - |
| 9 | September | - | - | - | - | - | - | - | - | - | - | - |
| 10 | October | - | - | - | - | - | - | - | - | - | - | - |
| 11 | November | - | - | - | - | - | - | - | - | - | - | - |
| 12 | December | - | - | - | - | - | - | - | - | - | - | - |
| 13 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | Depreciation Expense - General & Intangible | Amortization of Abandoned Plant | Payroll Taxes | Highway & Vehicle Taxes | Property Taxes | Gross Receipts Taxes | Other Taxes | Payments in lieu of Taxes | Amortized Investment Tax Credit (266.8f) | Excess Deferred Income Taxes | Tax Effect of Permanent Differences |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Attachment H, Page 3, Line Number | 17 | 19 | 23 | 24 | 26 | 27 | 28 | 29 | 37 | 38 | 39 |
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| 14 | January | - | - | - | - | - | - | - | - | - | - | - |
| 15 | February | - | - | - | - | - | - | - | - | - | - | - |
| 16 | March | - | - | - | - | - | - | - | - | - | - | - |
| 17 | April | - | - | - | - | - | - | - | - | - | - | - |
| 18 | May | - | - | - | - | - | - | - | - | - | - | - |
| 19 | June | - | - | - | - | - | - | - | - | - | - | - |
| 20 | July | - | - | - | - | - | - | - | - | - | - | - |
| 21 | August | - | - | - | - | - | - | - | - | - | - | - |
| 22 | September | - | - | - | - | - | - | - | - | - | - | - |
| 23 | October | - | - | - | - | - | - | - | - | - | - | - |
| 24 | November | - | - | - | - | - | - | - | - | - | - | - |
| 25 | December | - | - | - | - | - | - | - | - | - | - | - |
| 26 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | Bundled Sales for Resale included on page 4 of Attachment H | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | Transmission charges for all transmission transactions | Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10. | Account No. 457.1 Scheduling |
|---|---|---|---|---|---|---|
| | Attachment H, Page 4, Line No: | 27 | 29 | 31 | 32 | Attach H, p 1 line 4 |
| | | (a) | (b) | (c) | (d) | (e) |
| 27 | January | - | - | - | - | - |
| 28 | February | - | - | - | - | - |
| 29 | March | - | - | - | - | - |
| 30 | April | - | - | - | - | - |
| 31 | May | - | - | - | - | - |
| 32 | June | - | - | - | - | - |
| 33 | July | - | - | - | - | - |
| 34 | August | - | - | - | - | - |
| 35 | September | - | - | - | - | - |
| 36 | October | - | - | - | - | - |
| 37 | November | - | - | - | - | - |
| 38 | December | - | - | - | - | - |
| | | $ | $ | $ | $ | $ |
| 39 | Total | - | - | - | - | - |
| 40 | | | | | | |
| 41 | RETURN (R) Notes K, Q & R from Attachment H | | | | | |

| | | $ |
|---|---|---|
| 42 | Long Term Interest (117, sum of 62.c through 67.c) | - |
| 43 | Preferred Dividends (118.29c) (positive number) | - |
| 44 | Proprietary Capital (112.16.c) | - |
| 45 | Less Preferred Stock (line 49) | - |
| 46 | Less Account 216.1 (112.12.c) (enter negative) | - |

| | | | | | |
|---|---|---|---|---|---|
| 47 | | Common Stock | (sum lines 44-46) | | - |

| | | | $ | % | Cost | Weighted | |
|---|---|---|---|---|---|---|---|
| 48 | Long Term Debt | Note A | - | 0.00% | 0.0216 | 0.0000 | =WCLTD |
| 49 | Preferred Stock (112.3.c) | Note B | - | - | - | - | |
| 50 | Common Stock | Note C | - | 0.00% | 0.1030 | 0.0000 | |
| 51 | Total | (Sum of Lines 48 through 50) | - | | | 0.0000 | =R |

Note:

A Long Term debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c to 21.c in the Form No. 1, the cost is calculated by dividing line 42 by the Long Tern Debt balance in line 48.

B Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c in the Form No. 1

C Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 3.c 12.c, 16.c in the Form No. 1 as shown on lines 44-47 above

# Attachment 6
# True-Up Interest Calculation
## Transource SPP Entity
Company Name Here

| | | | | |
|---|---|---|---|---|
| | Monthly Interest Rate (Note A): | | | |
| 1 | 1st Qtr | - | - | |
| 2 | 2nd Qtr | - | - | |
| 3 | 3rd Qtr | - | - | |
| 4 | 4th Qtr | - | - | |
| 5 | 1st Qtr | - | - | |
| 6 | 2nd Qtr | - | - | |
| 7 | 3rd Qtr | - | - | |
| 8 | | | - | |
| 9 | Avg. Monthly FERC Rate | | - | - |

Note A: Lines 1-8 are the FERC interest rate under section 35.19(a) of the regulations for the period shown.
Line 9 is the average of lines 1-8.

Attachment 7

PBOPs
Transource SPP
Entity
Company Name
Here

**Calculation of PBOP Expenses**

| Line No. | | | AEP (a) | KCP&L (b) | Total (c) |
|---|---|---|---|---|---|
| 1 | | | Year Ended December 31, 2013 | Year Ended December 31, 2013 | |
| 2 | Total PBOP expenses | Note A | -$27,206,002 | $9,607,394 | |
| 3 | Amount relating to retired personnel | Note A | -$15,612,102 | $3,831,213 | |
| 4 | Amount allocated on Labor | Line 2 less line 3 | -$11,593,900 | $5,776,181 | |
| 5 | Labor dollars | Note B | $1,260,006,495 | $189,807,723 | |
| 6 | Cost per labor dollar | Line 4 divided by line 5 | -$0.009 | $0.030 | |
| 7 | labor (labor not capitalized) current year | Note C | - | - | |
| 8 | PBOP Expense for current year | Line 6 times line 7 | - | - | - |
| 9 | Lines 2 to 6 cannot change absent approval or acceptance by FERC in a separate proceeding. | | | | |
| 10 | PBOP amount included in Company's O&M and A&G expenses in Form No. 1 | | | | - |

| Note Letter | |
|---|---|
| A | Amounts on lines 2-3 reflect data from the April 2013 actuarial report for AEP and the 2013 actuarial report for KCP&L. |
| B | Amount on line 5 for AEP is the total labor expense across all AEP affiliates including AEP Service Company and is taken from AEP PeopleSoft accounting records. Line 5 labor dollars for KCP&L is the labor booked to O&M and A&G and included in the Form No. 1 on page 354.28.b less labor dollars associated with the Wolf Creek Nuclear Facility. |
| C | The labor in line 7 is the total labor charged by an AEP affiliate or KCP&L affiliate to this Transource SPP Entity in the year. |

Attachment 8

Example Financing Costs for Long Term Debt using the Internal Rate of Return Methodology

Transource SPP Entity

Company Name Here

This Attachment 8 is to be utilized until an entire project is placed in service (i.e. until all the facilities comprising the entire project are placed in service).
In the determination of the projected net revenue requirement for the year in which the project is placed in service, the cost of debt will be calculated in accordance with Attachment 5.
Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of Return formula below.
Each year, the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount will be updated on this attachment.

| | | |
|---|---|---|
| 1 | **Total Loan Amount** | **$ 200,000,000** |

| | | |
|---|---|---|
| 2 | **Internal Rate of Return (Note 1)** | **4.53%** |
| 3 | **Based on following Financial Formula (Note 2):** | |
| 4 | | |
| 5 | | $\sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$ |
| 6 | **NPV = 0 =** | |
| 7 | | |
| 8 | | |

Table 1

| | | | |
|---|---|---|---|
| 9 | | | |
| 10 | **Origination Fees** | Rates/Fees | Amount |
| 11 | Underwriting Discount | | - |
| 12 | Arrangement Fee | 0.150% | 300,000 |
| 13 | Upfront Fee | 0.350% | 700,000 |
| 14 | Rating Agency Fee | | 141,000 |
| 15 | Legal Fees | | 120,000 |
| 15 a | | - | - |
| 16 | Total Issuance Expense | | **1,261,000** |
| 17 | **Other Fee** | | - |
| 18 | **Annual Rating Agency Fee** | 0.07% | 175,000 |
| 19 | **Annual Bank Agency Fee** | | 50,000 |
| 21 | **Revolving Credit Commitment Fee** | 0.350% | |

| | | |
|---|---|---|
| 21 a | **Utilization Fee** | 0.100% |

Table 2

| | | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|---|
| 22 | | | | | | | | |
| 23 | LIBOR Rate | 0.000% | 0.405% | 1.051% | 1.673% | 1.912% | 2.087% | 2.238% |
| 24 | Spread | 0.000% | 1.750% | 1.750% | 1.750% | 1.750% | 1.750% | 1.750% |
| 25 | **Interest Rate (line 23 + line 24)** | 0.000% | 2.155% | 2.801% | 3.423% | 3.662% | 3.837% | 3.988% |

Table 3

| | (A) | (B) | ( C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|---|
| 26 | | | **Quarterly Construction Expenditures ( $000's)** | **Principal Drawn In Quarter ($000's)** | **Principal Drawn To Date ($000's)** | **Interest & Principal Payments ($000's)** 1/4 * Interest Rate from Line 25 x Col. E prior quarter | **Origination Fees ($000's)** | **Commitment, Utilization & Ratings Fees ($000's)** | **Net Cash Flows ($000's)** |
| 27 | **Year** | | | | | | | | |
| 28 | | | Estimated | Estimated | Cumulative Col. D | | Input in first Qtr of Loan | Note 11 | (D-F-G-H) |
| 29 | | | | | | | | | |
| 30 | 1/1/2015 | Prior Periods | 24,444 | | | | | | |
| 31 | 3/31/2015 | Q1 | 15,000 | 17,750 | 17,750 | - | 1,261 | | 16,489 |
| 32 | 6/30/2015 | Q2 | 15,000 | 6,750 | 24,500 | 95 | | 384 | 6,270 |
| 33 | 9/30/2015 | Q3 | 15,000 | 6,750 | 31,250 | 133 | | 154 | 6,463 |
| 34 | 12/31/2015 | Q4 | 15,000 | 6,750 | 38,000 | 170 | | 148 | 6,433 |
| 35 | 3/31/2016 | Q1 | 25,000 | 11,250 | 49,250 | 204 | | 142 | 10,904 |
| 36 | 6/30/2016 | Q2 | 25,000 | 11,250 | 60,500 | 344 | | 357 | 10,549 |
| 37 | 9/30/2016 | Q3 | 25,000 | 11,250 | 71,750 | 427 | | 122 | 10,701 |
| 38 | 12/31/2016 | Q4 | 25,000 | 11,250 | 83,000 | 507 | | 112 | 10,631 |
| 39 | 3/31/2017 | Q1 | 35,000 | 15,750 | 98,750 | 573 | | 102 | 15,074 |
| 40 | 6/30/2017 | Q2 | 35,000 | 15,750 | 114,500 | 843 | | 314 | 14,594 |
| 41 | 9/30/2017 | Q3 | 35,000 | 15,750 | 130,250 | 988 | | 103 | 14,659 |
| 42 | 12/31/2017 | Q4 | 35,000 | 15,750 | 146,000 | 1,124 | | 94 | 14,533 |
| 43 | 3/31/2018 | Q1 | 30,000 | 13,500 | 159,500 | 1,232 | | 84 | 12,184 |
| 44 | 6/30/2018 | Q2 | 30,000 | 13,500 | 173,000 | 1,456 | | 300 | 11,743 |
| 45 | 9/30/2018 | Q3 | 30,000 | 13,500 | 186,500 | 1,597 | | 67 | 11,836 |
| 46 | 12/31/2018 | Q4 | 30,000 | 13,500 | 200,000 | 1,722 | | 58 | 11,720 |
| 47 | 1/1/2019 | Q1 | | - | 200,000 | 200,020 | | 50 | (200,070) |
| 48 | | | | | | | | | |

49
50
51
52
53
54
55
56
57
58

No
tes

1 The IRR is the input to Debt Cost shown on Attachment H, Page 4, Line 20 during the construction period, after obtaining project financing, in accordance with Note Q of Attachment H.

2. The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation is shown on line 6.

N is the last quarter the loan would be outstanding

t is each quarter

Ct is the cash flow (Table 3, Col. I in each quarter)

Alternatively the equation can be written as 0 = C0 + C1/(1+IRR) + C2/(1+IRR)2 + C3/(1+IRR)3 + . . . +Cn/(1+IRR)n and solved for IRR

The Excel ™ formula on line 2 is : (round(XIRR(first quarter of loan Col A of Table 3:last quarter of loan Col A of Table 3, first quarter of loan Col I of Table 3:last quarter of loan Col I of Table 3, 8%),4)

The 8% in the above formula is a seed number to ensure the formula produces a positive number.

3. Line 1 reflects the loan amount, the maximum amount that can be drawn on

4. Lines 10 through 21a include the fees associated with the loan. They are estimated based on current bank condition and are updated with the actual fees

once the actual fees are known.

5. The estimate of the average 3 month LIBOR forward rate for the year on line 23 is that published by Bloomberg Finance L.P. during August of the prior year and is trued-up to actual

average 3 month LIBOR rate for the year.

6. Table 3, Col. C reflect the capital expenditures in each quarter

7. Table 3, Col. D reflect the amount of the loan that is drawn down in the quarter

8. Table 3, Col. E is the amount of principle drawn down

9. Table 5, Col F calculates the interest on the principle drawn down to date based on the applicable interest on line 25

10. Table 3, Col. G is the total origination fees in line 16 and is input in the first quarter that a portion of the loan in drawn

11. Table 3, Col. H is calculated as follows:

A x B + C

A. Loan amount in line 1 less the amount drawn down in the prior quarter

B. Annual dollar amount fees on lines 11 through 15a divided by 4 (divided by 4 to convert annual amounts to quarterly amounts)

C. Annual dollar amount fees divided by 1000 (applied in the quarters the payments are made)

12. The inputs shall be estimated based on the current market conditions and subject to true up for all inputs , e.g., fees, interest rates, spread, and Table 3 once the

amounts are known. Regardless of whether the credit spread was updated, Transource _____ will provide documentation to support the credit spread every year as long as Attachment 8 is used to determine the cost of debt.

13. Prior to issuing any debt, the cost of debt on Attachment 8, Line 25 for the relevant year will be used. If Construction Financing (where an amount is borrowed but the funds are drawn down over the construction period) is obtained, the cost of debt is determined using the internal rate of return methodology shown on Attachment 8 until a project is placed in service, subject to true-up pursuant to Attachment 9, and the cost of debt is determined using the methodology in Attachment 5 after a project is placed in service. Attachment 8 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Attachment H. If non-construction financing is obtained, the cost of debt is determined using the methodology in Attachment 5 and Attachments 8 and 9 are not used.

Attachment 9
Hypothetical Example of Final
True-Up of Interest Rates and
Interest Calculations for the
Construction Loan

Transource SPP Entity

Company Name Here

For the period that the Interest rate calculated on Attachment 8, line 2, uses estimates that would not be trued up under Attachment 3, absent this attachment. Accordingly, this attachment calculates the difference in interest rates actually charged during the period that the cost of debt is calculated on Attachment 8, Line 2, and the final interest rate calculation after the loan in Attachment 8 is paid off. This attachment calculates a one time true up that is entered into Attachment 3 as a Construction Loan True-Up.

**SUMMARY**

| (a) | | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| YEAR | | Cost of Debt Used in Determining the Actual Net Revenue Requirement in Attachment H, page 4, line 20 | Cost of Debt for the Construction Loan Calculated on Attachment 8 Once the Loan is Paid Off: | Actual Net Revenue Requirement in Attachment 3, col. (G) for the year | Actual Net Revenue Requirement if the Cost of Debt in Col. (c) had been Used | Over (Under) Recovery Col. (d) less Col. (e) | Refund/ Surcharge Interest Rate Calculated on Attachment 6 for the Year | Total Amount of Construction Loan Related True-Up with Interest (Refund)/Owed |
| 2015 | | 7.18% | 6.50% | $ 2,500,000 | $ 2,400,000 | $ 100,000.00 | 0.550% | $ (148,288) |
| 2016 | | 6.8% | 6.50% | $ 5,000,000 | $ 5,150,000 | $ (150,000.00) | 0.560% | $ 209,670 |
| 2017 | | 7.2% | 6.50% | $ 8,300,000 | $ 8,200,000 | $ 100,000.00 | 0.540% | $ (131,109) |
| 2018 | | 7.3% | 6.50% | $ 12,300,000 | $ 12,000,000 | $ 300,000.00 | 0.580% | $ (368,657) |
| 2019 | * | 7.1% | 6.50% | $ 18,000,000 | $ 17,900,000 | $ 100,000.00 | 0.570% | $ (114,946) |
| 2020 | ** | 6.50% | 6.50% | $ 25,000,000 | $ 25,000,000 | $ - | | |
| | | | | | | | | $ (553,330) |

***The Hypothetical Example:***
**** Assumes that the construction loan is retired on Sept 1, 2020***

***** Assumes permanent debt structure is put in place on Sept 1, 2020 with effective rate of 6.5%***

**Calculation of Applicable Interest Expense for each ATRR period**

| Interest Rate on Amount of Refunds or Surcharges from 35.19a | | Over (Under) Recovery Plus Interest | Hypothetical Monthly Interest Rate | Months | Calculated Interest | Amortization | Surcharge (Refund) Owed |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest for 2015 True-Up Period** | | | | | | | |
| | | | | | **Monthly** | | |
| January | Year 2015 | - | 0.5500% | 12.00 | - | | - |
| February | Year 2015 | - | 0.5500% | 11.00 | - | | - |
| March | Year 2015 | 10,000 | 0.5500% | 10.00 | (550) | | (10,550) |
| April | Year 2015 | 10,000 | 0.5500% | 9.00 | (495) | | (10,495) |
| May | Year 2015 | 10,000 | 0.5500% | 8.00 | (440) | | (10,440) |
| June | Year 2015 | 10,000 | 0.5500% | 7.00 | (385) | | (10,385) |
| July | Year 2015 | 10,000 | 0.5500% | 6.00 | (330) | | (10,330) |
| August | Year 2015 | 10,000 | 0.5500% | 5.00 | (275) | | (10,275) |
| September | Year 2015 | 10,000 | 0.5500% | 4.00 | (220) | | (10,220) |
| October | Year 2015 | 10,000 | 0.5500% | 3.00 | (165) | | (10,165) |
| November | Year 2015 | 10,000 | 0.5500% | 2.00 | (110) | | (10,110) |
| December | Year 2015 | 10,000 | 0.5500% | 1.00 | (55) | | (10,055) |
| | | | | | (3,025) | | **(103,025)** |
| | | | | | **Annual** | | |
| January through December | Year 2016 | (103,025) | 0.5600% | 12.00 | (6,923) | | **(109,948)** |
| January through December | Year 2017 | (109,948) | 0.5400% | 12.00 | (7,125) | | **(117,073)** |
| January through December | Year 2018 | (117,073) | 0.5800% | 12.00 | (8,148) | | **(125,221)** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| January through December | Year 2019 | (125,221) | 0.5700% | 12.00 | (8,565) | | **(133,786)** |
| January through December | Year 2020 | (133,786) | 0.5700% | 12.00 | (9,151) | | **(142,937)** |

| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2021 | **142,937** | 0.5700% | | (815) | (12,357) | (131,395) |
| February | Year 2021 | 131,395 | 0.5700% | | (749) | (12,357) | (119,786) |
| March | Year 2021 | 119,786 | 0.5700% | | (683) | (12,357) | (108,112) |
| April | Year 2021 | 108,112 | 0.5700% | | (616) | (12,357) | (96,371) |
| May | Year 2021 | 96,371 | 0.5700% | | (549) | (12,357) | (84,563) |
| June | Year 2021 | 84,563 | 0.5700% | | (482) | (12,357) | (72,687) |
| July | Year 2021 | 72,687 | 0.5700% | | (414) | (12,357) | (60,744) |
| August | Year 2021 | 60,744 | 0.5700% | | (346) | (12,357) | (48,733) |
| September | Year 2021 | 48,733 | 0.5700% | | (278) | (12,357) | (36,653) |
| October | Year 2021 | 36,653 | 0.5700% | | (209) | (12,357) | (24,505) |
| November | Year 2021 | 24,505 | 0.5700% | | (140) | (12,357) | (12,287) |
| December | Year 2021 | 12,287 | 0.5700% | | (70) | (12,357) | 0 |
| | | | | | (5,351) | | |

| | |
|---|---|
| Total Amount of True-Up Adjustment for 2012 ATRR | $ (148,288) |
| Less Over (Under) Recovery | $ 100,000 |
| Total Interest | $ (48,288) |

**Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan**

**Transource SPP Entity**

| **Calculation of Interest for 2016 True-Up Period** | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2016 | (12,500) | 0.5600% | 12.00 | 840 | | 13,340 |
| February | Year | | 0.5600% | 11.00 | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2016 | (12,500) | | | 770 | | 13,270 |
| March | Year 2016 | (12,500) | 0.5600% | 10.00 | 700 | | 13,200 |
| April | Year 2016 | (12,500) | 0.5600% | 9.00 | 630 | | 13,130 |
| May | Year 2016 | (12,500) | 0.5600% | 8.00 | 560 | | 13,060 |
| June | Year 2016 | (12,500) | 0.5600% | 7.00 | 490 | | 12,990 |
| July | Year 2016 | (12,500) | 0.5600% | 6.00 | 420 | | 12,920 |
| August | Year 2016 | (12,500) | 0.5600% | 5.00 | 350 | | 12,850 |
| September | Year 2016 | (12,500) | 0.5600% | 4.00 | 280 | | 12,780 |
| October | Year 2016 | (12,500) | 0.5600% | 3.00 | 210 | | 12,710 |
| November | Year 2016 | (12,500) | 0.5600% | 2.00 | 140 | | 12,640 |
| December | Year 2016 | (12,500) | 0.5600% | 1.00 | 70 | | 12,570 |
| | | | | | 5,460 | | **155,460** |

| | | | | | **Annual** | | |
|---|---|---|---|---|---|---|---|
| January through December | Year 2017 | 155,460 | 0.5400% | 12.00 | 10,074 | | **165,534** |
| January through December | Year 2018 | 165,534 | 0.5800% | 12.00 | 11,521 | | **177,055** |
| January through December | Year 2019 | 177,055 | 0.5700% | 12.00 | 12,111 | | **189,166** |
| January through December | Year 2020 | 189,166 | 0.5700% | 12.00 | 12,939 | | **202,104** |

| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2021 | **(202,104)** | 0.5700% | | 1,152 | 17,473 | 185,784 |
| February | Year 2021 | (185,784) | 0.5700% | | 1,059 | 17,473 | 169,370 |
| March | Year 2021 | (169,370) | 0.5700% | | 965 | 17,473 | 152,863 |
| April | Year 2021 | (152,863) | 0.5700% | | 871 | 17,473 | 136,262 |
| May | Year 2021 | (136,262) | 0.5700% | | 777 | 17,473 | 119,566 |
| June | Year 2021 | (119,566) | 0.5700% | | 682 | 17,473 | 102,775 |
| July | Year 2021 | (102,775) | 0.5700% | | 586 | 17,473 | 85,888 |
| August | Year 2021 | (85,888) | 0.5700% | | 490 | 17,473 | 68,905 |
| September | Year 2021 | (68,905) | 0.5700% | | 393 | 17,473 | 51,826 |
| October | Year 2021 | (51,826) | 0.5700% | | 295 | 17,473 | 34,649 |
| November | Year 2021 | (34,649) | 0.5700% | | 197 | 17,473 | 17,374 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| December | Year 2021 | (17,374) | 0.5700% | | 99 | 17,473 | (0) |
| | | | | | 7,566 | | |
| Total Amount of True-Up Adjustment for 2013 ATRR | | | | | | $ 209,670 | |
| Less Over (Under) Recovery | | | | | | $ (150,000) | |
| Total Interest | | | | | | $ 59,670 | |

**Calculation of Interest for 2017 True-Up Period**

| | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2017 | 8,333 | 0.5400% | 12.00 | (540) | | (8,873) |
| February | Year 2017 | 8,333 | 0.5400% | 11.00 | (495) | | (8,828) |
| March | Year 2017 | 8,333 | 0.5400% | 10.00 | (450) | | (8,783) |
| April | Year 2017 | 8,333 | 0.5400% | 9.00 | (405) | | (8,738) |
| May | Year 2017 | 8,333 | 0.5400% | 8.00 | (360) | | (8,693) |
| June | Year 2017 | 8,333 | 0.5400% | 7.00 | (315) | | (8,648) |
| July | Year 2017 | 8,333 | 0.5400% | 6.00 | (270) | | (8,603) |
| August | Year 2017 | 8,333 | 0.5400% | 5.00 | (225) | | (8,558) |
| September | Year 2017 | 8,333 | 0.5400% | 4.00 | (180) | | (8,513) |
| October | Year 2017 | 8,333 | 0.5400% | 3.00 | (135) | | (8,468) |
| November | Year 2017 | 8,333 | 0.5400% | 2.00 | (90) | | (8,423) |
| December | Year 2017 | 8,333 | 0.5400% | 1.00 | (45) | | (8,378) |
| | | | | | (3,510) | | **(103,510)** |
| | | | | | **Annual** | | |
| January through December | Year 2018 | (103,510) | 0.5800% | 12.00 | (7,204) | | **(110,714)** |
| January through December | Year 2019 | (110,714) | 0.5700% | 12.00 | (7,573) | | **(118,287)** |
| January through December | Year 2020 | (118,287) | 0.5700% | 12.00 | (8,091) | | **(126,378)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | | **Mont** | | |
|---|---|---|---|---|---|---|---|

| | | | | | hly | | |
|---|---|---|---|---|---|---|---|
| January | Year 2021 | **126,378** | 0.5700% | | (720) | (10,926) | (116,173) |
| February | Year 2021 | 116,173 | 0.5700% | | (662) | (10,926) | (105,909) |
| March | Year 2021 | 105,909 | 0.5700% | | (604) | (10,926) | (95,587) |
| April | Year 2021 | 95,587 | 0.5700% | | (545) | (10,926) | (85,206) |
| May | Year 2021 | 85,206 | 0.5700% | | (486) | (10,926) | (74,766) |
| June | Year 2021 | 74,766 | 0.5700% | | (426) | (10,926) | (64,266) |
| July | Year 2021 | 64,266 | 0.5700% | | (366) | (10,926) | (53,707) |
| August | Year 2021 | 53,707 | 0.5700% | | (306) | (10,926) | (43,087) |
| September | Year 2021 | 43,087 | 0.5700% | | (246) | (10,926) | (32,407) |
| October | Year 2021 | 32,407 | 0.5700% | | (185) | (10,926) | (21,666) |
| November | Year 2021 | 21,666 | 0.5700% | | (123) | (10,926) | (10,864) |
| December | Year 2021 | 10,864 | 0.5700% | | (62) | (10,926) | 0 |
| | | | | | (4,731) | | |
| Total Amount of True-Up Adjustment for 2014 ATRR | | | | | | $ (131,109) | |
| Less Over (Under) Recovery | | | | | | $ 100,000 | |
| Total Interest | | | | | | $ (31,109) | |

**Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan**

**Transource Oklahoma, LLC**

| **Calculation of Interest for 2018 True-Up Period** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | **Monthly** | | |
| January | Year 2018 | 25,000 | 0.5800% | 12.00 | (1,740) | | (26,740) |
| February | Year 2018 | 25,000 | 0.5800% | 11.00 | (1,595) | | (26,595) |
| March | Year 2018 | 25,000 | 0.5800% | 10.00 | (1,450) | | (26,450) |
| April | Year 2018 | 25,000 | 0.5800% | 9.00 | (1,305) | | (26,305) |
| May | Year 2018 | 25,000 | 0.5800% | 8.00 | (1,160 | | (26,160) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | ) | | |
| June | Year 2018 | 25,000 | 0.5800% | 7.00 | (1,015 ) | | (26,015) |
| July | Year 2018 | 25,000 | 0.5800% | 6.00 | (870) | | (25,870) |
| August | Year 2018 | 25,000 | 0.5800% | 5.00 | (725) | | (25,725) |
| September | Year 2018 | 25,000 | 0.5800% | 4.00 | (580) | | (25,580) |
| October | Year 2018 | 25,000 | 0.5800% | 3.00 | (435) | | (25,435) |
| November | Year 2018 | 25,000 | 0.5800% | 2.00 | (290) | | (25,290) |
| December | Year 2018 | 25,000 | 0.5800% | 1.00 | (145) | | (25,145) |
| | | | | | (11,31 0) | | **(311,310 )** |
| | | | | | **Annu al** | | |
| January through December | Year 2019 | (311,310) | 0.5700% | 12.00 | (21,29 4) | | **(332,604 )** |
| January through December | Year 2020 | (332,604) | 0.5700% | 12.00 | (22,75 0) | | **(355,354 )** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | | **Mont hly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2021 | **355,354** | 0.5700% | | (2,026 ) | (30,721) | (326,658 ) |
| February | Year 2021 | 326,658 | 0.5700% | | (1,862 ) | (30,721) | (297,798 ) |
| March | Year 2021 | 297,798 | 0.5700% | | (1,697 ) | (30,721) | (268,774 ) |
| April | Year 2021 | 268,774 | 0.5700% | | (1,532 ) | (30,721) | (239,585 ) |
| May | Year 2021 | 239,585 | 0.5700% | | (1,366 ) | (30,721) | (210,229 ) |
| June | Year 2021 | 210,229 | 0.5700% | | (1,198 ) | (30,721) | (180,706 ) |
| July | Year 2021 | 180,706 | 0.5700% | | (1,030 ) | (30,721) | (151,015 ) |
| August | Year 2021 | 151,015 | 0.5700% | | (861) | (30,721) | (121,154 ) |
| September | Year 2021 | 121,154 | 0.5700% | | (691) | (30,721) | (91,123) |
| October | Year 2021 | 91,123 | 0.5700% | | (519) | (30,721) | (60,921) |
| November | Year 2021 | 60,921 | 0.5700% | | (347) | (30,721) | (30,547) |
| December | Year 2021 | 30,547 | 0.5700% | | (174) | (30,721) | 0 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | (13,303) | | |
| Total Amount of True-Up Adjustment for 2015 ATRR | | | | | | $ (368,657) | |
| Less Over (Under) Recovery | | | | | | $ 300,000 | |
| Total Interest | | | | | | $ (68,657) | |

**Calculation of Interest for 2019 True-Up Period**

| | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2019 | 8,333 | 0.5700% | 12.00 | (570) | | (8,903) |
| February | Year 2019 | 8,333 | 0.5700% | 11.00 | (523) | | (8,856) |
| March | Year 2019 | 8,333 | 0.5700% | 10.00 | (475) | | (8,808) |
| April | Year 2019 | 8,333 | 0.5700% | 9.00 | (428) | | (8,761) |
| May | Year 2019 | 8,333 | 0.5700% | 8.00 | (380) | | (8,713) |
| June | Year 2019 | 8,333 | 0.5700% | 7.00 | (333) | | (8,666) |
| July | Year 2019 | 8,333 | 0.5700% | 6.00 | (285) | | (8,618) |
| August | Year 2019 | 8,333 | 0.5700% | 5.00 | (238) | | (8,571) |
| September | Year 2019 | 8,333 | 0.5700% | 4.00 | (190) | | (8,523) |
| October | Year 2019 | 8,333 | 0.5700% | 3.00 | (143) | | (8,476) |
| November | Year 2019 | 8,333 | 0.5700% | 2.00 | (95) | | (8,428) |
| December | Year 2019 | 8,333 | 0.5700% | 1.00 | (48) | | (8,381) |
| | | | | | (3,705) | | **(103,705)** |
| | | | | | **Annual** | | |
| January through December | Year 2020 | (103,705) | 0.5700% | 12.00 | (7,093) | | **(110,798)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | Year 2021 | **110,798** | 0.5700% | | (632) | (9,579) | (101,851) |
| February | Year 2021 | 101,851 | 0.5700% | | (581) | (9,579) | (92,853) |
| March | Year | | 0.5700% | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | 2021 | 92,853 | | (529) | (9,579) | (83,803) |
| April | Year 2021 | 83,803 | 0.5700% | (478) | (9,579) | (74,702) |
| May | Year 2021 | 74,702 | 0.5700% | (426) | (9,579) | (65,549) |
| June | Year 2021 | 65,549 | 0.5700% | (374) | (9,579) | (56,344) |
| July | Year 2021 | 56,344 | 0.5700% | (321) | (9,579) | (47,086) |
| August | Year 2021 | 47,086 | 0.5700% | (268) | (9,579) | (37,776) |
| September | Year 2021 | 37,776 | 0.5700% | (215) | (9,579) | (28,412) |
| October | Year 2021 | 28,412 | 0.5700% | (162) | (9,579) | (18,995) |
| November | Year 2021 | 18,995 | 0.5700% | (108) | (9,579) | (9,525) |
| December | Year 2021 | 9,525 | 0.5700% | (54) | (9,579) | 0 |
| | | | | (4,148) | | |
| Total Amount of True-Up Adjustment for 2016 ATRR | | | | | $ (114,946) | |
| Less Over (Under) Recovery | | | | | $ 100,000 | |
| Total Interest | | | | | $ (14,946) | |

Attachment 10

Depreciation Rates

Transource SPP Entity

Company Name Here

| | | Average Service Life (Years) | Iowa Curve | Salvage Factor | Cost of Removal Factor | Net Salvage Factor | Calculated Initial Annual Depreciation Rates |
|---|---|---|---|---|---|---|---|
| **TRANSMISSION PLANT** | | | | | | | |
| 350 | Rights of Way | 75 | R4.0 | 0% | 0% | 0% | 1.33% |
| 352.0 | Structures & Improvements | 60 | R4.0 | 0% | 23% | -23% | 2.05% |
| 353.0 | Station Equipment | 60 | R2.0 | 8% | 12% | -4% | 1.73% |
| 354.0 | Towers & Fixtures | 75 | R4.0 | 0% | 0% | 0% | 1.33% |
| 355.0 | Poles & Fixtures | 55 | S0.0 | 0% | 57% | -57% | 2.85% |
| 356.0 | OH Cond. & Devices | 70 | R3.0 | 0% | 38% | -38% | 1.97% |
| 358 | Underground Conductor and Devices | 40 | R3.0 | 0% | 0% | 0% | 2.50% |
| **GENERAL PLANT** | | | | | | | |
| 390.0 | Structures & Improvements | 40 | L0.0 | 39% | 4% | 35% | 1.63% |
| 391.0 | Office Furniture & Equipment | 23 | SQ | 5% | 0% | 5% | 4.13% |
| 391 | Computers | 5 | SQ | 1% | 1% | 0% | 20.00% |
| 392.0 | Transportation Equipment | 15 | SQ | 0% | 0% | 0% | 6.67% |
| 393.0 | Stores Equipment | 30 | SQ | 0% | 3% | -3% | 3.43% |
| 394.0 | Tools Shop & Garage Equipment | 25 | SQ | 1% | 1% | 0% | 4.00% |
| 395.0 | Laboratory Equipment | 28 | SQ | 1% | 0% | 1% | 3.54% |
| 396.0 | Power Operated Equipment | 25 | SQ | 0% | 1% | -1% | 4.04% |
| 397.0 | Communication Equipment | 19 | SQ | 1% | 4% | -3% | 5.42% |
| 398.0 | Miscellaneous Equipment | 20 | SQ | 0% | 0% | 0% | 5.00% |

# TRANSOURCE *PRO FORMA* FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed *pro forma* rate ("Formula Rate") available for subsidiaries of Transource Energy, LLC operating in SPP ("Transource SPP Entities") for transmission revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("SPP Tariff"). Transource SPP Entity shall follow the instructions specified in the Formula Rate to calculate annually its net revenue requirement, as set forth at page 1, line 10 of the Template ("Net Revenue Requirement"). The project-specific net revenue requirements determined under the Formula Rate are "up to" rates, i.e., ceiling rates, and permit Transource SPP Entity to discount the revenue requirement for a future project to the extent necessary to reflect the result of any competitive bidding on such a project. The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of Transource SPP Entity's Net Revenue Requirement upon the effective date for incorporation into the SPP Tariff through an appropriate filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d (2012).

## Section 1. Annual Projection

a. No later than September 30 preceding the first Rate Year, and each subsequent Rate Year, Transource SPP Entity shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with Transource SPP Entity's Formula Rate ("Annual Projection"). The Annual Projection shall include the True-up Adjustment described and defined in Section 2 below, if

applicable. Transource SPP Entity shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format ("PDF") and fully-functioning Excel file at a publicly accessible location on SPP's internet website and OASIS. Such posting shall include all inputs in sufficient detail to identify the components of Transource SPP Entity's projected Net Revenue Requirement, explanations of the bases for the projections and input data, and sufficient detail and explanation to enable Interested Persons (as that term is defined in footnote 1 of these Protocols) to replicate the calculation of the projected Net Revenue Requirement. With respect to any Accounting Change (as that term is defined in Section 3.e.iii), Transource SPP Entity shall (i) identify any Accounting Changes, including the initial implementation of an accounting standard or policy, the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction, correction of errors and prior period adjustments that impact the projected net revenue requirement calculation, the implementation of new estimation methods or policies that change prior estimates, and changes to income tax elections; (ii) identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments); (iii) identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement; and (iv) provide, for each item identified pursuant to Section 1.a.i - iii of these Protocols, a narrative explanation of the individual impact of such changes on the projected Net Revenue

Requirement. If the date for making such posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day. Within ten (10) days of such posting, SPP shall provide notice of such posting via an email exploder list ("SPP Exploder List"). Interested Persons can subscribe to the SPP Exploder List on the SPP website.

b. Together with the posting of the Annual Projection, Transource SPP Entity shall cause to be posted on the SPP internet website and OASIS, and distributed to the SPP Exploder List, the time, date and location for a stakeholder meeting with Interested Persons in order for Transource SPP Entity to explain its Annual Projection and to provide Interested Persons an opportunity to seek information and clarifications regarding the Annual Update ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after September 30.

c. To the extent Transource SPP Entity agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on SPP's internet website and OASIS, and e-mailed to the SPP Exploder List. Changes posted prior to November 30 of the preceding Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under SPP's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-up Adjustment for the Rate Year.

d. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

**Section 2. <u>True-up Adjustment</u>**

Transource SPP Entity will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in 2(b):

a. Transource SPP Entity's projected Net Revenue Requirement collected during the previous Rate Year will be compared to Transource SPP Entity's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with Transource SPP Entity's Formula Rate and based upon (i) Transource SPP Entity's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to Transource SPP Entity's calculation of its annual revenue requirement, (iii) the books and records of Transource SPP Entity (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the SPP OATT Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates, to determine any over- or under-recovery ("True-up Adjustment Over/Under Recovery"). Transource SPP Entity will include a variance analysis of, at

minimum, actual revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected revenue requirement that was calculated for the prior Rate Year with an explanation of material changes.

b. Interest on any True-up Adjustment Over/Under Recovery of the actual Net Revenue Requirement shall be calculated in accordance with Attachment 6 of the Formula Rate.

**Section 3. <u>Annual Update</u>**

a. On or before June 30 following each Rate Year, Transource SPP Entity shall calculate its actual Net Revenue Requirement and the True-up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and fully-functioning Excel format, at a publicly accessible location on SPP's internet website and OASIS and e-mailed to the SPP Exploder List.

b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c. The date on which the last of the events listed in Section 3(a) or 3(b) occurs shall be that year's "Publication Date."

d. Together with the posting of the Annual Update, Transource SPP Entity shall

cause to be posted on the SPP website and OASIS, and e-mailed to the SPP Exploder List, the time, date and location for a stakeholder meeting with Interested Persons in order for Transource SPP Entity to explain its Annual Update and to provide Interested Persons an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after June 30.

e. The Annual Update posting for the Rate Year:

(i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;

(ii) Shall provide sufficient detail and sufficient explanation to enable Interested Parties to replicate the calculation of the Annual True-Up results from the FERC Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii) Shall, identify:

a. any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:

i. The initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. any items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the True-Up Adjustment;

d. for each item identified pursuant to items 3.e.iii.a - c of these protocols, the individual impact (in narrative format) of such changes on the True-Up Adjustment.

e. for the applicable Rate Year the following information related to affiliate cost allocation:

i. a detailed description of the methodologies used to allocate and directly assign costs between Transource SPP Entity and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justifications for those

changes; and

ii. the magnitude of such costs that have been allocated or directly assigned between Transource SPP Entity and each affiliate by service category or function.

(iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Person seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).

a. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) "Post-Employment Benefits other than Pensions" pursuant to Statement of Financial

Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges; and (iii) the depreciation and/or amortization rates as set forth in Attachment 10 to the Formula Rate template.

b. **Example - Timeline for 2017 Annual Update**:

On or before September 30, 2015, Transource SPP Entity will determine the projected Net Revenue Requirement for the 2016 Rate Year, which is expected to be the first year that costs are recovered from SPP customers under the Formula Rate. Transource SPP Entity will post the Annual Projection for the 2016 Rate Year in accordance with Section 1 above. Transource SPP Entity will not determine a True-up Adjustment or post an Annual Update on June 30, 2016 if no costs have been recovered under the Formula Rate during 2015. On or before September 30, 2016, Transource SPP Entity will post the Annual Projection for the 2017 Rate Year. On or before June 30, 2017, Transource SPP Entity will post its first Annual Update, consisting of the actual Net Revenue Requirement and True-up Adjustment for the 2016 Rate Year determined pursuant to Section 2 above. Such True-up Adjustment will be reflected in the Annual Projection of the Net Revenue Requirement for the 2018 Rate Year posted on or before September 30, 2017. The Annual Update posted June 30, 2017 will be subject to the customer review and challenge procedures described in Sections 4, 5, and 6 of these Protocols.

**Section 4. <u>Annual Review Procedures</u>**

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Persons shall have up to the latest of one hundred fifty (150) calendar days after the Publication Date, thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of Transource SPP Entity), or thirty (30) calendar days after resolution of a dispute that does not result in the production of additional information ("Review Period"), to review the calculations and to notify Transource SPP Entity in writing of any specific challenges to the Annual Update ("Preliminary Challenge"), including challenges related to Accounting Changes. Transource SPP Entity shall promptly cause to be posted all Preliminary Challenges at a publicly accessible location on SPP's internet website and OASIS and a link to the website will be e-mailed to the SPP Exploder List.

Transource SPP Entity shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which Transource SPP Entity agrees or disagrees with the challenge. If Transource SPP Entity disagrees with the Preliminary Challenge, its response shall include supporting documentation. Transource SPP Entity shall promptly cause to be posted responses to all Preliminary Challenges at a publicly accessible location on SPP's internet website and OASIS and e-mailed to the SPP Exploder List.

b. Interested Persons shall have up to one hundred twenty (120) calendar days after each annual Publication Date (unless such period is extended with the written consent of Transource SPP Entity) to serve reasonable information requests on Transource SPP Entity. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the True-Up Adjustment fails to include data properly recorded in accordance with the Protocols; (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the changes shown in the Annual Update; (v) the prudence of the actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or applicable form; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior Transource SPP Entity Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC. Information requests received will be posted at a publicly accessible location on SPP's internet website and OASIS and a link to the website and OASIS will be e-mailed to the SPP Exploder List.

c. Transource SPP Entity shall make a good faith effort to respond to information

requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

To the extent Transource SPP Entity and any Interested Person(s) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, Transource SPP Entity or the Interested Person may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

d. Preliminary Challenges, or Formal Challenges as described in Section 5 below, related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update, nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update to the extent such Accounting Change affects the subsequent Annual Update.

e. If a change made by Transource SPP Entity to its accounting policies, practices or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any

remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

**Section 5. Resolution of Challenges**

a. Any Interested Person may, within ninety (90) calendar days after the end of the Review Period (unless such period is extended with the written consent of Transource SPP Entity to continue efforts to resolve an issue), file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the informational filing described in Section 7 and shall be served on Transource SPP Entity by electronic service on the date of such filing. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by Transource SPP Entity pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.

b. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Person from raising that issue in a Formal Challenge, provided the Interested Person submitted a Preliminary Challenge during the Review Period with respect to one or more other issues.

c. Any response by Transource SPP Entity to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the SPP

Exploder List on the date of such filing.

d. In any Formal Challenge proceeding concerning a given year's Annual Update (including corrections) or Accounting Change(s), Transource SPP Entity shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has reasonably and accurately calculated the Annual Update and/or reasonably adopted and applied the Accounting Change.

e. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Transource SPP Entity to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE, depreciation and amortization rates, and PBOPs), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.

**Section 6. Changes to Annual Updates**

If Transource SPP Entity determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, Transource SPP Entity shall promptly notify the SPP Exploder List, and cause a correction to the Annual Update to be posted at a publicly accessible location on SPP's internet website and OASIS. Such corrections shall be

subject to review at the time they are made and shall be reflected in the next Annual Update, with interest. A corrected posting shall reset the deadlines under Sections 4 and 5 of the Protocols for Interested Person review and the revised dates shall run from the posting date(s) for each of the corrections. The scope of review shall be limited to the aspects of the Annual Update affected by the corrections. Interest on any over- or under-recovery due to corrections for preceding True-up Adjustments shall be calculated monthly on such over- or under-recovery from January 1 of the corrected Rate Year through December 31 of the Rate Year in which such over- or under-recovery is reflected ("Correction Period"). That is equivalent to two years interest applied to over- or under- collection. The applicable monthly interest rates for the Correction Period for an over-recovery shall be the annual interest rates for each month pursuant to 18 C.F.R. § 35.19a (2014) divided by twelve (12) for each month from the beginning of the Correction Period through December 31 of the Rate Year immediately preceding the Rate Year in which such over-recovery is reflected. The applicable monthly interest rates for the Correction Period for an under-recovery shall be the annual interest rate determined in accordance 18 C.F.R § 35.19a divided by twelve (12) for each month from the beginning of the Correction Period through December 31 of the Rate Year immediately preceding the Rate Year in which such under-recovery is reflected.

**Section 7. Informational Filing**

Transource SPP Entity shall submit to FERC an informational filing ("Informational Filing") of its projected Net Revenue Requirement for a Rate Year, including the True-Up Adjustment determined during the preceding Annual Update, by March 15 of the Rate Year. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying

workpapers; (2) that Transource SPP Entity has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Net Revenue Requirement and rates under review; (4) the extent of accounting changes that affect Formula Rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Annual Update or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Additionally, the Informational Filing must include for the applicable Rate Year the following information related to affiliate cost allocation: (1) a detailed description of the methodologies used to allocate and directly assign costs between Transource SPP Entity and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (2) the magnitude of such costs that have been allocated or directly assigned between Transource SPP Entity and each affiliate by service category or function. Any challenges to the implementation of the Template must be made through the annual review and challenge procedures described in Sections 4 and 5 of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

**Section 8. Joint Informational Meeting**

Transmission Owners with transmission projects that are subject to regional cost sharing shall endeavor to hold a joint informational meeting to enable all interested parties to understand how those Transmission Owners are implementing their formula rates for cost recovery of such projects ("Joint Informational Meeting"). Notice of the Joint Informational Meeting, including the time, date, and location, shall be posted on the SPP website and OASIS and distributed to the SPP Exploder List no less than seven (7) days prior to such meeting.

Transource SPP Entity will participate in Joint Informational Meetings once it begins development of a project for which costs are to be regionally allocated.

**Section 9. Construction Work in Progress**

a. *Accounting.* Transource SPP Entity shall use the following accounting procedures to ensure that it does not recover an Allowance for Funds Used During Construction ("AFUDC") with respect to any amount of Construction Work In Progress ("CWIP") included in rate base.

(i) Transource SPP Entity shall assign each transmission project a unique Funding Project Number ("FPN") for internal cost tracking purposes.

(ii) Transource SPP Entity shall record actual construction costs to each FPN through work orders that are coded to correspond to the FPN for each project for which FERC has authorized all or part of the CWIP balance to be included in rate base ("CWIP Project".

(iii) Each project-specific FPN tracking account will be programmed to calculate and accrue AFUDC only on the balance of CWIP that is not eligible for inclusion in rate base.

(iv) For each project under construction, Transource SPP Entity shall prepare monthly work order summaries of costs incurred under the associated FPN. These summaries shall show monthly additions to CWIP in the FPN and, if less than 100% of the CWIP corresponding to the project FPN is eligible for inclusion in rate base, shall separately identify through FPN subaccounts (i) the component of the project CWIP balance included in rate base; and (ii) the component of the project CWIP balance

that is not included in rate base, including capitalized AFUDC. The summaries will also show any additions to plant in service. The summaries shall correspond to amounts recorded in FERC Account 107, CWIP, which account balance will be reported on Transource SPP Entity's FERC Form No. 1. Transource SPP Entity shall use these project-specific monthly summaries as data inputs into the annual CWIP report prepared under Section 7(b) and the Annual Update calculated pursuant to Section 3. Transource SPP Entity shall make such work order summaries available upon request under the review procedures of Section 4.

(v) When a project, or portion thereof, is placed into service, Transource SPP Entity shall deduct from total CWIP the accumulated balance of the FPN tracking account for that project, or portion thereof. The purpose of this control process is to ensure that expenditures are not double counted as both CWIP and as additions to plant.

(vi) For transmission projects for which the Commission has not authorized Transource SPP Entity to include any CWIP in rate base, Transource SPP Entity shall record AFUDC to be applied to the full CWIP balance of the FPN tracking account and capitalized when the project is placed into service.

b. *Annual Reporting.* For CWIP Projects, Transource SPP Entity shall file a report with the Commission at the time of Transource SPP Entity's Informational Filing that shall include the following information concerning each transmission

project under construction:

(i) a demonstration that each project for which CWIP is included in rate base was identified through SPP's regional planning process and awarded to Transource SPP Entity on the basis of a competitive bid;

(ii) the cost allocation methodology for each project under the SPP Tariff;

(iii) a tabulation of the monthly summaries described in Section 7(a)(iv) for each unique FPN tracking account, including thirteen (13) monthly balances illustrating the amount of CWIP included in rate base for the project, the amount of CWIP that is not included in rate base for the project, the amount of accumulated AFUDC associated with any CWIP not included in rate base, and any amounts recorded in related FERC accounts or subaccounts, such as regulatory liability;

(iv) the resulting effect of CWIP on the Net Revenue Requirement, including the percentage of any increase in the year-over-year Net Revenue Requirement that is attributable to CWIP, and the percentage of the total Net Revenue Requirement for the Rate Year that is attributable to CWIP;

(v) a statement of the current status of each project; and

(vi) the estimated in-service date for each project.

**Section 10. Competitive Bid Concessions**

For transmission development projects assigned to Transource SPP Entity as a result of the SPP competitive bidding process, Transource SPP Entity may, in its sole discretion, agree with SPP to apply a Competitive Bid Concession that will result in a lower Net Revenue Requirement on a project-specific basis than that which would otherwise be produced by the Transource SPP

Entity Addendum 48 to Attachment H formula rate. Any Competitive Bid Concession will appear as a zero or negative input to the formula, and will be determined on a project-specific basis using a workpaper that will be provided to Interested Parties as supporting documentation for each Transource SPP Entity Annual Update.

# ADDENDUM 49 TO ATTACHMENT H

## L and O Power Cooperative

Index

**L&O Power Cooperative**

Fiscal Year Ending December 31, 2XXX


| Line No. | Location | Description |
|---|---|---|
| 1 | Summary | ATRR Revenue Requirement Summary |
| 2 | Worksheet A | Rate Base |
| 3 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 4 | Worksheet C | Capital Structure, Rate of Return and Target Return |
| 5 | Worksheet D | Load |
| 6 | Worksheet E | Allocation Factors |
| 7 | Worksheet F | Input Section |
| 8 | Worksheet G | Depreciation Rates |
| 9 | Worksheet H | SPP Upgrades |
| 10 | Worksheet I | Calculation of Interest Applied to True-Up Calculations |
| 11 | Worksheet J | O&M Input - From RUS Form 12 |
| 12 | Worksheet K | Wage Input and Functionalization |
| 13 | Worksheet L | Depreciation Functionalization |
| 14 | Worksheet M | Other Revenue |
| 15 | Worksheet N | Regulatory and Commission Expenses |
| 16 | Worksheet O | Customer Accounting |
| 17 | Worksheet P | Construction Work in Progress |
| 18 | Worksheet Q | Plant Held for Future Use |
| 19 | Worksheet R | SPP Completed Not Classified |
| 22 | Worksheet S | RTO Expenses - Operation & Maintenance |
| 22 | Worksheet T | Transmission Stations |
| 22 | Worksheet U | Transmission Lines |


| Key | Shaded cell, denoting manual input |
|---|---|

Summary

# L&O Power Cooperative

# ATRR Revenue Requirement Summary

# Fiscal Year Ending December 31, 2XXX

| A<br>Line No. | B<br>Account Number | C<br>Description | D<br>Reference | E<br>Total Company | F<br>Adjustments | G<br>Adjusted Company | H<br>Allocation Factor | I<br>Allocation % | J<br>Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 38, Col J | | | | | | |
| 3 | | Revenue Credits-Operating | | | | | | | |
| 4 | | All SPP Facilities Leased | Worksheet M, Line 8, Col H | $ - | - | $ - | Direct | 100.0% | $ - |
| 5 | | Non SPP Facilities Leased | Worksheet M, Line 8, Col I | $ - | - | $ - | Direct | 0.0% | $ - |
| 6 | | Both SPP and Non SPP Facilities Leased | Worksheet M, Line 8, Col J | $ - | - | $ - | T-Tran Plan | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | t | | |
| | | Other Electric | Worksheet | | | | T- | | |
| | | Revenue | M, Line 8, | $ | | $ | Plan | | |
| 7 | | | Col K | - | - | - | t | | |
| | | Retail Related | Worksheet | | | | | | |
| | | | M, Line 8, | $ | | $ | Dire | 0.0 | $ |
| 8 | | | Col E | - | - | - | ct | % | - |
| | | SPP Sched 7 & 8 | Worksheet | | | | | | |
| | | P2P | M, Line 8, | $ | | $ | Dire | 100 | $ |
| 9 | | | Col G | - | - | - | ct | .0% | - |
| 1 | | Revenue Credits- | | $ | | $ | | | |
| 0 | | Operating | Sum | - | - | - | | | |
| | | Revenue Requirement | | | | | | | |
| 1 | | before SPP Adj and | Line 2 - | | | | | | |
| 1 | | Prior Yr corrections | Line 10 | | | | | | |
| | | Reconciliation | | | | | | | |
| | | Adjustment for Prior | Worksheet | | | | | | |
| 1 | | Period Errors (Gross | I Line 6, | | | | | | $ |
| 2 | | ATRR) | Col L | | | | | | - |
| | | Reconciliation | | | | | | | |
| | | Adjustment for Prior | +Workshe | | | | | | |
| 1 | | Period Errors (SPP | et I Line | | | | | | $ |
| 3 | | Upgrades) | 12, Col L | | | | | | - |
| | | | - | | | | | | |
| | | | Worksheet | | | | | | |
| 1 | | | H Line 18, | | | | | | |
| 4 | | SPP Upgrades | Col Q | | | | | | |
| | | | - | | | | | | |
| | | | Worksheet | | | | | | |
| 1 | 45 | Schd 11 P2P Revenue | M, Line 8, | | | | | | $ |
| 5 | 6 | Credits | Col F | | | | | | - |
| 1 | | | Sum Lines | | | | | | |
| 6 | | Sum | 11 thru 15 | | | | | | |
| 1 | | | | | | | | | |
| 7 | | | | | | | | | |
| 1 | | **B. Point-To-Point** | | | | | | | |
| 8 | | **Service (Divisor):** | | | | | | | |
| | | | Worksheet | | | | | | |
| 1 | | Network Transmission | D, Line 14, | | | | | | |
| 9 | | Load (kW) | Col C | | | | | | |
| 2 | | | | | | | | | |
| 0 | | | | | | | | | |
| | | **C. Rates** | | | | | | | |

| | | |
|---|---|---|
| 21 | | |
| 22 | Annual Point-to-Point Cost ($/kW-Yr) | Line 16 / Line 19 |
| 23 | Monthly Point-to-Point ($/kW-Mo) | Line 22 / 12 months |
| 24 | Weekly Point-to-Point ($/kW-Week) | Line 22 / 52 Weeks |
| 25 | Daily On-Peak Point-to-Point ($/kW-Day) | Line 24 / 5 days |
| 26 | Daily Off-Peak Point-to-Point ($/kW-Day) | Line 24 / 7 days |
| 27 | Hourly On-Peak Point-to-Point ($/MWh) | Line 25 / 16 hours * 1,000 |
| 28 | Hourly Off-Peak Point-to-Point ($/MWh) | Line 26 / 24 hours * 1,000 |

Worksheet A

# L&O Power Cooperative

## Rate Base
## Fiscal Year Ending December 31, 2XXX

| A Line No. | B Description | C Reference | D Beginning of Year | E End of Year | F Total Company | G Allocation Factor | H Allocation % | I Transmission |
|---|---|---|---|---|---|---|---|---|
| 1 | **Plant in Service** | | | | | | | |
| 2 | 301-303 Total Intangible Plant | Worksheet F, Line 38 Col D, E & F | $ - | $ - | $ - | T-Wages | #DIV/0! | #DIV/0! |
| 3 | 350 Land and Land Rights | Worksheet F, Line 40 Col D, E & F | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 4 | 352 Structures and Improvements | Worksheet F, Line 41 Col D, E & F | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 5 | 353 Station Equipment - Non-qualified Subs | Worksheet F, Line 3 Col D, E, F | $ - | $ - | $ - | Direct | 0.0 % | $ - |
| 6 | 353 Station Equipment Qualified | Worksheet F, Line 42 - Line 5 | $ - | $ - | $ - | Direct | 100.0% | $ - |
| 7 | 354 thru 359.1 Other Transmission | Worksheet F, Line 43 Col D, E & F | $ - | $ - | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | Plant Transmission Plant | Sum Lines 3 thru 7 | $ - | $ - | $ - | | | #DIV/0! |
| 9 | Total Distribution Plant | Worksheet F, Line 44 Col D, E & F | $ - | $ - | $ - | Dist Stations | #DIV/0! | #DIV/0! |
| 10 | 380-386 RTO/ISO Plant | Worksheet F, Line 45 Col D, E & F | $ - | $ - | $ - | Direct | 100.0% | $ - |
| 11 | 389 thru 399.1 Total General Plant | Worksheet F, Line 46 Col D, E & F | $ - | $ - | $ - | T-Wages | #DIV/0! | #DIV/0! |
| 12 | Gross Electric Plant in Service | Line 2 + Line 8 + Line 9 + Line10 + Line 11 | $ - | $ - | $ - | | | #DIV/0! |
| 13 | 105 Electric Plant Held For Future Use | Worksheet Q, Line 11, Col, E, F, G | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 14 | 106 Completed Construction Not Classified | Worksheet R, Line 4, Col H, I , J | $ - | $ - | $ - | Direct | 100.0% | $ - |
| 15 | 107 Construction Work in Progress | Worksheet P, Line 7 Cols I and J, and Line 5 Col L | $ - | $ - | $ - | Direct | 100.0% | $ - |
| 16 | Utility Plant | Sum Lines 12 thru 15 | $ - | $ - | $ - | | | #DIV/0! |
| 17 | **Accumulated Depreciation** | | | | | | | |
| 18 | 108.1 Depreciation of Steam Plant | Worksheet F, Line 48 Col D, E & F | $ - | $ - | $ - | | | |
| 19 | 108.4 Depreciation of Other Production Plant | Worksheet F, Line 49 Col D, E & F | $ - | $ - | $ - | | | |
| 20 | 108.5 Depreciation of Transmission Plant | Worksheet F, Line 50 Col D, E & F | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 21 | 108.6 Depreciation of Distribution Plant | Worksheet F, Line 51 Col D, E & F | $ - | $ - | $ - | Dist Stations | #DIV/0! | #DIV/0! |
| 22 | 108.7 Depreciation of General Plant | Worksheet F, Line 52 Col D, E & F | $ - | $ - | $ - | T-Wages | #DIV/0! | #DIV/0! |
| 2 | 108.8 | Worksheet F, Line | $ | $ | $ | T- | #DI | #DIV/ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 3 | Retirement Work in Progress | 53 Col D, E & F | - | - | - | Plant | V/0! | 0! |
| 24 | 111 Amortization of Electric Plant in Service | Worksheet F, Line 54 Col D, E & F | $ - | $ - | $ - | T-Wages | #DIV/0! | #DIV/0! |
| 25 | Total Accumulated Depreciation | Sum Lines 18 thru 24 | $ - | $ - | $ - | | | #DIV/0! |
| 26 | **Total Net Plant in Service** | | | | | | | |
| 27 | 301-303 Net Total Intangible Plant | Line 2 | $ - | $ - | $ - | | | #DIV/0! |
| 28 | Net Transmission Plant | Line 8 + Line 10 - Line 20 | $ - | $ - | $ - | | | #DIV/0! |
| 29 | Net Distribution Plant | Line 9 - Line 21 | $ - | $ - | $ - | | | #DIV/0! |
| 30 | Net General Plant | Line 11 - Line 22 | $ - | $ - | $ - | | | #DIV/0! |
| 31 | Electric Plant Held For Future Use | Line 13 | $ - | $ - | $ - | | | #DIV/0! |
| 32 | Completed Construction Not Classified | Line 14 | $ - | $ - | $ - | | | $ - |
| 33 | Construction Work in Progress | Line 15 | $ - | $ - | $ - | Direct | 100.0% | $ - |
| 34 | Retirement Work in Progress | Line 23 | $ - | $ - | $ - | | | #DIV/0! |
| 35 | Amortization of Electric Plant in Service | - Line 24 | $ - | $ - | $ - | | | #DIV/0! |
| 36 | Total Net Plant in Service | Sum Lines 27 thru 35 | $ - | $ - | $ - | | | #DIV/0! |
| 37 | **Adjustments to Rate Base** | | | | | | | |
| 38 | **Working Capital** | | | | | | | |
| 39 | Total Transmission O&M Costs | Worksheet B, Line 29, Col F& J | | | $ - | | | #DIV/0! |
| 40 | Billing Lag in Days | Worksheet F, Line 1 Col F | | | 45 | | | 45 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 41 | Working Capital | Line 39 * Line 40 / 365 | | | $ - | | | #DIV/0! |
| 42 | Prepayments | Worksheet F, Line 33 Col D, E & F | $ - | $ - | $ - | T-Plant | #DIV/0! | #DIV/0! |
| 43 | Materials and Supplies | Worksheet F, Line 62 Col D, E & F | $ - | $ - | $ - | T-Plant | #DIV/0! | #DIV/0! |
| 44 | **Rate Base** | Line 36 + Line 41 + Line 42 + Line 43 | $ - | $ - | $ - | | | #DIV/0! |

Work sheet B

# L&O Power Cooperative

## O&M, Depreciation, and Return Expenses

## Fiscal Year Ending December 31, 2XXX

| A Line No. | B Description | C Reference | D Total Company | E | F Total Company | G Allocation Factor | H Allocation % | I Notes | J Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Transmission Operation & Maintenance Expenses | | Lines | Stations | | | | | |
| 2 | 560 Supervision and Engineering | Worksheet J, Line 1, Col D & E | $ - | $ - | $ - | T-Plant Direct | 100.0% | | $ - |
| 3 | 561 Load Dispatching | Worksheet J, Line 2, Col D & E | $ - | $ - | $ - | T-Trans Stations | | | |
| 4 | 562 Station Expenses | Worksheet J, Line 3, Col D & E | $ - | $ - | $ - | T-Trans Lines | | | |
| 5 | 563 Overhead Line Expenses | Worksheet J, Line 4, Col D & E | $ - | $ - | $ - | T-Trans Lines | | | |
| 6 | 564 Underground Line Expenses | Worksheet J, Line 5, Col D & E | $ - | $ - | $ - | T-Trans Lines | | | |
| 7 | 565 Transmission | Worksheet J, Line 8, | | $ | $ | Direc | 0.0 | | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | of Electricity by Others | Col D & E | | - | - | t | % | - |
| 8 | 566 Miscellaneous Expenses | Worksheet J, Line 6, Col D & E | $ - | $ - | $ - | T-Tran Plant | | |
| 9 | 567 Rents | Worksheet J, Line 9, Col D & E | | $ - | $ - | T-Tran Plant | | |
| 10 | 568 Supervision and Engineering | Worksheet J, Line 11, Col D & E | $ - | $ - | $ - | T-Tran Plant | | |
| 11 | 569 Structures | Worksheet J, Line 12, Col D & E | $ - | $ - | $ - | Direct | 0.0 % | $ - |
| 12 | 570 Station Equipment | Worksheet J, Line 13, Col D & E | $ - | | $ - | T-Tran Stations | | |
| 13 | 571 Overhead Lines | Worksheet J, Line 14, Col D & E | | $ - | $ - | T-Trans Lines | | |
| 14 | 572 Underground Lines | Worksheet J, Line 15, Col D & E | $ - | $ - | $ - | T-Trans Lines | | |
| 15 | 573 Miscellaneous Transmission Plant | Worksheet J, Line 16, Col D & E | $ - | $ - | $ - | T-Tran Plant | | |
| 16 | RTO Expense - Operation | Worksheet S, Line 10, Col E & G | | | $ - | Direct | | $ - |
| 17 | RTO Expense - Maintenance | Worksheet S, Line 10, Col H & J | | | $ - | Direct | | $ - |
| 18 | Transmission O&M | Sum Lines 2 thru 17 | $ - | $ - | $ - | | | |
| 19 | 580-589 Distribution Expense - Operation | Worksheet J, Line 22, Col D & E | | | $ - | Dist Stations | | |
| 20 | 590-598 Distribution Expense - Maintenance | Worksheet J, Line 23, Col D & E | | | $ - | Dist Stations | | |
| 21 | Distribution O&M | Sum Lines 19 thru 20 | | $ - | $ - | | | |
| 22 | Administrative & General Expense | | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 3 | Customer Accounting Wages | Worksheet O, Line 10, Col D & F | | $ - | Direct | $ - |
| 2 4 | Customer Accounting Computer Support | Worksheet O, Line 12, Col D & F | | $ - | Direct | $ - |
| 2 5 | Admin and General Expense | Worksheet F, Line 18, Col F - Worksheet N, Line 6, Col D | | $ - | T-Wages | |
| 2 6 | Maintenance Expense General Plant | Worksheet F, Line 23, Col F | | $ - | T-Wages | |
| 2 7 | 928 Regulatory & Commission Expenses - SPP | Worksheet N, Line 6, Col D & F | | $ - | Direct | $ - |
| 2 8 | Total A&G Expenses | Sum Lines 23 thru 27 | | $ - | | |
| 2 9 | Subtotal O&M | Line 18 + Line 21 + Line 28 | | $ - | | |

| | | | Total Company | Adjustment | Adjusted Total | |
|---|---|---|---|---|---|---|
| 3 0 | Depreciation Expense | | | | | |
| 3 1 | Depr Expense Transmission Plant | Worksheet L, Line 6, Col E | $ - | | $ - | T-Tran Plant |
| 3 2 | Depr Expense Lines | Worksheet L, Line 6, Col F | $ - | | $ - | T-Trans Lines |
| 3 3 | Depr Expense Distribution Plant | Worksheet L, Line 6, Col G | $ - | | $ - | Dist Stations |
| 3 4 | Depr Expense General Plant | Worksheet L, Line 6, Col H | $ - | | $ - | T-Wages |
| 3 5 | Total Depreciation & Amortization | Sum Lines 31 thru 34 | $ - | $ - | $ - | |
| 3 6 | Tax - Gross Reciepts and Property Tax | Worksheet F, Line 24, Col F | | | $ - | T-Plant |
| 3 7 | Return | Worksheet C, Line 6, Col K | | | | |

| | | |
|---|---|---|
| 3<br>8 | Revenue<br>Requirement | Line 29 + Line 35 +<br>Sum Lines 36 thru<br>37 |

Worksheet C

# L&O Power Cooperative

## Capital Structure, Rate of Return and Target Return

## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Description | Reference | Total Co EoY | Actual Capitalization Ratios | Minimum Hypothetical Equity (Note A) | Maximum Hypothetical Equity (Note A) | Applied Cap Structure (Note B) | Interest Expense | Cost of Capital (Note C) | Weighted Rate of Return |
| 1 | Return Based on Defined ROE | | | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Line 35, Col F & Line 25, Col F | $ - | | 64.760% | 31.140% | | $ - | | |
| 3 | Total Margins and Equities | Worksheet F, Line 34, Col F | $ - | | 35.240% | 68.860% | | | 10.100% | |
| 4 | Total Capitalization | Sum Lines 2 thru 3 | $ - | | 100.000% | 100.000% | | $ - | | |
| 5 | Rate Base | Worksheet A, Line 44, Col I | | | | | | | | |
| 6 | Return | Line 5 * Line 6 | | | | | | | | |

7 Notes:

A.) The capital structure listed in Column (E) is calculated based on total capitalization amounts listed in Column (D).The capital structures listed in Column (F) and Column (G) are fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing.

B.) In the case where the actual equity percentage (Column (E)) is greater, or equal, to 35.24% and less, or equal, to 68.86%, Column (H) should be populated with the actual equity level (Column (E)). In the case where L&O's actual equity level is below 35.24 percent, Column (H) should be populated with the capital structure listed in Column (F). In the case where L&O's actual equity level is above 68.86 percent, Column (H) should be populated with the capital structure listed in Column (G).

C.) The Cost of Capital for Total Margins and Equities (ROE) is fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing. The Cost of Capital for Total Margins and Equities reflects a 50 basis point incentive adder for RTO participation. The Cost of Capital for Long Term Debt is calculated by dividing the interest expense in Column (I) by the total amount of LTD in Column (D).

Worksheet D

# L&O Power Cooperative

## Load

## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| | | Transfering Facilities | | | | |
| Line No | Description | Class I | Maple Street | Sub-Total | Class II | Peak Demand (KW) |
| 1 | January | | | - | | - |
| 2 | February | | | - | | - |
| 3 | March | | | - | | - |
| 4 | April | | | - | | - |
| 5 | May | | | - | | - |
| 6 | June | | | - | | - |
| 7 | July | | | - | | - |
| 8 | August | | | - | | - |
| 9 | September | | | - | | - |
| 10 | October | | | - | | - |
| 11 | November | | | - | | - |
| 12 | December | | | - | | - |
| 13 | Total (kW-Mo) | - | - | - | - | - |
| 14 | Average (kW-Mo) | #DIV/0! | #DIV/0! | - | #DIV/0! | - |

Worksheet E

# L&O Power Cooperative Allocation Factors

## Fiscal Year Ending December 31, 2XXX

| A Line No. | B Description | C Reference | D Total | E Allocation Factor Name | F Allocation Factor % | G ATRR Allocated |
|---|---|---|---|---|---|---|
| 1 | Station Expense Transmission | Worksheet K ,Line 12, Column E | $ - | T-Tran Stations | | |
| 2 | Overhead Line Expense | Worksheet K ,Line 12, Column F | $ - | T-Trans Lines | | |
| 3 | Maint. of Transmission Station Equipment | Worksheet K ,Line 12, Column G | $ - | T-Tran Stations | | |
| 4 | Maint. of Overhead Lines | Worksheet K ,Line 12, Column H | $ - | T-Trans Lines | | |
| 5 | Distribution Station Expense | Worksheet K ,Line 12, Column I | $ - | Dist Stations | | |
| 6 | Maint. of Distribution Station Equipment | Worksheet K ,Line 12, Column J | $ - | Dist Stations | | |
| 7 | Customer Assistance Expense | Worksheet K ,Line 12, Column K | $ - | Direct Zero | 0.0% | $ - |
| 8 | Office Supplies, Gen. & Admin. Exp. | Worksheet K ,Line 12, Column L | $ - | Direct Zero | 0.0% | $ - |
| 9 | Outside Services Employees | Worksheet K ,Line 12, Column M | $ - | Direct Zero | 0.0% | $ - |
| 10 | Miscellaneous General Expenses | Worksheet K ,Line 12, Column N | $ - | Direct Zero | 0.0% | $ - |
| 11 | Maintenance of General Plant | Worksheet K ,Line 12, Column O | $ - | Direct Zero | 0.0% | $ - |
| 12 | Total Wages, Excluding A&G | Sum Lines 1 thru 12 | $ - | | | |
| 13 | **T-Wage** | | | | | |
| 14 | 350 Land and Land Rights | Worksheet F, Line 40 | $ - | | | |
| 15 | 352 Structures and Improvements | Worksheet F, Line 41 | $ - | | | |
| 16 | 353 Transmission Stations Gross Plant | Worksheet F, Line 42 | $ - | | | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Sum | Sum Lines 14-16, and Worksheet F Line 2 | $ - | $ - | |
| 18 | **T-Tran Stations** | | | | |
| 19 | Plant in Service | Worksheet A, Line 16, Column F and Column I | $ - | | |
| 20 | **T-Plant** | | | | |
| 21 | Qualifing Transmission Segments | Worksheet A, Line 7, Column F and Worksheet F Column F Line 4 | $ - | | |
| 22 | **T-Trans Lines** | | | | |
| 23 | Qualifying Distribution Assets | Worksheet A, Line 9, Column F and Worksheet F Column F Line 5 | $ - | $ - | |
| | **Dist Stations** | | | | |
| 23 | **Direct Zero** | Fixed allocation | | | **0.0%** |
| 24 | **Direct 100** | Fixed allocation | | | **100.0%** |
| 25 | Transmission Qualifying Plant | Worksheet A, Line 8, Column F and Column I | $ - | | |
| 26 | **T-Tran Plant** | | | | |

Worksheet F

# L&O Power Cooperative

## Input Section

## Fiscal Year Ending December 31, 2XXX

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Total |
|---|---|---|---|---|---|
| 1 | Billing Lag in days | COS for L&O | | | 45 |
| 2 | 352/353 Station Equipment Qualified Gross Plant | Workpaper T Qualified Stations | $ - | $ - | $ - |
| 3 | 352/353 Non-Qualified Substations | (Line 42) - Line 3 | $ - | $ - | $ - |
| 4 | 354-359.1 Other Qualified Transmission Segments | Workpaper U Qualified Lines | | | |
| 5 | 361-362 Distribution Plant | Workpaper T Qualified Stations | $ - | $ - | $ - |
| 6 | **Data from Form-12** | | | | EoY |
| 7 | Electric Energy Revenues | Form 12, Part A, Sect A, L01b | | | |
| 8 | Other Operating Revenue & Income | Form 12, Part A, Sect A, L03b | | | |
| 9 | Op Exp-Production excluding fuel | Form 12, Part A, Sect A, L05b | | | |
| 10 | Op Exp-Production fuel | Form 12, Part A, Sect A, L06b | | | |
| 11 | Op Exp-Other Power Supply | Form 12, Part A, Sect A, L07b | | | |
| 12 | Op Exp-Transmission | Form 12, Part A, Sect A, L08b | | | |
| 13 | Op Exp-RTO/ISO | Form 12, Part A, Sect A, L09b | | | |
| 14 | Op Exp-Distribution | Form 12, Part A, Sect A, L10b | | | |
| 15 | Op Exp-Consumer Accounts | Form 12, Part A, Sect A, L11b | | | |

| | | | |
|---|---|---|---|
| 1 | | Form 12, Part A, Sect A, | |
| 6 | Op Exp-Customer Service | L12b | |
| 1 | | Form 12, Part A, Sect A, | |
| 7 | Op Exp-Sales | L13b | |
| 1 | | Form 12, Part A, Sect A, | |
| 8 | Op Exp-Admin and General | L14b | |
| 1 | | Form 12, Part A, Sect A, | |
| 9 | Maint Exp-Production | L16b | |
| 2 | | Form 12, Part A, Sect A, | |
| 0 | Maint Exp-Transmission | L17b | |
| 2 | | Form 12, Part A, Sect A, | |
| 1 | Maint Exp-RTO/ISO | L18b | |
| 2 | | Form 12, Part A, Sect A, | |
| 2 | Maint Exp-Distribution | L19b | |
| 2 | | Form 12, Part A, Sect A, | |
| 3 | Maint Exp-General Plant | L20b | |
| 2 | Tax - Gross Reciepts and | Form 12, Part A, Sect A, | |
| 4 | Property Tax | L23b | |
| | | Form 12, Part A, Sect A, L24b Less Interest on | |
| 2 | | Notes Payable included | $ |
| 5 | Interest on Long Term Debt | in Long Term Debt | - |
| 2 | | Form 12, Part A, Sect A, | |
| 6 | Other Interest Expense | L26b | |
| 2 | | Form 12, Part A, Sect A, | |
| 7 | Other Deductions | L28b | |
| 2 | | Form 12, Part A, Sect A, | |
| 8 | Operating Margin | L30b | |
| 2 | | Form 12, Part A, Sect A, | |
| 9 | Interest Income | L31b | |
| 3 | Other Non-Operating Income | Form 12, Part A, Sect A, | |
| 0 | (Net) | L34b | |
| 3 | G&T Capital Credits Cash | Form 12, Part A, Sect A, | |
| 1 | Payments | L35b | |
| | Other Capital Credits and | Form 12, Part A, Sect A, | |
| 3 | Patronage Dividends Cash | L36b | |
| 2 | Payments | | |

| | | | BoY | EoY | Average | |
|---|---|---|---|---|---|---|
| 3 | | Form 12, Part A, Section | | | | $ |
| 3 | Prepayment | B, Line 25 | | | | - |

| | | | EoY |
|---|---|---|---|
| 3 | | Form 12, Part A, Section | |
| 4 | Total Margins and Equities | B, Line 39 | |
| 3 | | Form 12, Part A, Sect B, | |
| 5 | Total Long Term Debt | L46 | |
| 3 | | Form 12, Part A, Sect B, | |
| 6 | Notes Payable | L50 | |

| | | | | | |
|---|---|---|---|---|---|
| 37 | Plant in Service | | BoY | EoY | Average |
| 38 | 301-303 Total Intangible Plant | Form 12, Suppl, Part H, Section A, Line 1 | | | $ - |
| 39 | Total Production Plant | Form 12, Suppl, Part H, Section A, Line 6 | | | $ - |
| 40 | 350 Land and Land Rights | Form 12, Suppl, Part H, Section A, Line 7 | | | $ - |
| 41 | 352 Structures and Improvements | Form 12, Suppl, Part H, Section A, Line 8 | | | $ - |
| 42 | 353 Station Equipment | Form 12, Suppl, Part H, Section A, Line 9 | | | $ - |
| 43 | 354 thru 359.1 Other Transmission Plant | Form 12, Suppl, Part H, Section A, Line 10 | | | $ - |
| 44 | Total Distribution Plant | Form 12, Suppl, Part H, Section A, Line 16 | | | $ - |
| 45 | 380-386 RTO/ISO Plant | Form 12, Suppl, Part H, Section A, Line 17 | | | $ - |
| 46 | 389 thru 399.1 Total General Plant | Form 12, Suppl, Part H, Section A, Line 18 | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 47 | Depreciation and Amortization Reserves | | BoY | EoY | Average |
| 48 | 108.1 Depr of Steam Plant | Form 12, Suppl, Part H, Section B, Line 1 | | | $ - |
| 49 | 108.4 Depreciation of Other Production Plant | Form 12, Suppl, Part H, Section B, Line 4 | | | $ - |
| 50 | 108.5 Depreciation of Transmission Plant | Form 12, Suppl, Part H, Section B, Line 5 | | | $ - |
| 51 | 108.6 Depreciation of Distribution Plant | Form 12, Suppl, Part H, Section B, Line 6 | | | $ - |
| 52 | 108.7 Depreciation of General Plant | Form 12, Suppl, Part H, Section B, Line 7 | | | $ - |
| 53 | 108.8 Retirement Work in Progress | Form 12, Suppl, Part H, Section B, Line 8 | | | $ - |
| 54 | 111 Amort of Electric Plant in Service | Form 12, Suppl, Part H, Section B, Line 12 | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 55 | Materials and Supplies | | BoY | EoY | Average |
| 56 | M&S Coal | Form-12, Part H, Section G, Line 1 | | | $ - |
| 57 | M&S Other Fuel | Form-12, Part H, Section G, Line 2 | | | $ - |
| 58 | M&S Production Plant Parts | Form-12, Part H, Section G, Line 3 | | | $ - |
| 59 | M&S Station Transformers & Equipment | Form-12, Part H, Section G, Line 4 | | | $ - |
| 60 | M&S Line Materials & Supplies | Form-12, Part H, Section | | | $ |

| | | | | | |
|---|---|---|---|---|---|
| 0 | | G, Line 5 | | | - |
| 6 | | Form-12, Part H, Section | | | $ |
| 1 | M&S Other | G, Line 6 | | | - |
| 6 | | | | | |
| 2 | Materials and Supplies | Sum Lines 56 thru 61 | - | - | - |
| 6 | | | | | |
| 3 | | | | | |
| 6 | | | | | |
| 4 | Construction Work in Progress | | | | |
| 6 | | Form-12, Supplement , | | | $ |
| 5 | Total CWIP | Section A, Line 28 | | | - |
| 6 | | | | | |
| 6 | | | | | |
| 6 | | | | | |
| 7 | Notes: | | | | |
| 6 | 1. If any interest expenses related to Notes Payabe or any other non-LTD instruments are | | | | |
| 8 | included in line item 25 Interest on Long Term Debt, they will be specified below: | | | | |
| 6 | | Form 12, Part A, Sect A, | | | |
| 9 | Interest on Long Term Debt | L24b | | | |
| 7 | Interest on Notes Payable | | | | |
| 0 | included in Long Term Debt | Company Records | | | |
| | Other Interest included in Long | | | | |
| 7 | Term Debt not associated with | | | | |
| 1 | LTD | Company Records | | | |
| 7 | Interest only associated with | | | | $ |
| 2 | Long Term Debt | | | | - |

Worksheet G

# L&O Power Cooperative

## Depreciation Rates

## Fiscal Year Ending December 31, 2XXX

| A | B | C | | D |
|---|---|---|---|---|
| Line No | Description of Plant | Description/Plant Account Number | | Annual Depreciation Rate |
| 1 | INTANGIBLE PLANT | AMORTIZATION RATE | | 0.00% |
| 2 | TRANSMISSION PLANT | | | |
| 3 | | 115 KV LINE | | |
| 4 | | | 355115 | 2.43% |
| 5 | | | 356115 | 1.91% |
| 6 | | 69 KV LINE | | |
| 7 | | | 355690 | 3.34% |
| 8 | | | 356690 | 2.41% |
| 9 | | STATIONS | | |
| 10 | | | 352000 | 1.84% |
| 11 | | | 353000 | 1.91% |
| 12 | | SCADA | | |
| 13 | | | 353100 | 9.13% |
| 14 | DISTRIBUTION PLANT | | | |
| 15 | | STATIONS | | |
| 16 | | | 361000 | 1.91% |
| 17 | | | 362000 | 2.37% |
| 18 | | SCADA | | |
| 19 | | | 362100 | 6.10% |
| 20 | | LOAD MANAGEMENT | | |
| 21 | | | 362200 | 0.35% |
| 22 | GENERAL PLANT | | | |
| 23 | | TRANSPORTATION | | |
| 24 | | | 392000 | 16.00% |
| 25 | | TOOLS-SHOP-GARAGE EQUIPMENT | | |

| | | | |
|---|---|---|---|
| 26 | | 394000 | 10.00% |
| 27 | COMMUNICATIONS | | |
| 28 | | 397000 | 10.00% |
| 29 | STORAGE YARD - BUILDING | | |
| 30 | | 389000 | 2.50% |
| 31 | OFFICE FURNITURE/EQUIP. | | |
| 32 | | 391000 | 5.00% |

33 Notes:

34 "Stated Values" are fixed and subject to change only pursuant to a FPA Section 205 or 206 filing.

Worksheet H

**L&O Power Cooperative**

**SPP Upgrades**

**Fiscal Year Ending December 31, 2XXX**

| A | B | C | D |
|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Company Total Transmission Amount** |
| 1 | Gross Transmission Plant | Worksheet A, Line 8, Col I | |
| 2 | Accumulat | Wor | |

| | | | |
|---|---|---|---|
| | ed Depreciation & Amortization | kshe et A, Line 20, Col I | |
| 3 | Net Transmission Plant | (line 1 minus line 2) | |
| 4 | Transmission O&M | Wor kshe et B, Line 18, Col J | |
| 5 | **Annual Allocation Factor for Transmission O&M** | (line 4 / line 1) | |
| 6 | General Plant Depreciation Expense | Wor kshe et B, Line 34, Col J | |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | (line 6 / line 1) | |
| 8 | Return on Rate Base | Wor kshe et B, Line 37, Col J | |

| | | | |
|---|---|---|---|
| 9 | **Annual Allocation Factor for Return** | (line 8 / line 3) | |
| 10 | **Depreciation Rates** | | |
| 11 | Sub | Worksheet G Column D | 1.84% |
| 12 | Line | Worksheet G Column D | 2.43% |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project Name and #** | **Type** | **Project Gross Plant** | **Depreciation** | **Transmission O&M Factor** | **Allocation for Transmission O&M** | **General Plant Depreciation Annual Allocation** | **Allocation for General Plant Depreciation** | **Annual Expense Charge** | **Project Net Plant** | **Annual Allocation Factor for Return** | **Annual Return Charge** | **Project Depreciation and Amortization Expense** | **Revenue Credits** | **Prior Year Adjustments** | **Project ATRR** |
| | | | | **Project Accumulated Depreciation** | **Annual Allocation Factor** | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Note A | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | Col G + Col I | Col D - Col E (Note B) | Line 9, Col D | Col K * Col L | (Note C) | | From Worksheet I, Reconciliation Column L Line 12 | Col J + Col M + Col N - Col O + Col P |
| 13 | | - | - | | | | | | - | | | - | - | - | |
| 14 | | - | - | | | | | | - | | | - | - | - | |
| 15 | | - | - | | | | | | - | | | - | - | - | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 16 | | - | - | | - | - | - | - |
| 17 | | - | - | | - | - | - | - |
| 18 | Total | - | - | | - | - | - | - |

19 Notes:
A. Project Gross Plant is the total capital investment for the project calculated in the same
20 method as the gross plant
value in line 1.
This value includes subsequent capital investments required to maintain the facilities to
21 their original
capabilities.
Gross Plant does not include CWIP, Unamortized Regulatory Asset or
22 Unamortized
23 Abandoned Plant.
B. Net Plant is the Gross Plant less the associated
24 Accumulated
Depreciation.
C. Depreciation
25 Expense is the
depreciation amount

associated with the specified line or sub. Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items will not require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols. L&O may not change the columns or the formulas included in these Worksheets during the Annual Update.

# L&O Power Cooperative

Worksheet I

## Calculation of Interest Applied to True-Up Calculations

## Fiscal Year Ending December 31, 2XXX

**Adjustments To ATRR Due To Error Corrections**

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | ERROR IDENTIFICATION | | | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred) /Chg | Calculated Interest (B) | Total Adjustment to ATRR |
| 1 | | | | | | | | | | | $ - |
| 2 | | | | | | | | | | | $ - |
| 3 | | | | | | | | | | | $ - |
| 4 | | | | | | | | | | | $ - |
| 5 | | | | | | | | | | | $ - |
| 6 | **Total Adjustment to Gross ATRR:** | | | | | | | | | | $ - |

**Adjustments To SPP Regional Projects' ATRR Due To Corrections**

| Line | ERROR IDENTIFICATION | | | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred) /Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | |
|---|---|---|---|
| 7 | | $ - | $ - |
| 8 | | | $ - |
| 9 | | | $ - |
| 10 | | | $ - |
| 11 | | | $ - |
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | | $ - |

13 Notes:

14 A. Rate Year in which the error occurred and affected the ATRR and rates paid by customers.

15 B. Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.

**Interest calculation for Item #1**

| | Period Start | Period Ending | Year description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance |
|---|---|---|---|---|---|---|---|---|
| 16 | | | | | | | | |
| 17 | | | Rate Year | $ - | $ - | | $ - | $ - |
| 18 | | | Rate Year | $ - | $ - | | $ - | $ - |
| 19 | | | Rate Year | $ - | $ - | | $ - | $ - |
| 20 | | | Rate Year | $ - | $ - | | $ - | $ - |
| 21 | | | | $ - | | | $ - | $ - |
| 22 | | | | $ - | | | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | $ | | | $ | $ |
| 23 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 24 | | | - | | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 25 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 26 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 27 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 28 | | Year | - | - | | - | - |
| | Tot | | | | | $ | |
| 29 | al | | | | | - | |

**Interest calculation for**
30 **Item #2…**
(Repeat interest calculation for
31 other items as necessary.)

C. Interest Note: The interest calculation may need to be modified to recognize the implementation
32 partial year.
D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does
33 not require a
Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal
34 Power Act

Worksheet J

# L&O Power Cooperative

## O&M Input - From RUS Form 12

## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E |
|---|---|---|---|---|

**SECTION A. EXPENSES AND COSTS**

| Line No. | | ACCOUNT NUMBER | LINES (a) | STATIONS (b) |
|---|---|---|---|---|
| **Transmission Operations** | | | | |
| 1 | Supervision and Engineering | 560 | | |
| 2 | Load Dispatching | 561 | | |
| 3 | Station Expenses | 562 | | |
| 4 | Overhead Line Expenses | 563 | | |
| 5 | Underground Line Expenses | 564 | | |
| 6 | Miscellaneous Expenses | 566 | | |
| **7** | **Subtotal (1 thru 6)** | | **$ -** | **$ -** |
| 8 | Transmission of Electricity by Others | 565 | | |
| 9 | Rents | 567 | | $ - |
| **10** | **Total Transmission Operations (7 thru 9)** | | **$ -** | **$ -** |
| **Transmission Maintenance** | | | | |
| 11 | Supervision and Engineering | 568 | $ - | $ - |
| 12 | Structures | 569 | | $ - |
| 13 | Station Equipment | 570 | | |
| 14 | Overhead Lines | 571 | | |
| 15 | Underground Lines | 572 | $ - | |
| 16 | Miscellaneous Transmission Plant | 573 | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **17** | **Total Transmission Maintenance (11 thru 16)** | | **$ -** | **$ -** |
| **18** | **Total Transmission Expense (10+17)** | | **$ -** | **$ -** |
| 19 | RTO/ISO Expense - Operation | 575.1-575.8 | $ - | $ - |
| 20 | RTO/ISO Expense - Maintenance | 576.1-576.5 | $ - | $ - |
| **21** | **Total RTO/ISO Expense (19+20)** | | **$ -** | **$ -** |
| 22 | Distribution Expense - Operation | 580-589 | $ - | |
| 23 | Distribution Expense - Maintenance | 590-598 | $ - | |
| **24** | **Total Distribution Expense (22+23)** | | **$ -** | **$ -** |
| **25** | **Total Operation and Maintenance (18+21+24)** | | **$ -** | **$ -** |
| **Fixed Costs** | | | | |
| 26 | Depreciation - Transmission | 403.5 | | |
| 27 | Depreciation - Distribution | 403.6 | | |
| 28 | Interest - Transmission | 427 | | |
| 29 | Interest - Distribution | 427 | | |
| **30** | **Total Transmission (18+26+28)** | | **$ -** | **$ -** |
| **31** | **Total Distribution (24+27+29)** | | **$ -** | **$ -** |
| **32** | **Total Lines and Stations (21+30+31)** | | **$ -** | **$ -** |

33 Notes

34 A. Lines can be added or removed from this Workpaper only if there are corresponding changes in the RUS Form

35 12 Format.

Worksheet K

# L&O Power Cooperative Wage Input and Functionalization

## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Account Description | Labor Total Company | 562 Trans Stations | 563 OH Line | 569-570 Str Maint - Wages | 571 Maint of OH Lines | 582 Distb Station Ops Exp | 591-592 Distb Station Maint Exp | 907-910 Cust Service-Wages | 921 Office Supplies, Gen. & Admin | 923 Outside Services | 930 Miscellaneous Genera | 935 Maintenance of General Plant |
| 1 | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Totals | - | - | - | - | - | - | - | - | - | - | - | - |

1 3 1 4 1 5 1 6 1 7 1 8 1 9 2 0 Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols. L&O may not change the columns or the formulas included in these Worksheets during the Annual Update.

Worksheet L

# L&O Power Cooperative

## Depreciation Functionalization
## Fiscal Year Ending December 31, 2XXX

| A<br>Line | B<br>Account | C<br>Description | D<br>Total Expense | E<br>Stations | F<br>Lines | G<br>Distribution | H<br>General |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | | | | | | | |
| | | Totals | $ | $ | $ | $ | $ |
| 6 | | | - | - | - | - | - |

7 Notes:
8 A. Lines representing detail and sub-accounts can be added only at the same depreciation rates shown in the groupings originally listed.

Worksheet M

# L&O Power Cooperative

## Other Revenue

## Fiscal Year Ending December 31, 2XXX

| Line No. | A | Account No | B | Account Description | C | Total Company | D | Retail Related | E | SPP Schd 11 P2P | F | SPP Schd 7 & 8 P2P | G | All SPP Facilities Leased | H | Non SPP Facilities Leased | I | Both SPP and Non SPP Facilities Leased | J | Other Electric Revenue | K |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | | | | | | | |
| 8 | | | | Total | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |

Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols. L&O may not change the column or the formulas included in these Workpapers during the Annual Update.

# L&O Power Cooperative

Work sheet N

## Regulatory and Commission Expenses

## Fiscal Year Ending December 31, 2XXX

| A<br>Line No. | B<br>Account 928 | C<br>Description | D<br>Total Company | E<br>Non-SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | Total | $ - | $ - | $ - |

7 Notes:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide
8 information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage
9 to updated Form 12 data requirements or other
1 similar supporting documentation. Additional line items or

0 line deletions will not require FPA Section 205 or 206
filings. L&O will describe such changes in
the Annual Update, and the changes will be subject to the
1 review of Interested Parties under the procedures set forth
1 in L&O's Implementation Protocols.
L&O may not change the columns or
1 the formulas included in these
2 Workpapers during the Annual Update.

Worksheet O

## L&O Power Cooperative

## Customer Accounting
## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line No.** | **Account 901-905** | **Description** | **Total Company** | **901-905 Non-SPP Expenses** | **901-905 SPP Expenses** |
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | Customer Accounting Wages | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 11 | | | | |
| | Customer Accounting Computer | $ | $ | $ |
| 12 | Support | - | - | - |
| 13 | | | | |
| | Total Customer Accounting | $ | $ | $ |
| 14 | | - | - | - |

15 Notes:
A. The addition of new lines and the removal of outdated lines may be necessary
16 in order to accurately provide information, and populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes
17 will provide detail and linkage to updated Form 12 data requirements or other
similar supporting documentation. Additional line items or line deletions will not
18 require FPA Section 205 or 206 filings. L&O will describe such changes in
the Annual Update, and the changes will be subject to the review of Interested
19 Parties under the procedures set forth in L&O's Implementation Protocols.
L&O may not change the columns or the formulas included in these
20 Workpapers during the Annual Update.

Worksheet P

# L&O Power Cooperative

## Construction Work in Progress

## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Description | Approval Docket No. | % Recovery Approved (Note A) | Pricing Zone (Note B) | Project ID | Construction Start Date | In-Service Date (Estimated) | BoY Balance | EoY Balance | Average Balance (Col I through J) /2 | Includable in Rate Base (Note C) (Col D * Col K) |
| 1 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2 | | 50.00% | Zone 19 | | | | $ - | $ - |
| 3 | | 50.00% | Zone 19 | | | | $ - | $ - |
| 4 | | 50.00% | Zone 19 | | | | $ - | $ - |
| 5 | Total CWIP Includable in Rate Base | | | | $ - | $ - | $ - | $ - |
| 6 | Total CWIP Not Included in Rate Base | | | | - | - | | |
| 7 | Total CWIP (Worksheet F, Line 65 Cols D and E) | | | | $ - | $ - | | |

8 Notes:

9 A. Percentage recovery cannot be added or changed absent approval from FERC

10 B. CWIP amounts should be directly assigned to pricing zone on Worksheet A.

11 C. AFUDC ceases when CWIP is recovered in rate base. Prior to recovering CWIP in rate base for any future project, L&O will file for and obtain Commission approval for inclusion of that project's CWIP in rate base. Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized. Projects are transmission related only.

12 D. L&O may not change the columns or the formulas included in these Worksheets during the Annual Update.

Work sheet Q

# L&O Power Cooperative

## Plant Held for Future Use

## Fiscal Year Ending December 31, 2XXX

| A Line No | B Facility No. | C Asset No. | D Description | E BoY Investment | F EOY Investment | G Average Investment |
|---|---|---|---|---|---|---|
| 1 | | | Production Future Use Assets | $ - | $ - | $ - |
| 2 | | | | | | |
| 3 | | | Transmission Future Use Assets | | | |
| 4 | | | | | | $ - |
| 5 | | | | | | $ - |
| 6 | | | | | | $ - |
| 7 | | | | | | $ - |
| 8 | | | | | | $ - |
| 9 | | | | | | $ - |
| 10 | | | | | | $ - |
| 11 | | | Subtotal Transmission Future Use Assets | $ - | $ - | $ - |
| 12 | | | | | | |

Notes:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols. L&O may not change the columns or the formulas included in these Workpapers during the Annual Update.

Work sheet R

# L&O Power Cooperative

## SPP Completed Not Classified

## Fiscal Year Ending December 31, 2XXX

| A Line No. | B Fac ID | C Work Order | D Project | E BoY Balance | F EoY Balance | G % SPP Eligible | H BoY Amount | I EoY Amount | J Average |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | $ - | $ - | $ - |
| 2 | | | | | | | $ - | $ - | $ - |
| 3 | | | | | | | $ - | $ - | $ - |
| 4 | | | Total | $ - | $ - | | $ - | $ - | $ - |

5 Notes:

6 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes

7 will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not

8 require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested

9 Parties under the procedures set forth in L&O's Implementation Protocols.

10 L&O may not change the columns or the formulas included in these Workpapers during the Annual Update.

Work sheet S

# L&O Power Cooperative

## RTO Expenses - Operation & Maintenance

## Fiscal Year Ending December 31, 2XXX

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account 575 - 576 | Description | Total Company | 575.1 - 575.8 Total Company Expenses | 575.1-575.8 Non-SPP Expenses | 575.1-575.8 SPP Expenses | 576.1-576.5 Total Company Expenses | 576.1-576.5 Non-SPP Expenses | 576.1-576.5 SPP Expenses |
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

11 Notes:
12 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or

remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols. L&O may not change the columns or the formulas included in these Workpapers during the Annual Update.

B. RTO/ISO expenses may only be recovered in accounts 575 and 576 following a change in accounting procedures classifying these expenses as eligible for transmission rate recovery.

Worksheet T

# L&O Power Cooperative

# Transmission Stations

## Fiscal Year Ending December 31, 2XXX

## TRANSMISSION PLANT

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Non Qualified | | |
| Line No | Substation | BoY Gross Plant | EoY Total Gross Plant | Percent High Side (A) | Qualified | BoY Total Gross Plant | EoY Total Gross Plant | BoY Gross Plant | EoY Total Gross Plant | Average |
| 1 | Cleveland S/W | | | | | $ - | $ - | $ - | $ - | $ - |
| 2 | Lester S/W | | | | | $ - | $ - | $ - | $ - | $ - |
| 3 | Sibley S/W | | | | | $ - | $ - | $ - | $ - | $ - |
| 4 | Luverne S/W | | | | | $ - | $ - | $ - | $ - | $ - |
| 5 | Hardwick S/W | | | | | $ - | $ - | $ - | $ - | $ - |
| 6 | Holland S/W | | | | | $ - | $ - | $ - | $ - | $ - |
| 7 | Total | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - |

## DISTRIBUTION

## PLANT

| | Substation | BoY Total Gross Plant | EoY Total Gross Plant | Percent High Side (1) | Qualified | BoY Total Gross Plant | EoY Total Gross Plant |
|---|---|---|---|---|---|---|---|
| 8 | | | | | | $ - | $ - |
| 9 | | | | | | $ - | $ - |
| 10 | | | | | | $ - | $ - |
| 11 | | | | | | $ - | $ - |
| 12 | | | | | | $ - | $ - |
| 13 | | | | | | $ - | $ - |
| 14 | | | | | | $ - | $ - |
| 15 | | | | | | $ - | $ - |
| 16 | | | | | | $ - | $ - |
| 17 | | | | | | $ - | $ - |
| 18 | | | | | | $ - | $ - |
| 19 | | | | | | $ - | $ - |
| 20 | | | | | | $ - | $ - |
| 21 | | | | | | $ - | $ - |
| 19 | | | | | | $ - | $ - |
| 20 | | | | | | $ - | $ - |
| 21 | | | | | | $ - | $ - |
| 22 | | | | | | $ - | $ - |
| 23 | | | | | | $ - | $ - |
| 24 | | | | | | $ - | $ - |
| 25 | Total | $ - | $ - | | | $ - | $ - |

Notes:
A. Percent high side
from CPR records.
B. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. L&O will describe such changes in
the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols.
L&O may not change the columns or the
formulas included in these Workpapers during
the Annual Update.

Worksheet U

# L&O Power Cooperative

## Transmission Lines

## Fiscal Year Ending December 31, 2XXX

| Line No | Transmission Line | Line Segment | BoY Total Gross Plant | EoY Total Gross Plant | Seg Miles | Total Miles | BoY Total Gross Plant | EoY Total Gross Plant | Qualified | Qual Miles | Voltage kV | BoY Total Gross Plant | EoY Total Gross Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | 0.00000 | | | |
| 2 | | | | | | | | | | 0.00000 | | | |
| 3 | | | | | | | | | | 0.00000 | | | |
| 4 | | | | | | | | | | 0.00000 | | | |
| 5 | | | | | | | | | | . | | | |

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| 6 | | | | 0 | |
| | | | | **0** | |
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| | | | | **0** | |
| **7** | | | | **0** | |
| | | | | **0** | |
| | | | | **.** | |
| | | | | **0** | |
| **8** | | | | **0** | |
| | | | | 0 | |
| | | | | . | |
| | | | | 0 | |
| 9 | | | | 0 | |
| | | | | 0 | |
| | | | | . | |
| 1 | | | | 0 | |
| 0 | | | | 0 | |
| | | | | **0** | |
| | | | | **.** | |
| **1** | | | | **0** | |
| **1** | | | | **0** | |
| | | | | 0 | |
| | | | | . | |
| 1 | | | | 0 | |
| 2 | | | | 0 | |
| | | | | 0 | |
| | | | | . | |
| 1 | | | | 0 | |
| 3 | | | | 0 | |
| | | | | **0** | |
| | | | | **.** | |
| **1** | | | | **0** | |
| **4** | | | | **0** | |
| | | | | 0 | |
| | | | | . | |
| 1 | | | | 0 | |
| 5 | | | | 0 | |
| | | | | **0** | |
| | | | | **.** | |
| **1** | | | | **0** | |
| **6** | | | | **0** | |
| | | | | 0 | |
| | | | | . | |
| 1 | | | | 0 | |
| 7 | | | | 0 | |
| 1 | | | | 0 | |

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|---|---|---|---|---|---|
| 8 | | | | .0000 | |
| 19 | | | | .0000 | |
| **20** | | | | **.0000** | |
| 21 | | | | .0000 | |
| 22 | | | | .0000 | |
| 23 | | | | .0000 | |
| 24 | | | | .0000 | |
| **25** | | | | **.0000** | |
| 26 | | | | .0000 | |
| **27** | | | | **.0000** | |
| 28 | | | | .0000 | |
| 29 | | | | .0000 | |
| 30 | | | | .0000 | |

| | | | | | |
|---|---|---|---|---|---|
| 31 | | | | | 0.000 |
| 32 | | | | | 0.000 |
| 33 | | | | | 0.000 |
| 34 | | | | | 0.000 |
| 35 | | | | | 0.000 |
| 36 | Total | | 0.00 | | - |

37

38 Notes:

39 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. L&O will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in L&O's Implementation Protocols. L&O may not change the columns or the formulas included in these Workpapers during the Annual Update.

## L&O Power Cooperative

## Transmission Formula Rate Implementation Protocols

The transmission formula rate template ("Formula Rate Template") of L&O Power Cooperative ("L&O") and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of L&O for transmission

service in Zone 19 of the Southwest Power Pool, Inc. ("SPP") footprint. L&O must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR").

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and with Attachment AI and Attachment J, respectively, of the SPP Open Access Transmission Tariff ("SPP Tariff"). The ATRR shall be determined for January 1 to December 31 of a given calendar year. The Formula Rate shall become effective for recovery of L&O ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC"). The Formula Rate shall be applicable to service on and after July 1 of each calendar year through June 30 of the following calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein. These Protocols specify the dates applicable to the activities described herein. Should any due date fall on a weekend or a holiday recognized by FERC, then the due date shall be no later than the next Business Day.

## Section I Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

A. "Accounting Change" means any change in L&O's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

1. revisions to Rural Utilities Service's ("RUS") Uniform System of Accounts ("USoA");

2. revisions to RUS Financial and Operating Report - Electric Power Supply ("Form No. 12") data and the requirement to report certain values within it;

3. correction of errors and prior period adjustments that impact the ATRR;

4. the implementation of new estimation methods or policies;

5. changes to income tax elections;

6. changes in accounting practices or policies mandated by a state regulatory authority with jurisdiction over L&O that could impact the Formula Rate or calculations under the Formula;

7. implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

8. a change in L&O's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor);

9. L&O's own Accounting Changes (which constitute a change to the ATRR greater than or equal to $10,000) such as the addition or deletion of a subaccount not specified by FERC's USoA; or

10. a change in L&O's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

B. "Annual Transmission Revenue Requirement" ("ATRR") means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by L&O for informational purposes with FERC and posted on the SPP Open Access Same-Time Information System ("OASIS") on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

C. "Annual Meeting" means the meeting hosted by L&O for the purpose of exchanging information with Interested Parties regarding the Formula Rate.

D. "Annual Update" means L&O's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

E. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

F. "Calendar Year" means January 1 through December 31 of a given year.

G. "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and which L&O has filed with FERC (*e.g.*, if the Annual Update is posted on April 15, 2021, and the Informational Filing is submitted to FERC on August 15, 2021, the Current Rate Year is July 1, 2021 through June 30, 2022).

H. "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS, service under Grandfathered Agreements, or PTP Transmission Service.

I. "FERC" or "Commission" means the Federal Energy Regulatory Commission.

J. "Final Posting" means the Annual Update information which L&O requests that SPP post to the SPP OASIS with changes agreed to during the Review Period.

K. "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with FERC and served on L&O by electronic service on the date of such filing.

L. "Form No. 12" means the RUS Financial and Operating Report - Electric Power Supply.

M. "Formula" means the Formula Rate Template set forth in Addendum 47 to Attachment H of the SPP Tariff.

N. "Formula Rate" has the meaning defined herein and means the L&O Implementation Protocols together with the Formula Rate Template.

O. "Formula Rate Template" means the L&O transmission formula rate template set forth herein.

P. "FPA" means Federal Power Act.

Q. "Informal Challenge" means written notification by an Interested Party to L&O of any specific challenge to the Annual Update.

R. "Information Request" means a written request submitted by an Interested Party to L&O.

S. "Informational Filing" means L&O's annual filing at the Commission with the information stipulated in these Protocols.

T. "Initial Posting" means the date on which SPP posts L&O's Annual Update to the SPP OASIS.

U. "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a)(2)(iii) or successor regulation.

V. "Interested Party" includes but is not limited to, (i) Transmission Customers under the SPP Tariff, (ii) state utility regulatory commissions with rate jurisdiction over a public utility located within the SPP footprint; (iii) consumer advocacy agencies authorized by state law to review and contest the rates for any such public utility; and (iv) state attorneys general.

W. "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

X. "OASIS" means Open Access Same-Time Information System.

Y. "OATT" or "SPP Tariff" means SPP's Open Access Transmission Tariff.

Z. "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is July 1, 2021 through June 30, 2022, then the Prior Rate Year is July 1, 2020 through June 30, 2021).

AA. "PTP Rates" means the point-to-point rates derived from the Formula Rate.

BB. "Publication Date" means the date on which L&O posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2021 shall be no later than April 15, provided, however, that if April 15 should fall on a weekend or a holiday recognized by FERC, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

CC. "Rate Year" means July 1 of a given year through June 30 of the subsequent Calendar year.

DD. "Review Period" means, unless otherwise extended in writing by L&O, 60 days after the Publication Date, which includes a period for submission of Information Requests and a period for preparation of Informal Challenges.

EE. "RUS" means Rural Utilities Service.

FF. "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity (ROE); (ii) depreciation and amortization rates; and (iii) other similar fixed values. Stated Values may be changed only pursuant to FPA Section 205 or 206.

GG. "USoA" means FERC's Uniform System of Accounts.

## Section II Annual Update

A. On or before April 15 of each calendar year (the Publication Date), L&O shall:

1. Recalculate the ATRR and the rates applicable to NITS for the new Rate Year in accordance with the Formula Rate and using the Formula Rate Template (Annual Update); and

2. Provide its Annual Update to SPP and request that SPP post such information to the SPP OASIS (the Initial Posting); and

3. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the Initial Posting shall be due on the next Business Day. The date on which such posting occurs shall be that year's Publication Date. Any delay in the Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

B. Concurrent with the Initial Posting, L&O shall provide the Annual Update to SPP to serve electronically upon the Formula Rate Posting Information Notification List.[1]

C. The Annual Update shall:

1. Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

[1] As used in these Protocols, "Formula Rate Posting Information Notification List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification List through the "Exploder List" link on the SPP website. As of September 2019, the Exploder List was titled "Formula Rate Posting Information Notification" and could accessed at http://www.spp.org/ stakeholder-center/exploder-lists/.

2. Be based on the independently-audited books and records of L&O for the most recent fiscal year including its certified RUS Form No. 12 or successor reports including the Financial and Operating Report Electric Power Supply (Op. Report – Power Supply), (January 1 through December 31);

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

4. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, L&O shall identify:

   a. Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR. Any items included in the Formula Rate at an amount other than a historic cost basis.

   b. Individual impact of any changes in i. above on charges billed under the Formula Rate.

   c. Accounting Changes related to any reorganization or merger transaction.

5. Not seek to modify the Formula Rate, as any modification to the Formula Rate will require filing under section 205 or 206 of the FPA.

6. With each Annual Update, L&O will include a list of any new transmission facilities included in the Formula Rate Template that were not included in the prior Annual Update. New transmission facilities include but are not limited to additional substations, breakers, other major substation equipment, and additional transmission line miles. The list will indicate the Zone 19 Attachment AI Guidance Document criteria that L&O believes supports each facility's inclusion in L&O's ATRR as well as the beginning-of-year and end-of-year balances associated with that facility. This provision in no way limits the rights of any Interested Party to challenge inclusion of new facilities.

## Section III Review of Annual Update

Within twenty (20) days of the posting of L&O's Annual Update, L&O will host a meeting for Interested Parties to discuss the Annual Update (Annual Meeting). L&O shall provide notice of this meeting concurrent with the posting of the Annual Update accessible on the SPP OASIS. The notice shall include the date, time and location of the Annual Meeting and also shall be provided to Interested Parties through the Formula Rate Posting Information Notification List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically.

A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Update and will have until sixty (60) days after the Publication Date to serve reasonable Information Requests on L&O for information and work papers supporting the Annual Update (the Review Period). Such Information Requests shall be limited to that which is necessary to determine:

    a. The extent or effect of an Accounting Change;

    b. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

    c. The proper application of the Formula Rate and procedures in these Protocols;

    d. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

    e. The effect of any change to the underlying USoA or Formula Rate Template; or

    f. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

    The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. L&O will not claim that responses to information and document requests pursuant the Protocols are subject to any settlement confidentiality provision; however, L&O may require that Interested Parties execute a non- disclosure agreement to obtain access to material that L&O deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR § 388.113(c)(1).

2. L&O shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within fifteen (15) Business Days of receipt.

3. L&O shall request that SPP post on a publicly accessible portion of the SPP OASIS all Information Requests from Interested Parties and L&O response(s) to such requests, and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Information Requests contain information deemed by L&O to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and L&O.

4. If the deadline for Interested Parties falls on a weekend or holiday recognized by the Commission the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until June 15 (or the first Business Day after June 15 if June 15 falls on a weekend or holiday) to notify L&O in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. L&O will make a good faith effort to respond to any Informal Challenge within twenty (20) calendar days of notification of such Informal Challenge. L&O, and, if appropriate, SPP, shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. L&O will request that SPP post on the SPP OASIS all Informal Challenges from Interested Parties and L&O responses to the Informal Challenges and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Informal Challenges contain information deemed by L&O to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and L&O.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by L&O and resolved prior to the end of the Review Period shall be reported in the Final Posting on the SPP OASIS. Any changes or adjustments agreed to by L&O after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges

1. An Interested Party shall have until September 15 (or the first Business Day after September 15 if September 15 falls on a weekend or holiday recognized by FERC) to file a Formal Challenge. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on at least one issue. Having submitted an Informal Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues. Regardless of whether an Interested Party pursues or fails to pursue Informal or Formal Challenges, an Interested Party may file a complaint under section 206 of the FPA at any time.

2. A Formal Challenge shall:

   a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

   b. Explain how the action or inaction violates the filed Formula Rate or Protocols;

   c. Set forth the business, commercial, economic or other issues presented

by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief.

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

3. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via section 206 of the FPA and shall be served upon L&O contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), or by facsimile, express delivery or messenger to the individual listed as the contact person in L&O's Informational Filing.

4. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, L&O shall bear the burden, consistent with

section 205 of the FPA, of proving that it has correctly applied the Formula Rate consistent with these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate. Modifications to the Formula Rate may be made only pursuant to Federal Power Act section 205 or section 206.

2. A change to the Formula Rate fixed inputs related to ROE, depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA, sections 205 or 206.

3. If L&O makes a correction to a Mistake in its financial information during the Current Rate Year that would affect the Formula Rate for the Current Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with 18 C.F.R. § 35.19a or successor regulation. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a or successor regulation.

E. Informational Filing

1. By August 15 of each year, L&O shall submit to FERC an informational filing (Informational Filing) of its Annual Update under a separate docket number.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   a. That input data under the Formula Rate is properly recorded in any underlying work papers;

   b. That L&O has properly applied the Formula Rate and these procedures;

   c. The accuracy of the data and the consistency with the Formula Rate of

the ATRR and rates under review; and

d. The extent of Accounting Changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, L&O shall provide notice of the Informational Filing to Interested Parties via the Formula Rate Posting Information Notification List and request that SPP post the notice and the docket number assigned to the Informational filing on the SPP OASIS.

## Section IV Joint SPP Transmission Owners' Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, L&O intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to Interested Parties via the Formula Rate Posting Information Notification List no less than seven (7) days prior to such meetings.

## Section V Example L&O Schedule

| Line No. | Action | Date |
|---|---|---|
| 1 | Rate Year | July 1-June 30 |
| 2 | Publication Date | April 15 |
| 3 | Annual Meeting of Interested Parties | May 5 |
| 4 | Interested Parties Review Period | April 15 – June 15 |
| 5 | Informal Challenges Due Date | June 15 |
| 6 | Final Posting | June 20 |
| 7 | Informational Filing | August 15 |
| 8 | Formal Challenge Due Date | September 15 |

## ADDENDUM 50 TO ATTACHMENT H

### Missouri Joint Municipal Electric Utility Commission

**Missouri Joint Municipal Electric Utility Commission**
**SPP Attachment H and Input Worksheets**
**Forecasted 12 Months Ended December 31, 2XXX**



For the 12 months ended 12/31/XX

Formula Rate - Non-Levelized

Rate Formula Template Utilizing EIA Form 412 Data

Missouri Joint Municipal Electric Utility Commission

| Line No. | | Allocated Amount |
|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 32) | #DIV/0! |

| | | (Note T) | Total | Allocator |
|---|---|---|---|---|
| | REVENUE CREDITS | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 34) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 37) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |
| 6a | Historic Year Actual ATRR | | | | | |
| 6b | Historic Year Projected ATRR | | | | | |
| 6c | Historic Year ATRR True-up | (line 6a - line 6b) | | | | 0 |
| 6d | Interest on Historic Year True-up | | | | | |
| 7 | NET REVENUE REQUIREMENT | (line 1 - line 6 + line 6c+ line 6d) | | | | #DIV/0! |
| | DIVISOR | | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | | (Note A) | |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | | | (Note C) | |
| 11 | Less 12 CP of firm P-T-P over one | | | | (N | |

| | | | | | |
|---|---|---|---|---|---|
| 1 | year (enter negative) | | | ote D) | |
| 1 2 | Plus Contract Demand of firm P-T-P over one year | | | | |
| 1 3 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | | |
| 1 4 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | |
| 1 5 | Divisor (sum lines 8-14) | | | | 0 |
| 1 6 | Annual Cost ($/kW/Yr) | (line 7 / line 15) | 0.000 | | |
| 1 7 | Network & P-to-P Rate ($/kW/Mo) (line 11 / 12) | | 0.000 | | |
| | | | Peak Rate | | Off-Peak Rate |
| 1 8 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16 / 52) | 0.000 | | $0.000 |
| 1 9 | Point-To-Point Rate ($/kW/Day) | (line 16 / 260; line 16 / 365) | 0.000 | Capped at weekly rate | $0.000 |
| 2 0 | Point-To-Point Rate ($/MWh) | (line 16 / 4,160; line 16 / 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 21 | FERC Annual Charge ($/MWh) | (Note E) | | Short Term | $0.000 | Short Term |
| 22 | | | | Long Term | $0.000 | Long Term |



For the 12 months ended 12/31/XX

Formula Rate - Non-Levelized

Rate Formula Template Utilizing EIA Form 412 Data

Missouri Joint Municipal Electric Utility Commission

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | **EIA 412** | | | **Transmission** (Col 3 times |
| | **RATE BASE:** | **Reference** | **Company Total** | **Allocator** | |

| | | | | | | Col 4) |
|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE (Note AA and GG) | | | | | |
| 1 | Production | IV.6.e | 0 | NA | | |
| | | IV.7.e less Line | 0 | | 0.0000 | |
| 2 | Transmission | 2a | | TP | 00 | 0 |
| 3 | Distribution | IV.8.e | 0 | NA | | |
| | | IV.1.e & | 0 | W/ | 0.0000 | |
| 4 | General & Intangible | IV.9.e | | S | 00 | 0 |
| | | | | | 0.0000 | |
| 5 | Common | | | CE | 00 | 0 |
| | TOTAL GROSS PLANT | | | GP | 0.0000 | |
| 6 | (sum lines 1-5) | | 0 | = | % | 0 |
| | ACCUMULATED DEPRECIATION (Note AA and GG) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | 0 | | 0.0000 | |
| 8 | Transmission | | | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| 10 | | | 0 | W/ | 0.0000 | |
| | General & Intangible | | | S | 00 | 0 |
| 11 | | | | | 0.0000 | |
| | Common | | | CE | 00 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE (Note GG) | | | | | |
| 13 | Production | (line 1- line 7) | 0 | | | |
| 14 | Transmission | (line 2- line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 16 | General & Intangible | 9) (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP = | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.0000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 23a | Unamortized balance of Abandoned Plant (Note DD and Note GG) | | 0 | N/A | 1.0000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 – 23a) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE (Note GG) | IV.12.e (Note G) | | TP | 0.0000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies (Note GG) | (Note G) | 0 | TE | 0.0000 | 0 |
| 28 | Prepayments (Note GG) | II.20. | 0 | GP | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | b | | | 0000 | |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |
| 30 | RATE BASE earning HCSR (lines 18 + 24 + 25 + 29) | | 0 | | | 0 |



For the 12 months ended 12/31/XX

Formula Rate - Non-Levelized

Rate Formula Template Utilizing EIA Form 412 Data

Missouri Joint Municipal Electric Utility Commission

| Line No. | (1) | (2) **EIA 412 Reference** | (3) **Company Total** | (4) **Allocator** | | (5) **Transmission** (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | O&M (Note BB) | | | | | |
| 1 | Transmission | VII.8.d | 0 | TE | 0.0000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | Less LSE Expenses included in | | | | 1.0 | |
| 1 | Transmission O&M Accounts (Note | | 0 | | 00 | |
| a | V) | | | | 00 | 0 |
| | | | | | 0.0 | |
| | | | 0 | | 00 | |
| 2 | Less Account 565 | | | TE | 00 | 0 |
| | | | | | 0.0 | |
| | | VII.1 | 0 | W/ | 00 | |
| 3 | A&G | 3.d | | S | 00 | 0 |
| | | | | | 0.0 | |
| | | | 0 | W/ | 00 | |
| 4 | Less FERC Annual Fees | | | S | 00 | 0 |
| | | | | | 0.0 | |
| | Less EPRI & Reg. Comm. Exp. & | | 0 | W/ | 00 | |
| 5 | Non-safety Ad. (Note I) | | | S | 00 | 0 |
| | | | | | 0.0 | |
| 5 | Plus Transmission Related Reg. | | 0 | | 00 | |
| a | Comm. Exp. (Note I) | | | TE | 00 | 0 |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 6 | Common | | | CE | 00 | 0 |
| | | | | | 1.0 | |
| | Transmission Lease | | | | 00 | |
| 7 | Payments | | | NA | 00 | 0 |
| | TOTAL O&M (sum lines 1, 3, 5a, 6, | | | | | |
| 8 | 7 less 1a, 2, 4, 5) | | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note AA) | | | | | |
| | | | | | 0.0 | |
| | | | 0 | | 00 | |
| 9 | Transmission | | | TP | 00 | 0 |
| | | | | | 1.0 | |
| 9 | Abandoned Plant | | | N/ | 00 | |
| a | Amortization (Note DD) | | | A | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | 0 | W/ | 00 | |
| 0 | General & Intangible | | | S | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 1 | Common | | | CE | 00 | 0 |
| 1 | TOTAL DEPRECIATION | | | | | |
| 2 | (sum lines 9 - 11) | | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | | | W/S | 0.000 | 0 |
| 14 | Highway and vehicle | | | W/S | 0.000 | 0 |
| 15 | PLANT RELATED | | | | | |
| 16 | Property- Transmission Related | | 0 | DA | 1.000 | 0 |
| 17 | Gross Receipts | | 0 | NA | zero | 0 |
| 18 | Other | | 0 | DA | 1.000 | 0 |
| 19 | Payments in lieu of taxes | | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | | 0 | | | 0 |
| | INCOME TAXES | (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.00% | | | |
| | where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | | | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes | (line | 0 | | | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 7 | | 25 plus line 26) | | | |
| 28 | RETURN from ACSR Not Used | 0 | NA | | 0 |
| 28a | RETURN from HCSR [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 29)] | 0 | NA | | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12, 20, 27, and 28a) | 0 | | | 0 |
| 30 | LESS ATTACHMENT GG ADJUSTMENT [Attachment GG, page 2, line 3, column 10] (Note W) Not Used | - | | | - |
| 30a | LESS ATTACHMENT MM ADJUSTMENT [Attachment MM, page 2, line 3, column 14] (Note Y) Not Used | - | | | - |
| 31 | REVENUE REQUIREMENT TO BE COLLECTED UNDER MISO ATTACHMENT O Worksheet 1, Line 17, column (7) | 0 | | | #DIV/0! |
| 32 | REVENUE REQUIREMENT - TOTAL UNDER SPP ATTACHMENT H Worksheet 1, Line 17, column (5) + (6) | | | | #DIV/0! |

For the 12 months ended 12/31/ XX

Formula Rate - Non-Levelized

Rate Formula Template Utilizing EIA Form 412 Data

Missouri Joint Municipal Electric Utility Commission

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | | |
|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | |
| 1 | Total transmission plant (page 2, line 2 and 2a, column 3) | | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | | |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | | TP= | 0.0 000 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | | 0 | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | | 0 | |
| 8 | Included transmission expenses ( line 6 less line 7) | | | | 0 | |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | | 0.0000 | |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | TP | 0 | |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | | | TE= | 0 | |

| | WAGES & SALARY ALLOCATOR (W&S) | $ | TP | Allocation | | | |
|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | |
| 14 | Distribution | 0 | 0.00 | 0 | | W&S Allocator ($ / Allocation) | |
| 15 | Other | 0 | 0.00 | 0 | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = W/S |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | COMMON PLANT ALLOCATOR (CE) (Note O) | | $ | | | % Electric (line 17 / line 20) | | Labor Ratio | | |
| 17 | Electric | | 0 | | | 0.000000 | * | 0.00000 | = | CE 0.00000 |
| 18 | Gas | | | | | | | | | |
| 19 | Water | | | | | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | | | |
| | ACTUAL CAPITAL STRUCTURE RETURN (ACSR) | | $ | | | | | | | |
| 21 | Long Term Interest | III.16.b + III.17.b (Note U) | $0 | | | | | | | |
| | | | $ | Act % | Hyp % | Cost (Note P) | | Weighted | | |
| 22 | Long Term Debt (Note GG) | II.37.b | 0 | 0% | | 0.0000% | | 0.0000 | | =WCLTD |
| 23 | Proprietary Capital (Note GG) | II.32.b | 0 | 0% | | 0.1030 | | 0.0000 | | |
| 24 | Total (sum lines 22, 23) | | 0 | 0% | | | | 0.0000 | | |
| 25 | | | | | | | Proprietary Capit | 10.30% | | |

| | | | al Cost Rate = | |
|---|---|---|---|---|
| 26 | Reserved for future use | | | |

| | HYPOTHETICAL CAPITAL STRUCTURE RETURN (HCSR) (NOTE FF) | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|
| 27 | Long Term Debt (Cost of Long-term Debt from page 4, line 22) | 50% | 0.00% | 0.0000 | =WCLTD |
| 28 | Proprietary Capital (Cost of Proprietary Capital from page 4, line 25) | 50% | 0.1030 | 0.0515 | |
| 29 | Total (sum lines 27, 28) | 100% | | 0.0515 | =R |
| 30 | Annual Allocation Factor for Incentive Return (line 29 minus line 24) | | | 5.15% | |

| | REVENUE CREDITS | Load |
|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) | |
| 31 | a. Bundled Non-RQ Sales for Resale | |
| 32 | b. Bundled Sales for Resale included in Divisor on page 1 | |
| 33 | Total of (a)-(b) | 0 |
| 34 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | |

| | | |
|---|---|---|
| 35 | a. Transmission charges for all transmission transactions | $0 |
| 36 | b. Transmission charges for all transmission transactions included in Divisor on page 1 | $0 |
| 36a | c. Transmission charges from Schedules associated with Attachment GG (Note X) | $0 |
| 36b | d. Transmission charges from Schedules associated with Attachment MM (Note Z) | 0 |
| 37 | Total of (a)-(b)-(c)-(d) | $0 |

SPP Attachment H Page 5 of 5 For the 12 months ended 12/31/XX

Formula Rate - Non-Levelized

Rate Formula Template Utilizing EIA Form 412 Data Missouri Joint Municipal Electric Utility Commission

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from EIA Form 412 are indicated as: x.y.z (section, line, column)

To the extent the page references to EIA Form 412 are missing, the entity will include a "Notes" section in the EIA 412 to provide this data.

| Note Letter | |
|---|---|
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. |
| G | Transmission related only. |
| H | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165 as shown on Schedule I of EIA Form 412. |
| I | Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting. |
| J | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| K | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, |

rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

| | | | | |
|---|---|---|---|---|
| Required: | Inputs | FIT = | 0.00% | |
| | | SIT= | 0.00% | (State Income Tax Rate or Composite SIT) |
| | | p = | 0.00% | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (Line 21) / long term debt (Line 22). A 50 basis point RTO participation adder may be added to the Base ROE (currently 9.80%) to produce Proprietary Capital Cost Rate, which will be capped at the upper end of the zone of reasonableness established by FERC, for transmission owners who have turned over functional control of their Transmission Facilities to MISO or provide service over Non-transferred Transmission Facilities through the MISO Tariff with MISO acting as agent, subject to the following criteria: MJMEUC affirms that it commits to provide refunds (with interest at the FERC refund interest rates) consistent with any refund effective date established in any proceedings resulting in a new base ROE or new zone of reasonableness for the MISO transmission owners' base ROE, to the extent that the ROE or zone of reasonableness established in any such proceedings, when applied as of the refund effective date established in such proceedings, would result in a lower revenue requirement than that charged. The obligation to provide refunds resulting from such a proceeding shall apply only prospectively as of effective date of rates charged under this transmission formula rate.

Q Not used

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1, lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U From Reference III.17.b include only the amount from Accounts 428, 429, and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Pursuant to Attachment GG of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment GG.

X Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment GG of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements.

Y Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM.

Z Removes from revenue credits revenues that are distributed pursuant to Schedules associated with Attachment MM of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment MM revenue requirements.

A Plant in Service, Accumulated

A Depreciation, and
Depreciation Expense
amounts exclude Asset
Retirement Obligation
amounts unless authorized by
FERC.

B Schedule 10-FERC charges

B should not be included in
O&M recovered under this
MISO Attachment O or SPP
Attachment H.

C Not Used

C

D Page 2, Line 23a includes any unamortized balances related to the recovery of

D abandoned plant costs for the projects approved by FERC. Page 3, line 9a is the annual amortization expense of abandoned plant costs for the projects approved by FERC. No abandoned plant costs will be included until approved by FERC under a separate docket.

E

E Not used

The Hypothetical Capital Structure Return (HCSR)

F calculation is 50% debt / 50% equity (subject to FERC

F approval)

G Calculated using 13 month

G average balance.

# Attachment H
# Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 1: ATRR by Zone and Rate Schedule

| Line No. | (1) Description | (2) Reference | (3) MJMEUC Total | (4) Allocator | (5) SPP Zone 10 Schedule 9 | (6) SPP Zone 10 Schedule 11 | (7) MISO AMMO PZ | (8) MISO Other |
|---|---|---|---|---|---|---|---|---|
| | **Plant in Service Data** | | | | | | | |
| 1 | Gross Plant in Service | | - | | - | - | - | - |
| 2 | Directly Assigned Net Plant in Service | | - | | - | - | - | - |
| 3 | Total Net Plant in Service | | - | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| | **Allocation Factors** | | | | | | | |
| 4 | GP | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | NP | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | GP-SPP | | | | #DIV/0! | #DIV/0! | 0.0% | 0.0% |
| 7 | GP-MISO | | | | | | 100.0% | 0.0% |
| | **Allocation of Operating and Maintenance Costs** | | | | | | | |
| 8 | Directly Assigned Trans O&M - SPP | | $ - | **GP-SPP** | #DIV/0! | #DIV/0! | - | - |
| 9 | Directly Assigned Trans | | $ | **GP-** | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | O&M - MISO | - | **MISO** | - | - | - | - |
| 10 | Allocated Transmission O&M | $ - | **GP** | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | Administration and General | $ - | **GP** | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | Depreciation - Directly Assigned | $ - | **DA** | - | - | - | - |
| 12 | Depreciation - Allocated | $ - | **GP** | #DIV/0! | #DIV/0! | #DIV/0! | - |
| | **Allocation of Return and Revenue Credits** | | | | | | |
| 12 | Return on Rate Base | $ - | **NP** | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 13 | Revenue Credits - SPP | $ - | **GP-SPP** | #DIV/0! | #DIV/0! | - | - |
| 14 | Revenue Credits - MISO | $ - | **GP-MISO** | - | - | - | - |
| | **True-Up** | | | | | | |
| 14 | Calculated True-Up Amount | | | - | - | - | - |
| 15 | Interest on True-Up Amount | | | - | - | #DIV/0! | #DIV/0! |
| 16 | Total True-Up with Interest | | | - | - | #DIV/0! | #DIV/0! |
| 17 | **Total ATRR by Zone and Schedule** | **#DIV/0!** | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| | Check-Sum (should be zero) | **#DIV/0!** | | | | | |
| | | | | #DIV/0! | | | |

$
-

# Attachment H Worksheets

Missouri Joint Municipal Electric Utility Commission
Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 2: Monthly Plant in Service

| | | | Transmission | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Gross Plant in Service** | **Year** | **Production** | **Zone 10 Schedule 9** | **Zone 10 Schedule 11** | **MISO AMMO PZ** | **MISO Other** | **General** | **Intangible** | **Common** | **Total Gross Plant in Service** | **Not Used** | **Total MISO** | **Total SPP** |
| 1 | December | 2xxx | | | | | | | | | $ - | | $ - | $ - |
| 2 | January | 2xxx | | | | | | | | | - | | - | - |
| 3 | February | 2xxx | | | | | | | | | - | | - | - |
| 4 | March | 2xxx | | | | | | | | | - | | - | - |
| 5 | April | 2x | | | | | | | | | - | | - | - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | May | xx2xxxxx | | | | | | | - | | - | - |
| 7 | June | xx2xxxxx | | | | | | | - | | - | - |
| 8 | July | xx2xxxxx | | | | | | | - | | - | - |
| 9 | August | xx2xxxxx | | | | | | | - | | - | - |
| 10 | September | xx2xxxxx | | | | | | | - | | - | - |
| 11 | October | xx2xxxxx | | | | | | | - | | - | - |
| 12 | November | xx2xxxxx | | | | | | | - | | - | - |
| 13 | December | xx2xxxxx | | | | | - | | - | | - | - |
| 14 | | | | | | | | | | | | | |
| 15 | **13 Month Average** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Attachment H, Page 2 | | Line 1 | Line 2 | Line 2 | Line 2 | Line 2 | Line 4 | Line 4 | Line 5 | | | | |

| Line No. | Accumulated Depreciation | Year | Production | Zone 10 Schedule 9 | Zone 10 Schedule 11 | MISO AMMO PZ | MISO Other | General | Intangible | Common | Total Accumulated Depreciation | Not Used | Total MISO | Total SPP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16 | December | 2xxx | | | | | | | | | $ - | | $ - | $ - |
| 17 | January | 2xxx | | | | | | | | | $ - | | $ - | - |
| 18 | February | 2xxx | | | | | | | | | $ - | | $ - | - |
| 19 | March | 2xxx | | | | | | | | | $ - | | $ - | - |
| 20 | April | 2xxx | | | | | | | | | $ - | | $ - | - |
| 21 | May | 2xxx | | | | | | | | | $ - | | $ - | - |
| 22 | June | 2xxx | | | | | | | | | $ - | | $ - | - |
| 23 | July | 2xxx | | | | | | | | | $ - | | $ - | - |
| 24 | August | 2xxx | | | | | | | | | $ - | | $ - | - |
| 25 | September | 2xx | | | | | | | | | $ - | | $ - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26 | October | xx2xxx | | | | | | | | | $ - | | $ - | - |
| 27 | November | xx2xxx | | | | | | | | | $ - | | $ - | - |
| 28 | December | xx2xxx | | | | | | | | | $ - | | $ - | - |
| 29 | | | | | | | | | | | | | | |
| 30 | **13 Month Average** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** | **$ -** | **$ -** |
| | Attachment H, Page 2 | | Line 7 | Line 8 | Line 8 | Line 8 | Line 8 | Line 10 | Line 10 | Line 11 | | | Line 8a | |

Adjustment for Unamortized Plant / CWIP (Zone 10) $ -

| **Line No.** | **Net Plant** | **Year** | **Production** | **Zone 10 Schedule 9** | **Zone 10 Schedule 11** | **MISO AMO PZ** | **MISO Other** | **General** | **Intangible** | **Common** | **Total Net Plant in Service** | **Not Used** | **Net Plant-MISO** | **Net Plant-SPP** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | December | xxx2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | January | xxx2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | February | x2x | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | March | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 35 | April | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 36 | May | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 37 | June | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 38 | July | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 39 | August | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 40 | September | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 41 | October | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 42 | November | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 43 | December | xx2xxxx | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 44 | | | | | | | | | | | | | | | | |
| 45 | **13 Month** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

| **Average** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Attachment H, Page 2 | Line 13 | Line 14 | Line 14 | Line 14 | Line 14 | Line 16 | Line 16 | Line 17 | |
| | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | $ - | | | | $ - | | | |
| | | | $ - | | | | | | |

# Attachment H Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2xxx

## Worksheet 3: Adjustments to Rate Base

**Adjustments to Rate Base**

| | | |
|---|---|---|
| Account 281 (enter as negative) | | Attachment H, page 2, line 19 |
| Account 282 (enter as negative) | | Attachment H, page 2, line 20 |
| Account 283 (enter as negative) | | Attachment H, page 2, line 21 |
| Account 190 | | Attachment H, page 2, line 22 |
| Account 255 (enter as negative) | | Attachment H, page 2, line 23 |
| Unamortized balance of Abandoned Plant | | Attachment H, page 2, line 23a |
| Total Adjustments to Rate Base | $ - | |

# Attachment H
# Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 4: Transmission Related Land Held for Future Use

| Line No. | Month | Year | Transmission Related Land Held for Future Use | |
|---|---|---|---|---|
| 1 | December | 2xxx | | |
| 2 | January | 2xxx | | |
| 3 | February | 2xxx | | |
| 4 | March | 2xxx | | |
| 5 | April | 2xxx | | |
| 6 | May | 2xxx | | |
| 7 | June | 2xxx | | |
| 8 | July | 2xxx | | |
| 9 | August | 2xxx | | |
| 10 | September | 2xxx | | |
| 11 | October | 2xxx | | |
| 12 | November | 2xxx | | |
| 13 | December | 2xxx | | |
| 14 | | | | |
| 15 | **13 Month Average** | | **$ -** | Attachment H, page 2, line 25 |

# Attachment H Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 5: Material and Supplies and Prepayments

| Line No. | Month | Year | Materials and Supplies | Prepayments - Account 165 |
|---|---|---|---|---|
| 1 | December | 2xxx | | |
| 2 | January | 2xxx | | |
| 3 | February | 2xxx | | |
| 4 | March | 2xxx | | |
| 5 | April | 2xxx | | |
| 6 | May | 2xxx | | |
| 7 | June | 2xxx | | |
| 8 | July | 2xxx | | |
| 9 | August | 2xxx | | |
| 10 | September | 2xxx | | |
| 11 | October | 2xxx | | |
| 12 | November | 2xxx | | |
| 13 | December | 2xxx | - | - |
| 14 | | | | |
| 15 | **13 Month Average** | | **$ -** | **$ -** |
| | Attachment H, Page 2 | | Line 27 | Line 28 |

**Asssumed 2022 the same as year-end 2020.**

# Attachment H
# Worksheets

## Missouri Joint Municipal Electric Utility Commission

## Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 6: Capital Structure

| Line No. | Month | Year | Outstanding Long-term Debt | Net Assets (Proprietary Capital) | |
|---|---|---|---|---|---|
| 1 | December | 2xxx | | | #DIV/0! |
| 2 | January | 2xxx | | | #DIV/0! |
| 3 | February | 2xxx | | | #DIV/0! |
| 4 | March | 2xxx | | | #DIV/0! |
| 5 | April | 2xxx | | | #DIV/0! |
| 6 | May | 2xxx | | | #DIV/0! |
| 7 | June | 2xxx | | | #DIV/0! |
| 8 | July | 2xxx | | | #DIV/0! |
| 9 | August | 2xxx | | | #DIV/0! |
| 10 | September | 2xxx | | | #DIV/0! |
| 11 | October | 2xxx | | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 12 | November | 2xxx | | | #DIV/0! |
| 13 | December | 2xxx | - | - | #DIV/0! |
| 14 | | | | | |
| 15 | **13 Month Average** | | $ - | $ - | |
| | Attachment H, Page 4 | | Line 22 | Line 23 | |

# Attachment H Worksheets Missouri Joint Municipal Electric Utility Commission Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 7: Transmission O&M Expenses

| Line No. | Transmission O&M Expenses | Internal | SPP Contract | MISO Contract | Total | |
|---|---|---|---|---|---|---|
| 1 | Operation | | | | | |
| 2 | 560 – Operation Supervision and Engineering | | | | $ - | |
| 3 | 561 – Load Dispatching | | | | $ - | |
| 4 | 561.1 – Load Dispatch – Reliability | | | | $ - | Attachment H, page 4, line 7 |
| 5 | 561.2 – Load Dispatch – Monitor and Operate Transmission System | | | | $ - | Attachment H, page 4, line 7 |
| 6 | 561.3 – Load Dispatch – Transmission Service and Scheduling | | | | $ - | Attachment H, page 4, line 7 |
| 7 | 561.4 – Scheduling, System Control and Dispatch Services | | | | $ - | Attachment H, page 3, line 1a |
| 8 | 561.5 – Reliability, Planning and Standards Development | | | | $ - | |
| 9 | 561.6 – Transmission | | | | $ | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Service Studies | | | | - | |
| 10 | 561.7 – Generation Interconnection Studies | | | | $ - | |
| 11 | 561.8 – Reliability, Planning and Standards Development Service | | | | $ - | Attachment H, page 3, line 1a |
| 12 | 562 – Station Expenses | | | | $ - | |
| 13 | 563 – Overhead Lines Expenses | | | | $ - | |
| 14 | 564 – Underground Lines Expenses | $ - | | | $ - | |
| 15 | 565 – Transmission of Electricity by Others | | | | $ - | Attachment H, page 3, line 2 |
| 16 | 566 – Miscellaneous Transmission Expenses | $ - | | | $ - | |
| 17 | 567 – Rents | $ - | | | $ - | |
| 18 | Maintenance | | | | | |
| 19 | 568 – Maintenance Supervision and Engineering | | | | $ - | |
| 20 | 569 – Maintenance of Structures | | | | $ - | |
| 21 | 570 – Maintenance of Station Equipment | | | | $ - | |
| 22 | 571 – Maintenance of Overhead Lines | | | | $ - | |
| 23 | 572 – Maintenance of Underground Lines | | | | $ - | |
| 24 | 573 – Maintenance of Miscellaneous Transmission Plant | | | | $ - | |
| 25 | | | | | | |
| 26 | Transmission O&M Expense | $ - | $ - | $ - | $ - | Attachment H, page 3, line 1, EIA 412, Schd 7, line 8 |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | | | | | | |
| 30 | | | | | | |
| 31 | Difference | $ | | | | |

| | | | | |
|---|---|---|---|---|
| 30 | | - | | |
| 31 | | | | |
| 32 | LSE Expenses included in Transmission O&M Accounts | $ - | | Attachment H, page 3, line 1a |

# Attachment H Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 8: Administrative and General Expenses

| Line No. | Administrative and General Expense | Year | Budgeted Expense | | |
|---|---|---|---|---|---|
| 1 | **Administrative and General Expenses** | | | EIA 412, Sch 7, line 13 | X |
| 2 | Reassigned to Production Acc't 557 | | | 2022 Budget- pg. 73 GF Overheads | X |
| 3 | Reassigned to MJMEUC Alliance Fund | | | 2022 Budget - pg 42 Alliance Fund | X |
| 4 | Reassigned to Apprentice Training | | | 2022 Budget - pg 47. Apprent. Train Exp | X |
| 5 | Reassigned to Electric Instrumentation Tech | | | 2022 Budget - pg 47. Instr. Tech Exp | X |
| 6 | Administrative and General Expenses in Rate | | $ - | Attach H, page 3, line 3 | Calc |
| 7 | | | | | |
| 8 | **Other Attachment H A&G Expense Information** | | | | |
| 9 | FERC Annual Fees | | | Attach H, page 3, line 4 | |
| 10 | EPRI & Regulatory Commission Expenses & Non-safety Advertising | | | Attach H, page 3, line 5 | X |
| 11 | Transmission Related Regulatory Commission Expenses | | | Attach H, page 3, line 5a | X |

Sources for Adjustments and Notes:
Line 2: Joint costs transfer from inter-funds (2XXX budget)

Line 3: Total expenses for
Alliance Fund (2XXX budget)
Line 4: Energy Service Fund budget (2XXX
budget) (should get actual 2XXX)
Line 5: Energy Service Fund budget (2XXX
budget) (should get actual 2XXX)
Line 9: FERC annual fees are recorded in Account 565
and thus already excluded from ATRR.
Line 11: Amortization of 2XXX professional services (legal/consulting in support of rate studies) over four years.

# Attachment H Worksheets Missouri Joint Municipal Electric Utility Commission Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 9: Functionalized Labor Expense

| Line No. | Account | Description | Total Utility | Allocation of Account 556 | A&G Assigned to Prod Account 557 | Adjusted Total Utility | | |
|---|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | | (E) | | |
| 1 | | | | | | | | |
| 2 | | **O&M Accounts:** | | | | | | |
| 3 | 500-557 | Production-O&M | | - | - | $0 | Attach O, page 4, line 12 | X |
| 4 | 556 | System Control & Load Dispatch | | - | - | | Attach O, page 4, line 13 | X |
| 5 | 560-575 | Transmission-O&M | | - | - | | Attach O, page 4, line 13 | X |
| 6 | 580-598 | Distribution-O&M | | | - | | | X |
| 7 | 800-89 | Other Electric | | | - | | Attach O, page 4, line 15 | X |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | 901-917 | Customer Accounts | | | - | | | X |
| 9 | 920-935 | Administrative & General | | | - | - | | X |
| 10 | | Subtotal | $0 | | | $0 | | |
| 11 | | | | | | | | |
| 12 | | **Allocation of System Control & Load Dispatch** | | | | | | |
| 13 | | Allocation to Production | 95% | $0 | | | | |
| 14 | | Allocation to Transmission | 5% | $0 | | | | |
| 15 | 556 | Total 556 | | - | | | | |

**Assumed 2XXX budget with following adjustments:**

1. Add labor costs to transmission associated with 2 FTEs.
2. Re-assign budgeted salaries and wages associated with individual projects to Account 557.

# Attachment H Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 10: Other Inputs for Attachment H and Worksheet 1

| Line No. | Expense | Budgeted Expense or Income | |
|---|---|---|---|
| 1 | Common Expenses | | Attach O, page 3, line 6 |
| 2 | Transmission Lease Payments | | Attach O, page 3, line 7 |
| 3 | Transmission Plant Depreciation Expense | | Attach O, page 3, line 9 |
| 4 | General Plant Depreciation Expense | | Attach O, page 3, line 10 |
| 5 | Common Plant Depreciation Expense | | Attach O, page 3, line 11 |
| 6 | Payroll Taxes | | Attach O, page 3, line 13 |
| 7 | Highway and Vehicle Taxes | | Attach O, page 3, line 14 |
| 8 | Property Taxes: | | |
| 9a | Production Property Taxes | | |
| 9b | Transmission Property Taxes | - | Attach O, page 3, line 16 |
| 9c | Property Taxes- Total | - | |
| 10 | Directly Assigned SPP O&M | $ - | Worksheet 1, line 7 |
| 11 | Directly Assigned MISO O&M | $ - | Worksheet 1, line 8 |
| 13 | Directly Assigned Depreciation - SPP Schedule 9 | | Worksheet 1, line 10, column (3) |
| 14 | Directly Assigned Depreciation - SPP Schedule 11 | | Worksheet 1, line 10, column (4) |
| 15 | Directly Assigned Depreciation - MISO AMMO PZ | | Worksheet 1, line 10, column (5) |
| 16 | Directly Assigned Depreciation - MISO Other | | Worksheet 1, line 10, column (6) |

| | | | |
|---|---|---|---|
| 17 | Gross Receipts Taxes | | Attach O, page 3, line 17 |
| 18 | Other Taxes | | Attach O, page 3, line 18 |
| 19 | Payments in Lieu of Taxes | | Attach O, page 3, line 19 |
| 20 | 427- Long Term Interest Expense | | Attach O, page 4, line 21 |
| 21 | 428- Amortization of debt discount and expense | | Attach O, page 4, line 21 |
| 22 | 428.1- Amortization of loss on reacquired debt | | Attach O, page 4, line 21 |
| 23 | 429- Amortization of premium on debt | | Attach O, page 4, line 21 |
| 24 | 429.1 Amortization of gain on reacquired debt | | Attach O, page 4, line 21 |
| 25 | 430- Interest on debt to associated companies | | Attach O, page 4, line 21 |
| 26 | 431- Other interest expense (Build American Bonds rebate) | - | Attach O, page 4, line 21 |
| 27 | Total Interest Expense | $ - | Attach O, page 4, line 21 |
| 28 | | | |
| 29 | 454- Rent from Electric Property | | Attach O, page 4, line 34 |
| 30 | 456.1- Other Electric Revenue | | |
| 31 | a. Transmission charges for transmission transactions | | Attach O, page 4, line 35 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on page 1 | | Attach O, page 4, line 36 |
| 33 | c. Transmission charges associated with Schedule 26 (SPP Schedule 1) | | Attach O, page 4, line 36a |
| 34 | d. Transmission charges associated with Schedule 26-A | | Attach O, page 4, line 36b |
| 35 | Transmission expense included in OATT | | Attach O, page 4, line 37 |
| 30 | Allocated Revenue Credits - SPP | | Worksheet 1, line 12 |
| 31 | Allocated Revenue Credits - MISO | | Worksheet 1, line 13 |
| 32 | **Return on Equity:** | | |
| 33 | FERC Approved MISO Return on Equity | 10.02% | |
| 34 | RTO Adder | 0.50% | |
| 35 | RTO Adder | 10.52% | Attach O, page 4, line 17 |

**Assumed 2022 budget with following adjustments:**

1. Add estimated O&M costs for SPP and MISO projects (not included in budget)

# Attachment H Worksheets Missouri Joint Municipal Electric Utility Commission Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 11: True-Up of Actual Costs for FY 2XXX

| Line No. | (1) Description | (2) Reference | (3) SPP Zone 10 Schedule 9 | (4) SPP Zone 10 Schedule 11 | (5) MISO AMMO PZ | (6) MISO Other |
|---|---|---|---|---|---|---|
| | **Annual Transmission Revenue Requirement (ATRR) True-Up:** | | | | | |
| 1 | Actual ATRR, excluding interest | | | | | |
| 2 | Revenue Collected | | | | | |
| 3 | **ATRR True-Up, excluding Interest** | **(line 1 - line 2)** | - | - | - | - |
| | **Interest on Historic Year True-Up:** | | | | | |
| 4 | Average Interest Rate (18 CFR 35.19a) (January 2XXX-April 2XXX) | **Schedule 12, Line 25** | | | | |
| 5 | Estimated Interest for 24 months (January 2XXX-December 2XXX) | (ln 4)/12 * 24 * (ln 3) | - | - | - | - |
| 6 | **Total True-Up** | **(line 3 + line 5)** | - | - | - | - |

Note: First true-up will occur with rate going into effect January 1, 2023.

# Attachment H Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 12: Interest Rate

**Instructions:** Inputs are indicated by light yellow highlighted cells with blue bold font

**Purpose:** To calculate the average interest rates to be applied to the true-up calculations

**Per Section _____ of the Annual True-up, Information Exchange and Challenge Procedures**

Interest on over-recovery will be based on FERC's regulation 18 C.F.R 35.19a

Interest on under-recovery will be based on the annual average of the one-month

LIBOR rate **capped** at the FERC refund interest rate
MJMEUC to enter monthly LIBOR amounts and provide a cite to source of LIBOR rate

The interest payable will be calculated using an average interest rate for the twenty-four (24) months
during which the over or under recovery in the net revenue requirement or load volume changes exists.
The interest rate to be applied to the over or under recovery amounts will be determined using the average

rate for the twenty (20) months preceding September of the current year.

| Line No. | (1) | (2) | (3) |
|---|---|---|---|
| | | True-Up- September 2XXX<br>1 Month LIBOR** - Annualized Rate | FERC Rates*<br>Annual |
| 1 | Jan-xx | | |
| 2 | Feb-xx | | |
| 3 | Mar-xx | | |
| 4 | Apr-xx | | |
| 5 | May-xx | | |
| 6 | Jun-xx | | |
| 7 | Jul-xx | | |
| 8 | Aug-xx | | |
| 9 | Sep-xx | | |
| 10 | Oct-xx | | |
| 11 | Nov-xx | | |
| 12 | Dec-xx | | |

| | | | |
|---|---|---|---|
| 13 | Jan-xx | | |
| 14 | Feb-xx | | |
| 15 | Mar-xx | | |
| 16 | Apr-xx | | |
| 17 | May-xx | | |
| 18 | Jun-xx | | |
| 19 | Jul-xx | | |
| 20 | Aug-xx | | |
| 21 | Sep-xx | | |
| 22 | Oct-xx | | |
| 23 | Nov-xx | | |
| 24 | Dec-xx | | |
| 25 | Average Annualized | #DIV/0! | #DIV/0! |
| 26 | Average Monthly | #DIV/0! | #DIV/0! |

* = 18 CFR 35 19a for overcharges (Per true-up procedures)
** = 1 month LIBOR for undercharges (Per true-up procedures)

# Attachment H
# Worksheets
# Missouri Joint Municipal Electric Utility Commission
# Forecasted 12 Months Ended December 31, 2XXX

## Worksheet 13: Depreciation Rates

| TRANSMISSION | DESCRIPTION | Depreciation Rate |
|---|---|---|
| 350 | Land Rights | N/A |
| | Rights of Way | 1.80% |
| 352 | Structures and Improvements | 1.33% |
| 353 | Station Equipment | 1.89% |
| 354 | Towers and Fixtures | 1.14% |
| 355 | Poles and Fixtures | 2.42% |
| 356 | Overhead Conductors & Devices | 2.26% |
| 357 | Underground Conduit | 1.00% |
| 358 | Underground Conductors & Devices | 0.42% |
| 359 | Roads and Trails | 0.00% |
| | | |
| GENERAL AND INTANGIBLE | | |
| 302 | Franchises and Consents (Note 1) | |
| 303 | Intangible Plant - 5 Year | |
| 390 | Structures and Improvements | 2.04% |
| 391 | Office Furniture | 7.15% |
| 391 | Office Equipment | 11.54% |
| 391 | Network Equipment | 23.36% |
| 392 | Transportation Equipment - Auto | 7.77% |
| 392 | Transportation Equipment - Light Truck | 7.77% |
| 392 | Transportation Equipment - Trailers | 7.77% |
| 392 | Transportation Equipment - Heavy Trucks | 7.77% |
| 393 | Stores Equipment | 5.21% |
| 394 | Tools, Shop and Garage Equipment | 5.92% |
| 395 | Laboratory Equipment | 5.35% |
| 396 | Power Operated Equipment | 6.38% |
| 397 | Communication Equipment | 9.43% |
| 398 | Miscellaneous Equipment | 8.89% |

Note 1:

Electric Intangible Franchises and Transmission Land Rights are amortized over the life of the franchise agreement or land right.

## Schedule 2, Electric Balance Sheet

| Line No. | Assets and Other Debits | Column b Amount | Line No. | Liabilities and Other Credits | Column b Amount |
|---|---|---|---|---|---|
| | **Electric Plant** | | | **Proprietary Capital** | |
| 1 | Electric Plant and Adjustments (101-106, 114, 116) | | 29 | Investment of Municipality (208) | $ - |
| 2 | Construction Work in Progress (107) | | 30 | Miscellaneous Capital (211) | - |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization, and Depletion (108, 111, 115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | Net Electric Plant (sum of lines 1-2 less line 3) | - | 32 | Total Proprietary Capital (sum of lines 29-31) | - |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | - | | **Long-Term Debt** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | - | 33 | Bonds (221, 222) | |
| 7 | Net Electric Plant including Nuclear Fuel (sum of lines 4-5, less line 6) | - | 34 | Advances From Municipality and Other Long-Term Debt (223, 224) | |
| | **Other Plant and Investments** | | 35 | Unamortized Premium on Long-Term Debt (225) | |
| 8 | Non-electric Plant Property (121) | - | 36 | (Less) Unamortized Discount on Long-Term Debt (226) | |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | - | 37 | Total Long-Term Debt (sum of lines 33-35, less line 36) | - |
| 10 | Investment in Associated Enterprises (123-123.1) | - | | **Other Noncurrent Liabilities** | |
| 11 | Investments and Special Funds (124-128) | | 38 | Accumulated Operating Provisions (228.1-228.4) | |
| 12 | Total Other Property and Investments (sum of lines 8, 10, 11 less line 9) | - | 39 | Accumulated Provision for Rate Refunds (229) | |
| | **Current and Accrued Assets** | | 40 | Total Other Noncurrent Liabilities (sum of lines 38-39) | - |
| 13 | Cash, Working Funds, and Investments (131-136) | | | **Current and Accrued Liabilities** | |
| 14 | Notes and Other Receivables (141, 143, 145, 146, 172) | | 41 | Notes Payable (231) | |
| 15 | Customer Accounts Receivable (142) | | 42 | Accounts Payable (232) | |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | - | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 17 | Fuel Stock and Expenses Undistributed (151-152) | | 44 | Customer Deposits (235) | |
| 18 | Plant Materials and Operating Supplies (154) | - | 45 | Taxes Accrued (236) | - |
| 19 | Other Supplies and Miscellaneous (153, 155-163) | - | 46 | Interest Accrued (237) | |

| | | | | | |
|---|---|---|---|---|---|
| 20 | Prepayments (165) | | 47 | Miscellaneous Current and Accrued Liabilities (239-243) | |
| 21 | Accrued Revenues (173) | - | 48 | Total Current and Accrued Liabilities (sum of lines 41-47) | - |
| 22 | Miscellaneous Current and Accrued Assets (171, 174) | - | | | |
| 23 | Total Current and Accrued Assets (sum of lines 13-15, 17-22 less line 16) | - | | | |
| | **Deferred Debits** | | | **Deferred Credits** | |
| 24 | Unamortized Debt Expense (181) | | 49 | Customer Advances for Construction (252) | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 183) | | 50 | Other Deferred Credits (253, 256, 281-283) | |
| 26 | Miscellaneous Debt, Research and Development Expenses and Unamortized Losses (184-191) | | 51 | Unamortized Gain on Reacquired Debt (257) | |
| 27 | Total Deferred Debits (sum of lines 24-26) | - | 52 | Total Deferred Credits (sum of lines 49-51) | - |
| 28 | Total Assets and Other Debits (sum of lines 7, 12, 23, 27) | $ - | 53 | Total Liabilities and Other Credits (sum of lines 32,37,40,48,52) | $ - |

## Schedule 3. Electric Income Statement

| Line No. | | Column b Amount |
|---|---|---|
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | - |
| 3 | Maintenance Expenses (402) | - |
| 4 | Depreciation Expenses (403) | - |
| 5 | Amortization of Electric Plant, Property Losses and Regulatory Study Cost (404-407) | - |
| 6 | Taxes and Tax Equivalents (see Schedule 6) (408.1, 409.1) | - |
| 7 | Total Electric Operating Expenses (sum of lines 2-6) | - |
| 8 | Net Electric Operating Income (line 1, less line 7) | - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | - |
| 10 | Electric Operating Income (sum of lines 8, 9) | - |
| 11 | Other Electric Income (explain significant amounts in a footnote on Schedule 12) (415, 417, 418, 419 421,421.1) | - |
| 12 | Other Electric Deductions (explain significant amounts in a footnote on Schedule 12) (416, 417.1, 421.2) | - |
| 13 | Allowance for Other Funds Used During Construction (419.1) | - |
| 14 | Taxes Applicable to Other Income and Deductions (see Schedule 6) (408.2, 409.2) | - |
| 15 | Electric Income (sum of lines 10, 11, 13, less lines 12, 14) | - |
| 16 | Income Deductions from Interest on Long-Term Debt (427) | |
| 17 | Other Income Deductions (explain significant amounts in a footnote on Schedule 12) (428-431) | - |
| 18 | Allowance for Borrowed Funds Used During Construction (432) | |
| 19 | Total Income Deductions (sum of lines 16-18) | - |
| 20 | Income Before Extraordinary Items (line 15, less line 19) | - |
| 21 | Extraordinary Items (434) | |
| 22 | Extraordinary Deductions (435) | |
| 23 | Net Income (sum of lines 20, 21, less line 22) | $ - |

Detail for Line 11:

Investment Income

Unrealized gain (loss) on investments

Gain (Loss) on Disposal of Capital Assets

MAMU and MGCM Income

$ $

| | | | |
|---|---|---|---|
| | | - | - |

Detail for Line 12:

| | | | |
|---|---|---|---|
| | MAMU and MGCM Payroll Costs | | |
| | Return of Equity to Members | | |
| | Future years cost recovered in current rates | | |
| | | $ | $ |
| | | - | - |

Detail for Line 17:

| | | | |
|---|---|---|---|
| 428 | Amortization of debt expense | | |
| 428.1 | Amortization of loss on reacquired debt | | |
| 428 | Amortization of debt discount | | |
| 431 | Build America Bonds | | |
| 429 | Amortization of debt premium | | |
| | | $ | $ |
| | | - | - |

## Schedule 4- Electric Plant

| Line No. | - | Balance Beginning of Year (Dollars) (a) | Additions (b) | Retirements (c) | Transfers & Adjustments (d) | Balance End of Year (Dollars) (e) |
|---|---|---|---|---|---|---|
| 1 | Intangible Plant (301-303) | | | | | |
| 2 | Steam Production (310-316) | | | | | |
| 3 | Nuclear Production (320-325) | | | | | |
| 4 | Hydraulic Production (330-336) | | | | | |
| 5 | Other Production (340-346) Specify: Natural Gas | | | | | |
| 5 | Other Production (340-346) Specify: Solar | | | | | - |
| 6 | Total Production Plant (sum of lines 2-5) | - | - | - | - | - |
| 7 | Transmission Plant (350-359) | - | - | - | - | - |
| 8 | Distribution Plant (360-373) | - | - | - | - | - |
| 9 | General Plant (389-399) | | | | | - |
| 10 | Total Electric Plant in Service (sum of lines 1, 6-9) | - | - | - | - | - |
| 11 | Electric Plant Leased to Others (104) | | | | | - |
| 12 | Electric Plant Held for Future Use (105) | | | | | - |
| 13 | Electric Plant Miscellaneous (102, 103, 106, 114, 116) | | | | | - |
| 14 | Electric Plant and Adjustments (sum of lines 10-13) | - | - | - | - | - |
| 15 | Construction Work in Progress-Electric (107) | | | | | - |
| 16 | Total Electric Plant and Adjustments (sum lines 14, 15) | $ - | $ - | $ - | $ - | $ - |

Balance per 12/31/XX Audited Financial Statements

Difference $ -

## Schedule 7- Electric Operations and Maintenance Expenses

| Line No. | - | Fuel Cost (Dollars) (a) | Operations (Dollars) (b) | Maintenance (Dollars) (c) | Total Dollars (d) |
|---|---|---|---|---|---|
| | Power Production Expenses | | | | |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | | | | |
| 2 | Nuclear Power Generation (517-525, 528-532) Fuel Cost (518) | | | | |
| 3 | Hydraulic Power Generation (535-540, 541-545) | | | | |
| 4 | Other Power Generation (546-550, 551-554) Fuel Cost (547) | | | | |
| 5 | Purchased Power (555) | | | | |
| 6 | Other Production Expenses (556-557) | | | | |
| 7 | Total Production Expenses (sum of lines 1-6) | - | - | - | - |
| 8 | Transmission Expenses (560-567, 568-573) | | | | |
| 9 | Distribution Expenses (580-589, 590-598) | | | | |
| 10 | Customer Accounts Expenses (901-905) | | | | |
| 11 | Customer Service and Information Expenses (907-910) | | | | |
| 12 | Sales Expenses (911-916) | | | | |
| 13 | Administrative and General Expenses (920-931, 935) | | | | - |
| 14 | Total Electric Operation and Maintenance Expenses (sum of lines 7-13) | $ - | $ - | $ - | $ - |
| | Number of Electric Department Employees | | | | |
| 15 | Payroll Ended (Date) | | | | |
| 16 | Total Number of Regular Full-Time Employees (if Federal agency, full-time equivalents) | | | | |
| 17 | Total Number of Part-Time and Temporary Employees | | | | |
| 18 | Total Number of Employees (sum of lines 16 and 17) | | | 0 | |

Depreciation and Amortization

Future Recoverable Costs

Property Taxes

Total Operating Expenses $ -

Total Operating Expenses Per 12/31/XX Audit

Difference $ -

**MISSOURI JOINT MUNICIPAL ELECTRIC UTILITY COMMISSION**

**(MJMEUC)**

**TRANSMISSION FORMULA RATE IMPLEMENTATION PROTOCOLS: ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES**

## Section I. Applicability

The following procedures shall apply to Missouri Joint Municipal Electric Utility Commission's ("MJMEUC") calculation of its actual net revenue requirement, True-Up Adjustment, and projected net revenue requirement.

## Section II. Annual True-Up and Projected Net Revenue Requirement

A. Beginning on or before June 1, 2023, and on or before each subsequent June 1, MJMEUC shall determine its Annual True-Up under this Attachment H and Section VII of these protocols, to derive a True-Up Adjustment to be included in MJMEUC's projected net revenue requirement for the subsequent calendar year (the "Rate Year").

B. On or before June 1, 2023, and on or before each subsequent June 1, MJMEUC shall provide its Annual True-Up, actual net revenue requirement, and True-Up Adjustment to Southwest Power Pool, Inc. ("SPP") and cause such information to be posted on the SPP OASIS. Within ten (10) days of such posting, MJMEUC shall provide notice of such posting via an SPP email exploder list (Formula Rate Posting Information Notification). Interested Parties as that term is defined in Section II.F of these protocols) can subscribe to the SPP email exploder list (Formula Rate Posting Information Notification) on the SPP website or request to be notified of the posting by emailing MJMEUC at FormulaRates@mpua.org.

C. On or before October 1, 2023, and on or before each subsequent October 1, MJMEUC shall provide its projected net revenue requirement to SPP and cause such information to be posted on the SPP OASIS. Within ten (10) days of posting of the projected net revenue requirement, MJMEUC shall provide notice of such posting via an SPP email exploder list (Formula Rate Posting Information Notification). Interested parties as that term is defined in Section II.G of these protocols) can subscribe to the SPP email exploder list (Formula Rate Posting Information Notification) on the SPP website or request to be notified of the posting by emailing MJMEUC at FormulaRates@mpua.org.

D. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("Commission" or "FERC"), then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the projected net revenue requirement will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

E. The Annual True-Up shall:
   1. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;
   2. Be based on MJMEUC's audited financial statements and EIA Form 412[1] information for the prior calendar year;
   3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in MJMEUC's audited financial statements and EIA Form 412 information;[2]
   4. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the Annual True-Up results from the MJMEUC audited financial statements and EIA Form No. 412;
   5. Identify any changes in the formula references (page and line numbers) to the MJMEUC audited financial statements and EIA Form No. 412;
   6. Identify all material adjustments made to the MJMEUC audited financial statements or the EIA Form No. 412 data in determining formula inputs, including relevant footnotes to the MJMEUC audited financial statements or EIA Form 412;

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[1] While the EIA no longer requires the submission of EIA-Form 412, MJMEUC will make the data from EIA Form No. 412 that is used in calculating the rates publicly available.

[2] It is the intent of the formula rate, including the supporting explanations and allocations described therein, that each input to the formula rate will be either taken directly from MJMEUC's audited financial statement, EIA Form No. 412 information, or reconcilable to EIA Form No. 412 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

7. Provide underlying data for formula rate inputs that provide greater granularity than is required for the MJMEUC audited financial statements and EIA Form No. 412; and
8. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):
    a. Identify any Accounting Changes, including:
        i. The initial implementation of an accounting standard or policy;
        ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
        iii. Correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;
        iv. The implementation of new estimation methods or policies that change prior estimates; and
        v. Changes related to taxes, including new or increased taxes and changes in the application of existing taxes;
    b. Identify terms included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);
    c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up; and
    d. Provide, for each item identified pursuant to items II.E.8.a – II.E.8.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

F. The projected net revenue requirement shall:
    1. Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;
    2. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement;
    3. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the projected net revenue requirement; and
    4. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):
        a. Identify any Accounting Changes, including:
            i. The initial implementation of an accounting standard or policy;
            ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
            iii. Correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

iv. The implementation of new estimation methods or policies that change prior estimates; and
v. Changes related to taxes, including new or increased taxes and changes in the application of existing taxes;

b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);
c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement; and
d. Provide, for each item identified pursuant to items II.F.4.a – II.F.4.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

G. MJMEUC shall hold an open meeting for Interested Parties ("Annual True-Up Meeting") between the Publication Date and September 1st. No less than ten (10) days prior to such Annual True-Up Meeting, MJMEUC shall provide notice on SPP's OASIS and via an SPP email exploder list (Formula Rate Posting Information Notification) of the date, time, and location of the Annual True-Up Meeting, including web conference and teleconference information. For purposes of these protocols, the term "Interested Party" includes, but is not limited to, customers under the SPP Tariff, state regulatory commissions, and consumer advocacy agencies. The Annual True-Up Meeting shall (i) permit MJMEUC to explain and clarify its Annual True-Up and True-Up Adjustment; and (ii) provide Interested Parties an opportunity to seek information and clarifications from MJMEUC regarding its Annual True-Up and True-Up Adjustment.

H. MJMEUC shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") between the date that the projected net revenue requirement is posted to the SPP OASIS (as described in Sections II.C and II.D of these protocols) and October 31. No less than ten (10) days prior to such Annual Projected Rate Meeting, MJMEUC shall provide notice on SPP's OASIS and via an SPP email exploder list (Formula Rate Posting Information Notification) of the date, time, and location of the Annual Projected Rate Meeting, including web conference and teleconference information. The Annual Projected Rate Meeting shall (i) permit MJMEUC to explain and clarify its projected net revenue requirement and (ii) provide Interested Parties an opportunity to seek information and clarifications from MJMEUC regarding the projected net revenue requirement.

I. If SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, MJMEUC will participate in that process and will provide notice to Interested Parties of the time, date, and location of the joint meeting (including web conference and teleconference information) via posting on SPP's OASIS and via an SPP email exploder list (Formula Rate Posting Information Notification) no less than ten (10) days prior to

such meeting.

**Section III. Information Exchange Procedures**

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until December 1st following the Publication Date (unless such period is extended with the written consent of MJMEUC or by FERC order) to serve reasonable information and document requests on MJMEUC ("Information Exchange Period"). If December 1st falls on a weekend or holiday recognized by FERC, the deadline for submitting all information and document requests shall be the next business day. Information and document requests shall be limited to what is necessary to determine:
    1. The extent or effect of an Accounting Change;
    2. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;
    3. The proper application of the formula rate and procedures in these protocols;
    4. The accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;
    5. The prudence of actual costs and expenditures;
    6. The effect of any change to the underlying Uniform System of Accounts, the MJMEUC audited financial statements, or EIA Form No. 412; or
    7. Any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the formula.

    The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. MJMEUC shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. MJMEUC shall respond to all information and document requests by no later than January 10th following the Publication Date unless the Information Exchange Period is extended by MJMEUC or FERC.

C. MJMEUC will cause to be posted on the SPP OASIS and via an SPP email exploder list (Formula Rate Posting Information Notification) all information requests from Interested Parties and MJMEUC's response(s) to such requests; except, however, if responses to information and document requests include material deemed confidential information by MJMEUC, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by MJMEUC and the requesting party.

D. MJMEUC shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege in any subsequent

FERC proceeding addressing MJMEUC's Annual True-Up or projected net revenue requirement.

**Section IV. Challenge Procedures**

A. Interested Parties shall have until January 31st following the Publication Date (unless such period is extended with the written consent of MJMEUC or by FERC order) to review the inputs, supporting explanations, allocations, and calculations and to notify MJMEUC in writing, which may be submitted electronically, of any specific Informal Challenges to the Annual True-Up or projected net revenue requirement. The period of time from the Publication Date until January 31st shall be referred to as the "Review Period". If January 31st falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that Annual True-Up or projected net revenue requirement but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement.

B. A party submitting an Informal Challenge to MJMEUC must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. MJMEUC shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. MJMEUC shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If MJMEUC disagrees with such challenge, MJMEUC will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31st, and MJMEUC must respond to all Informal Challenges by no later than February 28th, unless the review period is extended by MJMEUC or FERC.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV.

D. Formal Challenges shall be filed with FERC pursuant to these protocols and shall satisfy all the following requirements:
    1. A Formal Challenge shall:
        a. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        b. Explain how the action or inaction violates the filed rate formula or protocols;

c. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relates to or affects the party filing the Formal Challenge, including:
    i. The extent or effect of an Accounting Change;
    ii. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;
    iii. The proper application of the formula rate and procedures in these protocols;
    iv. The accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;
    v. The prudence of actual costs and expenditures;
    vi. The effect of any change to the underlying Uniform System of Accounts, the MJMEUC audited financial statements, or the EIA Form No. 412; or
    vii. Any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the formula.
d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
e. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;
g. Include all documents that support the facts in the Formal Challenge in the possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and
h. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on MJMEUC. Service to MJMEUC must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on MJMEUC's Informational Filing required under Section IV of these protocols.

E. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine:
    1. The extent or effect of an Accounting Change;

2. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;
3. The proper application of the formula rate and procedures in these protocols;
4. The accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;
5. The prudence of actual costs and expenditures;
6. The effect of any change to the underlying Uniform System of Accounts, the MJMEUC audited financial statements, or the EIA Form No. 412; or
7. Any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the formula.

F. MJMEUC will cause to be posted all Informal Challenges from Interested Parties and MJMEUC's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by MJMEUC to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by MJMEUC and the requesting party.

G. Any changes or adjustments to the True-Up Adjustment or projected net revenue requirement resulting from the Information Exchange and Informal Challenge processes that are agreed to by MJMEUC will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by MJMEUC on or before December 1st will be reflected in the projected net revenue requirement for the upcoming Rate Year. Any changes or adjustments agreed to MJMEUC after December 1st will be reflected in the following year's Annual True-up, as discussed in Section V of these protocols.

H. An Interested Party shall have until April 15th following the Review Period (unless such date is extended with the written consent of MJMEUC to continue efforts to resolve the Informal Challenge) to file a Formal Challenge with FERC, which shall be served on MJMEUC on the date filed in the same docket as MJMEUC's Informational Filing discussed in Section VI of these protocols. MJMEUC shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

I. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, MJMEUC shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols and the applicable requirements and procedures in this Attachment H, Addendum 50 – MJMEUC. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

J. Except as specifically provided in these protocols, nothing shall be deemed to limit in any way the right of MJMEUC to file unilaterally, pursuant to section 205 of the Federal Power Act and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

K. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual True-Up and projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

L. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts, the MJMEUC audited financial statements, or the EIA Form No. 412, shall first raise the matter with MJMEUC in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to True-Up Adjustment or Projected Net Revenue Requirement**

Except as provided in Section IV.G of these protocols, any changes to the data inputs, including, but not limited to, revisions to MJMEUC's audited financial statements or EIA Form No. 412, or as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the changes produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

**Section VI. Informational Filings**

A. By March 15$^{th}$ of each year, MJMEUC shall submit to FERC an informational filing ("Informational Filing") of its projected net revenue requirement for the Rate Year, including its Annual True-Up and True-Up Adjustment. This Informational Filing must include the information that is reasonably necessary to determine:
    1. That input data under the formula rate is properly recorded in any underlying workpapers;
    2. That MJMEUC has properly applied the formula rate and these procedures;
    3. The accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review;
    4. The extent of accounting changes that affect formula rate inputs; and
    5. The reasonableness of projected costs.

B. The Informational Filing must also describe any corrections or adjustments made during that period and must describe aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, SPP shall provide notice of the Informational Filing and the associated docket number via an email exploder list (Formula Rate Posting Information Notification) and by posting on the SPP OASIS.

C. Any challenges to the implementation of the Attachment H, Addendum 50 - MJMEUC formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

**Section VII. Calculation of True-Up Adjustment**

True-Up Procedure: The True-Up Adjustment will be determined in the following manner:

1. The actual net revenue requirement (page 1, line 7) for the previous year shall be compared to the revenue received for the same year ("True-Up Year") to determine any excess or shortfall in the projected net revenue requirement that was used for billing purposes in this True-Up Year. The True-Up Adjustment and related calculations will be posted in accordance with Section II of these protocols.

2. Interest on any over-recovery of the net revenue requirement will be determined based upon the Commission's regulation at 18 C.F.R. 35.19a. Interest on any under-recovery of the net revenue requirement will be based on the one-month U.S. Treasury Daily Treasury Par Yield Curve Rates for the first day of the month ("One Month Treasury Yield")[3] capped at the applicable Commission refund interest rate. In either case, the interest payable will be calculated using the average interest rate calculated below and applied for the twenty-four (24) months during which the over- or under-recovery in the net revenue requirement exists. The average interest rate to be applied to the over- or under-recovery amounts will be determined using the average rate for the twenty (20) months preceding September of the current year. The interest amount will be included in the projected costs made available by October 1st in accordance with Section II.C above.

3. The net revenue requirement for transmission services for the following year shall be the sum of the projected net revenue requirement for the following year, plus or minus the True-Up Adjustment (page 1, sum of lines 6c and 6d) from the previous year, if any, including interest as explained above.

[3] MJMEUC does not have any short-term debt, which is the interest rate other SPP transmission owners typically apply to under-recoveries in their true-up calculations. Therefore, MJMEUC proposes to use the One Month Treasure Yield, capped at the Commission refund interest rate, as an equivalent approximation of MJMEUC's short-term debt interest rate costs.

4. MJMEUC may accelerate the refund of any over-recovery amounts by one year. The interest calculation will be adjusted to reflect the period during which the over-recovery exists.

**Example of True-Up of 2022 Net Revenue Requirement:**

Projected net ATRR was $2,100,000.

Actual ATRR (including point-to-point revenue) is $2,000,000.

**True-Up Calculation:**
There is an over-recovery of the net revenue requirement for 2022 equal to $100,000 ($2,100,000 - $2,000,000 = $100,000).
The total True-Up Adjustment amount would be a reduction of $100,000 plus interest on the $100,000 shortfall calculated using the FERC statutory interest rate. This amount would be applied as a decrease to the 2024 projected ATRR beginning January 2024.

Attachment H Addendum 51

People's Electric Cooperative

# People's Electric Cooperative

## INDEX

| A Line No. | B Worksheet | C Description |
|---|---|---|
| | Summary | |
| 1 | ATRR | Summary of Total ATRR Revenue Requirement |
| 2 | Worksheet A | Calculation of Rate Base |
| 3 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 4 | Worksheet C | Capital Structure & Rate of Return based on Return on Equity |
| 5 | Worksheet D | Load |
| 6 | Worksheet E | Allocation Factors |
| 7 | Worksheet F | General Input Section |
| 8 | Worksheet G | Depreciation Rates |
| 9 | Worksheet H | Other Operating Revenue |
| 10 | Worksheet I | O&M Input |
| 11 | Worksheet J | Wage Input & Functionalization |
| 12 | Worksheet K | Annual Depreciation Expense |
| 13 | Worksheet L | RTO / ISO Expenses |
| 14 | Worksheet M | Regulatory and Commission Expenses |
| 15 | Worksheet N | Customer Accounting Input |
| 16 | Worksheet O | Plant Input, Accum Dep, Amortization |
| 17 | Worksheet P | Plant Held for Future Use |
| 18 | Worksheet Q | Construction Completed Not Classified |
| 19 | Worksheet R | Construction Work in Process |
| 20 | Worksheet S | SPP Upgrades |
| 21 | Worksheet T | Reconciliation |
| 22 | Worksheet U | Qualified Transmission Substations |
| 23 | Worksheet V | Qualified Transmission Lines |
| 24 | Notes: | |
| 25 | A. Green Shading denotes input values. | |
| 26 | B. If not already provided for in automatic updates of the cell text references and line references describing the | |
| 27 | source of the values should be updated accordingly. | |

# People's Electric Cooperative

## Summary of Total ATRR Revenue Requirement

| A Line No. | B Account Number | C Description | D Reference | E Total Company | F Allocation Factor | G Allocation % | H Transmission ATRR |
|---|---|---|---|---|---|---|---|
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | |
| 2 | | Transmission Costs | , Line 36, Column H | | | | #DIV/0! |
| 3 | | Revenue Credits- Operating | | | | | |
| 4 | 450-454 | Retail Related | , Line 13, Column F | $ - | Direct Zero | 0.0% | $ - |
| 5 | 454.1-454.15 | Rent from Elec Property and Facilities Charges | , Line 13, Column E | $ - | Direct Zero | 0.0% | $ - |
| 6 | 454.11 | Rents Transmission | , Line 13 Column G | $ - | Direct 100 | 100.0 % | $ - |
| 7 | 456.1 | Other Electric Revenue | , Line 13 Column H | $ - | T-Plant | #DIV/0! | #DIV/0! |
| 8 | 456.0 | Facility Discount | , Line 13 Column I | $ - | Direct Zero | 0.0% | $ - |
| 9 | 456.2 & 456.3 | SPP Wheeling, Sch 7 & 8 | , Line 13 Column J | $ - | Direct 100 | 100.0 % | $ - |
| 10 | 458.0 | Direct Assigned Revenues | , Line 13 Column L | $ - | Direct 100 | 100.0 % | $ - |
| 11 | 459.0 | Renewable Energy Credits | , Line 13 Column M | $ - | Direct Zero | 0.0% | $ - |
| 12 | | Revenue Credits- Operating | Subtotal | $ - | | | #DIV/0! |
| 13 | | Revenue Requirement before SPP Adj and Prior Yr corrections | Line 2 - Line 12 | | | | #DIV/0! |
| 14 | | Reconciliation Adjustment for Prior Period Errors (Gross ATRR) | , Line 6, Column L | | | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 15 | | Reconciliation Adjustment for Prior Period Errors (SPP Upgrades) | - , Line 12, Column L | | | | | $ - |
| 16 | | SPP Upgrades | - , Line 28, Column O | | | | | $ - |
| 17 | 456.4 | Sch 11 P2P Revenue Credits | - , Line 13 Column K | | | | | $ - |
| 18 | | Sum | Sum Lines 13 thru 17 | | | | | #DIV/0! |
| 19 | | Zonal Allocation to Pricing Zone 7 (OGE) | Col H, Line 18 * Col G Line 19 | | | T-Tran Plant--Z7 | #DIV/0! | #DIV/0! |
| 20 | | Zonal Allocation to Pricing Zone 10 (SWPA) | Col H, Line 18 * Col G Line 20 | | | T-Tran Plant--Z10 | #DIV/0! | #DIV/0! |
| 21 | | Zonal Allocation to Pricing Zone 13 (WFEC) | Col H, Line 18 * Col G Line 21 | | | T-Tran Plant--Z13 | #DIV/0! | #DIV/0! |
| 22 | | | | | | | #DIV/0! | #DIV/0! |

## People's Electric Cooperative

Worksheet A

## Calculation of Rate Base

| A Line No. | B Account Number | C Description | D Reference | E Beginning of Year | F End of Year | G Total Company | H Allocation Factor | I ATRR Allocation % | J Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Plant in Service** | | | | | | | |
| 2 | 301 - 303 | Intangible Plant | , Line 38, Columns E and F | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! |
| 3 | | Production Plant | N/A | | | $ | Direct | 0.0 | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 310 - 340 | | | | | - | Zero | % | - |
| 4 | 350 | Land and Land Rights | , Line 164, Columns F and G | $ - | $ - | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 5 | 352 | Structures and Improvements | , Line 164, Columns H and I | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 6 | 353 | Station Equipment - SCADA | , Line 164, Columns J and K | $ - | $ - | $ - | Direct 100 | 100.0% | $ - |
| 7 | 353 | Station Equipment | , Line 164, Columns L and M | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 8 | 354 - 359 | Other Transmission Plant | Line 9 Less Lines 4 thru 7 | $ - | $ - | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 9 | | Transmission Plant | , Line 39, Columns D and E | $ - | $ - | $ - | | | #DIV/0! |
| 10 | 360.00 | Land and Land Rights | , Line 164, Columns P and Q | $ - | $ - | $ - | T-Distb Plant | #DIV/0! | #DIV/0! |
| 11 | 361.00 | Structures and Improvements | , Line 164, Columns R and S | $ - | $ - | $ - | T-Distb Stations | 0.0% | $ - |
| 12 | 362.00 | Station Equipment | , Line 164, Columns T and U | $ - | $ - | $ - | T-Distb Stations | 0.0% | $ - |
| 13 | 364 - 373 | Other Distribution Plant | Line 14 Less Lines 10 thru 12 | $ - | $ - | $ - | Direct Zero | 0.0% | $ - |
| 14 | | Distribution Plant | , Line 35, Columns D and E | $ - | $ - | $ - | | | #DIV/0! |
| 15 | 389 - 399.1 | General Plant Subtotal | , Line 36, Columns D and E | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! |
| 16 | 389 | Headquarters Plant | , Line 37, Columns D | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | -390 | | and E | | | | | | | |
| 17 | | Gross Electric Plant in Service | Subtotal | $ - | $ - | $ - | | | #DIV/0! | |
| 18 | 105 | Electric Plant Held For Future Use | , Line 7, Columns E, F and H | $ - | $ - | $ - | Direct | | | $ - |
| 19 | 106 | Completed Construction Not Classified | , Line 12, Columns E, F, and K | $ - | $ - | $ - | Direct | | | $ - |
| 20 | 107 | Construction Work in Progress | , Line 42, Columns D and E and , Line 18, Column K | $ - | $ - | $ - | Direct | | $ - | |
| 21 | | Utility Plant | Sum | $ - | $ - | $ - | | | #DIV/0! | |
| 22 | | **Accumulated Depreciation** | | | | | | | | |
| 23 | 108.4 | Depr Rsv of Other Prod Plant | , Line 173, Columns X and Y | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | |
| 24 | 108.5 | Accumulated Depreciation of Transmission Stations | , Line 182, Columns D and E | $ - | $ - | $ - | T-Tran Stations | #DIV/0! | #DIV/0! | |
| 25 | 108.5 | Accumulated Depreciation of Transmission SCADA | , Line 183, Columns D and E | $ - | $ - | $ - | Direct 100 | 100.0% | $ - | |
| 26 | 108.5 | Accumulated Depreciation of Transmission Lines | , Line 184, Columns D and E | $ - | $ - | $ - | T-Tran Lines | #DIV/0! | #DIV/0! | |
| 27 | 108.6 | Accumulated Depreciation of Distribution Stations | , Line 186, Columns D and E | $ - | $ - | $ - | T-Distb Stations | 0.0% | $ - | |
| 28 | 108.6 | Accumulated Depreciation of Distribution Plant Other | , Line 187, Columns D and E | $ - | $ - | $ - | Direct Zero | 0.0% | $ - | |
| 29 | 108.7 | Accumulated Depreciation of General Plant | , Line 173, Columns Z and AA | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | |
| 30 | 108.8 | Retirement Work in Progress | , Line 173, Columns AB and AC | $ - | $ - | $ - | T-Wage | #DIV/0! | #DIV/0! | |
| 31 | | Amort of Electric | , Line 173, | $ | $ | $ | T- | #DI | #DIV/0 | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 111 | Plant in Service | Columns AD and AG | - | - | - | | Wage | V/0! | ! |
| 32 | | Total Accumulated Depreciation | Sum | $ - | $ - | $ - | | | | #DIV/0! |
| 33 | | **Total Net Plant in Service** | | | | | | | | |
| 34 | | Net Intangible Plant | Line 2 | $ - | $ - | $ - | | | | #DIV/0! |
| 35 | | Net Production Plant | Line 3 - Line 23 | $ - | $ - | $ - | | | | $ - |
| 36 | | Net Transmission Plant | Line 9 - Line 24 thru 26 | $ - | $ - | $ - | | | | #DIV/0! |
| 37 | | Net Distribution Plant | Line 14 - Line 27 thru 28 | $ - | $ - | $ - | | | | #DIV/0! |
| 38 | | Net General Plant | Line 15 + Line 16 - Line 29 | $ - | $ - | $ - | | | | #DIV/0! |
| 39 | | Net Completed Construction Not Classified | Line 19 | $ - | $ - | $ - | | | | $ - |
| 40 | | Retirement work in progress | - Line 30 | $ - | $ - | $ - | | | | #DIV/0! |
| 41 | | Total Net Plant in Service | Sum | $ - | $ - | $ - | | | | #DIV/0! |
| 42 | | **Adjustments to Rate Base** | | | | | | | | |
| 43 | | Plant Held for Future Use | Line 18 | $ - | $ - | $ - | | | | $ - |
| 44 | | Construction Work in Progress | Line 20 | $ - | $ - | $ - | | Direct | | $ - |
| 45 | | Working Capital | | | | | | | | |
| 46 | | Total Transmission O&M Costs | , Line 24, Columns E and H | | | $ - | | | | #DIV/0! |
| 47 | | Billing Lag in Days | , Line 1 Col F | | | | 45 | | | 45 |
| 48 | | Working Capital | Line 46 * Line 47 / 365 | | | $ - | | | | #DIV/0! |
| 49 | 165 | Prepayments | , Line 27, Columns D and E | $ - | $ - | $ - | | T-Plant | #DIV/0! | #DIV/0! |
| 49 | | Materials and Supplies | , Line 26, Columns D and E | - | - | $ - | | T-Plant | #DIV/0! | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 50 | Rate Base | Total | $ - | | #DIV/0! |

## People's Electric Cooperative

Worksheet B

## O&M, Depreciation, and Return Expenses

| ALine No. | B<br>Account Number | C<br>Description | D<br>Reference | E<br>Total Company | F<br>Allocation Factor | G<br>Allocation % | H<br>Transmission |
|---|---|---|---|---|---|---|---|
| 1 | | **Transmission Expenses** | | | | | |
| 2 | 561 | Load Dispatch Expense | Worksheet I, Line 41 column F | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 3 | 562 | Transmission Station Expenses | Worksheet I, Line 41 columns G, M, and N | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 4 | 563-564, 571-572 | Transmission Line Expenses | Worksheet I, Line 41 columns H, O, and P | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 5 | 565 | Transmission of Electricity by Others | Worksheet I, Line 41 column I | $ - | Direct Zero | 0.0% | $ - |
| 6 | 560, 566-567 | Super, Misc & Rents Transmission Expenses | Worksheet I, Line 41 columns E, J, K, L, and Q | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 7 | 575-576 | Regional Market Expenses | Worksheet L, Line 2 and 4 columns F | $ - | Direct | | $ - |
| 8 | | Transmission O&M | Subtotal | $ - | | | #DIV/0! |
| 9 | 582 | Distribution Expense - Stations Operations | Worksheet I, Line 41 Column T | $ - | T-Distb Stations | 0.0% | $ - |
| 10 | 580-589 | Distribution Expense - Operations All Other | , Line 9, Column E Less Line 9 | $ - | Direct Zero | 0.0% | $ - |
| 11 | 591-592 | Distribution Expense - Stations Maintenance | Worksheet I, Line 41 Column V | $ - | T-Distb Stations | 0.0% | $ - |
| 11 | 590- | Distribution Expense - | , Line 10, Column E | $ | Direct | 0.0 | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2 | 598 | Maintenance All Other | Less Line 11 | - | Zero | % | - |
| 1 | | | | $ | | | $ |
| 3 | | Distribution O&M | Subtotal | - | | | - |
| 1 | 901- | | , Line 11, Column E | $ | T-Wage | #DIV/0! | #DIV/0! |
| 4 | 905 | Customer Accounting | - Line 15 | - | | | |
| 1 | 901- | Customer Accounting | | $ | | | $ |
| 5 | 905 | SPP Expenses | , Line 8, Column E | - | Direct | | - |
| 1 | 907- | Customer Services & | | $ | Direct | 0.0 | $ |
| 6 | 910 | Information | , Line 12, Column E | - | Zero | % | - |
| 1 | 911- | | | $ | Direct | 0.0 | $ |
| 7 | 916 | Sales | , Line 13, Column E | - | Zero | % | - |
| 1 | | Customer Related | | $ | | | #DIV/0! |
| 8 | | Expense | Subtotal | - | | | |
| 1 | | Administrative & | | | | | |
| 9 | | General Expense | | | | | |
| 2 | 920- | Admin and General | , Line 14, Column E | $ | T-Wage | #DIV/0! | #DIV/0! |
| 0 | 931 | Operations Expense | - lines 21 and 22 | - | | | |
| 2 | | SPP Commission and | | $ | Direct | 100. | $ |
| 1 | 928 | Regulatory Expenses | , Line 7, Column F | - | 100 | 0% | - |
| 2 | | Non-SPP Commission | | | | | |
| 2 | 928 | and Regulatory | | $ | Direct | 0.0 | $ |
| | | Expenses | , Line 7, Column E | - | Zero | % | - |
| 2 | | | | $ | | | |
| 3 | | Total A&G Expenses | Subtotal | - | | | #DIV/0! |
| 2 | | | Line 8 + Line 13 + | $ | | | |
| 4 | | Subtotal O&M | Line 18 + Line 23 | - | | | #DIV/0! |
| 2 | | | | | | | |
| 5 | | Depreciation Expense | | | | | |
| 2 | | Depreciation Expense- | | $ | Direct | 0.0 | $ |
| 6 | 403 | Production | , Line 7, Col E | - | Zero | % | - |
| 2 | | Depreciation Expense- | | $ | T-Tran | #DI | |
| 7 | 403 | Transmission Plant | , Line 7, Col F | - | Plant | V/0! | #DIV/0! |
| 2 | | Depreciation Expense- | | $ | Direct | 0.0 | $ |
| 8 | 403 | Distribution | , Line 7, Col G | - | Zero | % | - |
| 2 | | Depreciation Expense- | | $ | T-Wage | #DI | |
| 9 | 403 | General | , Line 7, Col H | - | | V/0! | #DIV/0! |
| 3 | | Unrecovered Plant | | $ | Direct | 100. | $ |
| 0 | 405 | Expense (Note A) | , Line 7, Col K | - | 100 | 0% | - |
| 3 | | Accretion Expense - | | $ | Direct | 0.0 | $ |
| 1 | 411.1 | Plant Retirement | , Line 7, Col J | - | Zero | % | - |
| 3 | | Amortization of | | $ | T-Wage | #DI | |
| 2 | 407 | Intangible Plant | , Line 7, Col I | - | | V/0! | #DIV/0! |
| 3 | | Total Depreciation & | | $ | | | |
| 3 | | Amortization | sum lines 26 thru 32 | - | | | #DIV/0! |
| 3 | | Electric Generation, | | $ | | #DI | |
| 4 | | Distribution, and | , Line 17, Column E | - | T-Tax | V/0! | #DIV/0! |

| | | | |
|---|---|---|---|
| | Transmission Taxes | | |
| 35 | Return | , Line 6, Column J | #DIV/0! |
| 36 | Revenue Requirement | Line 24 + Line 33 + Line 34 + Line 35 | #DIV/0! |

37 Notes:

38 A. Any unrecovered plant expense are associated with the contribution in aid of construction. No amounts should be included on this line absent specific FERC approval.

Worksheet C

## People's Electric Cooperative

## Capital Structure & Rate of Return based on Return on Equity

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line No | Description | Reference | Total Co EoY | Actual Cap Str Weight (A) | Minimum Proxy Equity (A) | Applied Cap Str (B) | Interest Expense | Cost of Capital (C) | Weighted Rate of Return (D) |
| 1 | **Capital Structure & Return** | | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Lines , 29, 30, 31, 32 and 33, Col E and Line 19, Col E | $ - | #DIV/0! | 64.76% | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | Total Margins and Equities | Worksheet F, Line 28, Col E | $ - | #DIV/0! | 35.24% | #DIV/0! | | 10.93% | #DIV/0! |
| 4 | Total Capitalization | Subtotal | $ - | #DIV/0! | 100.00% | #DIV/0! | $ - | | #DIV/0! |

| | | | |
|---|---|---|---|
| 5 | Rate Base | Worksheet A, Line 50, Column J | #DI V/0! |
| 6 | Return | Line 4 * Line 5 | #DI V/0! |

7 Notes:

8 A.) The capital structure listed in Column (E) is calculated based on total capitalization amounts listed in Column (D). The capital structures listed in Column (F) are fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing.

9 B.) In the case where PEC's actual capital structure (Column (E)) contains a Total Margins and Equities percentage greater than 35.24%, Column (G) should be populated with the actual capital structure. In the case where PEC's actual Margins and Equities percentage is below 35.24 percent, Column (G) should be populated with the capital structure listed in Column (F).

10 C.) The Cost of Capital for Total Margins and Equities (ROE) is fixed and cannot be modified or deleted absent authorization from FERC via a Section 205 or 206 filing. The Cost of Capital for Total Margins and Equities reflects a 50 basis point incentive adder for RTO participation. The Cost of Capital for Long Term Debt is calculated by dividing the interest expense in Column (H) by the total amount in Column (D).

11 D.) Column (J) values for lines 2-3 equal Column (G) values multiplied by Column (I) values.

## People's Electric Cooperative

Worksheet D

## Load

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| Line No | Description | TOTAL Load (MW) D + E + F | Zone 7 (OGE) Load (MW) | Zone 10 (SWPA) Load (MW) | Zone 13 (WFEC) Load (MW) |
| 1 | January | 0.0 | | | |
| 2 | February | 0.0 | | | |
| 3 | March | 0.0 | | | |
| 4 | April | 0.0 | | | |
| 5 | May | 0.0 | | | |
| 6 | June | 0.0 | | | |
| 7 | July | 0.0 | | | |
| 8 | August | 0.0 | | | |
| 9 | September | 0.0 | | | |
| 10 | October | 0.0 | | | |
| 11 | November | 0.0 | | | |

| | | | | | |
|---|---|---|---|---|---|
| 12 | December | 0.0 | | | |
| 13 | Total (MW-Mo) | 0.0 | 0.0 | 0.0 | 0.0 |
| 14 | Average (MW-Mo) | **0.0** | **0.0** | **0.0** | **0.0** |

## People's Electric Cooperative

Worksheet E

## Allocation Factors

| A Line No. | B Description | C Reference | D Total | E Allocation Factor Name | F Allocation Factor % | G ATRR Allocated |
|---|---|---|---|---|---|---|
| 1 | Production Wages | , Line 41, Column E | $ - | Direct Zero | 0.0% | $ - |
| 2 | Transmission Supervision Operations | , Line 41, Column F | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 3 | Transmission Load Dispatch and Scheduling | , Line 41, Column G | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 4 | Transmission Station Operations | , Line 41, Column H | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 5 | Transmission Line Operations | , Line 41, Column I | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 6 | Transmission of Elect by Others | , Line 41, Column J | $ - | Direct Zero | 0.0% | $ - |
| 7 | Transmission Misc | , Line 41, Column K | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 8 | Transmission Supervision Maintenance | , Line 41, Column L | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 9 | Transmission Station Maintenance | , Line 41, Column M | $ - | T-Tran Stations | #DIV/0! | #DIV/0! |
| 10 | Transmission Line Maintenance | , Line 41, Column N | $ - | T-Tran Lines | #DIV/0! | #DIV/0! |
| 11 | Transmission Maintenance - Misc | , Line 41, Column O | $ - | T-Tran Plant | #DIV/0! | #DIV/0! |
| 12 | Distribution Operations-Stations | , Line 41, Column P | $ - | T-Distb Stations | 0.0% | $ - |
| 13 | Distribution Operations-All Other | , Line 41, Column Q | $ - | Direct Zero | 0.0% | $ - |
| 14 | Distribution Maintenance-Stations | , Line 41, Column R | $ - | T-Distb Stations | 0.0% | $ - |
| 15 | Distribution Maintenance-All Other | , Line 41, Column S | $ - | Direct Zero | 0.0% | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 16 | Customer Accounts Less meter reading | , Line 41, Column U | $ - | Direct Zero | 0.0% | $ - | |
| 17 | Customer Accounts Meter Reading | , Line 41, Column T | $ - | Direct 100 | 100.0 % | $ - | |
| 18 | Customer Service | , Line 41, Column V | $ - | Direct Zero | 0.0% | $ - | |
| 19 | Sales | , Line 41, Column W | $ - | Direct Zero | 0.0% | $ - | |
| 20 | Total Wages, Excluding A&G | Sum Lines 1 thru 19 | $ - | | | | #DIV/0! |
| 21 | **T-Wage** | | | | | | **#DIV/0!** |
| 22 | 353 Transmission Stations Gross Plant | Line 7, Column G | $ - | Direct WS-U | | $ - | |
| 23 | **T-Tran Stations** | | | | | | **#DIV/0!** |
| 24 | 362 Distribution Stations Gross Plant | Line 12, Column G | $ - | Direct WS-U | | | |
| 25 | **T-Distb Stations** | | | | | | **0.0%** |
| 26 | 354-359.1Transmission Lines Gross Plant | Line 8, Column G | $ - | Direct WS-V | | $ - | |
| 27 | **T-Tran Lines** | | | | | | **#DIV/0!** |
| 28 | Transmission Qualifying Plant | , Lines 4 thru 8, Column G | $ - | | | $ - | |
| 29 | **T-Tran Plant** | | | | | | **#DIV/0!** |
| 30 | Distribution Qualifying Plant | , Lines 11 thru 13, Column G | $ - | | | $ - | |
| 31 | **T-Distb Plant** | | | | | | **#DIV/0!** |
| 30 | Plant in Service | Line 17, Column G | $ - | | | | #DIV/0! |
| 31 | **T-Plant** | | | | | | **#DIV/0!** |
| 32 | Zone 7 Transmission Qualifying Plant | Column G, Line 28 | $ - | | | $ - | |
| 33 | **T-Tran Plant--Z7** | | | | | | **#DIV/0!** |
| 34 | Zone 10 Transmission Qualifying Plant | Column G, Line 28 | $ - | | | $ - | |
| 35 | **T-Tran Plant--Z10** | | | | | | **#DIV/0!** |
| 36 | Zone 13 Transmission Qualifying Plant | Column G, Line 28 | $ - | | | $ - | |
| 37 | **T-Tran Plant--Z13** | | | | | | **#DIV/0!** |

| | | | |
|---|---|---|---|
| 38 | **Direct Zero** | Fixed allocation | **0.0%** |
| 39 | **Direct 100** | Fixed allocation | **100.0%** |
| 40 | SPP Trans. as % of Total Company Trans. + Dist. | , Lines 9 and 14, Col. G and J | $ - #DIV/0! |
| 41 | **T-Tax** | | **#DIV/0!** |

## People's Electric Cooperative

Worksheet F

## General Input Section

| A Line No. | B Description | C Reference | D BoY | E EoY | F End of Year Value or Amount |
|---|---|---|---|---|---|
| 1 | Billing Lag in days | Industry Standard | | | 45 |
| 2 | CWIP included in Rate Base | Per ER21-___ | | | 50% |
| 3 | Fiscal Year | | | | |
| 4 | Operating Revenue and Patronage Capital | Form 7, Part A, Line 1, Column B | | | |
| 5 | Power Production Expense | Form 7, Part A, Line 2, Column B | | | |
| 6 | Cost of Purchased Power | Form 7, Part A, Line 3, Column B | | | |
| 7 | Transmission Expense | Form 7, Part A, Line 4, Column B | | | |
| 8 | Regional Market Operations Expense | Form 7, Part A, Line 5, Column B | | | |
| 9 | Distribution Expense-Operation | Form 7, Part A, Line 6, Column B | | | |
| 10 | Distribution Expense-Maintenance | Form 7, Part A, Line 7, Column B | | | |
| 11 | Customer Account Expense | Form 7, Part A, Line 8, Column B | | | |
| 12 | Customer Sales and Informational Expense | Form 7, Part A, Line 9, Column B | | | |
| 13 | Sales Expense | Form 7, Part A, Line 10, Column B | | | |
| 14 | Administrative and General Expense | Form 7, Part A, Line 11, Column B | | | |

| | | | | |
|---|---|---|---|---|
| 15 | Subtotal-Operations & Maintenance Expense | Sum Lines 5 thru 14 | $ - | $ - |
| 16 | Depreciation and Amortization Expense | Form 7, Part A, Line 13, Column B | | |
| 17 | Electric Generation, Dist., and Trans. Taxes | Form 7, Part A, Line 14, Column B | | |
| 18 | Tax Expense - Other | Form 7, Part A, Line 15, Column B | | |
| 19 | Interest on Long Term Debt | Form 7, Part A, Line 16, Column B | | |
| 20 | Interest Charged to Construction (Credit) | Form 7, Part A, Line 17, Column B | | |
| 21 | Other Interest Expense | Form 7, Part A, Line 18, Column B | | |
| 22 | Other Deductions | Form 7, Part A, Line 19, Column B | | |
| 23 | Subtotal Cost of Electric Service | Sum Lines 15 and 16 thru 22 | $ - | $ - |
| 24 | Patronage Capital and Operating Margins | Line 4 - Line 23 | $ - | $ - |

| | | | BoY | EoY | Average |
|---|---|---|---|---|---|
| 26 | Materials and Supplies | Form 7, Part C, Line 23 (Prior year & current) | | | $ - |
| 27 | Prepayments | Form 7, Part C, Line 24 (Prior year & current) | | | $ - |

| | | | BoY | EoY |
|---|---|---|---|---|
| 28 | Total Margins and Equities | Form 7, Part C, Line 35 | | |
| 29 | Total Long Term Debt | Form 7, Part C, Line 38 | | |
| 30 | Obligations Under Capital Leases - Noncurrent | Form 7, Part C, Line 39 | | |
| 31 | Current Maturities Long-Term Debt | Form 7, Part C, Line 45 | | |
| 32 | Current Maturities Long-Term Debt - Economic Development | Form 7, Part C, Line 46 | | |
| 33 | Current Maturities Capital Leases | Form 7, Part C, Line 47 | | |

| | | | BoY | EoY | Average |
|---|---|---|---|---|---|
| 34 | Plant in Service | | | | |
| 35 | Total Distribution Plant | Form 7, Part E, Line 1, Cols A and E | | | $ - |
| 36 | General Plant | Form 7, Part E, Line 2, Cols A and E | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 3 | | Form 7, Part E, Line 3, | | | $ |
| 7 | Headquarters Plant | Cols A and E | | | - |
| 3 | | Form 7, Part E, Line 4, | | | $ |
| 8 | 301-303 Total Intangible Plant | Cols A and E | | | - |
| 3 | | Form 7, Part E, Line 5, | | | $ |
| 9 | Transmission Plant | Cols A and E | | | - |
| 4 | | Form 7, Part E, Line 6, | | | $ |
| 0 | 380-386 RTO/ISO Plant | Cols A and E | | | - |
| 4 | | Form 7, Part E, Line | | | $ |
| 1 | All Other Utility Plant | 11, Cols A and E | | | - |
| 4 | | Form 7, Part E, Line | | | $ |
| 2 | Construction Work in Progress | 13, Cols A and E | | | - |
| 4 | | Subtotal | $ | $ | $ |
| 3 | Plant in Service | | - | - | - |

4
4 Notes:
4 A. Acquisition adjustments will not be used in the calculation of
5 ATRR absent Commission approval through a 205 or 206 filing.
4 B. The addition of new lines and the removal of outdated lines may
6 be necessary in order to accurately provide
4 information, and populate or remove data in the Worksheet with
7 changes in future years. Where appropriate, these
4 changes will provide detail and linkage to updated
8 Form 7 data requirements or other similar supporting
4 documentation. Additional line items or line deletions will not
9 require FPA Section 205 or 206 filings. PEC will
5 describe such changes in the Annual Update, and the changes
0 will be subject to the review of Interested Parties under
5 the procedures set forth in PECs's Implementation Protocols.
1 PEC may not change the columns or the formulas
included in these
5 Worksheets during the Annual
2 Update.

## People's Electric Cooperative

Worksheet G

## Depreciation Rates

| A | B | C | D |
|---|---|---|---|
| **Line No** | **Description** | **Plant Account Number** | **Annual Depr Rate** |
| 1 | Transmission: | | |
| 2 | Land and Land rights | 350.00 | N/A |

| | | | |
|---|---|---|---|
| 3 | Structures & Improvements | 352.00 | 3.108% |
| 4 | Transmission Station Equipment | 353.00 | 3.108% |
| 5 | Poles and Fixtures | 355.00 | 3.108% |
| 6 | Overhead Conductors and devices | 356.00 | 3.108% |
| 7 | Underground Conductors and Devices | 358.00 | 3.108% |
| 8 | | | |
| 9 | Distribution: | | |
| 10 | Land and Land rights | 360 | N/A |
| 11 | Structures & Improvements | 361 | 3.108% |
| 12 | Distribution Station Equipment | 362 | 12.000% |
| 13 | Poles, Towers & Fixtures | 364 | 3.108% |
| 14 | Overhead Conductor & Devices | 365 | 3.108% |
| 15 | Undergound Conduit | 367 | 3.108% |
| 16 | Line Transformers | 368 | 3.108% |
| 17 | Services | 369 | 3.108% |
| 18 | Meters | 370 | 3.108% |
| 19 | Instal on Cust Premises | 371 | 3.108% |
| 20 | Street Lighting and Signal | 373 | 3.108% |
| 21 | | | |
| 22 | General: | | |
| 23 | Structures & Improvements | 390 | 3.108% |
| 24 | Transportation Equip | 392 | 20.000% |
| 25 | Power Operated Equip | 396 | 20.000% |
| 26 | Other Tangible SCADA | 399 | N/A |
| 27 | | | |
| 28 | Note: | | |
| 29 | A. Stated Values in Column D are fixed and cannot be changed absent Commission approval through | | |
| 30 | a Section 205 or 206 filing. | | |

## People's Electric Cooperative

Workshe et H

## Other Operating Revenue

| A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|

| Line No. | Account No | Account Description | Total Company | Electric Plant, Leased 454.1-454.15 | Retail Related 450-454 | Rents Transmission 454.11 | Other Electric Revenue 456.1 | Facility Discount 456 | Sch 7 & 8 P2 P456.2-456.3 | Sch 11 P2 P456.4 | Direct Assigned Revenues 458 | Renewable Energy Credits 459 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | |
| 8 | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | |
| | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 13 | | Total | - | - | - | - | - | - | - | - | - | - |
| 14 | | | | | | | | | | | | |
| 15 | Note: | | | | | | | | | | | |
| | A. The addition of new lines and the removal of outdated lines may be necessary in order to | | | | | | | | | | | |
| 16 | accurately provide | | | | | | | | | | | |
| | information, and populate or remove data in the Worksheet with changes in future years. Where | | | | | | | | | | | |
| 17 | appropriate, these | | | | | | | | | | | |
| | changes will provide detail and linkage to updated Form 7 data requirements or other | | | | | | | | | | | |
| 18 | similar supporting | | | | | | | | | | | |
| | documentation. Additional line items or line deletions will not require FPA Section 205 or 206 | | | | | | | | | | | |
| 19 | filings. PEC will | | | | | | | | | | | |
| | describe such changes in the Annual Update, and the changes will be subject to the review of Interested | | | | | | | | | | | |
| 20 | Parties under | | | | | | | | | | | |
| | the procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the | | | | | | | | | | | |
| 21 | formulas | | | | | | | | | | | |
| | included in these Worksheets during the | | | | | | | | | | | |
| 22 | Annual Update. | | | | | | | | | | | |
| | B. The total amount shown for Column D must match | | | | | | | | | | | |
| 26 | the amount shown in PECs's RUS Form No. 7 for | | | | | | | | | | | |

Other Revenues.

**People's Electric Cooperative**

**O&M Input**

Worksheet I

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | 568-Supervision and Engineering | | | | | | | | | 580-589 Distribution Operations | | 590-598 Distribution Maintenance |
| | | | | | | | | 565-Transmission of Elec. By Others | 566-Miscellaneous Expenses | | | 569-Structures | 570-Station Equipment | | | 573-Misc Transmission Plant | | | 582 Distribution Station Operations | All Other Expenses | 591-592 Distribution Station Maintenance | All Other Expenses |
| Line No. | Account | Description | Balance | 560-Supervision & Engr. | 561-Load Dispatching | 562-Station Expenses | 563-OH Line Expenses | | | 567-Rents | | | | 571-OH Lines | 572-UG Lines | | 575.1-575.8 | 576.1-576.5 | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures

set forth in PEC's Implementation Protocols.

Worksheet J

**People's Electric Cooperative**

**Wage Input & Functionalization**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Account Description | Labor Total Company | 555 Purchased Power | 560 Tran Ops Super-Wages | 561 Load Dispatch | 562 Trans Stations | 563-564 OH&UG Line Expense | 565 Tran of Elect by Others | 566 Misc-Wages | 568 Maint-Supervision and E | 569-570 Str Maint-Wages | 571 Maint-OH Lines | 573 Maint-Misc Tran Plant | 582 Dist b Station Ops Exp | 580-589 Dist Operation | 591-592 Dist b Station Maint E | 590-598 Dist Maint | 902 Meter Reading-Wages | 901, 903-905 Cust Acct-Wages | 907-910 Cust Service-Wages | 911-916 Cust Sales-Wages | 920-932 Admin & General |

| | | n g i n e e r i n g | x p |
|---|---|---|---|
| 1 | | | |
| 2 | | | |
| 3 | | | |
| 4 | | | |
| 5 | | | |
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| 21 | | | |
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| 23 | | | |
| 24 | | | |
| 25 | | | |
| 26 | | | |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 41 | Totals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

42 Note:
A. The addition of new lines and the removal of outdated lines may be
43 necessary in order to accurately provide information, and populate or remove data in the Worksheet with
44 changes in future years.
44 Where appropriate, these changes will
45 provide detail and linkage to updated

Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

## People's Electric Cooperative

Worksheet K

## Annual Depreciation Expense

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Account | Description | Year End Balance | Production | Transmission | Distribution Expense | General | Amort | Plant Retirement | Unrecovered Plant Expense |
| 1 | | | | | | | | | | |
| 2 | | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| | Totals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

7

8

Note:

9 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

## People's Electric Cooperative

Worksheet L

## RTO / ISO Expenses

| A<br>Line | B<br>Account No. | C<br>Description | D<br>Annual Expense Amount | E<br>% Included in SPP | F<br>SPP Amount |
|---|---|---|---|---|---|
| | **575.1-575.8 RTO/ISO Expense - Operation** | | | | |
| 1a | | | $0.00 | 100% | $0.00 |
| 1b | | | $0.00 | 100% | $0.00 |
| … | | | $0.00 | 100% | $0.00 |
| 2 | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)** | | $0.00 | | $0.00 |

| | | | | |
|---|---|---|---|---|
| | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | |
| 3a | | $0.00 | 100% | $0.00 |
| 3b | | $0.00 | 100% | $0.00 |
| … | | $0.00 | 100% | $0.00 |
| 4 | **576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)** | $0.00 | | $0.00 |

5 Notes
A. The total on line 2, column D must reconcile to
6 the amounts shown on Form 7.
B. The total on line 4, column D must reconcile to
7 the amounts shown on Form 7.
C. Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for
8 inclusion in SPP Zone 19 ATRR following a change in
accounting procedures to the Form 7 or Uniform System of
9 Accounts, which would classify amounts in these accounts
as eligible for transmission rate recovery. To the extent that this
10 occurs, PEC may file a single-issue Section 205 filing with the
Commission to seek recovery of these amounts in Zone 19 rates. PEC may not include any
11 costs absent authorization from FERC via a Section 205 or 206 filing.
D. The addition of new lines and the removal of outdated lines necessary to populate or
12 remove data in the Worksheet with the changes in future years does not
require a Federal Power Act section 205 or 206 filing. The addition or removal of columns
13 and formulas contained with those columns cannot be changed absent a
14 Federal Power Act section 205 or 206 filing.

## People's Electric Cooperative

Workshe
et M

## Regulatory and Commission Expenses (A928)

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line No.** | **Account 928** | **Description** | **Total Company** | **Non-Qualifying SPP Expenses** | **SPP Expenses** |
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |

| | | | | |
|---|---|---|---|---|
| 5 | | | | |
| 6 | | | | |
| | Total | $ | $ | $ |
| 7 | | - | - | - |

8 Note:
A. The addition of new lines and the removal of outdated lines may be necessary in
9 order to accurately provide
information, and populate or remove data in the Worksheet with changes in future years.
10 Where appropriate, these
changes will provide detail and linkage to updated Form 7 data requirements or
11 other similar supporting
documentation. Additional line items or line deletions will not require FPA
12 Section 205 or 206 filings. PEC will
describe such changes in the Annual Update, and the changes will be subject to the review
13 of Interested Parties under
the procedures set forth in PEC's Implementation Protocols. PEC may not
14 change the columns or
the formulas included in these Worksheets during the
15 Annual Update.

## People's Electric Cooperative

Work sheet N

## Customer Accounting Input

| A<br>Line No. | B<br>Account | C<br>Description | D<br>Total Company | E<br>901-905 SPP Expenses |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| | | Total Customer | $ | $ |
| 8 | | Accounting | - | - |

9

Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.

with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting

documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require

FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the

procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the

Annual Update.

**People's Electric Cooperative**

**Plant Input, Accum Dep, Amortization**

Worksheet O

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y | Z | AA | AB | AC | AD | AG |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Description | Balance BO | Balance EO | 350 Tran L | 350 Tran L | 352 Tran S | 352 Tran S | 353 Tran S | 353 Tran S | 353 Tran S | 353 Tran S | 355-358 Tra | 355-358 Tr | 360 Distb | 360 Distb | 361 Struct | 361 Struct | 362 Distri | 362 Distri | 363-373 Ot | 363-373 Ot | 108 Genera | 108 Genera | 108 General | 108 Genera | 108.8 RWIP | 108.8 RWIP | 111 Amorto | 111 Amorto |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Y | Y | and BOY | and EOY | tructure BOY | tructure EOY | tation SCADA BOY | tation SCADA EOY | tation BOY | tation EOY | n Lines BOY | an Lines EOY | Land & Rights BOY | Land & Rights EOY | ures & Improvements BOY | ures & Improvements EOY | b Station Equipment BOY | b Station Equipment EOY | herDistribtion BOY | herDistribtion EOY | tors BOY | tors EOY | Plant BOY | lPlant EOY | BOY | EOY | fElec.Plantin Serv BOY | fElec.Plantin Serv EOY |
| 1 | Gross Plant | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
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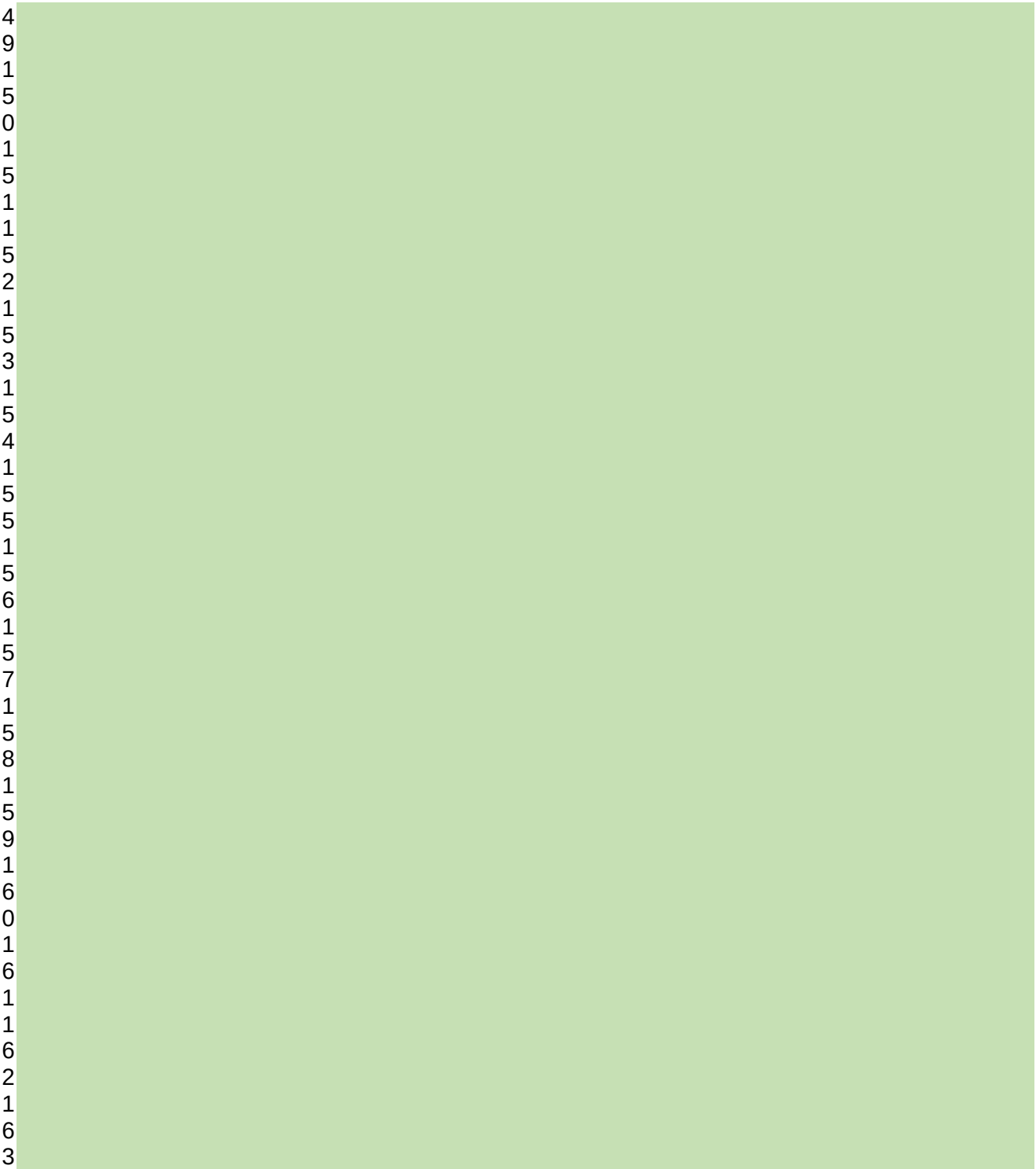

| | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 164 | Total Gross Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 165 | **Accumulated Depreciation Reserves** | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 166 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 167 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
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| 171 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 172 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 173 | Total Accumulated Depreciation Reserves | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 174 | **Transmission** | Bal a | Bal a | Ave r | | | | | | | | | | | | | | | | | | | | | | | | |

| | | nce - BOY | nce - EOY | age |
|---|---|---|---|---|
| | **Plant Functionalization** | | | |
| 175 | 350-353 Transmission Stations | $ - | $ - | $ - |
| 176 | 352-353 Transmission Stations SCADA | $ - | $ - | $ - |
| 177 | 354-359.1 Other Transmission Plant (Lines) | $ - | $ - | $ - |
| | **Distribution Plant Functionalization** | | | |
| 179 | 360-362 Distribution | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | Stations 364-373 Distribution | | | |
| 180 | All Other | $ - | $ - | $ - |
| | | | | |
| 181 | **Transmission Depreciation Functionalization** 108.5 Accumulated Depreciation Reserves - Transmission | | | |
| 182 | Stations 108.5 Accumulated Depreciation | $ - | $ - | $ - |
| 183 | | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | Reserves - Transmission SCADA 108.5 Accumulated Depreciation Reserves - Transmission | | | |
| 184 | Lines | $ - | $ - | $ - |
| | | | | |
| 185 | **Distribution Depreciation Functionalization** 108.5 Accumulated Depreciation | | | |
| 186 | Reserves - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | Distribution Stations 108.5 Accumulated Depreciation Reserves - Distribution | | | |
| 187 | All Other | $ - | $ - | $ - |

Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and

linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

## People's Electric Cooperative

Worksheet P

# Plant Held for Future Use

| A<br>Line No | B<br>Facility No. | C<br>Asset No. | D<br>Description | E<br>BoY Investment | F<br>EOY Investment | G<br>Average Investment | H<br>Qualified |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | Transmission Qualified Future Use Assets | | | | |
| 3 | | | | | | $ - | $ - |
| 4 | | | | | | $ - | |
| 5 | | | | | | $ - | |
| 6 | | | | | | $ - | |
| 7 | | | Total Plant Held for Future Use | $ - | $ - | $ - | $ - |

8 Note:

9 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet.

10 with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting

11 documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA

12 Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures

13 set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

## People's Electric Cooperative

Worksheet Q

# Construction Completed Not Classified

| A<br>Line No. | B<br>Fac ID | C<br>Work Order | D<br>Project | E<br>BoY Balance | F<br>EoY Balance | G<br>Facility | H<br>% SPP Eligible | I<br>BoY Amount | J<br>EoY Amount | K<br>Average | L<br>Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | $ - | $ - | $ - | |
| 2 | | | | | | | | $ - | $ - | $ - | |
| 3 | | | | | | | | $ - | $ - | $ - | |
| 4 | | | | | | | | $ - | $ - | $ - | |
| 5 | | | | | | | | $ - | $ - | $ - | |
| 6 | | | | | | | | $ - | $ - | $ - | |
| 7 | | | | | | | | $ - | $ - | $ - | |
| 8 | | | | | | | | $ - | $ - | $ - | |
| 9 | | | | | | | | $ - | $ - | $ - | |
| 10 | | | | | | | | $ - | $ - | $ - | |
| 11 | | | | | | | | $ - | $ - | $ - | |
| 12 | | | Total | $ - | $ - | | | $ - | $ - | $ - | |

13 Note:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the
14 Worksheet.
with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other
15 similar supporting
documentation. Additional linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will
16 not require FPA
Section 205 or 206 filings. PEC will describe such changes in the Annual
17 Update, and the changes will be subject to the review of Interested Parties under

the procedures
set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the Annual
18 Update.

## People's Electric Cooperative

Worksheet R

## Construction Work in Process

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project ID | Project Description | Approval Docket No. | Recovery Approved | Approximate Construction Start Date | Close-out Date (Estimated) | BoY Balance | EoY Balance | Average Balance (Col H + I) /2 | Includable in SPP ATRR Rate Base (Col E * Col J) |
| 1 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 2 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 3 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 4 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 5 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 6 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 7 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 8 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 9 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 10 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |
| 11 | | | Per ERxx-xxx | 50% | | | | | $ - | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | | Per ERxx-xxx | 50% | | $ - | $ - |
| 2 | | | | | | |
| 1 | | Per ERxx-xxx | 50% | | $ - | $ - |
| 3 | | | | | | |
| 1 | | Per ERxx-xxx | 50% | | $ - | $ - |
| 4 | | | | | | |
| 1 | | Per ERxx-xxx | 50% | | $ - | $ - |
| 5 | | | | | | |
| 1 | | Per ERxx-xxx | 50% | | $ - | $ - |
| 6 | | | | | | |
| 1 | | Per ERxx-xxx | 50% | | $ - | $ - |
| 7 | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 1 | **Totals** | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | | | | | |
| 1 | | | | | |
| 9 | | | | | |

2 0 Notes:

A. Percentage of "Recovery Approved" cannot be added or changed absent approval from FERC.

B. AFUDC ceases when CWIP is recovered in rate base corresponding to the amount of CWIP included in Rate Base. No CWIP will be included in rate base absent FERC authorization.

Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized. Projects are transmission related only.

C. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation.

Additional line items will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheet during the Annual Update.

# People's Electric Cooperative

Worksheets

## SPP Upgrades

| A | B | C | D |
|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Company Total Transmission Amount** |
| 1 | Gross Qualified Transmission Plant | , Line 9, Column J | $ - |
| 2 | Accumulated Qualified Transmission Depreciation | , Lines 24 thru 26, Column J | $ - |
| 3 | Net Transmission Plant | Line 1 - Line 2 | $ - |
| 4 | Transmission O&M | , Line 8, Column H | $ - |
| 5 | **Annual Allocation Factor for Transmission O&M** | Line 4 / Line 1 | 0.00% |
| 6 | General Plant | , Line 29, | $ - |

| | | | |
|---|---|---|---|
| | Depreciation Expense | Column H | |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | Line 6 / Line 1 | 0.00% |
| 8 | Return on Rate Base | , Line 35, Column H | $ - |
| 9 | **Annual Allocation Factor for Return** | Line 8 / Line 3 | 0.00% |
| 10 | **Depreciation Rates** | | |
| 11 | Sub | , Line 4 Col D | 3.11% |
| 12 | Line | , Line 5 Col D | 3.11% |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project Name and #** | **Type** | **Project Gross** | **Project Accumulated Depreciatio** | **Transmission O&M Annual Allocation Factor** | **Allocation for Transmi** | **General Plant Depreciation Annual Allocatio** | **Allocation for General Plant Depreciation** | **Annual Expense Charge** | **Project Net Pl** | **Annual Allocation Factor for Return** | **Annual Return Charg** | **Project Depreciation and Amortization Expense** | **Project ATR** |

| | | | Plant | n | ssi on O& M | n Fac tor | | an t | | e | | R |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Note A | | Lin e 5, Col D | Col D * Col F | Lin e 7, Col D | Col D * Col H | Col G + Co l I | Col D - Col E (N ot e B) | Lin e 9, Co l D | Col K * Col L | Not e C | Col J + Col M + Col N |
| 13 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 14 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 15 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 16 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 17 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 18 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 19 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 20 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 21 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 22 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 23 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 24 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 25 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 26 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 27 | | | | | 0.00% | $ - | 0.00% | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - |
| 28 | Total | | | | | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |

2 Notes:

A. Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1.

This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

B. Net Plant is the Gross Plant less the associated Accumulated Depreciation.

C. Depreciation Expense is the depreciation amount associated with the specified line or sub.

Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties

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## People's Electric Cooperative

Worksheet T

## Reconciliation

**Adjustments To ATRR Due To Error Corrections**

| Line | A ERROR IDENTIFICATION | B Formula Reference | C Rate Year (A) | D Incorrect Amount | E Correct Amount | F Difference (Cred)/ Chg | G Impact on ATRR (Cred)/ Chg | H Calculated Interest (B) | I Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | $ - |
| 2 | | | | | | | | | $ - |
| 3 | | | | | | | | | $ - |
| 4 | | | | | | | | | $ - |
| 5 | | | | | | | | | $ - |

| | | |
|---|---|---|
| 6 | **Total Adjustment to Gross ATRR:** | $ - |

**Adjustments To SPP Regional Projects' ATRR Due To Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/ Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | | | | $ - |
| 8 | | | | | | | | | $ - |
| 9 | | | | | | | | | $ - |
| 10 | | | | | | | | | $ - |
| 11 | | | | | | | | | $ - |
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | | | | | | | | $ - |

13 Notes:
A. Rate Year in which the error occurred and
14 affected the ATRR and rates paid by customers.
B. Each ATRR adjustment shall include Interest to be calculated at the lesser of PEC's short
15 term debt costs or the amount calculated pursuant to 18 C.F.R. § 35.19a

| | Period Start | Period Ending | Year description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance |
|---|---|---|---|---|---|---|---|---|
| 16 | | | | | | | | |

**Interest calculation for Item #1**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 17 | | | Rate Year | $ - | $ - | | $ - | $ - |
| 18 | | | Rate | $ | $ | | $ | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Year | - | - | | - | - |
| | | Rate | $ | $ | | $ | $ |
| 19 | | Year | - | - | | - | - |
| | | Rate | $ | $ | | $ | $ |
| 20 | | Year | - | - | | - | - |
| | | | $ | | | $ | $ |
| 21 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 22 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 23 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 24 | | | - | | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 25 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 26 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 27 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 28 | | Year | - | - | | - | - |
| 29 | Total | | | | | $ - | |

30 **Interest calculation for Item #2…**

31 (Repeat interest calculation for other items as necessary.)

32 C. Interest Note: The interest calculation may need to be modified to recognize the implementation partial year.

33 D. The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas

34 contained with those columns cannot be changed absent a Federal Power Act section 205 or 206

35 filing.

## People’s Electric Cooperative

Worksheet U

## Qualified Transmission Substations

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| Line No. | Description | BOY Gross Plant | EOY Gross Plant | BOY Qualified Gross Plant | EOY Qualified Gross Plant | Average Qualified Gross Plant |
| 1 | Zone 7 OG&E | | | | | |
| 2 | | | | | | $ - |
| 3 | | | | | | $ - |
| 4 | | | | | | |
| 5 | Total Investment | $ - | $ - | $ - | $ - | $ - |
| 6 | | | | | | |
| 7 | Zone 10 SPA | | | | | |
| 8 | | | | | | $ - |
| 9 | | | | | | $ - |
| 10 | | | | | | $ - |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | Total Investment | $ - | $ - | $ - | $ - | $ - |
| 14 | | | | | | |
| 15 | Zone 13 WFEC | | | | | |
| 16 | | | | | | $ - |
| 17 | | | | | | $ - |
| 18 | | | | | | $ - |
| 19 | Total Investment | $ - | $ - | $ - | $ - | $ - |
| 20 | | | | | | |
| 21 | Total SPP Investment | $ - | $ - | $ - | $ - | $ - |
| 22 | | | | | | |
| 23 | Note: | | | | | |
| 24 | A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately | | | | | |
| 25 | provide information, and populate or remove data in the Worksheet with changes in future years. | | | | | |
| 26 | Where appropriate, these changes will provide detail and linkage to updated Form 7 data | | | | | |

requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in PEC's Implementation Protocols. PEC may not change the columns or the formulas included in these Worksheets during the Annual Update.

## People's Electric Cooperative

Worksheet V

## Qualified Transmission Lines

| Line No. | A<br>Description | B<br>kV Voltage | C<br>Line Length (Miles) | D<br>BOY Gross Plant | E<br>EOY Gross Plant | F<br>BOY Qualified Gross Plant | G<br>EOY Qualified Gross Plant | H<br>Average Qualified Gross Plant |
|---|---|---|---|---|---|---|---|---|
| 1 | Zone 7 OG&E | | | | | | | |
| 2 | | | | | | | | $ - |
| 3 | | | | | | | | $ - |
| 4 | | | | | | | | |
| 5 | Total Investment | | - | - | - | - | - | - |
| 6 | | | | | | | | |
| 7 | Zone 10 SPA | | | | | | | |
| 8 | | | | | | | | $ - |
| 9 | | | | | | | | $ - |
| 10 | | | | | | | | $ - |
| 11 | | | | | | | | $ - |
| 12 | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 13 | | | | | | | |
| 14 | Total Investment | - | - | - | - | - | - |
| 15 | | | | | | | |
| 16 | Zone 13 WFEC | | | | | | |
| 17 | | | | | | | $ - |
| 18 | | | | | | | $ - |
| 19 | | | | | | | $ - |
| 20 | Total Investment | 0.00 | 0 | 0 | 0 | 0 | 0 |
| 21 | | | | | | | |
| 22 | Total SPP Investment | 0.00 | $ - | $ - | $ - | $ - | $ - |
| 23 | | | | | | | |

24 Note:

25 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately

26 provide information, and populate or remove data in the Worksheet with changes in future years.

27 Where appropriate, these changes will provide detail and linkage to updated Form 7 data requirements or

28 other similar supporting documentation. Additional line items or line deletions will not require FPA Section

29 205 or 206 filings. PEC will describe such changes in the Annual Update, and the changes will be

30 subject to the review of Interested Parties under the procedures set forth in PEC's Implementation

31 Protocols. PEC may not change the columns or the formulas included in these Worksheets during

32 the Annual Update.

# People's Electric Cooperative

## Transmission Formula Rate Implementation Protocols

The transmission formula rate template ("Formula Rate Template") of People's Electric Cooperative ("PEC") and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of PEC for transmission service in Zones 7, 10, and 13 of the Southwest Power Pool, Inc. ("SPP") footprint. PEC must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point Transmission Service.

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and the SPP Tariff. The ATRR shall be determined for January 1 to December 31 of a given calendar year. The Formula Rate shall become effective for recovery of PEC ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC") under Section 205 of the Federal Power Act ("FPA").

The Formula Rate shall be applicable to service on and after July 1 of each calendar year through June 30 of the following calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

### Section I Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

(a) "Accounting Change" means any change in PEC accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula Rate. Accounting Changes include any changes resulting from:

(i) revisions to FERC's Uniform System of Accounts ("USoA"); (ii) revisions to CFC Form 7 data and the requirement to report certain values within it; (iii) correction of errors and prior period adjustments that impact the ATRR; (iv) the implementation of new estimation methods or policies; (v) changes to income tax elections; (vi) changes in accounting practices or policies mandated by FERC or a state regulatory authority with jurisdiction over PEC that could impact the Formula Rate or calculations under the Formula Rate; (vii) implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction; (viii) a change in PEC accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor); (ix) PEC's own Accounting Changes (which constitute a change to the ATRR greater than or equal to $10,000) such as the addition or deletion of a subaccount not

specified by FERC's USoA; or (x) a change in PEC's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

(b) "Annual Transmission Revenue Requirement" or "ATRR" means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by PEC for informational purposes with FERC and posted on the SPP OASIS on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

(c) "Annual Meeting" means the meeting hosted by PEC for the purpose of exchanging information with Interested Parties regarding the Formula Rate.

(d) "Annual Update" means PEC's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

(e) "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

(f) "Calendar Year" means January 1 through December 31 of a given year.

(g) "CFC" means National Rural Utilities Cooperative Finance Corporation.

(h) "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS (*e.g.*, if the Annual Update is filed on April 15, 2021, the Current Rate Year is July 1, 2021 through June 30, 2022).

(i) "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS service, service under Grandfathered Agreements, or PTP Service.

(j) "FERC" or "Commission" means the Federal Energy Regulatory Commission.

(k) "Final Posting" means the Annual Update information which PEC requests that SPP post to the SPP OASIS with changes agreed to during the Review Period.

(l) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with FERC and served on PEC by electronic service on the date of such filing.

(m) "Formula Rate" has the meaning defined herein.

(n) "FPA" means Federal Power Act.

(o) "Grandfathered Agreement" has the meaning set forth in the SPP Tariff.

(p) "Informal Challenge" means written notification by an Interested Party to PEC of any specific challenge to the Annual Update.

(q) "Information Request" means a written request submitted by an Interested Party to PEC.

(r) "Informational Filing" means PEC's annual filing at the Commission with the information stipulated in these Protocols.

(s) "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19(a) or successor regulation.

(t) "Interested Party" includes but is not limited to, Customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

(u) "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

(v) "OASIS" means Open Access Same-Time Information System.

(w) "OATT" or "SPP Tariff" means SPP's Open Access Transmission Tariff.

(x) "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is July 1, 2021 through June 30, 2022, then the Prior Rate Year is July 1, 2020 through June 30, 2021).

(y) "PTP Rates" means the point-to-point rates derived from the Formula Rate.

(z) "PTP Service" means "Point-To-Point Transmission Service" as defined in the SPP Tariff.

(aa) "Publication Date" means the date on which PEC posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2021 shall be no later than April 15, provided, however, that if April 15 should fall on a weekend or a holiday recognized by FERC, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

(bb) "Rate Year" means July 1 of a given year through June 30 of the subsequent year. (cc)

"Review Period" means unless otherwise extended in writing by PEC, 60 days after the Publication Date.

(dd) "Stated Values" mean values that are fixed and not subject to change in an Annual Update. Stated Values include: (i) the authorized return on equity ("ROE"); (ii) depreciation and amortization rates; and (iii) other similar fixed values. Stated Values may be changed only pursuant to FPA Sections 205 or 206.

(ee) "USoA" means FERC's Uniform System of Accounts.

**Section II Annual Update**

A. On or before the Publication Date for each calendar year, PEC shall:

1. Prepare its Annual Update by recalculating the revenue requirements applicable to Network Integration Transmission Service for the new Rate Year in accordance with the Formula Rate; and

2. Provide its Annual Update to SPP and request that SPP post such information to the SPP OASIS (such posting, the "Initial Posting"); and

3. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the Initial Posting shall be due on the next Business Day. The date on which such posting occurs shall be that year's Publication Date. Any delay in the Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

B. Concurrent with the Initial Posting, PEC shall provide the Annual Update to SPP to serve electronically upon the Formula Rate Posting Information Notification List.[1]

C. The Annual Update shall:

1. Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

2. Be based on the independently-audited books and records of PEC for the most recent fiscal year including its certified CFC Form 7 or successor reports used by PEC;

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1 As used in these Protocols, "Formula Rate Posting Information Notification List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification List through the "Exploder List" link on the SPP website. As of September 2020, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at http://www.spp.org/ stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff "Transmission Customers" (as defined in the SPP Tariff); (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

4. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, PEC shall identify:

(a) Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR;

(b) Any items included in the Formula Rate at an amount other than a historic cost basis;

(c) Individual impact of any changes in 4 ( a) above on charges billed under the Formula Rate; and

(d) Accounting Changes related to any reorganization or merger transaction.

5. Not seek to modify the Formula Rate, as any modification to the Formula Rate will require filing under Section 205 or 206 of the FPA.

**Section III Review of Annual Update**

Within twenty (20) days of the posting of PEC's Annual Update, PEC will host an Annual Meeting for Interested Parties to discuss the Annual Update. PEC shall provide notice of the Annual Meeting concurrent with the posting of the Annual Update accessible on the SPP OASIS. The notice shall include the date, time and location of the Annual Meeting and also shall be provided to Interested Parties through the Formula Rate Posting Information Notification List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically.

A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Update and will have until sixty (60) days after the Publication Date to serve reasonable Information Requests on PEC for information and work papers supporting the Annual Update. Such

Information Requests submitted during the Review Period shall be limited to that what is necessary to determine:

(a) The extent or effect of an Accounting Change;

(b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

(c) The proper application of the Formula Rate and procedures in these Protocols;

(d) The accuracy of data and consistency with the Formula Rate of the calculation shown in the Annual Update;

(e) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

(f) The effect of any change to the underlying USoA or Formula Rate Template; or

(g) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. PEC will not claim that responses to information and document requests pursuant the Protocols are subject to any settlement confidentiality provision however, PEC may require that Interested Parties execute a non- disclosure agreement to obtain access to material that PEC deems commercially sensitive or that contains " Critical Energy Infrastructure Information" as that term is defined in 18 C.F.R. § 388.113(c)(1).

2. PEC shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within seven (7) Business Days

3. PEC shall request to be posted on a publicly accessible portion of the SPP OASIS all Information Requests from Interested Parties and PEC response(s) to such requests, and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Information Requests contain information deemed by PEC to be

confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and PEC.

4. If the deadline for Interested Parties falls on a weekend or holiday recognized by the Commission the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until June 15 (or the first Business Day after June 15 if June 15 falls on a weekend or holiday) to notify PEC in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. PEC will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. PEC shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. PEC will request that SPP post on the SPP OASIS all Informal Challenges from Interested Parties and PEC's responses to the Informal Challenges and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Informal Challenges contain information deemed by PEC to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and PEC.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by PEC and resolved prior to the end of the Review Period shall be reported in the Final Posting on the SPP OASIS. Any changes or adjustments agreed to by PEC after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges

1. A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The accuracy of data and consistency with the Formula Rate of the calculation shown in the Annual Update;

v. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

vi. The effect of any change to the underlying USoA or Formula Rate Template; or

vii. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and

if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief.

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC either in the FERC docket assigned to the Informational Filing or in the docket assigned to a challenge brought under Section 206 of the FPA and shall be served upon PEC contemporaneously with the filing at FERC. Service shall be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in PEC's Informational Filing.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of ROE, depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to FPA Sections 205 or 206. Any modification to the Formula Rate will require a filing under FPA Sections 205 or 206.

3. If PEC makes a correction to a Mistake in its financial information during the Current Rate Year that would affect the Formula Rate for the Current Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with 18 C.F.R. § 35.19a or successor regulation. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate Template, such

as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a or successor regulation. Refunds arising from PEC's first rate case shall be calculated at the lesser of PEC's short-term debt costs or the amount calculated pursuant to 18 C.F.R. § 35.19a or successor regulation.

5. Any Commission orders specifically applicable to PEC's calculation of its ATRR.

E. Informational Filing

1. By August 15 of each year, PEC shall submit its Information Filing to FERC of its Annual Update under a separate docket number.

2. The Informational Filing must include information that is reasonably necessary to determine:

(a) That input data under the Formula Rate is properly recorded in any underlying work papers;

(b) That PEC has properly applied the Formula Rate and these procedures;

(c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

(d) The extent of Accounting Changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, PEC shall provide notice of the Informational Filing to Interested Parties via the Formula Rate Posting Information Notification List and request that SPP post the notice and the docket number assigned to the Informational filing on the SPP OASIS.

## Example PEC Schedule

| Action | Date |
|---|---|
| Data Available | March 1 |
| Initial Posting | April 15 |
| Annual Meeting, Interested Parties | May 5 |
| Interested Parties Review Period | April 15 –June 15 |
| Final Posting | June 20 |
| FERC Informational Filing | August 15 |
| Rate Year | July 1-June 30 |

# Addendum 3 to Attachment H - Part 1

## Evergy Kansas Central, Inc. Formula Rate

**Evergy Kansas Central, Inc. (EKC)**
**Evergy Kansas South, Inc. (EKS)**
**Rate Formula Template**

**Table of Contents**

**Overview**
The formula is calculated in two steps. The first step is to fill out Tabs A-1 thru A-12, and the Actual Gross Rev. Req. tab with data from the previous year's Form 1 information. This information is used to update the formulas in the Actual Net Rev Req tab to calculate the Actual Revenue Requirement (Actual ATRR) for the previous year. The results of this calculation are presented to the customers for review no later than June 15 each year.

The TU (True-up) tab uses the Actual ATRR from the Actual Net Rev Req tab and compares it to the Projected ATRR customers were billed for the same period. Interest is added to the difference and the amount is added to the Projected Net Rev Req tab.

The projected O&M and plant balances are calculated in Tabs P-1 thru P-5. These sheets feed into the Projected Gross Rev Req tab and ultimately into the Projected Net Rev Req tab. The BPF tab retrieves project specific data from A-9, A-11 and P-4 to calculate the amount of revenue requirements associated with those projects which are contained in the total Projected Net Revenue Requirement amount. The EPP tab does the same process for Economic Portfolio projects by combining data from A-11, A-12 and P-5. The total revenue requirements for these two groups of upgrades (lines 9 and 9a) are subtracted from the Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. Revenue Requirement (line 8) to obtain the Zonal ATRR (line 10). This calculation is shown on the Projected Net Rev Req tab. The Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. tariff rates are calculated based on the Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. Revenue Requirements and the specific point-to-point charges are shown on the same tab. The SPP rates are set on the BPF Revenue Requirements, Economic Portfolio Revenue Requirements and the Zonal Revenue requirements. The specific charges are calculated in the SPP tariff.

Cells highlighted in yellow are data input cells, however, some cells may reference the results from other worksheets in the formula. Such cell references may change from year to year requiring manual adjustment of the reference or the direct entry of the proper value.

Cells highlighted in green signify that the data is pulled from other worksheets in the formula and that the reference is static.

| Tab | Schedule/Worksheet Designation | Description | Date to be Posted |
|---|---|---|---|
| Actual Net Rev Req | Schedule "Actual Net Rev Req (page 1) | Actual net revenue requirements for most recent calendar year | June 15 |
| Actual Gross Rev Req | Schedule Actual Gross Rev Req (1-5 pages) | Actual gross revenue requirements for most recent calendar year | June 15 |
| ARO Adj. | Schedule ARO Adj. (pages 1-2) | Determination of Net Plant, Net of Asset Retirement Obligations (“AROs”) | June 15 |
| A-1 (Rev. Credit) | Worksheet A-1 | Actual revenue credits | June 15 |
| A-2 (Divisor) | Worksheet A-2 | Actual transmission load | June 15 |
| A-3 (Retail Adder) | Worksheet A-3 | Actual Retail Adder | June 15 |
| A-4 (EKC O&M Exclusions) | Worksheet A-4 | Actual O&M Expense Exclusions (EKC) | June 15 |
| A-5 (EKC ADIT) | Worksheet A-5 | Actual Accumulated Deferred Income Taxes (ADIT) (EKC) | June 15 |
| *A-5-2 (EKC EDIT)* | *Worksheet A-5-2* | *Actual Accumulated Deferred Income Taxes (ADIT) (EKC)* | *June 15* |
| *A-5-3 (EKC Computation)* | *Worksheet A-5-3* | *Computation of Excess Deferred Income Taxes (EDIT) (EKC)* | *June 15* |
| A-6 (EKS O&M Exclusions) | Worksheet A-6 | Actual O&M Expense Exclusions (EKS) | June 15 |
| A-7 (EKS ADIT) | Worksheet A-7 | Actual Accumulated Deferred Income Taxes (ADIT) (EKS) | June 15 |
| *A-7-2 (EKS EDIT)* | *Worksheet A-7-2* | *Actual Accumulated Deferred Income Taxes (ADIT) (EKS)* | *June 15* |
| *A-7-3 (EKS Computation)* | *Worksheet A-7-3* | *Computation of Excess Deferred Income Taxes (EDIT) (EKS)* | *June 15* |
| A-8 (Depr Calc-Opt) | Worksheet A-8 | Actual Depreciation Rate Calculation | June 15 |
| A-9 (Actual BPF Summary) | Worksheet A-9 | Actual Base Plan Funded Projects | June 15 |
| A-10 (Wages & Salaries) | Worksheet A-10 | Actual Wages and Salaries | June 15 |
| A-11 (Incentive Plant) | Worksheet A-11 | Actual Incentive Return on Incentive Plant | June 15 |

| | | | |
|---|---|---|---|
| A-12 (Act Econ Projects) | Worksheet A-12 | Actual Economic Portfolio Funded Projects | June 15 |
| TU (True-up) | Worksheet TU | True-up Adjustment and Interest Calculation | October 15 |
| BPF (BPF Summary) | BPF Summary | Total Actual and Projected BPF projects | October 15 |
| EPP (Econ Proj Sum)'!A1 | EPP Summary | Total Actual and Projected Economic Portfolio projects | October 15 |
| Projected Net Rev Req | Projected Net Rev Req (1 page) | Projected net revenue requirements for next calendar year | October 15 |
| Projected Gross Rev Req | Projected Gross Rev Req (5 pages) | Projected gross revenue requirements for next calendar year | October 15 |
| P-1 (Trans Plant) | Worksheet P-1 | Projected transmission plant for next calendar year | October 15 |
| P-2 (Exp. & Rev. Credits) | Worksheet P-2 | Projected expenses and revenue credits for next calendar year | October 15 |
| P-3 (Trans. Network Load) | Worksheet P-3 | Projected transmission load for next calendar year | October 15 |
| P-4 (BPF Projects)'!A1 | Worksheet P-4 | Projected Base Plan Funded Projects | October 15 |
| P-5 (Econ. Projects)'!A1 | Worksheet P-5 | Projected Economic Portfolio Funded Projects | October 15 |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Net Revenue Requirements
For the 12 months ended - December 31, xxxx

Actual Net Rev Req


EVERGY KANSAS CENTRAL, INC. AND EVERGY KANSAS SOUTH, INC.

| (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|
| | Reference | | | | Allocated Amount |
| **REVENUE REQUIREMENTS** | | | | | |
| GROSS REVENUE REQUIREMENT | [Actual Gross Rev, p. 3, ln. 32, col. 7] | | | | $ - |

| REVENUE CREDITS | | Total | Allocator | |
|---|---|---|---|---|
| Account No. 454 | (Wksht. A-1, p. 2, Sec. II, ln. 5, EKC + EKS) | $ - | 1.00000 | $ - |
| Account No. 456 | (Wksht. A-1, p. 1, Sec. I, ln. 22, Total) | - | 1.00000 | - |
| Revenues from Grandfathered Interzonal Transactions | (Wksht. A-1, p. 2, Sec. III) | - | 1.00000 | - |
| Revenues from service provided by the ISO at a discount | (Wksht. A-1, p. 2, Sec. III) | - | 1.00000 | - |
| TOTAL REVENUE CREDITS (sum lines 2-5) | | | | $ - |
| ACTUAL NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | **$ -** |
| SPP BASE PLAN FUNDED REVENUE REQUIREMENT Collected under SPP Schedule 11 (A-9, page 1, line 5) | | | | - |
| SPP ECONOMIC PORTFOLIO FUNDED REVENUE REQUIREMENT Collected under SPP Schedule 11 (A12, page 1, line 5) | | | | - |
| SPP ZONAL REVENUE REQUIREMENT (line 7 - line 8 - line 9) | | | | $ - |
| Total Net Transmission Plant | (Actual Gross Rev, page 1, line14, col 7) | | | $ - |
| Actual Facility Carrying Charge | (line 7 / line 11) | | | 0.0000% |

Rate Formula Template

Utilizing FERC Form 1 Data

Actual Gross Revenue Requirements

For the 12 months ended - December 31, xxxx

Actual Gross Rev Page 1 of 5

EVERGY KANSAS CENTRAL, INC. and
EVERGY KANSAS SOUTH, INC.

| Line No | (1) | (2) Form No. 1 Page, Line, Col. | (3) Evergy Kansas Central, Inc (EKC) | (4) Evergy Kansas South, Inc. (EKS) | (5) Company Total | Allocator | (6) | (7) Transmission (Col 5 times Col 6) |
|---|---|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | | | |
| | PLANT IN SERVICE | **Note T** | | | | | | |
| 1 | Production | Schedule ARO Adj, pg 2, ln 1 | | | $ - | | | $ - |
| 2 | Transmission | Schedule ARO Adj, pg 2, ln 2 | | | $ - | TP | 0.0000 | $ - |
| 3 | Distribution | Schedule ARO Adj, pg 2, ln 3 | | | $ - | | | $ - |
| 4 | General | Schedule ARO Adj, pg 2, ln 4 | | | $ - | W/S | 0.0000 | $ - |
| 4a | Intangible | Schedule ARO Adj, pg 2, ln 5 | | | $ - | W/S | 0.0000 | $ - |
| 5 | Common | Schedule ARO Adj, pg 2, ln 6 | | | $ - | W/S | 0.0000 | $ - |
| 6 | TOTAL GROSS PLANT | (sum lines 1-5) | $ - | $ - | $ - | | | $ - |
| | ACCUMULATED DEPRECIATION | (Notes Q & T) | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 7 | Production | Schedule ARO Adj, pg 2, ln 7 | | | $ - | | | $ - |
| 8 | Transmission | Schedule ARO Adj, pg 2, ln 8 | | | - | TP | 0.0000 | $ - |
| 9 | Distribution | Schedule ARO Adj, pg 2, ln 9 | | | - | | | $ - |
| 10 | General | Schedule ARO Adj, pg 2, ln 10 | | | - | W/S | 0.0000 | $ - |
| 11a | Intangible | Schedule ARO Adj, pg 2, ln 11 | | | $ - | W/S | 0.0000 | $ - |
| 11 | Common | Schedule ARO Adj, Pg 2 ln 12 | | | - | W/S | 0.0000 | $ - |
| 12 | TOTAL ACCUM. DEPRECIATION | (sum lines 7-11) | $ - | $ - | $ - | | | $ - |
| | NET PLANT IN SERVICE | | | | | | | |
| 13 | Production | (line 1 less line 7) | $ - | $ - | $ - | | | $ - |
| 14 | Transmission | (line 2 less line 8) | $ - | $ - | $ - | | | $ - |
| 15 | Distribution | (line 3 less line 9) | $ - | $ - | $ - | | | $ - |
| 16 | General | (line 4 less line 10) | $ - | $ - | $ - | | | $ - |
| 16a | Intangible | (line 4a less line 10a) | $ - | $ - | $ - | | | $ - |
| 17 | Common | (line 5 less line 11) | $ - | $ - | $ - | | | $ - |
| 18 | TOTAL NET PLANT | (sum lines 13-17) | $ - | $ - | $ - | | | $ - |
| | ADJUSTMENTS TO RATE BASE | | | | | | | |
| 19 | Accumulated Deferred Income Taxes | (Wkshts. A-5 & A-7, p. 1) | $ - | $ - | $ - | DA | 1.0000 | $ - |
| 19a | Unamortized Extraordinary Property Loss | Account 182.1 (Note S) | | | $ - | TE | 0.0000 | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 19b | Transmission Storm Damage Reserve | Account 228.1 (Note S) | | | $ - | TE | 0.0000 0 | $ - |
| 20 | TOTAL ADJUSTMENTS | (line 19 + line 19a - line 19b) | $ - | $ - | $ - | | | $ - |
| 21 | LAND HELD FOR FUTURE USE | 214.x.d (Note B) | | | 0 | TP | 0.0000 0 | 0 |
| | WORKING CAPITAL | | | | | | | |
| 22 | CWC | calculated (Note C) | | | | | | $ - |
| 23 | Materials & Supplies | 227.8.c (Note B) | | | - | TP | 0.0000 0 | - |
| 23a | Stores Expense | 227.16.c (Note B) | | | - | W/S | 0.0000 0 | - |
| 24 | Prepayments (Account 165) | 111.57.c (Note C) | | | - | GP | 0.0000 0 | - |
| 25 | TOTAL WORKING CAPITAL | (sum lines 23 - 24) | $ - | $ - | $ - | | | $ - |
| 26 | Rate Base | (sum lines 18, 20, 21, & 25) | | | | | | $ - |

Rate Formula Template

Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, xxxx

Actual Gross Rev Page 2 of 5

EVERGY KANSAS CENTRAL, INC. and
EVERGY KANSAS SOUTH, INC.

| Line No | (1) | (2) Form No. 1 Page, Line, Col. | (3) Evergy Kansas Central, Inc (EKC) | (4) Evergy Kansas South, Inc. (EKS) | (5) Company Total | Allocator | (6) | (7) Transmission (Col 5 times Col 6) |
|---|---|---|---|---|---|---|---|---|
| | **O&M** | | | | | | | |
| 1 | Transmission (Note D) | (Worksheet A-4 & Worksheet A-6) | $ - | $ - | $ - | | 1.0000 | $ - |
| 2 | Less Account 561 | 321.84.b thru 321.92.b | | | - | | 1.0000 | - |
| 2a | Less Account 565 (Note E) | 321.96.b | | | - | | 1.0000 | - |
| 3 | A&G | 323.197.b | | | - | W/S | 0.0000 | - |
| 3a | Less: Actual PBOP | (Note R) | | | - | W/S | 0.0000 | - |
| 4 | Plus: PBOP adder | (Note R) | 9,697,558 | 6,642,051 | 16,339,609 | W/S | 0.0000 | - |
| 5 | Less FERC Annual Fees | Included as part of line 6b | | | - | W/S | 0.0000 | - |
| 6 | Less EPRI | 335 (Note F) | | | - | W/S | 0.0000 | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 6a | Less Total Advertising Costs | 323.191(b) (Note F) | | | - | W/S | 0.0000 0 | - |
| 6b | Less Total Regulatory Commission Expenses | 323.189(b) (Note F) | | | - | W/S | 0.0000 0 | - |
| 7 | Plus Transmission Related Reg. Comm. Exp. | 351.h (Note F) | | | - | TE | 0.0000 0 | - |
| 8 | Plus Safety Advertising | (Note F) | | | - | W/S | 0.0000 0 | - |
| 9 | Common | 356.1 | | | - | CE | 0.0000 0 | - |
| 10 | Transmission Lease Payments | | | | - | | 1.0000 0 | - |
| 11 | TOTAL O&M | (sum lines 1, 3, 4, 7-10 less lines 2, 2a, 3a, 5- 6b) | $ 9,697,558 | $ 6,642,051 | $ 16,339,609 | | | $ - |
| | **DEPRECIATION EXPENSE** | | | | | | | |
| 12 | Transmission | 336.7.f or Worksheet A-8 | | | $ - | TP | 0.0000 0 | $ - |
| 13 | General | 336.10.f | | | - | W/S | 0.0000 0 | - |
| 13a | Intangible | 336.1f | | | - | W/S | 0.0000 0 | - |
| 14 | Common | 336.11.b | | | - | CE | 0.0000 0 | - |
| 14a | Amortization of Property Loss | Acct. 407-Unrecovered Plant and Regulatory Study Costs (Note S) | | | - | TE | 0.0000 0 | - |
| 15 | TOTAL DEPRECIATION | (Sum lines 12-14a) | $ - | $ - | $ - | | | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **TAXES OTHER THAN INCOME TAXES (Note G)** | | | | | | | | |
| | LABOR RELATED | | | | | | | | |
| 1 | | | | | $ | W/ | 0.0000 | $ | |
| 6 | Payroll | 263.i | | | - | S | 0 | - | |
| 1 | | | | | | W/ | 0.0000 | | |
| 7 | Highway and vehicle | 263.i | | | - | S | 0 | - | |
| | PLANT RELATED | | | | | | | | |
| 1 | | | | | | | 0.0000 | | |
| 8 | Property (Note P) | 263.i | | | - | GP | 0 | - | |
| 1 | | | | | | | 0.0000 | | |
| 9 | Gross Receipts | 263.i | | | - | NA | 0 | - | |
| 2 | | | | | | | 0.0000 | | |
| 0 | Other | 263.i | | | - | GP | 0 | - | |
| 2 | | | | | | | 0.0000 | | |
| 1 | Payments in lieu of taxes | | | | - | GP | 0 | - | |
| 2 | | (sum lines | $ | $ | $ | | | $ | |
| 2 | TOTAL OTHER TAXES | 16 - 22) | - | - | - | | | - | |
| | **INCOME TAXES** | (Note H) | | | | | | | |
| 2 | | | | | | | 0.00 | | |
| 3 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | | | | % | | |
| 2 | | | | | | | 0.00 | | |
| 4 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | | | | | % | | |
| | where WCLTD=(page 5, line 21) and R= (page 5, line 24) and | | | | | | | | |
| | FIT, SIT & p are as given in Note H. | | | | | | | | |
| 2 | | | | | | | | | |
| 5 | 1 / (1 - T) = (from line 23) | | | | | | - | | |
| 2 | | | | | $ | | | | |
| 6 | Amortized Investment Tax Credit (266.8f) (enter negative) | | | | - | | | | |
| *2* | | | | | | | | | |
| *6* | | | | | | | | | |
| *a* | *(Excess)/Deficient Deferred Income Taxes* | *(Note U)* | *$-* | *$-* | *$-* | | | | |
| 2 | | | | | | | | $ | |
| 7 | Income Tax Calculation = line 24 * line 30 | | | | | NA | | - | |
| 2 | | | | | | | 0.0000 | | |
| 8 | ITC adjustment | (line 25 * line 26) | | | - | NP | 0 | - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 28a | *(Excess)/Deficient Deferred Income Tax Adjustment* | *(line 25 * line 26a)* | *$-* | *DA* | *1.000000* | *-* |
| 29 | Total Income Taxes | (line 27 plus line 28 *plus line 28a*) | | | | $ - |
| 30 | **RETURN**<br>[ Rate Base (page 2, line 16) * Rate of Return (page 4, line 24) plus Incentive Return (page 4, line 28)] | | | NA | | $ - |
| 31 | Interest on Network Credits | | 0 | DA | 1.000000 | 0 |
| 32 | **GROSS REV. REQUIREMENT** | (sum lines 11,15, 22, 29, 30 & 31) | $ 16,339,609 | | | $ - |

Actual Gross Rev Page 3 of 5

Rate Formula Template

Utilizing FERC Form 1 Data

Actual Gross Revenue Requirements

For the 12 months ended - December 31, xxxx

EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.

**SUPPORTING CALCULATIONS**

| Li | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | **Form No. 1** | **Evergy** | **Evergy** | | | **Transmi** |

| ne | | | Kansas Central, Inc | Kansas South, Inc. | | | ssion |
|---|---|---|---|---|---|---|---|
| No | | Page, Line, Col. | (EKC) | (EKS) | Company Total | Allocator | (Col 5 times Col 6) |
| | **TRANSMISSION PLANT INCLUDED IN FORMULA** | | | | | | |
| 1 | Total transmission plant | (page 3, Line 13, col. 5) | - | - | $ - | | $ - |
| 2 | Less transmission plant excluded from ISO rates | (Note I) | | | $ - | | - |
| 3 | Less transmission plant included in OATT Anc. Srvc | (Notes J&K) | | | $ - | | - |
| 4 | Transmission plant included in rates | (line 1 less lines 2 & 3) | $ - | $ - | $ - | | $ - |
| 5 | Percentage of transmission plant included in rates | (line 4 divided by line 1) | | | | TP = | 0.000000 |
| | **TRANSMISSION EXPENSES** | | | | | | |
| 6 | Transmission expenses | (Page 2, line 1, col. 7) (Note L) | | | | | $ - |
| 7 | Less transmission other expenses included in Anc. Srvc | (Page 2, line 2, col 7) | | | | | - |
| 8 | Included transmission expenses (line 6 less line 7) | | | | | | $ - |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | | | | 0.000000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | | | TP = | 0.000000 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | T | |
| 1 | | | | | | | | E | 0.00 |
| 1 | Percentage of transmission expenses included in rates (line 9 times line 10) | | | | | | | = | 000 |
| | **GROSS AND NET PLANT ALLOCATORS** | | | | | | | | |
| | GROSS PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | | | |
| 1 | | (page 1, | $ | $ | $ | | | | |
| 2 | Production | line 1) | - | - | - | NA | | | |
| | | | | | | | 0.0 | | |
| 1 | | (page 1, | | - | | | 000 | | |
| 3 | Transmission | line 2) | | | - | TP | 0 | | 0 |
| 1 | | (page 1, | | | | | | | |
| 4 | Distribution | line 3) | - | - | - | NA | | | |
| | General & Intangible | | | | | | 0.0 | | |
| 1 | | (page 1, | - | - | | W/ | 000 | | |
| 5 | | line 4) | | | - | S | 0 | | 0 |
| | | | | | | | 0.0 | | |
| 1 | | (page 1, | | | | | 000 | | |
| 6 | Common | line 5) | - | - | - | CE | 0 | | 0 |
| | | | | | | | 0.0 | | |
| 1 | | (sum lines | $ | $ | $ | GP | 00 | $ | |
| 7 | TOTAL GROSS PLANT | 12-16) | - | - | - | = | % | - | |
| | ACCUMULATED DEPRECIATION (ACTUAL HISTORICAL COST) (Note Q) | | | | | | | | |
| 1 | | (page 1, | $ | $ | $ | | | | |
| 8 | Production | line 7) | - | - | - | NA | | | |
| | | | | | | | 0.0 | | |
| 1 | | (page 1, | | - | | | 000 | | |
| 9 | Transmission | line 8) | | | - | TP | 0 | | 0 |
| 2 | | (page 1, | | | | | | | |
| 0 | Distribution | line 9) | - | - | - | NA | | | |
| | | | | | | | 0.0 | | |
| 2 | | (page 1, | - | - | | W/ | 000 | | |
| 1 | General & Intangible | line 10) | | | - | S | 0 | | 0 |
| | | | | | | | 0.0 | | |
| 2 | | (page 1, | | | | | 000 | | |
| 2 | Common | line 11) | - | - | - | CE | 0 | | 0 |
| 2 | | (sum lines | $ | $ | $ | | | $ | |
| 3 | TOTAL ACCUM. DEPRECIATION | 12-16) | - | - | - | | | - | |
| | NET PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | | | |
| | | (line 12 | | | | | | | |
| 2 | less | line | $ | $ | $ | | | | |
| 4 | Production | 18) | - | - | - | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 25 | Transmission | (line 13 less line 19) | - | - | - | | | | 0 |
| 26 | Distribution | (line 14 less line 20) | - | - | - | | | | |
| 27 | General & Intangible | (line 15 less line 21) | - | - | - | | | | 0 |
| 28 | Common | (line 16 less line 22) | - | - | - | | | | 0 |
| 29 | TOTAL NET PLANT | (sum lines 24-28) | $ - | $ - | $ - | NP = | 0.000 % | $ - | |

Actual Gross Rev Page 4 of 5

Rate Formula Template

Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, xxxx

EVERGY KANSAS CENTRAL, INC. and
EVERGY KANSAS SOUTH, INC.

**SUPPORTING CALCULATIONS**

| Line | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | **Form No. 1** | **Evergy Kansas Central, Inc** | **Evergy Kansas South, Inc.** | | | **Transmission** |

| No | | Page, Line, Col. | (EKC) | (EKS) | Company Total | | Allocator | | | (Col 5 times Col 6) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **WAGES & SALARY ALLOCATOR (W&S)** | | $ | $ | $ | TP | | Allocation | | | | |
| 1 | Production | (Worksheet A-10) | 0 | 0 | $ - | 0.000000 | | 0 | | | | |
| 2 | Transmission | (Worksheet A-10) | 0 | 0 | - | 0.000000 | | 0 | | | | |
| 3 | Distribution | (Worksheet A-10) | 0 | 0 | - | 0.000000 | | 0 | | W&S Allocator ($ / Allocation) | | |
| 4 | Other | (Worksheet A-10) | 0 | 0 | - | 0.000000 | | 0 | | | | |
| 5 | Total (sum lines 1-4) | | 0 | 0 | $ - | | | 0 | = | 0.000000 | = | WS |
| | **COMMON PLANT ALLOCATOR (CE) (Note M)** | | | | **$** | | | % Electric (line 17 / line 20) | | W&S Allocator | | |
| 6 | Electric | 200.3.c | | | $ - | | | | | (line 16) | | CE |
| 7 | Gas | 200.3.d | - | - | - | | | 0.000000 | * | 0.000000 | = | 0.000000 |
| 8 | Water | 200.3.e | - | - | - | | | | | | | |
| 9 | Total (sum lines 6 - 8) | | $ - | $ - | $ - | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **RETURN (R)** | | | | | | | $ |
| 10 | Interest on Long-Term Debt | 117.62.c | | | $ - | | | |
| 11 | Amort. of Debt Disc. and Expense | 117.63.c | | | - | | | |
| 12 | Amortization of Loss on Reacquired Debt | 117.64.c | | | - | | | |
| 13 | Less: Amort. of Premium on Debt-Credit | 117.65.c | - | - | - | | | |
| 14 | Less: Amort. of Gain on Reacquired Debt-Credit | 117.66.c | - | - | - | | | |
| 15 | Long Term Interest (sum of lines 10 - 12 less 13 and 14) | | $ - | $ - | $ - | | | $ - |
| 16 | | Preferred Dividends (118.29c) (positive number) | | $ - | $ - | | | $ - |
| | Development of Common Stock: | | | | | | | |
| 17 | | Proprietary Capital (112.16.c)( EKC Form 1) | | | $ - | | | $ - |
| 18 | | Less Preferred Stock (line 28) | | | | | | - |
| 19 | | Less Adjusted 216.1 Subsidiary Retained Earnings (Note N) | | | | | | - |
| 20 | | Common Stock | (Line 17 less Line 18 less Line 19) | | | | | $ - |
| | | | | | | | Cost | |

| | | | EKC | EKS | $ | % | (Note O) | Weighted | |
|---|---|---|---|---|---|---|---|---|---|
| 21 | Long Term Debt (112, sum of 18.c., 19c and 21.c) | | | | $ - | 0.00% | - | 0.0000 | =WCLTD |
| 22 | Preferred Stock (112.3.c)(EKC Only) | | | - | - | 0.00% | - | 0.0000 | |
| 23 | Common Stock (line 26)(EKC Only) | | - | - | - | 0.00% | 0.1003 | 0.0000 | |
| 24 | Total (sum lines 21-23) | | | | $ - | 0.00% | | 0.0000 | = R |
| | **Incentive Return** | | | | | | | | |
| 25 | Total Incentive Plant | (Worksheet A-11) | | | $ - | | | | |
| 26 | Less: Total Accumulated Depreciation | (Worksheet A-11) | | | - | | | | |
| 27 | Net Incentive Plant | (line 25 less line 26) | | | $ - | | | | |
| 28 | Incentive Return | (Worksheet A-11) | | | | | $ - | | |



Rate Formula Template

Utilizing FERC Form 1 Data

Actual Gross Revenue Requirements

For the 12 months ended - December 31, xxxx

EVERGY KANSAS CENTRAL, INC. and
EVERGY KANSAS SOUTH, INC.

**NOTES**

General Note: References to pages in this formula rate are indicated as: (page#, line#, col.#).

References to data from FERC Form 1 are indicated as: page#.line#.col

| Note Letter | |
|---|---|
| A | Reserved for future use. |
| B | Identified in Form 1 as being only transmission related. |
| C | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 11, col. 7.<br>Prepayments are the electric related prepayments booked to Account No. 165 and reported on FERC Form 1, p. 111, ln. 57.c. |
| D | Transmission O&M expense does not include any SPP charges for Schedule 1-A of the SPP OATT. |
| E | Transmission By Others, Account 565 includes only costs associated with transmission facilities which are assigned to the Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. pricing zone by SPP. |
| F | Industry Association Dues are capped at $1,000,000. Line 6 - EPRI Annual Membership Dues listed in Form 1 at p. 335,<br>Line 6a Remove all Advertising expenses in Account 930.1.<br>Line 6b Remove all Regulatory Commission Expenses itemized at 351.h.<br>Line 6c - Add in wholesale Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.<br>Line 6d Add in Safety related advertising that are in Account 930.1. |
| G | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.<br>Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| H | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p ="the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 28). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory<br>rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. |

Inputs Required:

FIT =

SIT= (State Income Tax Rate or

| | | | |
|---|---|---|---|
| | | p = | Composite SIT) (percent of federal income tax deductible for state purposes) |

Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor I test (until FERC Form 1 balances are adjusted to reflect application of seven-factor test).

J Unless otherwise specified, OATT refers to the Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. and SPP OATTs.

K Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to be included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates. Costs related to Ancillary 1, Scheduling and Control, Acct 561 is shown on Actual Gross Rev, page 2, line 2.

M Enter dollar amounts

N To determine what is entered in Line 19, EKC shall take EKC's Account 216.1 Balance (EKC.112.12.c) and subtract EKS's Retained Earnings (EKS 112.11.c). If the resulting amount is positive, enter such amount in the formula. If the resulting amount is negative, enter zero.

O Debt cost rate = long-term interest (line 15) / long term debt (line 21). Preferred cost rate = preferred dividends (line 16) / preferred stock (line 22).

The approved ROE is 11.3%, no change in ROE may be made absent a filing with FERC. Any incentive ROEs approved by the Commission are shown by project in Worksheet A-11.

If the transmission related component of property tax is specifically identified in Form 1, then a TP allocator shall be used.

P Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the Form 1.

Q The initial depreciation rates below will be used to calculate depreciation expense and accumulated depreciation balances absent an appropriate filing with FERC.

| | Depreciation Rate | | | |
|---|---|---|---|---|
| | Non-incentive Plant EKC | Non-incentive Plant EKS | Wichita-to-Reno-to-Summit | Future Incentive Project |
| FERC Account Number | | | | |
| 350 Land and Land Rights | | | | |
| 351 (reserved) | | | | |
| 352 Structures and Improvements | 1.75 | 1.74 | 6.67 | - |

| | | | | | |
|---|---|---|---|---|---|
| | 353 Station Equipment | 1.74 | 1.67 | 6.67 | - |
| | 354 Towers and Fixtures | 2.01 | 1.43 | 6.67 | - |
| | 355 Poles and Fixtures | 2.57 | 2.59 | 6.67 | - |
| | 356 Overheard Conductors and Devices | 2.58 | 2.46 | 6.67 | - |
| | 357 Underground Conduit | 0.00 | 1.06 | 6.67 | - |
| | 358 Underground Conductors and Devices | 0.00 | 1.99 | 6.67 | - |
| | 359 Roads and Trails | 0.00 | 0.70 | 6.67 | - |

The incentive depreciation rates will be applied to assets recorded in the Wichita-to-Reno-to-Summit location code in EKS's transmission depreciation groups.

R The initial Post-Employment Benefits Other than Pensions (PBOP) expense set forth below will be used in lieu of the actual PBOP expense incurred in the year absent an appropriate filing with FERC.

| | **EKC** | **EKS** | **TOTAL** |
|---|---|---|---|
| Post-Employment Benefits Other than Pensions | $ 9,697,558 | $ 6,642,051 | $16,339,609 |

S Page 1 line 19a is the unamortized balance related to the recovery of transmission expense for the December 2007 ice storm booked in Account 182.3. Accrued transmission expenses for the December 2007 ice storm shall be amortized in the transmission O&M accounts over 36 months beginning June 1, 2008. The total amount to be amortized in the transmission O&M accounts shall be $6,647,679, developed as follows:

| | EKC | EKS | Total |
|---|---|---|---|
| Total transmission expenses accrued for the December 2007 ice storm | $6,758,037.33 | $0.00 | $6,758,037.33 |
| Less total transmission storm damage reserve as of December 2007 | $110,358.00 | $0.00 | $110,358.00 |
| Total transmission expense to be amortized | $6,647,679.33 | $0.00 | $6,647,679.33 |

* All future accruals of transmission storm damage reserves will be subtracted from rate base until they are applied to offset the December 2007 ice storm damage expenses.

T The gross plant, accumulated depreciation, deferred tax balances, and depreciation expense do not include balances related to Asset Retirement Obligations (AROs). This is to comply with the requirements of FERC Rulemaking RM02-7-000, Order No. 631.

*Includes the amortization of any excess/deficient income taxes resulting from changes to income tax rates (including changes in apportionment) and other actions taken by a taxing authority.*
*Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T). The EKC input comes from worksheet A-5-2 (EKC ADIT wksht), Net (Excess)/Deficient Deferred Income Taxes, Column (l) and the EKS input comes from worksheet A-7-2 (EKS ADIT wksht), U Net (Excess)/Deficient Deferred Income Taxes, Column (l).*

## Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.

## Determination of Net Plant, Net of Asset Retirement Obligations ("AROs")
## For the 12 months ended - December 31, XXXX

ARO Adj
Page 1 of 2

| Line No | | (1) Form No. 1 Page, Line, Col. | (2) Evergy Kansas Central, Inc. (EKC) | (3) Evergy Kansas South, Inc. (EKS) |
|---|---|---|---|---|
| | **PLANT IN SERVICE** | | | |
| 1 | Production | 205.46.g | $ - | $ - |
| 2 | Transmission | 207.58.g | - | - |
| 3 | Distribution | 207.75.g | - | - |

| | | | | |
|---|---|---|---|---|
| | General | 207.99.g | | |
| 4 | | | - | - |
| | Intangible | 205.5.g | | |
| 5 | | | - | - |
| 6 | Common | 356.1 | - | - |
| | | | $ | $ |
| | TOTAL GROSS PLANT | (sum lines 1-6) | - | - |
| | **ACCUMULATED DEPRECIATION** | | | |
| | | | $ | $ |
| 7 | Production | 219.20-24.c | - | - |
| 8 | Transmission | 219.25.c | - | - |
| 9 | Distribution | 219.26.c | - | - |
| 10 | General<br>Intangible | 219.28.c<br>Workpaper | - | - |
| 11 | | | - | - |
| 12 | Common | 356.1 | - | - |
| | | | $ | $ |
| | TOTAL ACCUM. DEPRECIATION | (sum lines 7-12) | - | - |
| | **PLANT IN SERVICE FOR AROs** | | | |
| | | (sum lines 13a-13d) | $ | $ |
| 13 | Production (Total) | | - | - |
| 13 | | | $ | $ |
| a | Steam Production (Acct 317) | 205.15.g | - | - |

| | | | | |
|---|---|---|---|---|
| 13 b | Nuclear Production (Acct 326) | 205.24.g | - | - |
| 13 c | Hydraulic Produciton (Acct 337) | 205.34.g | - | - |
| 13 d | Other Production (Acct 347) | 205.44.g | - | - |
| 14 | Transmission | 207.57.g | - | - |
| 15 | Distribution | 207.74.g | - | - |
| | General | 207.98.g | | |
| 16 | Intangible | Workpaper | - | - |
| 17 | | | - | - |
| 18 | Common | Workpaper | - | - |
| | TOTAL GROSS PLANT FOR AROs | (sum lines 13-18) | $ - | $ - |
| | **ACCUMULATED DEPRECIATION FOR AROs** | | | |
| 19 | Production (Total) | (sum lines 19a-19d) | $ - | $ - |
| 19 a | Steam Production | Workpaper | $ - | $ - |
| 19 b | Nuclear Production | Workpaper | - | - |
| 19 c | Hydraulic Produciton | Workpaper | - | - |
| 19 d | Other Production | Workpaper | - | - |

| | | | | |
|---|---|---|---|---|
| 20 | Transmission | Workpaper | - | - |
| 21 | Distribution | Workpaper | - | - |
| 22 | General | Workpaper | - | - |
| | Intangible | Workpaper | | |
| 23 | | | - | - |
| 24 | Common | Workpaper | - | - |
| | TOTAL ACCUM. DEPRECIATION FOR AROs | (sum lines 19-24) | $ - | $ - |

**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

**Determination of Net Plant, Net of Asset Retirement Obligations ("AROs")**
**For the 12 months ended - December 31, XXXX**

ARO Adj
Page 2 of 2

| Line No | (1) | (2) Form No. 1 Page, Line, Col. | (3) Evergy Kansas Central, Inc. (EKC) | (4) Evergy Kansas South, Inc. (EKS) |
|---|---|---|---|---|
| | **PLANT IN SERVICE, NET of AROs** | | | |
| 1 | Production | pg 1, ln 1 less pg 1, ln 13 | $ - | $ - |
| 2 | Transmission | pg 1, ln 2 less pg 1, ln 14 | - | - |

| | | | | |
|---|---|---|---|---|
| 3 | Distribution | pg 1, ln 3 less pg 1, ln 15 | - | - |
| 4 | General | pg 1, ln 4 less pg 1, ln 16 | - | - |
| 5 | Intangible | pg 1, ln 5 less pg 1, ln 17 | - | - |
| 6 | Common | pg 1, ln 6 less pg 1, ln 18 | - | - |
| | TOTAL GROSS PLANT, NET of AROs | (sum lines 1-6) | $ - | $ - |
| | **ACCUMULATED DEPRECIATION, NET of AROs** | | | |
| | | pg 1, ln 7 less pg | $ | $ |
| 7 | Production | 1, ln 19 | - | - |
| 8 | Transmission | pg 1, ln 8 less pg 1, ln 20 | - | - |
| 9 | Distribution | pg 1, ln 9 less pg 1, ln 21 | - | - |
| 10 | General | pg 1, ln 10 less pg 1, ln 22 | - | - |
| 11 | Intangible | pg 1, ln 11 less pg 1, ln 23 | - | - |
| 12 | Common | pg 1, ln 12 less pg 1, ln 24 | - | - |
| | TOTAL ACCUM. DEPRECIATION, NET of AROs | (sum lines 7-12) | $ - | $ - |

**Worksheet A-1 - Revenue Credit**



**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**
**Determination of Revenue Credits**
**For the 12 months ended - December 31, xxxx**

**I. Account 456** ( see Note A in Section IV on page 3 of 3 )

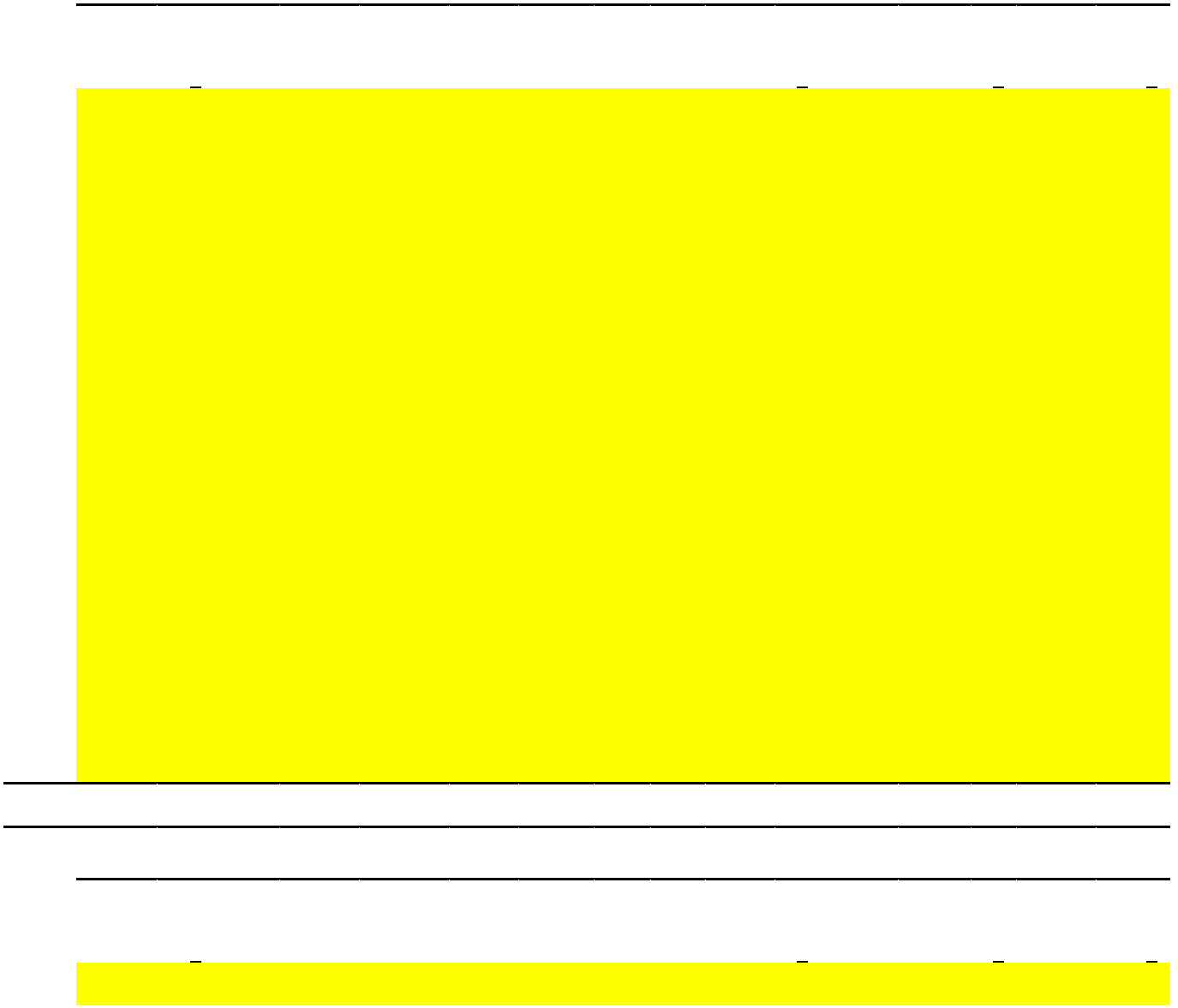
| Line No. | EKC and EKS | | Company TOTAL | CMCPH | EMe | MIDW | MOPEP | OMPA | SWPP | SWPP Studies | DEC | KVE | NMEC | n/a | CCHAN | CGIRA | n/a | CNEOD | CWINF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 456.1000 | Transmission Service | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 | | | | | | | | | | | | | | | | | | | |
| 2 | 456.1001 | Trans Service - Retail Only | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | 456.1500 | Anc 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | 456.1501 | Anc 1 - Retail Only | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | 456.1100 | Anc 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | 456.1210 | n/a | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | 456.1101 | Anc 2 - Retail Only | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | 456.1020 | Anc 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | 456.1030 | Anc 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | 456.1040 | Anc 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | 456.1050 | Anc 6 SPP | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | 456.1060 | Losses/MID W Cntrl Dist. | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | 456.1200 | Facilities Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13a | 456.xxxx | Trans. Fac. Charge | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | 456.1003 | Trans Studies | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | Total | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Less: Accounts 456.1020 through 456.1501 less | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 17 | TFC | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 18 | Revenue for Demands in Divisor -- 456.1000 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | Revenue for Demands in Divisor -- 456.1001 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20 | **Sub Total Revenue Credit** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Previous Years Adjustment | | - | | | | | | | | | | | | | | | | | | | |
| 21 | Rev. Adj. not captured in 456.1 or 456.1001(Note B) | | - | | | | | | | | | | | | | | | | | | | |
| 21b | Ratio of Rev Credit to Trans Rev. [(line 20/(line1+line2)] | | 0.00 % | | | | | | | | | | | | | | | | | | | |
| 21c | Rev. Adj. Alloc. To Rev Credit. | (line 21a * 21b) | - | | | | | | | | | | | | | | | | | | | |
| 22 | **Total Revenue Credit** | (lines 20 - 21c) | **$ -** | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | Company | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **EKC** | | TOTAL | CMCPH | EMe | MIDW | MOPEP | OMPA | SWPP | SWPP Studies | DEC | KVE | NMEC | n/a | CCHAN | CGIRA | n/a | CNEOD | CWINF |
| 23 | 456.1000 | Transmission Service Trans | $ - | | | | | | | | | | | | | | | | |
| 24 | 456.1001 | Service - Retail Only | - | | | | | | | | | | | | | | | | |
| 25 | 456.1500 | Anc 1 | - | | | | | | | | | | | | | | | | |
| 26 | 456.1501 | Anc 1 - Retail Only | - | | | | | | | | | | | | | | | | |
| 27 | 456.1100 | Anc 2 | - | | | | | | | | | | | | | | | | |
| 28 | 456.1210 | n/a | - | | | | | | | | | | | | | | | | |
| 29 | 456.1101 | Anc 2 - Retail Only | - | | | | | | | | | | | | | | | | |
| 30 | 456.1020 | Anc 3 | - | | | | | | | | | | | | | | | | |
| 31 | 456.1030 | Anc 4 | - | | | | | | | | | | | | | | | | |
| 32 | 456.1040 | Anc 5 | - | | | | | | | | | | | | | | | | |
| 33 | 456.1050 | Anc 6 | - | | | | | | | | | | | | | | | | |
| 34 | 456.1060 | SPP Losses/MID W Cntrl Dist. | - | | | | | | | | | | | | | | | | |
| 35 | 456.1200 | Facilities Charge | - | | | | | | | | | | | | | | | | |
| 36a | 456.xxxx | Trans. Fac. Charge | - | | | | | | | | | | | | | | | | |
| 36 | 456.1003 | Trans Studies | - | | | | | | | | | | | | | | | | |
| 37 | Total | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | Company | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **EKS** | | TOTAL | CMCPH | EMe | MIDW | MOPEP | OMPA | SWPP | SWPP Studies | DEC | KVE | NMEC | n/a | CCHAN | CGIRA | n/a | CNEOD | CWINF |
| | 456.1000 | Transmissi | $ | | | | | | | | | | | | | | | | |

38 0 on Service -



| | | | |
|---|---|---|---|
| 39 | 456.1001 | Trans Service - Retail Only | - |
| 40 | 456.1500 | Anc 1 | - |
| 41 | 456.1501 | Anc 1 - Retail Only | - |
| 42 | 456.1100 | Anc 2 | - |
| 43 | 456.1210 | n/a | - |
| 44 | 456.1101 | Anc 2 - Retail Only | - |
| 45 | 456.1020 | Anc 3 | - |
| 46 | 456.1030 | Anc 4 | - |
| 47 | 456.1040 | Anc 5 | - |
| 48 | 456.1050 | Anc 6 | - |
| 49 | 456.1060 | SPP Losses/MID W Cntrl | - |
| 50 | 456.1200 | Dist. Facilities Charge | - |
| 50a | 456.xxxx | Trans. Fac. Charge | - |
| 51 | 456.1003 | Trans Studies | - |
| 52 | Total | | $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - $ - |



**Worksheet A-1 - Revenue Credit**

| **Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.** |
|---|

**Determination of Revenue Credits**

**Account 454**

| Line No. | EKC | | | Balance at End of Year | EKS | | | Balance at End of Year |
|---|---|---|---|---|---|---|---|---|
| | **REVENUE CREDITS** | | | | **REVENUE CREDITS** | | | |
| 1 | Account 454 (Rent from Electric Property) | | | | Account 454 (Rent from Electric Property) | | | |
| | **Excluded:** | | | | **Excluded:** | | | |
| 2 | | Distribution rental (see below) | | $ - | | Land rental for Gordon Evans CTs | | |
| 3 | | Other Electric Property Rents | | | | Other Electric Property Rents | | |
| 4 | | | | | | Distribution rental (see below) | | $ - |
| 5 | Included in template | | | $ - | | Included in template | | $ - |

| | EKC | EKS |
|---|---|---|
| | 300.19.b | 300.19.b |
| | | 454.08000 |
| | 454.07000 | 454.07000 |

Distribution rental developed as follows:

| | Description | (Sum 454.01-.05) |
|---|---|---|
| 6 | Description | |
| 7 | Distribution pole attachment ratio | - |
| 8 | Distribution rental | $ - |

| | | Per Attachments | Ratio |
|---|---|---|---|
| 9 | Transmission | | - |
| 10 | Distribution | | - |
| 11 | Total | - | - |

For both EKC and EKS, only non-transmission related items included. Determined by the ratio of pole attachments on transmission vs distribution.

Distribution rental developed as follows:

| | Description | (Sum 454.01-.05) |
|---|---|---|
| | Description | |
| | Distribution pole attachment ratio | - |
| | Distribution rental | $ - |

| | | Per Attachments | Ratio |
|---|---|---|---|
| | Transmission | | - |
| | Distribution | | - |
| | Total | - | - |

I

I

I **Revenue from Grandfathered Interzonal Transactions and service provided by the RTO at a discount in Account 454**

| | |
|---|---|
| Revenues from Grandfathered Interzonal Transactions | $ - |
| Revenues from service provided by the ISO at a discount | $ - |

**Worksheet A-1 - Revenue Credit**

**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**
**Determination of Revenue Credits**

**IV**

**Notes**

Account 456 revenue treated as a credit to cost of service in this formula is from subaccount 456.1000, Transmission Service. Revenue **A** from Grandfathered point-to-point (GFA - all Companies in Section I except SWPP).

Revenue from Grandfathered point-to-point (GFA - all Companies in Section I except SWPP).

**Wholesale NITS Revenues - The content in these categories can change over time:**

| Month | SWPP Allocated NITS | SWPP Individual NITS | SWPP NITS Bought by Others | Total $ |
|---|---|---|---|---|
| January | | | | - |
| February | | | | - |

| | | | | |
|---|---|---|---|---|
| March | | | | - |
| April | | | | - |
| May | | | | - |
| June | | | | - |
| July | | | | - |
| August | | | | - |
| September | | | | - |
| October | | | | - |
| November | | | | - |
| December | | | | - |
| Total | $ - | $ - | $ - | $ - |

Monthly loads associated with the remaining revenue for Transmission Service (subaccount 456.1001) from SWPP (e.g., retail) are also included in the DIVISOR. However, the associated revenue is

included as a revenue credit to offset the associated SWPP expenses booked to account 566, Miscellaneous Transmission Expense.

Revenue from Grandfathered Agreements involving interzonal transactions whose rates have been changed to eliminate or mitigate pancaking are included in Section III above and the corresponding

loads are included in the DIVISOR.

Revenue from Grandfathered Agreements involving interzonal transactions whose rates have not been changed to eliminate or mitigate pancaking are not included in Section III above and the corresponding

loads are not included in the DIVISOR.

Revenue credits do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services and/or facilities not included in this template, e.g., directly assigned facilities, GSUs, etc.

Account 454 (Rent from Electric Property) includes income related only to transmission facilities, such as pole attachments, rentals and special use.

**B** Line 21a represents a refund or surcharge that is done by SPP where the increase or decrease in revenue is not reflected in the 456.1000 or 456.1001 revenues. If a value is entered into this

line, a support worksheet will be included with the posted formula. Refunds will be entered as a negative value, surcharges as a positive value. The adjustment does not included any refunds or surcharges
associated with the sale of ancillary services.
Line 21b is the ratio of the amount of the revenue credit on line 20 to the total amount of revenue collected from the transmission charges, excluding ancillary revenues.

C The Transmission Facilities Charge is the revenue from transmission customers that pay for direct assigned costs related to transmission facilities. This revenue is anticipated from the implementation of the SPP definition of transmission (Attachment AI) which requires the direct assignment of costs related to 1) single customer radial facilities and 2) those facilities which are booked into transmission accounts, but operate at less than 60 kV and have not been determined to be transmission facilities by the Commission using the seven factor test.

**Worksheet A-2 - Divisor**



**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

**Determination of Transmission Network Load (MW)**
**For the 12 months ended - December 31, xxxx**

**I. Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

| Date | Hour Ending | Company Transmission Peak Load | Adjustment | EKC and EKS's Transmission System Peak Load | Less: GFA PTP Scheduled Load | Plus: GFA PTP Contract Demand | Less: Non-Firm Sales to Cities | Plus: Non-EKC and EKS Generation | Plus: Non-Control-Area Transmission Load | Less: Load Not Connected to the EKC and EKS Transmission Network | EKC and EKS's Transmission Network Load (e-f+g-h+i+j-k) | Percentage of Maximum Transmission Network Load During Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | Syst em | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (i) |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| | | n/a | n/a | | - | - | - | - | - | - | - | 0.00% |
| Total | | n/a | n/a | - | - | - | - | - | - | - | - | |
| 12-CP | | n/a | n/a | - | - | - | - | - | - | - | - | |



**Worksheet A-2 - Divisor**

**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

**Determination of EKC's and EKS' Contribution to Transmission Network Load (MW)**

**For the 12 months ended - December 31, xxxx**

| II. EKC | | Company Transmission Peak Load[1] | | Load at EKC's Transmission System Peak Load[3] | Less: GFA PTP Scheduled Load[4] | Plus: GFA PTP Contract Demand[5] | Less: Non-Firm Sales to Cities[6] | Plus: Non-EKC Generation[7] | Plus: Non-Control-Area Transmission Load[8] | Less: Load Not Connected to the EKC Transmission System[9] | EKC's Transmission Network Load (e-f+g-h+i+j-k) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Hour Ending[1] | | Adjustment[2] | | | | | | | | |
| Date[1] | | | | | | | | | | | |
| (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (I) | (j) | (k) | (l) |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
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| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |

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| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| Total | | - | - | - | - | - | - | - | - | - | - |
| 12-CP | | - | - | - | - | - | - | - | - | - | - |

| III. EKS | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Company Transmission Peak Load [1] | | Load at EKS's Transmission System Peak Load[3] | | Plus: GFA PTP Contract Demand[5] | | Plus: Non-EKS Generation[7] | Plus: Non-Control-Area Transmission Load[8] | Less: Load Not Connected to the EKS Transmission System[9] | EKS's Transmission Network Load (e-f+g-h+i+j-k) |
| | Hour Ending[1] | | Adjustment[2] | | Less: GFA PTP Scheduled Load[4] | | Less: Non-Firm Sales to Cities[6] | | | | |
| Date[1] | | | | | | | | | | | |
| (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |

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| | | | | - | - | - | - | - | - | - | - |
| | | | | - | - | - | - | - | - | - | - |
| Total | - | - | - | - | - | - | - | - | - | - | |
| 12-CP | - | - | - | - | - | - | - | - | - | - | |



**Worksheet A-2 - Divisor**

**Evergy Kansas Central and Evergy Kansas South, Inc.**

**Notes to the Determination of EKC's and EKS' Contribution to Transmission Network Load (MW, unless otherwise noted)**

**For the 12 months ended - December 31, xxxx**

**(all load data in these notes comes from Evergy Kansas Central, Inc. and Evergy Kansas South's "NETWORK BILLING DETERMINANTS" spreadsheet or successor spreadsheet)**

| | |
|---|---|
| Note: 1 | These are the dates, times and loads at the time of EKC's and EKS' transmission peak, as reported in FERC Form 1, page 400. |
| Note: 2 | This is the difference between "Company Transmission Peak Load" and "Load at Transmission System Peak Load." |
| Note: 3 | These are the EKC and EKS values that, when added together, equal the transmission system peak load in Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s Energy Accounting System, Monthly Min/Max Load Values report. |
| Note: 4 | "GFA PTP Scheduled Load" is the load in MW scheduled by Grandfathered Agreements' (GFA) customers taking firm point-to-point (PTP) service at the time of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s monthly transmission system peak load. These amounts are assigned equally between EKC and EKS in Sections II and III above. Details are as follows: |

| | | | | | | | | | | | | | | GFA PTP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Burlington | KMEA-SPA | KMEA | OMPA-WRI | OMPA | Kaw Valley | N-M | KEPCo | | Midwest | | Firm |
| | | 0- | #1-JEC | (Chanute only) | Nearman | PPA1 | PPA2 | SWPA | SWPA | Sch B | McPherson | Energy | Altamont | Schedules |
| Jan | 0 | Jan-000- | | | | | | | | | | | | - |
| Feb | 0 | Jan-000- | | | | | | | | | | | | - |
| Mar | 0 | Jan-000- | | | | | | | | | | | | - |
| Apr | 0 | Jan-000- | | | | | | | | | | | | - |
| May | 0 | Jan-000- | | | | | | | | | | | | - |
| Jun | 0 | Jan-000- | | | | | | | | | | | | - |
| Jul | 0 | Jan-000- | | | | | | | | | | | | - |
| Aug | 0 | Jan-000- | | | | | | | | | | | | - |
| Sep | 0 | Jan-000- | | | | | | | | | | | | - |
| Oct | 0 | Jan-000- | | | | | | | | | | | | - |
| Nov | 0 | Jan-000- | | | | | | | | | | | | - |
| Dec | 0 | Jan-00 | | | | | | | | | | | | - |

Note: 5

"GFA PTP Contract Demand" is the contract demand in MW for these customers. These amounts are assigned equally between EKC and EKS in Sections II and III above. Details are as follows:

| | | | Burlington #1-JEC | KMEA-SPA (Chanute only) | KMEA Neraman | OMPA-WRI PPA1 | OMPA PPA2 | Kaw Valley SWPA | N-M SWPA | KEPCo Sch B | McPherson | Midwest Energy | Altamont | GFA PTP Firm Schedules |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 0- | | | | | | | | | | | | |
| Jan | 0 | Jan-000- | | | | | | | | | | | | - |
| Feb | 0 | Jan-000- | | | | | | | | | | | | - |
| Mar | 0 | Jan-000- | | | | | | | | | | | | - |
| Apr | 0 | Jan-000- | | | | | | | | | | | | - |
| May | 0 | Jan-000- | | | | | | | | | | | | - |
| Jun | 0 | Jan-000- | | | | | | | | | | | | - |
| Jul | 0 | Jan-000- | | | | | | | | | | | | - |
| Aug | 0 | Jan-000- | | | | | | | | | | | | - |
| Sep | 0 | Jan-000- | | | | | | | | | | | | - |
| Oct | 0 | Jan-000- | | | | | | | | | | | | - |
| Nov | 0 | Jan-000- | | | | | | | | | | | | - |
| Dec | 0 | Jan-00 | | | | | | | | | | | | - |

**Worksheet A-2 - Divisor**



**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

**Notes to the Determination of EKC's and EKS' Contribution to Transmission Network Load (MW, unless otherwise noted)**
**For the 12 months ended - December 31, xxxx**
**(all load data in these notes comes from Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s "NETWORK BILLING DETERMINANTS" spreadsheet or successor spreadsheet)**

Note: 6 "Non-Firm Sales to Cities" are MW loads at the time of Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s monthly transmission system peak load associated with non-firm GFA transmission service or loads solely utilizing SPP PTP transmission service.

| | | | | | EKS | | | | | | | EKC | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Contract Type | GM | SPP PTP | | | | | SPP PTP | | | | | | | Total Part. Req. Demand |
| | | Customer | Chanute | KPP | Future use | Future use | Future use | Total (MW) (a+b+c+d+e) | KPP | Future use | Future use | Future use | Total (MW) (g+h+i+j) | (MW) (f+k) |
| | | | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| | | 0- | | | | | | | | | | | | |
| Jan | 0 | Jan-00 0- | | | | | | - | | | | | - | - |
| Feb | 0 | Jan-00 0- | | | | | | - | | | | | - | - |
| Mar | 0 | Jan-00 0- | | | | | | - | | | | | - | - |
| Apr | 0 | Jan-00 | | | | | | - | | | | | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | |
| | | 0- | | | | | | | | | | | | |
| May | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Jun | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Jul | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Aug | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Sep | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Oct | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Nov | 0 | Jan-00 | | | | | - | | | | | - | - | |
| | | 0- | | | | | | | | | | | | |
| Dec | 0 | Jan-00 | | | | | - | | | | | - | - | |

Note: 7 "Non-Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. Generation" in MW is shown below. Only generators operating synchronously with the transmission system, and not already included in the transmission peak value, shall be included.

| | | | | | EKS | | | | | | EKC | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Contract Type Customer | SPP PTP | SPP NITS | SPP NITS Mulvane | Future use | Future use | Total (MW) (a+b+c+d+e) | SPP PTP | Future use | Future use | Future use | Total (MW) (g+h+i+j) | Total Gen. (MW) (f+k) |
| | | | KPP | KPP | | | | | KPP | | | | | |
| | | | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| | | 0- | | | | | | | | | | | | |
| Jan | 0 | Jan-00 | | | | | | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | |
| | | 0- | | | | | | | | | | | | |
| Feb | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Mar | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Apr | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| May | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Jun | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Jul | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Aug | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Sep | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Oct | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Nov | 0 | Jan-000- | | | | | | - | - | - | - | - | - | - |
| Dec | 0 | Jan-00 | | | | | | - | - | - | - | - | - | - |

**Worksheet A-2 - Divisor**



**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

**Notes to the Determination of EKC's and EKS' Contribution to Transmission Network Load (MW, unless otherwise noted)**
**For the 12 months ended - December 31, xxxx**

**(all load data in these notes comes from Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s "NETWORK BILLING DETERMINANTS" spreadsheet or successor spreadsheet)**

Note: 8

"Non-Control Area Transmission Load" in kW is load on Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s transmission system that is electronically transferred to control areas other than Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.
Details are as follows:

| | | | | | EKS | | | | | | EKC | | | Total Load. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Future use | Future use | Future use | Future use | Future use | Total (MW) (a+b+c+d+e) | Future use | Future use | Future use | Future use | Total (MW) (g+h+i+j) | (MW) (f+k) |
| | | 0- | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| Jan | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Feb | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Mar | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Apr | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| May | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Jun | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Jul | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Aug | 0 | Jan-000- | - | - | - | - | - | - | - | - | - | - | - | - |
| Sep | 0 | Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 0- | | | | | | | | | | | | |
| Oct | 0 | Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - |
| Nov | 0 | 0-Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - |
| Dec | 0 | 0-Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - |

Note: 9 "Load in Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s Balancing area and included in the Transmission peak number, but is physically connected to a different SPP Transmission Owner's system."

| | | | | | EKS | | | | | EKC | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Future use | Future use | Future use | Future use | Future use | Total (MW) | KEPCO MID W and MKEC load | Future use | Future use | Future use | Future use | Total (MW) | Total Load. (MW) |
| | | | | | | | | (a+b+c+d+e) | | | | | | (g+h+i+j) | (f+k) |
| | | 0- | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| Jan | 0 | Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |
| Feb | 0 | 0-Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |
| Mar | 0 | 0-Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |
| Apr | 0 | 0-Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |
| May | 0 | 0-Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |
| Jun | 0 | 0-Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | |
| | | 0- | | | | | | | | | | | | |
| Jul | 0 | Jan-00 0- | - | - | - | - | - | - | | - | - | - | - | - |
| Aug | 0 | Jan-00 0- | - | - | - | - | - | - | | - | - | - | - | - |
| Sep | 0 | Jan-00 0- | - | - | - | - | - | - | | - | - | - | - | - |
| Oct | 0 | Jan-00 0- | - | - | - | - | - | - | | - | - | - | - | - |
| Nov | 0 | Jan-00 0- | - | - | - | - | - | - | | - | - | - | - | - |
| Dec | 0 | Jan-00 | - | - | - | - | - | - | | - | - | - | - | - |



**Worksheet A-3 - Retail Adder**

**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

**Items Deemed to be Allocated Exclusively to the Retail Jurisdiction**

For the 12 months ended - December 31, xxxx

| Line No | | | | | EKC | EKS | Total |
|---|---|---|---|---|---|---|---|
| 1 | Rate Base | | | | | | |
| 2 | | ADIT - Retail | | [A5, pg 1, line 4 & A7, pg1, line4) | $ - | - | $ - |
| 3 | | | Total | | $ - | $ - | $ - |
| 4 | | Alloc. Fact. - Gross Plant | | (Actual Gross Rev, pg 3, line 17) | 0.000% | 0.000% | |
| 5 | | Transmission Related | | [ line 3 x line 4 ] | $ - | $ - | $ - |
| 6 | Rate of Return | | | [Actual Gross Rev, pg 4, line 24) | 0.000% | 0.000% | |
| 7 | Return | | | [ line 5 x line 6 ] | $ - | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 8 | Income Tax Factor | | | [Actual Gross Rev, pg 2, line 24) | | 0.000% | 0.000% |
| 9 | Income Taxes | | | [ line 7 x line 8 ] | $ | - | $ - | $ - |
| 10 | Other Expenses | | | | | | | |
| 11 | | Item 1 | | | $ | - | $ - | $ - |
| 12 | | Item 2 | | | | - | - | - |
| 13 | | Item 3 | | | | - | - | - |
| 14 | | Item 4 | | | | - | - | - |
| 15 | | | Total | [ sum of lines 11 through 14 ] | $ | - | $ - | $ - |
| 16 | Revenue Requirement | | | [ line 7 + line 9 + line 15 ] | | - | - | - |

**Worksheet A-4 - EKC O&M Exclusions**



**Evergy Kansas Central, Inc.**

**Determination of O&M Exclusions from the Formula Rate**

For the 12 months ended - December 31, xxxx

Page.
Line No.
Col.

321.112.b **O&M**

| | |
|---|---|
| Transmission (321.112.b) | |
| **Exclude:** | |
| Network service for Evergy Kansas Central, Inc. Retail load including ancillaries and schedule 12 (Account 566.0011) | |
| Total (Included in Sch. EKC, p. 2, ln. 1, col. 3) | **$ -** |

**Worksheet A-5 - EKC ADIT**



**Evergy Kansas Central, Inc.**
**Allocation of ADIT**
For the 12 months ended - December 31, xxxx

| Line No. | | Summary | 100% NonTrans. Related | 100% Transmission Related | Plant Related | Labor Related | 100% Retail Related | Total ADIT | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Less | **ADIT-282** | $ - | $ - | $ - | $ - | $ - | | |
| 2 | Less | **ADIT-283** | $ - | $ - | $ - | $ - | $ - | | |
| 3 | Plus | **ADIT-190** | $ - | $ - | $ - | $ - | $ - | | |
| 4 | | **Subtotal** | $ - | $ - | $ - | $ - | $ - | $ - | |
| 5 | | **Wages & Salary Allocator** | | | | 0.0000 % | | | |
| 6 | | **Gross Plant Allocator** | | 100.0000% | 0.0000% | | | | |
| 7 | | **ADIT *Subtotal*** | | $ - | $ - | $ - | $ - | $ - | |
| *8* | | ***EDIT Adjustment*** | | | | | | *$ -* | *(worksheet A-5-2, Net* |

| | | | |
|---|---|---|---|
| 9 | ***ADIT Total*** | $ - | *(Excess)/Deficient Deferred Income Taxes, column (n).* |

**Worksheet A-5 - EKC ADIT**



**Evergy Kansas Central, Inc.**
**Allocation of ADIT**

| **ADIT-190** | **(A)** | **(B)** | **(C)** | **(D)** | **(E)** | **(F)** | **(G)** | ***(G)*** |
|---|---|---|---|---|---|---|---|---|
| | | ***100%*** | ***100%*** | | | **100% Retail** | **In** | |
| | **YE Balance** | **NonTrans. Related** | **Transmission Related** | **Plant Related** | **Labor Related** | **[Allocate by Plant]** | **Adjustment to Ratebase** | ***Description and Justification*** |

**Worksheet A-5 - EKC ADIT**



**Evergy Kansas Central, Inc.**

| CONTINUE ADIT-190 | (A) | (B) | (C) | (D) | Allocation of ADIT (E) | (F) | (G) | (G) |
|---|---|---|---|---|---|---|---|---|
| | 0 YE Balance | 100% NonTrans. Related | 100% Transmission Related | Plant Related | Labor Related | 100% Retail [Allocate by Plant] | In Adjustment to Ratebase | *Description and Justification* |
| *Accumulated Deferred Income Tax Non Utility* | | | | | | | | |
| *Less 19001 Tax Reclass* | - | - | | - | | | | Cur vs L/T Reclass (for financial reporting) |
| **Subtotal - p234** | | - | - | - | - | - | - | |
| **Less FASB 109 Above if not separately removed** | | | | - | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Less FASB 106 Above if not separately removed** | | | | - | - | - | | |
| **Total** | | - | - | - | - | - | | |

**Worksheet A-5 - EKC ADIT**



**Evergy Kansas Central, Inc.**
**Allocation of ADIT**

| ***ADIT- 281 & 282*** | ***(A)*** | ***(B)*** | ***(C)*** | ***(D)*** | ***(E)*** | ***(F)*** | ***(G)*** | ***(G)*** |
|---|---|---|---|---|---|---|---|---|
| | **0** ***YE Balance*** | ***100% NonTrans. Related*** | ***100% Transmission Related*** | ***Plant Related*** | ***Labor Related*** | ***100% Retail [Allocate by Plant]*** | ***In Adjustment to Ratebase*** | ***Description and Justification*** |
| *Accumulated Deferred Income Tax Accelerated Amortization Property* | | | | | | | | |
| *Subtotal Page 273* | *$-* | *$-* | *$-* | *$-* | *$-* | *$-* | *$-* | |
| *Accumulated Deferred Income Tax Other Property* | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Subtotal** al -p275 | - | - | - | - | - | - | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Total** | - | - | - | - | - | | | |

**Worksheet A-5 - EKC ADIT**



**Evergy Kansas Central, Inc.**

**Allocation of ADIT**

| *ADIT-283* | *(A)* | *(B)* | *(C)* | *(D)* | *(E)* | *(F)* | *(G)* | *(G)* |
|---|---|---|---|---|---|---|---|---|
| | ***0 YE Balance*** | ***100% NonTrans. Related*** | ***100% Transmission Related*** | ***Plant Related*** | ***Labor Related*** | ***100% Retail [Allocate by Plant]*** | ***In Adjustment to Ratebase*** | ***Description and Justification*** |
| *Accumulated Deferred Income Tax Other Utility* | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Subtotal - p277** | | | - | - | - | - | - | - | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | | |
| **Total** | | | - | - | - | - | - | | |

***Evergy Kansas Central, Inc.***

***Worksheet A-5-2***

***Accumulated Excess / Deficient Deferred Income Taxes("EDIT/DDIT")***

***Actuals - For the 12 months ended 12/31/20XX***

| *No.* | | *(a)* | *12/31/XX (b)* | *12/31/XX (c)* | *12/31/XX (d)* | *20XX (e)* | *20XX (f)* | *12/31/XX (g)* | *(h)* |
|---|---|---|---|---|---|---|---|---|---|
| ***Line No.*** | ***Account*** | ***Item*** | ***Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)*** | ***BOY Cumulative Amortization*** | ***BOY Cumulative Other Adjustments (Note B)*** | ***Current Period Amortization (Expense) Benefit*** | ***Current Period Other Activity (Note B)*** | ***EOY Balance (Note C)*** | ***Allocator*** |

***190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES***

*190200*

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| *Total (EDIT)/DDIT - Account 190* | - | - | - | - | - | - | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| *12/31/XX* | *12/31/XX* | *12/31/XX* | *20XX* | *20XX* | *12/31/XX* | | | *12/31/XX* | *12/31/XX* | |
| *(i)* | *(j)* | *(k)* | *(l)* | *(m)* | *(n)* | *(o)* | *(p)* | *(q)* | *(r)* | *(s)* |
| ***Beginning Balance of Transmission Deficient (Excess) ADIT*** | ***BOY Transmission Cumulative Other Adjustments (Note B)*** | ***BOY Transmission Cumulative Amortization*** | ***Current Period Transmission Amortization (Expense) Benefit*** | ***Current Period Transmission Other Activity (Note B)*** | ***EOY Allocated Transmission Balance (Note C)*** | ***Amort Period or Method*** | ***Explanation (Note D)*** | ***Grossed-up EOY amount recorded to Account 182.3*** | ***Grossed-up EOY amount recorded to Account 254*** | ***Expense Account Amortization recorded to*** |

***190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES***

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| - | - | - | - | - | - | | | | | - |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** | **Allocator** |
| | | **283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | |
| | 283300 | | | | | | | | |
| | | Total (EDIT)/DDIT - Account 283 | - | - | - | - | - | - | |
| | | **Total Non-Plant Unprotected (EDIT)/DDIT** | - | - | - | - | - | - | |

| 12/31/XX (i) | 12/31/XX (j) | 12/31/XX (k) | 20XX (l) | 20XX (m) | 12/31/XX (n) | (o) | (p) | 12/31/XX (q) | 12/31/XX (r) | (s) |
|---|---|---|---|---|---|---|---|---|---|---|
| **Beginning Balance of Transmission Deficient (Excess) ADIT** | **BOY Transmission Cumulative Other Adjustments (Note B)** | **BOY Transmission Cumulative Amortization** | **Current Period Transmission Amortization (Expense) Benefit** | **Current Period Transmission Other Activity (Note B)** | **EOY Allocated Transmission Balance (Note C)** | **Amort Period or Method** | **Explanation (Note D)** | **Grossed-up EOY amount recorded to Account 182.3** | **Grossed-up EOY amount recorded to Account 254** | **Expense Account Amortization recorded to** |
| **283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | | | |
| - | - | - | - | - | - | | | | - | |
| - | - | - | - | - | - | | | - | - | |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** | **Allocator** |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** | **Allocator** |
| | | **281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | |
| | 281000 | | | | | | | | |
| | 282611 | | | | | | | | |
| | | Basis Differences (Unprotected): | | | | | | | |
| | 282611 | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Total Plant (EDIT)/DDIT* | | | - | - | - | | - | - | - | | |
| ***Net (Excess)/Deficient Deferred Income Taxes*** | | | - | - | - | | - | - | - | | |
| ***EDIT Amortization:*** | | | *Total* | | | | *Allocator* | *Rate* | *Allocated* | | |
| ***Total 190 Deficient Deferred Income Taxes*** | | | - | | | | *See above* | *See above* | - | | |
| ***Total 283 Excess Deferred Income Taxes*** | | | - | | | | *See above* | *See above* | - | | |
| ***Total 281/282 Excess Deferred Income Taxes*** | | | - | | | | *See above* | *See above* | - | | |
| | | | - | | | | | | - | | |
| *12/31/XX* | *12/31/XX* | *12/31/XX* | *20XX* | *20XX* | *12/31/XX* | | | *12/31/XX* | *12/31/XX* | | |
| *(i)* | *(j)* | *(k)* | *(l)* | *(m)* | *(n)* | *(o)* | *(p)* | *(q)* | *(r)* | *(s)* | |
| ***Beginning Balance of Transmission Deficient (Excess) ADIT*** | ***BOY Transmission Cumulative Other Adjustm*** | ***BOY Transmission Cumulative*** | ***Current Period Transmission Amortization (Expense) Benefit*** | ***Current Period Transmission Other Activity (Note B)*** | ***EOY Allocated Transmission Balance (Note C)*** | ***Amort Period or Method*** | ***Explanation (Note D)*** | ***Grossed-up EOY amount recorded to*** | ***Grossed-up EOY amount recorded to*** | ***Expense Account Amortization recorded to*** | |

| | ents (Note B) | Amortiza tion | | | | Account 182.3 | Account 254 |
|---|---|---|---|---|---|---|---|
| **281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| - | - | - | - | - | - | - | - |
| | | | | | | | |
| - | - | - | - | - | - | - | - |

*Notes:*

| | |
|---|---|
| *A* | *Amount carried from EKC Computation tab column (h).* |
| *B* | *Includes return to accrual adjustments, amended return adjustments, book adjustments and other.* |
| *C* | *Excess and Deficient balances exclude income tax gross-ups recorded to accounts 182.3 and 254.* |
| *D* | *Each EDIT item is categorized into 1 of 5 categories. The selected category will determine the Allocator applied to the EDIT balance.* |
| | *1) NonTrans: The EDIT balance is 100% unrelated to the Transmission of electricity and the NA Allocator is applied.* |
| | *2) Retail: The EDIT balance is 100% related to retail operations and the NA allocator is applied.* |
| | *3) Trans: The EDIT balance is 100% related to transmission operations and the DA Allocator is applied.* |
| | *4) Plant: The EDIT balance is related to Property, Plant & Equipment "PP&E" and the GP Allocator is applied.* |
| | *5) Labor: The EDIT balance is labor related and the W/S allocator is applied.* |

*Worksheet A-5-3 - EKC Computation*

***Evergy Kansas Central, Inc.***
***Computation of EDIT due to Tax Cut and Jobs Act***

| *No.* | *(a)* | *(b)* | *(c)* | *(d)* | *(e)* | *(f)* | *(g)* | *(h)* |
|---|---|---|---|---|---|---|---|---|

| Line No. | Account | Description | Temporary Differences Before Rate Change | Prior Tax Rate | Balance Before Tax Rate Change | New Tax Rate | Balance of ADIT after Tax Rate Change | Deficient/ (Excess)ADIT |
|---|---|---|---|---|---|---|---|---|
| | | 190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES | | | | | | |
| | 190200 | | | | | | | |
| | | Total (EDIT)/DDIT - Account 190 (Unprotected) | - | | - | | - | - |
| | | 283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES | | | | | | |
| | 283300 | | | | | | | |
| | | Total (EDIT)/DDIT - Account 283 (Unprotected) | - | | - | | - | - |

| | | | | | |
|---|---|---|---|---|---|
| | ***Total Non-Plant Unprotected (EDIT)/DDIT*** | | | | - |
| | *190 NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES* | | | | |
| *190300* | | | | | |
| | ***Total NOL (EDIT)/DDIT - Account 190*** | | | | - |
| | *281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES* | | | | |
| *281100* | | | | | |
| *282611* | | | | | |
| | *Basis Differences (Unprotected):* | | | | |
| *282611* | | | | | |
| | *Total Plant (EDIT)/DDIT - Accounts 281 & 282* | - | - | - | - |

| | |
|---|---|
| ***Net (Excess)/Deficient Deferred Income Taxes*** | - |

**Worksheet A-6 - EKS O&M Exclusions**



**Evergy Kansas South, Inc.**

**Determination of O&M Exclusions from the Formula Rate**

For the 12 months ended - December 31, xxxx

| Page. Line No. Col. | | |
|---|---|---|
| 321.112.b | **O&M** | |
| | Transmission | |
| | **Exclude:** | |
| | Network service for Evergy Kansas South, Inc. Retail load including ancillaries and schedule 12 (Account 566.0011) | |
| | Total (Included in Sch. EKS, p. 2, ln. 1, col. 3) | **$** - |

**Worksheet A-7 - EKS ADIT**



**– Evergy Kansas South, Inc.**
**– Allocation of ADIT**

For the 12 months ended - December 31, xxxx

| Line No. | | Summary | 100% NonTrans. Related | 100% Transmission Related | Plant Related | Labor Related | 100% Retail Related | Total ADIT | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Less | **ADIT-282** | $ - | $ - | $ - | $ - | $ - | | |
| 2 | Less | **ADIT-283** | $ - | $ - | $ - | $ - | $ - | | |
| 3 | Plus | **ADIT-190** | $ - | $ - | $ - | $ - | $ - | | |
| 4 | | **Subtotal** | $ - | $ - | $ - | $ - | $ - | $ - | |
| 5 | | **Wages & Salary Allocator** | | | | 0.0000% | | | |
| 6 | | **Gross Plant Allocator** | | | 0.0000% | | | | |
| 7 | | **ADIT *Subtotal*** | | $ - | $ - | $ - | $ - | $ - | |
| *8* | | ***EDIT Adjustment*** | | | | | | *$-* | *(worksheet A-7-2, Net (Excess)/Deficient Deferred Income Taxes, column (n).* |
| *9* | | ***ADIT Total*** | | | | | | *$-* | |

**Worksheet A-7 - EKS ADIT**



**Evergy Kansas South, Inc.**
**Allocation of ADIT**

| ADIT-190 | (A) | (B) | (C) | (D) | (E) | (F) | (G) | *(G)* |
|---|---|---|---|---|---|---|---|---|
| | | *100%* | *100%* | | | 100% Retail | In | |
| | *20XX* YE Balance | NonTrans. Related | Transmission Related | Plant Related | Labor Related | [Allocate by Plant] | Adjustment to Ratebase | *Description and Justification* |

**Worksheet A-7 - EKS ADIT**



| ADIT-190 | (A) | (B) | (C) | (D) | Evergy Kansas South, Inc. Allocation of ADIT (E) | (F) | (G) | *(G)* |
|---|---|---|---|---|---|---|---|---|
| | | 100% | 100% | | | 100% Retail | In | |
| | *20XX* YE Balance | NonTrans. Related | Transmission Related | Plant Related | Labor Related | [Allocate by Plant] | Adjustment to Ratebase | *Description and Justification* |
| *Accumulated Deferred Income Tax Non Utility* | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| *Less 19001 Tax Reclass* | - | - | | | - | | | Cur vs L/T Reclass (for financial reporting) |
| **Subtotal - p234** | | $ - | $ - | $ - | $ - | $ - | - | |
| **Less FASB 109 Above if not separately removed** | | | | $ - | $ - | $ - | | |
| **Less FASB 106 Above if not separately removed** | | | | $ - | $ - | $ - | | |
| **Total** | | $ - | $ - | $ - | $ - | $ - | | |

**Worksheet A-7 - EKS ADIT**



**Evergy Kansas South, Inc.**
**Allocation of ADIT**

| *ADIT- 281 & 282* | (A) | (B) 100% | (C) 100% | (D) | (E) | (F) 100% Retail | (G) In | *(G)* |
|---|---|---|---|---|---|---|---|---|
| | ***20XX* YE Balance** | **NonTrans. Related** | **Transmission Related** | **Plant Related** | **Labor Related** | **[Allocate by Plant]** | **Adjustment to Ratebase** | ***Description and Justification*** |
| *Accumulated Deferred Income Tax Accelerated Amortization Property* | | | | | | | | |
| Subtotal p 273 *Accumulated Deferred Income Tax Other Property* | $- | $- | $- | $- | $- | $- | $- | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | |
| **Subtotal - p275** | - | - | - | - | - | - |
| **Less FASB 109 Above if not separately removed** | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | |
| **To tal** | $ - | $ - | $ - | $ - | $ - | |

**Worksheet A-7 - EKS ADIT**



**Evergy Kansas South, Inc.**
**Allocation of ADIT**

| *ADIT-283* | (A) | (B) | (C) | (D) | (E) | (F) | (G) | *(G)* |
|---|---|---|---|---|---|---|---|---|
| | | **100%** | **100%** | | | **100% Retail** | **In** | |

| | *20XX* YE Balance | NonTrans. Related | Transmission Related | Plant Related | Labor Related | [Allocate by Plant] | Adjustment to Ratebase | *Description and Justification* |
|---|---|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | $ | $ | | $ | $ | $ |
| **Subtotal - p277** | | | - | - | | - | - | - - |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **To tal** | | | | $ - | $ - | $ - | $ - | $ - |

*A*

***Evergy Kansas South, Inc.***

***Worksheet A-7-2***

***Accumulated Excess / Deficient Deferred Income Taxes("EDIT/DDIT")***

***Actuals - For the 12 months ended 12/31/20XX***

| *No.* | | *(a)* | *12/31/XX (b)* | *12/31/XX (c)* | *12/31/XX (d)* | *20XX (e)* | *20XX (f)* | *12/31/XX (g)* | *(h)* |
|---|---|---|---|---|---|---|---|---|---|
| ***Line No.*** | ***Account*** | ***Item*** | ***Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)*** | ***BOY Cumulative Amortization*** | ***BOY Cumulative Other Adjustments (Note B)*** | ***Current Period Amortization (Expense) Benefit*** | ***Current Period Other Activity (Note B)*** | ***EOY Balance (Note C)*** | ***Allocator*** |

***190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES***

*190200*

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| *Total (EDIT)/DDIT - Account 190* | - | - | - | - | - | - | | | | |

| *12/31/XX* (i) | *12/31/XX* (j) | *12/31/XX* (k) | *20XX* (l) | *20XX* (m) | *12/31/XX* (n) | (o) | (p) | *12/31/XX* (q) | *12/31/XX* (r) | (s) |
|---|---|---|---|---|---|---|---|---|---|---|
| ***Beginning Balance of Transmission Deficient (Excess) ADIT*** | ***BOY Transmission Cumulative Other Adjustments (Note B)*** | ***BOY Transmission Cumulative Amortization*** | ***Current Period Transmission Amortization (Expense) Benefit*** | ***Current Period Transmission Other Activity (Note B)*** | ***EOY Allocated Transmission Balance (Note C)*** | ***Amort Period or Method*** | ***Explanation (Note D)*** | ***Grossed-up EOY amount recorded to Account 182.3*** | ***Grossed-up EOY amount recorded to Account 254*** | ***Expense Account Amortization recorded to*** |

***190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES***

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| - | - | - | - | - | - | | | | | - |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** | **Allocator** |
| | | ***283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES*** | | | | | | | |
| | *283300* | | | | | | | | |
| | | *Total (EDIT)/DDIT - Account 283* | - | - | - | - | - | - | |
| | | ***Total Non-Plant Unprotected EDIT*** | - | - | - | - | - | - | |

| 12/31/XX (i) | 12/31/XX (j) | 12/31/XX (k) | 20XX (l) | 20XX (m) | 12/31/XX (n) | (o) | (p) | 12/31/XX (q) | 12/31/XX (r) | (s) |
|---|---|---|---|---|---|---|---|---|---|---|

| Beginning Balance of Transmission Deficient (Excess) ADIT | BOY Transmission Cumulative Other Adjustments (Note B) | BOY Transmission Cumulative Amortization | Current Period Transmission Amortization (Expense) Benefit | Current Period Transmission Other Activity (Note B) | EOY Allocated Transmission Balance (Note C) | Amort Period or Method | Explanation (Note D) | Grossed-up EOY amount recorded to Account 182.3 | Grossed-up EOY amount recorded to Account 254 | Expense Account Amortization recorded to |
|---|---|---|---|---|---|---|---|---|---|---|
| **283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | | | |
| - | - | - | - | - | - | | | | - | |
| - | - | - | - | - | - | | | - | - | |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Item | Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A) | BOY Cumulative Amortization | BOY Cumulative Other Adjustments (Note B) | Current Period Amortization (Expense) Benefit | Current Period Other Activity (Note B) | EOY Balance (Note C) | Allocator |
| **190 NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | | |
| | 190300 | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Total NOL (EDIT)/DDIT | - | - | - | | - | - | - | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 12/31/XX (i) | 12/31/XX (j) | 12/31/XX (k) | 20XX (l) | 20XX (m) | 12/31/XX (n) | (o) | (p) | 12/31/XX (q) | 12/31/XX (r) | (s) |
| **Beginning Balance of Transmission Deficient (Excess) ADIT** | **BOY Transmission Cumulative Other Adjustments (Note B)** | **BOY Transmission Cumulative Amortization** | **Current Period Transmission Amortization (Expense) Benefit** | **Current Period Transmission Other Activity (Note B)** | **EOY Allocated Transmission Balance (Note C)** | **Amort Period or Method** | **Explanation (Note D)** | **Grossed-up EOY amount recorded to Account 182.3** | **Grossed-up EOY amount recorded to Account 254** | **Expense Account Amortization recorded to** |
| **190 NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | | | |
| - | - | - | - | - | - | | | - | - | - |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) | (h) |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity** | **EOY Balance (Note C)** | **Allocator** |

| | | (Excess) ADIT (Note A) | | | | (Note B) | |
|---|---|---|---|---|---|---|---|
| | **281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | |
| 281100 | | | | | | | |
| 282611 | | | | | | | |
| | Basis Differences (Unprotected): | | | | | | |
| 282611 | | | | | | | |
| | Total Plant (EDIT)/DDIT | - | - | - | - | - | - |
| | **Net (Excess)/Deficient Deferred Income Taxes** | - | - | - | - | - | - |
| | **EDIT Amortization:** | Total | | | Allocator | Rate | Allocated |
| | **Total 190 Deficient Deferred Income Taxes** | - | | | See above | See above | - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | ***Total 283 Excess Deferred Income Taxes*** | - | | | *See above* | *See above* | - | | |
| | | ***Total 281/282 Excess Deferred Income Taxes*** | - | | | *See above* | *See above* | - | | |
| | | | - | | | | | - | | |
| *12/31/XX* | *12/31/XX* | *12/31/XX* | *20XX* | *20XX* | *12/31/XX* | | | *12/31/XX* | *12/31/XX* | |
| *(i)* | *(j)* | *(k)* | *(l)* | *(m)* | *(n)* | *(o)* | *(p)* | *(q)* | *(r)* | *(s)* |
| ***Beginning Balance of Transmission Deficient (Excess) ADIT*** | ***BOY Transmission Cumulative Other Adjustments (Note B)*** | ***BOY Transmission Cumulative Amortization*** | ***Current Period Transmission Amortization (Expense) Benefit*** | ***Current Period Transmission Other Activity (Note B)*** | ***EOY Allocated Transmission Balance (Note C)*** | ***Amort Period or Method*** | ***Explanation (Note D)*** | ***Grossed-up EOY amount recorded to Account 182.3*** | ***Grossed-up EOY amount recorded to Account 254*** | ***Expense Account Amortization recorded to*** |
| ***281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES*** | | | | | | | | | | |
| - | - | - | - | - | - | | | - | - | |
| - | - | - | - | - | - | | | - | - | - |

*Notes:*

*A* *Amount carried from EKS Computation tab column (h).*
*B* *Includes return to accrual adjustments, amended return adjustments, book adjustments and other.*

*C* *Excess and Deficient balances exclude income tax gross-ups recorded to accounts 182.3 and 254.*

*D* *Each EDIT item is categorized into 1 of 5 categories. The selected category will determine the Allocator applied to the EDIT balance.*

*1) NonTrans: The EDIT balance is 100% unrelated to the Transmission of electricity and the NA Allocator is applied.*
*2) Retail: The EDIT balance is 100% related to retail operations and the NA allocator is applied.*
*3) Trans: The EDIT balance is 100% related to transmission operations and the DA Allocator is applied.*
*4) Plant: The EDIT balance is related to Property, Plant & Equipment "PP&E" and the GP Allocator is applied.*
*5) Labor: The EDIT balance is labor related and the W/S allocator is applied.*

*Worksheet A-7-3 - EKS Computation*

***Evergy Kansas South, Inc.***
***Computation of EDIT due to Tax Cut and Jobs Act***

| *No.* | *(a)* | *(b)* | *(c)* | *(d)* | *(e)* | *(f)* | *(g)* | *(h)* |
|---|---|---|---|---|---|---|---|---|
| *Line No.* | *Account* | *Description* | *Temporary Differences Before Rate Change* | *Prior Tax Rate* | *Balance Before Tax Rate Change* | *New Tax Rate* | *Balance of ADIT after Tax Rate Change* | *Deficient/ (Excess)ADIT* |
| | | *190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES* | | | | | | |
| | *190200* | | | | | | | |

| | | | | |
|---|---|---|---|---|
| *Total (EDIT)/DDIT - Account 190 (Unprotected)* | - | - | - | - |

*283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES*

*283300*

| | | | | |
|---|---|---|---|---|
| *Total (EDIT)/DDIT - Account 283 (Unprotected)* | - | - | - | - |
| ***Total Non-Plant Unprotected (EDIT)/DDIT*** | | | | - |

*190 NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES*

*190300*

| | | | | | |
|---|---|---|---|---|---|
| | *Total NOL (EDIT)/DDIT - Account 190* | | | | - |
| | *281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES* | | | | |
| *281100* | | | | | |
| *282611* | | | | | |
| | *Basis Differences (Unprotected):* | | | | |
| *282611* | | | | | |
| | *Total Plant (EDIT)/DDIT - Accounts 281 & 282* | - | - | - | - |
| | ***Net (Excess)/Deficient Deferred Income Taxes*** | | | | - |

**Worksheet A-8 - EKC & EKS**
**DEPRECIATION CALCULATION**
**BASED ON DEPRECIATION**
**RATES USED IN FORMULA RATE**
**TEMPLATE**
For the 12 months ended - December 31, xxxx

**This Worksheet will only be used if the depreciation rates used to determine the depreciation expenses shown in Form 1 differ from the depreciation rates shown in EKC/EKS Footnote Q.**

**EKC-Non-Incentive**
**Plant**

| Plant In Service Account # | Jan | Feb | Mar | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Total Plant In Service (Total PIS) | Annualized Depr Rates | Monthly Depr Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | 0.01 | 0.00 | |
| 352 | - | - | - | - | - | - | - | - | - | - | - | - | - | 75 | 833 | |
| | | | | | | | | | | | | | | 0.01 | 0.00 | |
| 353 | - | - | - | - | - | - | - | - | - | - | - | - | - | 74 | 145 000 | |
| | | | | | | | | | | | | | | 0.02 | 0.00 | |
| 354 | - | - | - | - | - | - | - | - | - | - | - | - | - | 01 | 167 500 | |
| | | | | | | | | | | | | | | 0.02 | 0.00 | |
| 355 | - | - | - | - | - | - | - | - | - | - | - | - | - | 57 | 214 167 | |
| | | | | | | | | | | | | | | 0.02 | 0.00 | |
| 356 | - | - | - | - | - | - | - | - | - | - | - | - | - | 58 | 215 000 | |
| | | | | | | | | | | | | | | 0.00 | 0.00 | |
| 357 | - | - | - | - | - | - | - | - | - | - | - | - | - | 00 | 000 000 | |
| | | | | | | | | | | | | | | 0.00 | 0.00 | |
| 358 | - | - | - | - | - | - | - | - | - | - | - | - | - | 00 | 000 000 | |
| | | | | | | | | | | | | | | 0.00 | 0.00 | |
| 359 | - | - | - | - | - | - | - | - | - | - | - | - | - | 00 | 000 000 | |
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | | | |
| Total | - | - | - | - | - | - | - | - | - | - | - | - | - | | | |

EKC

EKC

**EKS-Non-Incentive Plant**

| Plant In Service Account # | Jan | Feb | Mar | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Total Plant In Service (Total PIS) | Annualized Depr Rates | Monthly Depr Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | 0.01 | 0.00 |
| 352 | - | - | - | - | - | - | - | - | - | - | - | - | - | 74 | 145 000 |
| | | | | | | | | | | | | | | 0.01 | 0.00 |
| 353 | - | - | - | - | - | - | - | - | - | - | - | - | - | 67 | 139 167 |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 354 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.01 43 | 0.00 119 167 | | |
| 355 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.02 59 | 0.00 215 833 | | |
| 356 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.02 46 | 0.00 205 000 | | |
| 357 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.01 06 | 0.00 088 333 | | |
| 358 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.01 99 | 0.00 165 833 | | |
| 359 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.00 70 | 0.00 058 333 | | |
| Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | |

| Depreciation Rate Comparison | EKC | | EKS | | Non-Incentive Plant |
|---|---|---|---|---|---|
| Plant In Service Account # | Form 1 Rates | Depr Rate used in Formula | Form 1 Rates | Depr Rate used in Formula | |
| 352 | 0.000% | 1.75 | 0.000% | 1.74 | |
| 353 | 0.000% | 1.74 | 0.000% | 1.67 | |
| 354 | 0.000% | 2.01 | 0.000% | 1.43 | |
| 355 | 0.000% | 2.57 | 0.000% | 2.59 | |
| 356 | 0.000% | 2.58 | 0.000% | 2.46 | |
| 357 | 0.000% | 0.00 | 0.000% | 1.06 | |
| 358 | 0.000% | 0.00 | 0.000% | 1.99 | |
| 359 | 0.000% | 0.00 | 0.000% | 0.70 | |

**Worksheet A-8 - EKC & EKS**
**DEPRECIATION CALCULATION**
**BASED ON DEPRECIATION**
**RATES USED IN FORMULA RATE**
**TEMPLATE**
For the 12 months ended - December 31, xxxx
**EKC-Wichita-to-Reno-to-Summit**

| Plant In Service Account # | Jan | Feb | Mar | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Total Plant In Service (Total PIS) | FR Fixed Annualized Depr Rates | FR Fixed Monthly Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | | 0.0055583 |
| 352 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 353 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 354 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 355 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 356 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 357 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 358 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | | | | | | | | | | | | | | | 0.0055583 |
| 359 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 3 |
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | | |
| Total | - | - | - | - | - | - | - | - | - | - | - | - | - | | |

**EKS-Wichita-to-Reno-to-Summit**

| Plant In Service Account # | Jan | Feb | Mar | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Total Plant In Service (Total PIS) | FR Fixed Annualized Depr Rates | FR Fixed Monthly Rate |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | 0.0667 | 0.005555833 |
| 352 | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 353 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| 354 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| 355 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| 356 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| 357 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| 358 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| 359 | - | - | - | - | - | - | - | - | - | - | - | - | - | 0.0667 | 0.005555833 |
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | | |
| Total | - | - | - | - | - | - | - | - | - | - | - | - | - | | |

**Depreciation Rate Comparison**

**Non-Incentive Plant**

| Plant In Service Account # | EKC Form 1 Rates | EKC Depr Rate used in Formula | EKS Form 1 Rates | EKS Depr Rate used in Formula |
|---|---|---|---|---|
| **352** | 0.000% | 6.67 | 0.000% | 6.67 |
| **353** | 0.000% | 6.67 | 0.000% | 6.67 |
| **354** | 0.000% | 6.67 | 0.000% | 6.67 |
| **355** | 0.000% | 6.67 | 0.000% | 6.67 |
| **356** | 0.000% | 6.67 | 0.000% | 6.67 |
| **357** | 0.000% | 6.67 | 0.000% | 6.67 |
| **358** | 0.000% | 6.67 | 0.000% | 6.67 |
| **359** | 0.000% | 6.67 | 0.000% | 6.67 |

| **Summary of Depreciation Adjustments** | **EKC** | **EKS** | |
|---|---|---|---|
| **Expenses** | | | |
| Based on Rates in Formula NON-INCENTIVE | **$** - | **$** - | |
| Based on Rates in Formula WICHITA-TO-RENO-TO-SUMMIT | **$** - | **$** - | |
| Total Plant Depreciation Form 1 Reported Expenses | - | - | **< Inputs into Template: EKC or EKS, Page 2, Line 12, Col 3** |
| Expense Difference | $ - | $ - | |
| **Accumulated Depreciation** | | | |
| Form 1 reported Accum Depr | $ - | $ - | |

| | | | |
|---|---|---|---|
| Adjusted Accum Depr (Exp Diff + Form 1) | | $ - | $ - |
| | Inputs to Formula Rate Pages | EKC: 1.8.3 | EKS: 1.8.3 |



**Worksheet A-9 - Actual Base Plan Funded Plant**
**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**
For the 12 months ended - December 31, xxxx

**Calculation of Revenue Requirements for BPF projects**

| | | | |
|---|---|---|---|
| 1 | Net Plant for the Form 1 year from table below. | (Act. Net RR, line 12) | 0.0000 |
| 2 | Actual Facility Carrying Charge | | % |
| 3 | BPF Rev Req. | (line 1 * line 2) | $0 |
| 4 | Act. Incentive Rev Req. | (from A-11, pg 2) | $0 |
| 5 | Tot. Act. BPF Rev Req. | (line 3 + line 4) | $0 |
| 6 | | | |
| 7 | | | |
| 8 | | | |
| 9 | | | |
| 10 | **Total** | | |
| 11 | | | |
| 12 | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project:** | | | **Project:** | | | **Project:** | | | **Project:** | | |
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| Deprec. Rate: | 0.0000 | % | Deprec. Rate: | 0.0000 | % | Deprec. Rate: | 0.0000 | % | Deprec. Rate: | 0.0000 | % |
| (B) Beginning Bal: | | (A) | (B) Beginning Bal: | | (A) | (B) Beginning Bal: | | (A) | (B) Beginning Bal: | | (A) |
| Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| Mult-Year Proj.: | Yes | ( C ) | Mult-Year Proj.: | No | ( C ) | Mult-Year Proj.: | No | ( C ) | Mult-Year Proj.: | No | ( C ) |

| | Year | Gross Plant | Accm. Deprec. | Net Plant | Year | Gross Plant | Accm. Deprec | Net Plant | Gross Plant | Accm. Deprec | Net Plant | Gross Plant | Accm. Deprec | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2007 | | | | | | | | | | | | |
| 13 | 2007 | | | | 2008 | | | | | | | | | | | | |
| 14 | 2008 | $0 | $0 | $0 | 2009 | | | | | | | | | | | | |
| 15 | 2009 | $0 | $0 | $0 | 2010 | | | | | | | | | | | | |
| 16 | 2010 | $0 | $0 | $0 | 2011 | | | | | | | | | | | | |
| 17 | 2011 | $0 | $0 | $0 | 2012 | | | | | | | | | | | | |
| 18 | 2012 | $0 | $0 | $0 | 2013 | | | | | | | | | | | | |
| 19 | 2013 | $0 | $0 | $0 | 2014 | | | | | | | | | | | | |
| 20 | 2014 | $0 | $0 | $0 | 2015 | | | | | | | | | | | | |
| 21 | 2015 | $0 | $0 | $0 | 2016 | | | | | | | | | | | | |
| 22 | 2016 | $0 | $0 | $0 | 2017 | | | | | | | | | | | | |
| 23 | 2017 | $0 | $0 | $0 | 2018 | | | | | | | | | | | | |
| 24 | 2018 | $0 | $0 | $0 | 2019 | | | | | | | | | | | | |
| 25 | 2019 | $0 | $0 | $0 | 2020 | | | | | | | | | | | | |
| 26 | 2020 | $0 | $0 | $0 | 2021 | | | | | | | | | | | | |
| 27 | 2021 | $0 | $0 | $0 | 2022 | | | | | | | | | | | | |
| 28 | 2022 | $0 | $0 | $0 | 2023 | | | | | | | | | | | | |
| 29 | 2023 | $0 | $0 | $0 | 2024 | | | | | | | | | | | | |
| 30 | 2024 | $0 | $0 | $0 | 2025 | | | | | | | | | | | | |
| 31 | 2025 | $0 | $0 | $0 | 2026 | | | | | | | | | | | | |
| 32 | 2026 | $0 | $0 | $0 | 2027 | | | | | | | | | | | | |
| 33 | 2027 | $0 | $0 | $0 | 2028 | | | | | | | | | | | | |
| 34 | 2028 | $0 | $0 | $0 | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ |
| 35 | 2029 | $0 | $0 | $0 | 29 | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ |
| 36 | 2030 | $0 | $0 | $0 | 30 | - | - | - | - | - | - | - | - |

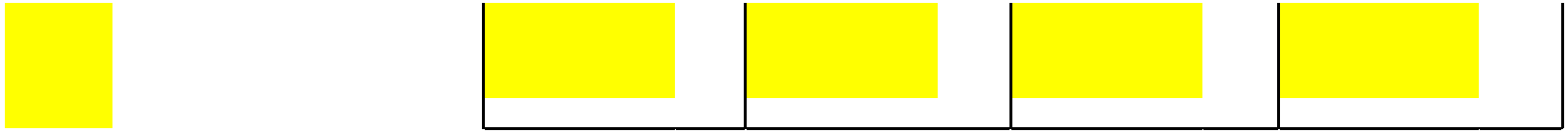
Notes:
(A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 12) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)
(B) Special depreciation rates may be utilized for specific incentive transmission projects if approved by the FERC.
( C ) Only Base Plan Funded projects that have been completed and whose costs are in the Form 1 should be entered on this page. If a pr oject is done in phases over multiple years, that project should be entered in sheet P-4 until the entire project Is completed and in the Form 1.
(D) All Base Plan Funded projects whose costs are in the Form 1 and are also incentive projects should be entered into sheet A-11.

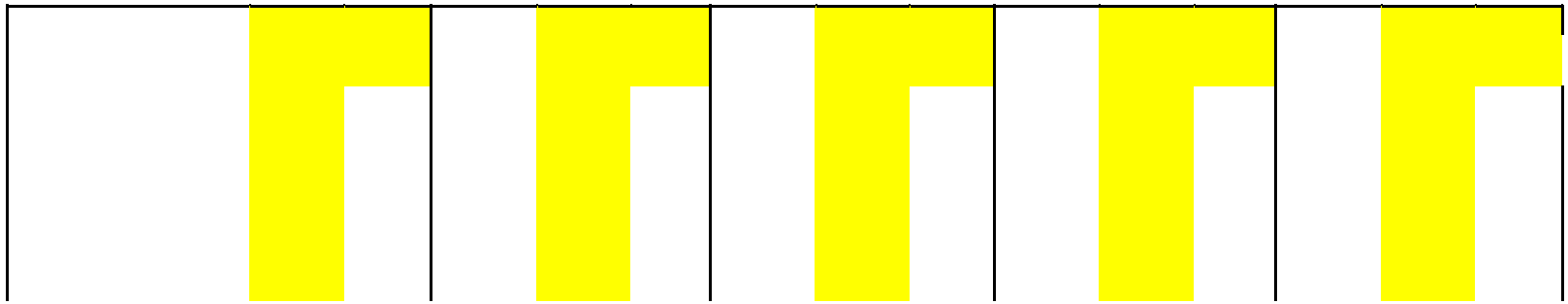
**Worksheet A-9 - Actual Base Plan Funded Plant**
**Evergy Kansas Central, Inc. and**
**Evergy Kansas South, Inc.**
For the 12 months ended - December 31, xxxx



| **Project:** | | | **Project:** | | | **Project:** | | | **Project:** | | | **Project:** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| Deprec. Rate: (B) | 0.0000 % | (A) | Deprec. Rate: (B) | 0.0000 % | (A) | Deprec. Rate: (B) | 0.0000 % | (A) | Deprec. Rate: (B) | 0.0000 % | (A) | Deprec. Rate: (B) | 0.0000 % | (A) |
| Beginning Bal: | | | Beginning g Bal: | | | Beginning g Bal: | | | Beginning g Bal: | $ - | | Beginning g Bal: | $ - | |
| Beginning Dep: | | | Beginning g Dep: | | | Beginning g Dep: | | | Beginning g Dep: | - | | Beginning g Dep: | - | |
| | | | Beg Year- | | | Beg Year- | | | Beg Year- | | | Beg Year- | | |

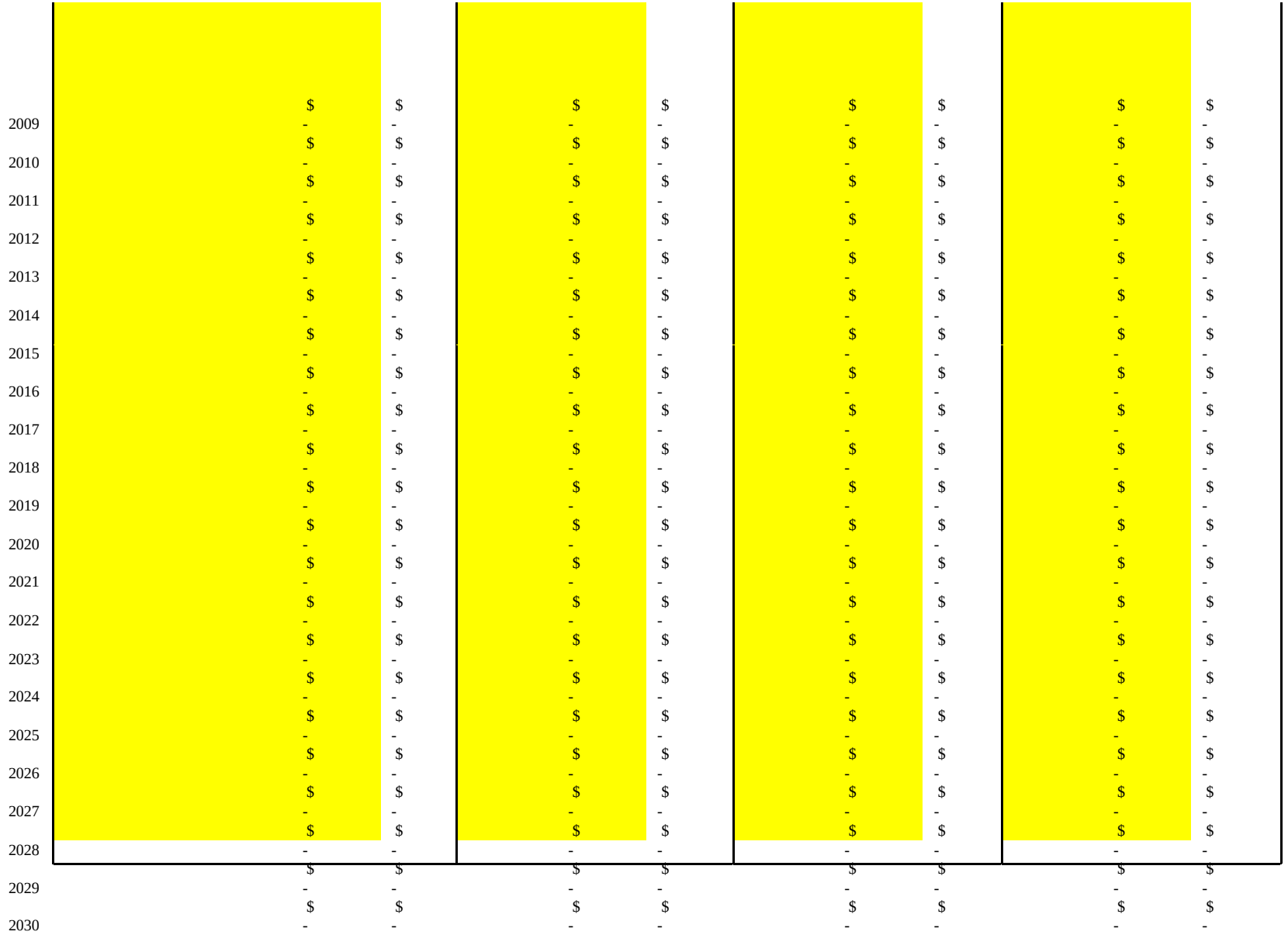
Beg Year-Mo.: Mo.: Mo.: Mo.: Mo.:





| Year | Mult-Year Proj.: Gross Plant | No Accm. Deprec. | (C) Net Plant | ~~Mult~~ Year Proj.: Gross Plant | No Accm. Deprec. | (C) Net Plant | ~~Mult~~ Year Proj.: Gross Plant | No Accm. Deprec. | (C) Net Plant | ~~Mult~~ Year Proj.: Gross Plant | No Accm. Deprec. | (C) Net Plant | ~~Mult~~ Year Proj.: Gross Plant | No Accm. Deprec. | (C) Net Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2007 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2008 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2009 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2010 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2011 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2012 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2013 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2014 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2015 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2016 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2017 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2018 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2019 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2020 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2021 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2022 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2023 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2024 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2025 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2026 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 2027 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | |


2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030

**Worksheet A-10 - Wages and Salaries**
**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**
For the 12 months ended - December 31, xxxx



| | | | (a) | | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|---|---|
| | | | EKC | | | | EKS | | |
| | | | | | | Wolf Creek | Wolf Creek | La Cygne | |
| | **Wages & Salaries (W&S)** | **Form 1 Reference** | **Form 1 Values** | | **Form 1 Values** | **Total Wolf Creek Form 1 354.18.b** | **Evergy Kansas South, Inc. Share 47% (1)** | **(2)** | **Total (Col b+d+e)** |
| 1 | Production | 354.20.b | | | | | $ - | | $ - |
| 2 | Transmission | 354.21.b | | | | | | | - |
| 3 | Distribution | 354.23.b | | | | | | | - |
| 4 | Other (excluding A&G) | 354.24,25, 26.b | | | | | | | - |
| 5 | Total | | $ - | | | | | | $ - |

Footnotes:
(1) Wolf Creek W&S Production (Form 1 Reference 354.18.b) x 47% (Evergy Kansas South, Inc. Share)
(2) As billed by Evergy Metro, Inc.

**Worksheet A-11 - Actual Incentive Plant**
**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**
For the 12 months ended - December 31, xxxx

**Zonal Projects**

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | **Project:** | Project A | | | | **Project:** | Project B | | | | **Project:** | Project C | | |
| 2 | | | | | | | SPP Proj. ID | N/A | | | | | | | | | | | | |
| 3 | | | | | | | Deprec. Rate: | 6.67% | (Note A) | | | Deprec. Rate: | | (Note A) | | | Deprec. Rate: | | (Note A) | |
| 4 | | | | | | | ROE Adder | .70% | | | | ROE Adder | | | | | ROE Adder | | | |
| 5 | | | | | | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% | | |
| 6 | | | | | | | Beginning Bal: | | | | | Beginning Bal: | | | | | Beginning Bal: | | | |
| 7 | | **Total** | | | | | Beginning Dep: | - | | | | Beginning Dep: | | | | | Beginning Dep: | | | |
| 8 | | | | | | | Beginning Year: | 2008 | | | | Beginning Year: | | | | | Beginning Year: | | | |
| | | **Year** | **Beginning Amt** | **Depreciation** | **Net Plant** | **Incentive RR** | **Year** | Beginning Amt | Depreciation | Net Plant | Incentive RR | Beginning Amt | Depreciation | Net Plant | Incentive ROR | | Beginning Amt | Depreciation | Net Plant | Incentive ROR |
| 9 | | 2007 | $0 | $0 | $0 | $0 | 2007 | $ - | $ - | $ - | $ - | $ - | $ - | | | | $ - | $ - | | |
| 10 | | 2008 | $0 | $0 | $0 | $0 | 2008 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 11 | | 2009 | $0 | $0 | $0 | $0 | 2009 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 12 | | 2010 | $0 | $0 | $0 | $0 | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | |
| 13 | | 2011 | | | | | 2011 | | | | | | | | | | | | | |
| 14 | | 2012 | | | | | 2012 | | | | | | | | | | | | | |
| 15 | | 2013 | | | | | 2013 | | | | | | | | | | | | | |
| 16 | | 2014 | | | | | 2014 | | | | | | | | | | | | | |

| | | |
|---|---|---|
| 17 | 2015 | 2015 |
| 18 | 2016 | 2016 |
| 19 | 2017 | 2017 |
| 20 | 2018 | 2018 |
| 21 | 2019 | 2019 |
| 22 | 2020 | 2020 |
| 23 | 2021 | 2021 |
| 24 | 2022 | 2022 |
| 25 | 2023 | 2023 |
| 26 | 2024 | 2024 |
| 27 | 2025 | 2025 |
| 28 | 2026 | 2026 |
| 29 | 2027 | 2027 |
| 30 | 2028 | 2028 |
| 31 | 2029 | 2029 |
| 32 | 2030 | 2030 |

(A) Special depreciation rates may be utilized for specific incentive transmission projects if approved by the FERC.

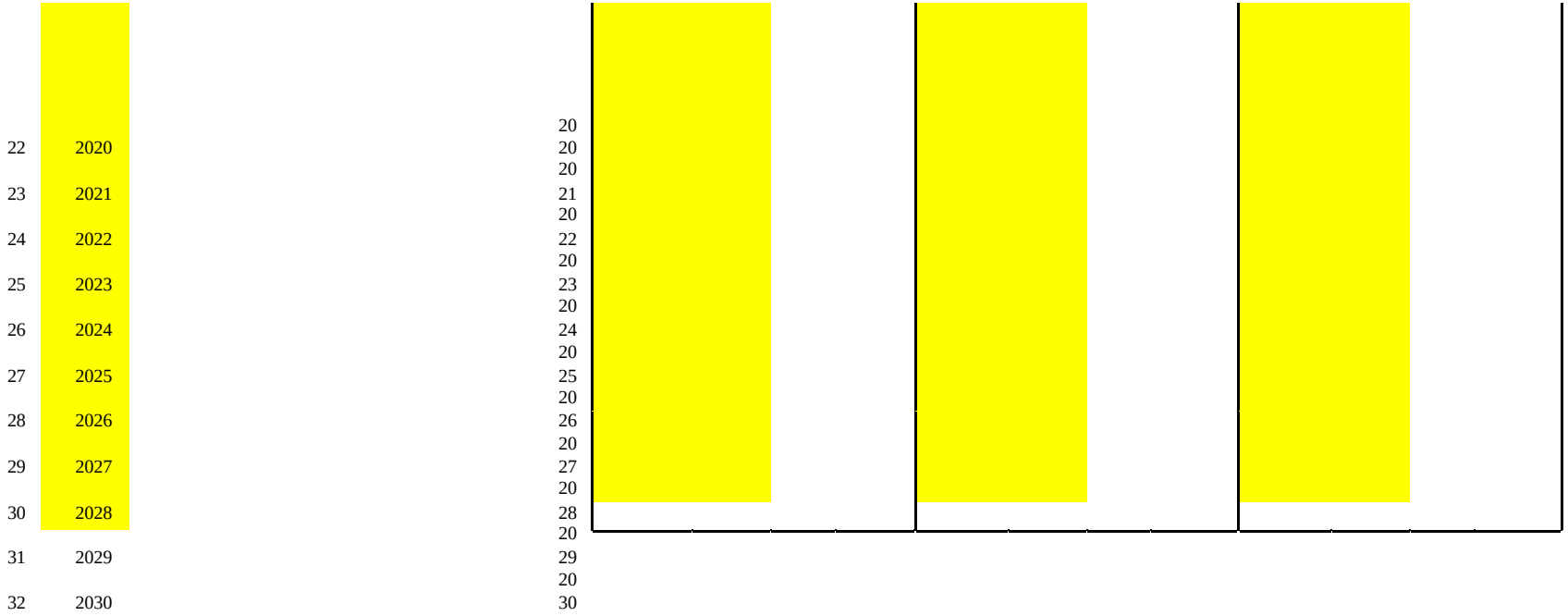


**Worksheet A-11 - Actual Incentive Plant**
**Evergy Kansas Central, Inc. and**
**Evergy Kansas South, Inc.**
For the 12 months ended - December 31, xxxx

**Base Plan Funded Projects**

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | **Project:** | Project A1 | **Project:** | Project B1 | **Project:** | Project C1 |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | SPP Proj. ID | N/A | | | Deprec. | | | | Deprec. | | | |
| 3 | | | | | | Deprec. Rate: | 6.67% | (Note A) | | Rate: | | (Note A) | | Rate: | | (Note A) | |
| 4 | | | | | | ROE Adder | 1.00% | | | ROE Adder | | | | ROE Adder | | | |
| 5 | | | | | | Weighted ROE: | 0.00% | | | Weighted ROE: | 0.00% | | | Weighted ROE: | 0.00% | | |
| 6 | | | | | | Beginning Bal: | $ - | | | Beginning Bal: | | | | Beginning Bal: | | | |
| 7 | | **Total** | | | | Beginning Dep: | - | | | Beginning Dep: | | | | Beginning Dep: | | | |
| 8 | | | | | | Beginning Year: | 2008 | | | Beginning Year: | | | | Beginning Year: | | | |
| | **Year** | **Beginning Amt** | **Depreciation** | **Net Plant** | **Incentive RR** | **Year** | Beginning Amt | Depreciation | Net Plant | Incentive RR | Beginning Amt | Depreciation | Net Plant | Incentive ROR | Beginning Amt | Depreciation | Net Plant | Incentive ROR |
| 9 | 2007 | $0 | $0 | $0 | $0 | 2007 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | 2008 | $0 | $0 | $0 | $0 | 2008 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | 2009 | $0 | $0 | $0 | $0 | 2009 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | 2010 | $0 | $0 | $0 | $0 | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | 2011 | | | | | 2011 | | | | | | | | | | | | |
| 14 | 2012 | | | | | 2012 | | | | | | | | | | | | |
| 15 | 2013 | | | | | 2013 | | | | | | | | | | | | |
| 16 | 2014 | | | | | 2014 | | | | | | | | | | | | |
| 17 | 2015 | | | | | 2015 | | | | | | | | | | | | |
| 18 | 2016 | | | | | 2016 | | | | | | | | | | | | |
| 19 | 2017 | | | | | 2017 | | | | | | | | | | | | |
| 20 | 2018 | | | | | 2018 | | | | | | | | | | | | |
| 21 | 2019 | | | | | 2019 | | | | | | | | | | | | |




(A) Special depreciation rates may be utilized for specific incentive transmission projects if approved by the FERC.

**Worksheet A-12 - Actual Economic Portfolio Funded Plant (non-incentive)**
**Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.**

For the 12 months ended - December 31, xxxx

| | **Calculation of Revenue Requirements for EPP projects** | | |
|---|---|---|---|
| 1 | Net Plant for the Form 1 year | | $0 |
| 2 | Actual Facility Carrying Charge | (Act. Net RR, line 12) | 0.00 00% |
| 3 | Act. EPP Rev Req. | (line 1 * line 2) | $0 |
| 4 | Act. Incentive Rev Req. | (from A-11, pg 3) | $0 |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | Tot. Act. EPP Rev Req. | | (line 3 + line 4) | $0 | | | | | | | | | | | | | | | |
| 6 | | | | | **Project:** | Project E1 | | **Project:** | Project E2 | | **Project:** | Project E3 | | **Project:** | Project E4 | | **Project:** | Project E5 | |
| 7 | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 8 | | | | | Deprec. Rate: (B) | #DIV/0! | (A) | Deprec. Rate: (B) | #DIV/0! | (A) | Deprec. Rate: (B) | #DIV/0! | (A) | Deprec. Rate: (B) | #DIV/0! | (A) | Deprec. Rate: (B) | #DIV/0! | (A) |
| 9 | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 10 | | | **Total** | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 11 | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| 12 | | | | | Mult-Year Proj.: | Yes | (C) | Mult-Year Proj.: | Yes | (C) | Mult-Year Proj.: | Yes | (C) | Mult-Year Proj.: | Yes | (C) | Mult-Year Proj.: | Yes | (C) |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 13 | 2007 | $0 | $0 | $0 | 2007 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | 2008 | $0 | $0 | $0 | 2008 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 15 | 2009 | $0 | $0 | $0 | 2009 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 16 | 2010 | $0 | $0 | $0 | 2010 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 17 | 2011 | $0 | $0 | $0 | 2011 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 18 | 2012 | $0 | $0 | $0 | 2012 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 19 | 2013 | $0 | $0 | $0 | 2013 | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - | | $ - | $ - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 20 | 2014 | $0 | $0 | $0 | 14 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 21 | 2015 | $0 | $0 | $0 | 15 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 22 | 2016 | $0 | $0 | $0 | 16 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 23 | 2017 | $0 | $0 | $0 | 17 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 24 | 2018 | $0 | $0 | $0 | 18 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 25 | 2019 | $0 | $0 | $0 | 19 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 26 | 2020 | $0 | $0 | $0 | 20 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 27 | 2021 | $0 | $0 | $0 | 21 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 28 | 2022 | $0 | $0 | $0 | 22 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 29 | 2023 | $0 | $0 | $0 | 23 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 30 | 2024 | $0 | $0 | $0 | 24 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 31 | 2025 | $0 | $0 | $0 | 25 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 32 | 2026 | $0 | $0 | $0 | 26 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 33 | 2027 | $0 | $0 | $0 | 27 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 34 | 2028 | $0 | $0 | $0 | 28 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 35 | 2029 | $0 | $0 | $0 | 29 | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 36 | 2030 | $0 | $0 | $0 | 30 | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:

(A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 12) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)

(B) Incentive Economic Portfolio Projects are listed on A11, page 3 of 3.

( C ) Only Economic Portfolio projects that have been completed and whose costs are in the Form 1 should be entered on this page. If a project is done in phases over multiple years, that project should be entered in sheet P-4 until the entire project Is completed and in the Form 1.

(D) All Economic Portfolio projects whose costs are in the Form 1 and are also incentive projects should be entered into sheet A-11.

# Addendum 3 to Attachment H - Part 2

**Worksheet TU - True-up Adjustment and Timeline**

**Timeline**

| Step | Month | Year | Action |
|---|---|---|---|
| 1 | Oct | Year 0 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using projected costs for Year 1 |
| 2 | Oct | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Oct | Year 1 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using projected costs for Year 2 |
| 5 | Oct | Year 1 | Post results of Step 4 |
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | Jun | Year 2 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |
| 9 | Jun | Year 2 | Post results from Step 7 and Step 8 |
| 10 | Oct | Year 2 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |
| 11 | Oct | Year 2 | Post results of Step 10 |

**Reconciliation details**

| | | | | |
|---|---|---|---|---|
| 1 | Oct | Year 0 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using projected costs for Year 1 | |
| | | | $ - | Rev Req based on Year 1 data |

| | | | |
|---|---|---|---|
| 2 | Oct | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Oct | Year 1 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using projected costs for Year 2 |
| | | | $ - |
| 5 | Oct | Year 1 | Post results of Step 4 |
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | Jun | Year 2 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |

| | | Zonal Rev. Req. (1) | BPF Rev. Req. (2) | EPP Rev. Req (3) | Total Rev. Req. (4) |
|---|---|---|---|---|---|
| 8a | Actual Revenue Requirements from Step 7 | $ - | - | - | $ - |
| 8b | Projected Revenue Requirements from Step 1 (Note E) | | | | $ - |
| 8b (i) | Prior Period Adjustment (Note G) | - | - | - | - |
| 8c | True-up Amount (before interest) | $ - | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| 9 | Jun | Year 2 | Post results from Step 7 and Step 8 |

| | | | |
|---|---|---|---|
| 10 | Oct | Year 2 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |

**Interest Calculation**

| | | | | Avg. Ann Short Term Int |
|---|---|---|---|---|
| | | **Short term Interest Rate** | | |
| 11 | | Other Interest Exp.(Acct. 431) | | |
| 12 | | Notes Payable (Acct. 231) Sum of the Daily amounts (Note C) | | |
| 13 | | No. of Days | | |
| 14 | | Annual Short-term Int Rate | (line 11 / line 12 * line 13 / 2) | 0.0000% |
| | | **FERC Qtr Int. Rate (A)** | | |
| 15 | | Qtr 4 (Form 1 Year) | | |
| 16 | | Qtr 1 (Previous Year) | | |
| 17 | | Qtr 2 (Previous Year) | | |
| 18 | | Qtr 3 (Previous Year) | | |
| 19 | | Qtr 4 (Previous Year) | | |
| 20 | | Qtr 1 (Current Year) | | |
| 21 | | Qtr 2 (Current Year) | | |
| 22 | | Qtr 3 (Current Year) | | |
| 23 | | Average of the last 4 quarters | (Lines 15-18 / 4) | 0.0000% |
| 24 | | Interest Rate Used for True-up adjustment (Note D) | | 0.0000% |

| | | | Zonal True-up | BPF True-up | EPP True-up | Total True-up |
|---|---|---|---|---|---|---|
| | | | (1) | (2) | (3) | (4) |
| | | | $ | $ | $ | $ |
| 25 | | True-Up Amount (line 8c) (Note F) | - | - | - | - |
| 26 | | Interest on True-up Amount ([Average Interest Rate / 12 months]*24 months] | - | - | - | - |
| 27 | | One time, first year adjustment (proj. year 2009) (Note B) | | | | $ - |
| 28 | | **True-up Adjustment (Note G)** | **$ -** | **$ -** | **$ -** | **$ -** |

Not
e: A Interest rate divided in half for first year (2007 historic, 2009 projected) to account for only 1 year of interest rather than two.

B First year adjustment is to allow for any adjustments in the Revenue Requirement for the change from an historic to a projec ted test period.

C Sum of the daily short-term borrowings is supplied from the Finance Department.

D Use the lower of line 14 and line 23 if the True-up Amount (line 25) is greater than or equal to zero.
Use line 23 if the True-up amount (line 25) is less than zero.

E Enter the Projected Revenue Requirement for the Actual period without a true-up adjustment.
If the annual update is for a partial year, not 12 months, then the amount on line
F 25 shall be number of months in the partial year/12.

G Prior Period Adjustment, if any, is calculated to the same timing basis as balance of true up (i.e. before interest applied on line 26).
Workpapers for the Prior Period Adjustment calculation will be included in supporting documentation.

**Worksheet BPF - Base Plan Funded (BPF) Summary**

**Revenue Requirement of SPP Base Plan Funded Projects (BPF) included in Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. Projected Revenue Requirements [Note: (E)]**

For the 12 months ended - December 31, 20xx

| | | | TOTAL |
|---|---|---|---|
| 1 | Projected 12 mo avg non-incentive depr. exp. | (P-1, page 2, line 28) | $ - |
| 2 | Total Allocated Transmission-Related Plant in Service | (Projected Gross Rev Req, page 1, line 1) | $ - |
| 3 | Less: Gross Plant - Incentive Projects | (Projected Gross Rev Req, page 4, line 28a) | - |
| 4 | Total Non-incentive Transmission-Related Plant in Service | (line 2 - line 3) | $ - |
| 5 | Rate Base Adjustments | (Projected Gross Rev Req, page 1, line 10) | $ - |
| 6 | Projected 13 mo. Avg. Non-incentive Gross Plant | (P-1, page 2, line 29) | - |
| 7 | Net Transmission Plant | (Projected Gross Rev Req, page 1, line 6) | - |

| | | | |
|---|---|---|---|
| 8 | Non Incentive Net Plant | (line 7 - page 2, line T1) | - |
| 9 | O&M Expenses | (Projected Gross Rev Req, page 2, line 9) | - |
| 10 | Revenue Credits | (Projected Net Rev Req, page 1, line 6 | - |
| 11 | Other Taxes | (Projected Gross Rev Req, page 2, line 22) | - |
| 12 | Return without Incentives | (Projected Gross Rev Req, page 2, line 30 - line 14) | - |
| 13 | Income Taxes | (Projected Gross Rev Req, page 2, line 29) | - |
| 14 | Incentive Return | (Projected Gross Rev Req, page 4, line 29) | - |
| 15 | Incentive Net Plant | (Projected Gross Rev Req, page 4, line 27) | - |
| 16 | Effective Tax Rate | (Projected Gross Rev Req.: Page 2, Line 29 / Page 2, line 30) | 0.00% |
| 16a | True-up Amount | (TU, page 1, line 28)) | $ - |
| 17 | Rate Base Adjustments as a Percentage of Net Plant | (line 5 / line 7) | 0.00% |
| 18 | O&M Expenses as a Percentage of Net Plant | (line 9 / line 7) | 0.00% |
| 19 | Revenue Credits as a Percentage of Net Plant | (line 10 / line 7) | 0.00% |
| 20 | Other Taxes as a Percentage of Net Plant | (line 7 / line 7) | 0.00% |
| 21 | Return as a Percentage of Net Plant | (Projected Gross Rev Req, page 4, line 24) | 0.00% |
| 22 | Income Taxes as a Percentage of Net Plant | (line 13 / line 7) | 0.00% |
| 23 | Ratio of Common Stock to Total Debt | (Projected Gross Rev Req, Page 5, line 23) | 0.00% |
| 24 | Ratio of True-up amount to Net Plant | (line 16a / line T9) | 0.00% |



**Worksheet BPF - Base Plan Funded (BPF) Summary**

**Revenue Requirement of SPP Base Plan Funded Projects (BPF) included in Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. Projected Revenue Requirements [Note: (E)]**

For the 12 months ended - December 31, 20xx

Note A: All line references are to Worksheet BPF, page 1.
Note B: The depreciation rate for Non-qualifying Projects is calculated by: line 1/line 6.
Note C: To be completed with any BPF project approved by the Southwest Power Pool.
Note D: To be completed with any BPF project which has incentives approved by the Commission.
Note E: This tab shows the amount in column q that SPP is required to recover for each BPF project.

| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate (line 1 / line 6)** | **Projected Depreciation** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Incentive Return Adder** | **Weighted Incentive Return** | **Total Return** | **Income Taxes** | **Revenue Credits** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** |
| | | | | **(a - b)** | | **1.5 * (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | | **(i * j)** | **(k+[j * f])** | **(I * line 16)** | **(f * line 19)** | **(e+g+h+l+m+n)** | **(f * line 24)** | **(o + p)** |
| | **Non-Incentive Projects ( C ) Actual Projects (Inputs from Worksheet A-9)** | | | | | | | | | | | | | | | | | |
| 20xx-x2 | | | | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 0xx-x | | | | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-x20xx-x20xx-x20xx-x20xx-x20xx-x20xx-x20xx-x20xx-x | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-x20xx-x20xx-x20xx-x2 | | | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x20xx-x20xx-x20xx-x2 | | | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x20xx-x20xx-x20xx-x2 | | | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xT1 | **Total of all Actual, non-incentive, BPF Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Depreciation (Worksheet P-4) | Projected Net Plant (a - e) | O&M Expenses (f * line 17) | Other Taxes (f * line 19) | Non-Incentive Return (line 20) | Incentive Return Adder | Weighted Incentive Return (i * j) | Total Return (k+ [j * f]) | Income Taxes (f * line 21) | Revenue Credits (f * line 18) | Rev. Req w/o True-up (e+g+ h+l+ m+n) | True-up Adjustment (f * line 24) | Revenue Requirement (o + p) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-xx | **Projected projects (Inputs from Worksheet P-4)** | | | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate (A-11, P1, L3) | Projected Depreciation | Projected Net Plant | O&M Expenses | Other Taxes | Non-Incentive Return | Incentive Return Adder (A-11, P1, L5) | Weighted Incentive Return | Total Return | Income Taxes | Revenue Credits | Rev. Req w/o True-up | True-up Adjustment | Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (a - b) | | 1.5 * (a * d) | (a - b - e) | (f * line 18) | (f * line 20) | (line 21) | | (i * j) | (k+[j * f]) | (I * line 16) | (f * line 18) | (e+g+h+l+m+n) | (f * line 24) | (o + p) |
| | | **Actual (Input data from Worksheet A-11)** | | | | | | | | | | | | | | | | | |
| 20xx-xx20xx | | Project A1 | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| xx-xx | | Project B1 | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T4 | | **Total of all Actual, incentive, BPF Projects** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Depreciation (Worksheet P-1) | Projected Net Plant | O&M Expenses | Other Taxes | Non-Incentive Return | Incentive Return Adder | Weighted Incentive Return | Total Return | Income Taxes | Revenue Credits | Rev. Req w/o True-up | True-up Adjustment | Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (a - b) | | | (a - e) | (f * line 17) | (f * line 19) | (line 20) | | (i * j) | (k+[j * f]) | (f * line 21) | (f * line 18) | (e+g+h+l+m+n) | (f * line 24) | (o + p) |
| | | **Projected Projects (Inputs from Worksheet P-1)** | | | | | | | | | | | | | | | | | |
| 20x | | Project X | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | |

| | | | | |
|---|---|---|---|---|
| | | | | $ |
| 5 | | Rate Base Adjustments | (Projected Gross Rev Req, page 1, line 10) | - |
| 6 | | Projected 13 mo. Avg. Non-incentive Gross Plant | (P-1, page 2, line 29) | - |
| 7 | | Net Transmission Plant | (Projected Gross Rev Req, page 1, line 6) | - |
| 8 | | Non Incentive Net Plant | (line 7 - page 2, line T1) | - |
| 9 | | O&M Expenses | (Projected Gross Rev Req, page 2, line 9) | - |
| 10 | | Revenue Credits | (Projected Net Rev Req, page 1, line 6) | - |
| 11 | | Other Taxes | (Projected Gross Rev Req, page 2, line 22) | - |
| 12 | | Return without Incentives | (Projected Gross Rev Req, page 2, line 30 - line 14) | - |
| 13 | | Income Taxes | (Projected Gross Rev Req, page 2, line 29) | - |
| 14 | | Incentive Return | (Projected Gross Rev Req, page 4, line 29) | - |
| 15 | | Incentive Net Plant | (Projected Gross Rev Req, page 4, line 27) | - |
| 16 | | Effective Tax Rate | (Projected Gross Rev Req.: Page 2, Line 29 / Page 2, line 30) | 0.00% |
| | | | | $ |
| | 16a | True-up Amount | (Proposed Net Rev Req, Page 1, line 7) | - |
| 17 | | Rate Base Adjustments as a Percentage of Net Plant | (line 5 / line 7) | 0.00% |
| 18 | | O&M Expenses as a Percentage of Net Plant | (line 9 / line 7) | 0.00% |
| 19 | | Revenue Credits as a Percentage of Net Plant | (line 10 / line 7) | 0.00% |
| 20 | | Other Taxes as a Percentage of Net Plant | (line 7 / line 7) | 0.00% |
| 21 | | Return as a Percentage of Net Plant | (Projected Gross Rev Req, page 4, line 24) | 0.00% |
| 22 | | Income Taxes as a Percentage of Net Plant | (line 13 / line 7) | 0.00% |
| 23 | | Ratio of Common Stock to Total Debt | (Projected Gross Rev Req, Page 5, line 23) | 0.00% |
| 24 | | Ratio of True-up amount to Net Plant | (line 16a / line 7) | 0.00% |

**Worksheet EPP - Economic Portfolio**

**Project (EPP) Summary**

**Revenue Requirement of SPP Economic Portfolio Funded Projects (EPP) included in Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s Projected Revenue Requirements [Note:(E)]**

For the 12 months ended - December 31, 20xx

Note A: All line references are to Worksheet EPP, page 1.

Note B: The depreciation rate for Non-qualifying Projects is calculated by: line 1/line 4.

Note C: To be completed with any EPP project approved by the Southwest Power Pool.

Note D: To be completed with any EPP project which has incentives approved by the Commission.

Note E: This tab shows the amount in column q that SPP is required to recover for each BPF project.

| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Plant in** | **Accum** | **Actual Net** | **Depreciation** | **Projected** | **Projected Net** | **O&M** | **Other** | **Non-Incentive** | **Incentive** | **Weighted** | **Total** | **Income** | **Revenue** | **Rev. Req** | **True-up** | **Revenue** |
| **Project ID** | **Project Description** | **Service** | **Depreciation** | **Plant** | **Rate** | **Depreciation** | **Plant** | **Expenses** | **Taxes** | **Return** | **Return Adder** | **Incentive Return** | **Return (k +[i * f])** | **Taxes (I * line 16)** | **Credits (f * line 19)** | **w/o True-up (e+g+h+l+m+n)** | **Adjustment (f * line 24)** | **Requirement (o + p)** |
| | | | | **(a - b)** | **(line 1 / line 6)** | **1.5 * (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | | **(i * j)** | | | | | | |

| | | |

| Project ID | Project Description | | Service | Depreciation | Plant | Rate | Depreciation (Worksheet P-5) | Plant (a - e) | Expenses (f * line 17) | Taxes (f * line 19) | Return (line 20) | Return Adder | Incentive Return (i * j) | Return (k +[i * f]) | Taxes (f * line 21) | Credits (f * line 18) | w/o True-up (e+g+h+l+m+n) | Adjustment (f * line 24) | Requirement (o + p) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (a - b) | | | | | | | | | | | | | | | | |
| | **Projected projects from P-5)** | **(Inputs Worksheet** | | | | | | | | | | | | | | | | | |
| 20xx-xx | P.xxx | Project E6 | $ - | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | Project E7 | $ - | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | Project E8 | $ - | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | Project E9 | $ - | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | Project E10 | $ - | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | | | | $ - | | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx | | | | $ - | | $ - | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| xx- xx | | | | | | | | | | | | | | | | | | | |
| T2 | **Total of Projected Non-Incentive Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| T3 | **Total Non-Incentive Projects (lines T2 + T3)** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| | **Incentive Projects (D)** | | | | | | | | | | | | | | | | | | |
| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | |
| | **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Rate** | **Projected Depreciation** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Incentive Return Adder** | **Weighted Incentive Return** | **Total Return** | **Income Taxes** | **Credits** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** |
| | | | | | (a - b) | (A-11, P 1, L 3) | 1.5 * (a * d) | (a - b - e) | (f * line 18) | (f * line 20) | (line 21) | (A-11, P 1, L 5) | (i * j) | (k +[i * f]) | (I * line 16) | (f * line 18) | (e+g+h+l+m+n) | (f * line 24) | (o + p) |
| | **Actual data (Input from Worksheet A-12)** | | | | | | | | | | | | | | | | | | |
| 20xx-xx | Project A2 | $ - | $ - | $ - | 0.0 0% | $ - | $ - | $ - | $ - | 0.0 0 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | Project B2 | $ - | $ - | $ - | 0.0 0% | $ - | $ - | $ - | $ - | 0.0 0 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-x | | | | $ - | | $ - | $ - | $ - | $ - | 0.00% | | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| T4 | **Total of Actual Incentive Projects** | | $ - | $ - | | $ - | | | $ - | $ - | $ - | | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant (a - b)** | **Depreciation Rate** | **Projected Depreciation (Worksheet P-1)** | **Projected Net Plant (a - e)** | **O&M Expenses (f * line 17)** | **Other Taxes (f * line 19)** | **Non-Incentive Return (line 20)** | **Incentive Return Adder** | **Weighted Incentive Return (i * j)** | **Total Return (k +[i * f])** | **Income Taxes (f * line 21)** | **Revenue Credits (f * line 18)** | **Rev. Req w/o True-up (e+g+h+l+m+n)** | **True-up Adjustment (f * line 24)** | **Revenue Requirement (o + p)** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Project ID** | **Project Description** | | | | | | | | | | | | | | | | | |
| | **Projected Projects (Inputs from Worksheet P-1)** | | | | | | | | | | | | | | | | | | |
| 20xx-x | | Project Y | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 20xx-x | | Project Y1 | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 20xx-x | | | - | $ - | 0.00% | | $ - | $ - | $ - | 0.00% | | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| T5 | **Total of Projected** | | $ - | $ - | | $ - | | $ - | $ - | $ - | | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Incentive Projects** | | | | | | | | | | | | | | | | | |
| T6 | **Total Incentive Projects (lines T4 + T5)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| T7 | **Total Actual Projects (lines T1 + T4)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| T8 | **Total Projected Projects (lines T2 + T5)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| T9 | **Total (lines T3 + T6)** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Net Revenue Requirements
For the 12 months ended - December 31, 20xx

EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.



| Line No. | (1) | (2) | (3) | (4) | (5) Allocated Amount |
|---|---|---|---|---|---|
| | **REVENUE REQUIREMENTS** | | | | |
| 1 | GROSS REVENUE REQUIREMENT | (Projected Gross Revenue, page 3, line 32) | | | $ - |
| | REVENUE CREDITS | | Total | Allocator | |
| 2 | Account No. 454 | (Wksht. P-2, line 24) | $ - | WT P 1.00000 | $ - |
| 3 | Account No. 456 | (Wksht. P-2, line 25) | - | WT P 1.00000 | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | (Wksht. P-2, line 26) | - | WT P 1.00000 | - |
| 5 | Revenues from service provided by the ISO at a discount | (Wksht. P-2, line 27) | - | WT P 1.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6 | TOTAL REVENUE CREDITS | (sum lines 2-5) | | | | $ - |
| 7 | Total True-Up Amount (prior year amount) | (Wksht. TU, line 28) | | | | $ - |
| 8 | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. REVENUE REQUIREMENT | (line 1 minus line 6 plus line 7) | | | | **$ -** |
| 9 | SPP BASE PLAN FUNDED REVENUE REQUIREMENT Collected under SPP Schedule 11 (Worksheet BPF, p. 3, line T9, Col. q) | | | | | - |
| 9a | SPP ECONOMIC PORTFOLIO FUNDED REVENUE REQUIREMENT Collected under SPP Schedule 11 (Worksheet EPP, p. 2, line T9, Col. q) | | | | | - |
| 10 | SPP ZONAL REVENUE REQUIREMENT (line 8 - line 9 - line 9a) | | | | | $ - |
| | **DIVISOR** | | | | | |
| 11 | Network transmission for firm wholesale and retail service sinking on Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s transmission | | | | (Worksheet P-3, p. 1, Sec. I, 12-CP, | |
| 12 | system, plus long-term P-T-P Contract Demands that are not under the SPP OATT | | | | Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s Transmission Network Load) | - |
| 13 | Divisor | | | | | - |
| | **RATES (used in Evergy Kansas Central, Inc. and Evergy Kansas South, Inc.'s OATT only)** | | | | | |
| 14 | Annual Cost ($/kW/Yr) | (line 8 / line 13) | $ - | | | |
| 15 | P-to-P Rate ($/kW/Mo) | (line 14 / 12 months) | $ - | | | |
| | | | Peak Rate | | | Off-Peak Rate |
| 16 | Point-To-Point Rate ($/kW/Wk) | (Peak: line 14 / 52 weeks, Off Peak, line 14 / 52 weeks) | $ - | | | $ - |
| 17 | Point-To-Point Rate ($/kW/Day) | (Peak: line 16 / 5 days, Off Peak: line 16 / 7 days) | $ - | Capped at weekly rate | | $ - |

| | | | | |
|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/MWh) | (Peak: (line 17 / 16 hours) times 1000);<br>Off Peak; (line 17 / 24 hours) times 1000 | $ - Capped at weekly and daily rates | $ - |
| 19 | Net Transmission Plant | (Projected Gross Rev Req, line 6) | | $ - |
| 20 | Facility Carrying Charge | (line 8 divided by line 19) (Note 2) | | 0.00% |
| 21 | Monthly Facility Carrying Charge | (line 20 divided by 12 months) (Note 2) | | 0.00% |
| 22 | Additional Revenue Requirement Allocated to the Retail Jurisdiction | (Worksheet A-3, p. 1, ln. 16, Total) | | $ - |

**NOTES**

NOTE 1:
Hold for future use.

NOTE 2:
The Facility Carrying Charge and Monthly Facility Carrying Charge on Page 1, lines 21 and 22 are to be used to compute the revenue requirements for facilities directly assigned to a customer.

Rate Formula Template

Utilizing FERC Form 1 Data

Projected Gross Revenue Requirements

For the 12 months ended - December 31, 20xx

Projected
Page 1 of 5

EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.

| Line | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | **Form No. 1** | **Evergy Kansas Central, Inc** | **Evergy Kansas South, Inc.** | | | |

| No | RATE BASE: | Page, Line, Col. | (EKC) | (EKS) | Company Total | Allocator | | Transmission (5)*(6) |
|---|---|---|---|---|---|---|---|---|
| | PLANT IN SERVICE | | | | $ | | 0.0000 | $ |
| 1 | Transmission | (Worksheet P-1) | | | - | TP | 0 | - |
| 2 | General | (Actual Gross Rev, Page 1, line 4) | - | - | - | W/S | 0.0000 0 | - |
| 2a | Intangible | (Actual Gross Rev, Page 1, line 4a) | - | - | - | W/S | 0.0000 0 | - |
| 3 | TOTAL GROSS PLANT | (sum lines 1-3) | | | | | | $ - |
| | ACCUMULATED DEPRECIATION | (Note Q) | | | $ | | 0.0000 | $ |
| 3 | Transmission | (Worksheet P-1) | | | - | TP | 0 | - |
| 4 | General | (Actual Gross Rev, Page 1, line 10) | $ - | $ - | - | W/S | 0.0000 0 | $ - |
| 4a | Intangible | (Actual Gross Rev, Page 1, line 10a) | - | - | - | W/S | 0.0000 0 | - |
| 5 | TOTAL ACCUM. DEPRECIATION | (sum lines 3-4) | | | | | | $ - |
| | NET PLANT IN SERVICE | | $ | $ | $ | | | $ |
| 6 | Transmission | (line 1 less line 3) | - | - | - | | | - |
| 7 | General | (line 2 less line 4) | $ - | $ - | - | | | $ - |
| 7a | Intangible | (line 3 less line 5) | $ - | $ - | - | | | - |
| 8 | TOTAL NET PLANT | (sum lines 6-7) | | | | | | $ - |
| | ADJUSTMENTS TO RATE BASE | | | | | | | |
| 9 | Accumulated Deferred Income Taxes | *(Actual Gross Rev Req, Page 1, Line 19)* | $ - | $ - | $ - | DA | | - |
| 9a | Unamortized Extraordinary Property Loss | Account 182.1 (Note S) | | $ - | $ - | TE | 0.0000 0 | - |
| 9b | Transmission Storm Damage Reserve | Account 228.1 (Note S) | | | $ - | TE | 0.0000 0 | - |
| 10 | TOTAL ADJUSTMENTS | (line 9 + line 9a - line 9b) | | | $ - | | | $ - |
| 11 | LAND HELD FOR FUTURE USE | (Actual Gross Rev Req, Page 1, line 11) | 0 | 0 | 0 | TP | 0.0000 0 | 0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | WORKING CAPITAL | | | | | | | |
| 12 | CWC | calculated (Note C) | | | | | | $ - |
| 13 | Materials & Supplies | (Actual Gross Rev, Page 1, line 23) | - | - | - | TP | 0.0000 0 | - |
| 13a | Stores Expense | (Actual Gross Rev, Page 1, line 23a) | - | - | - | W/S | 0.0000 0 | - |
| 14 | Prepayments (Account 165) | (Actual Gross Rev, Page 1, line 14) | - | - | - | GP | 0.0000 0 | - |
| 15 | TOTAL WORKING CAPITAL | (sum lines 12 - 14) | | | $ - | | | $ - |
| 16 | Rate Base | (sum lines 8, 10, 11, & 15) | | | | | | $ - |

Rate Formula Template

Utilizing FERC Form 1 Data

Projected Gross Revenue Requirements

For the 12 months ended - December 31, 20xx

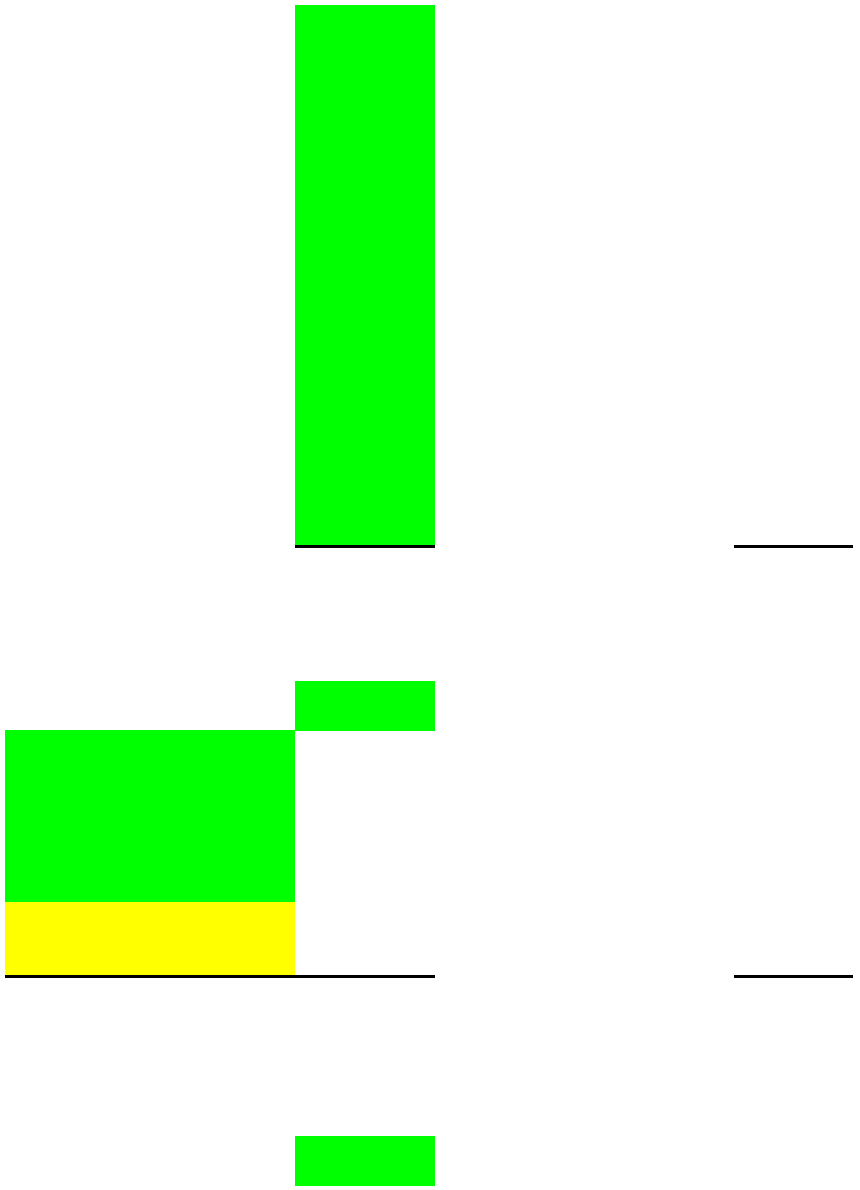
Projected
Page 2 of 5

EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.

| | (1) | (2) | (3) | (4) | (5) | | (6) | (7) |
|---|---|---|---|---|---|---|---|---|
| Line No | | **Reference** | **Evergy Kansas Central, Inc (EKC)** | **Evergy Kansas South, Inc. (EKS)** | **Company Total** | **Allocator** | | **Transmission (5)*(6)** |
| | **O&M** | | | | | | | |
| 1 | Transmission (Note D) | (Worksheet P-2. line 3) | | | $ - | | 1.0000 0 | $ - |
| 2 | Less Account 561 | (Worksheet P-2, line 4) | | | - | | 1.0000 0 | - |
| 2a | Less Account 565 (Note E) | (Worksheet P-2, line 5) | | | - | | 1.0000 0 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | 0.0000 |
| 3 | A&G | (Worksheet P-2, line 6) | | | - | - |
| 3a | Less: Actual PBOP | (Worksheet P-2, line 7) | | | - | |
| 4 | Plus: PBOP adder | (Worksheet P-2, line 8) | | | 16,339,609 | |
| 5 | Less FERC Annual Fees | (Worksheet P-2, line 9) | | | - | |
| 6 | Less EPRI | (Worksheet P-2, line 10) | | | - | |
| 6a | Less Total Advertising Costs | (Worksheet P-2, line 11) | | | - | |
| 6b | Less Total Regulatory Commission Expenses | (Worksheet P-2, line 12) | | | - | |
| 7 | Plus Transmission Related Reg. Comm. Exp. | (Worksheet P-2, line 13) | | | - | |
| 8 | Plus Safety Advertising | (Worksheet P-2, line 14) | | | - | |
| 9 | Common | (Worksheet P-2, line 15) | | | - | |
| 10 | Transmission Lease Payments | (Worksheet P-2, line 16) | | | - | |
| 11 | TOTAL O&M | (sum lines 1, 3, 4, 7, 8, 9, 10 less lines 2, 2a, 3a, 5, 6, 6a, 6b) | | | $ 16,339,609 | |
| | **DEPRECIATION EXPENSE** | | | | | |
| 12 | Transmission | (Worksheet P-1) | | | $ - | |
| 13 | General | (Actual Gross Rev, page 2, line 13) | - | - | - | |
| 13a | Intangible | (Actual Gross Rev, page 2, line 13a) | - | - | - | |
| 14 | Common | (Actual Gross Rev, page 2, line 14) | - | - | - | |
| 14a | Amortization of Property Loss | Acct. 407-Unrecovered Plant and Regulatory Study Costs (Note S) | - | - | - | |
| 15 | TOTAL DEPRECIATION | (Sum lines 12 - 14a) | | | $ - | |
| | **TAXES OTHER THAN INCOME TAXES (Note G)** | | | | | |
| | LABOR RELATED | | | | | |
| 16 | Payroll | (Worksheet P-2, line 18) | | | $ | |

| | | | |
|---|---|---|---|
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 1.0000 | | |
| | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| CE | 0 | - | |
| | 1.0000 | | |
| | 0 | - | |
| | | $ | |
| | | - | |
| | 0.0000 | $ | |
| TP | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| W/S | 0 | - | |
| | 0.0000 | | |
| CE | 0 | - | |
| | 0.0000 | | |
| TE | 0 | | |
| | | - | |
| | | $ | |
| | | - | |
| | 0.0000 | $ | |
| W/S | 0 | - | |



| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 17 | Highway and vehicle | (Worksheet P-2, line 19) | | | $ - | | W/S | 0.0000 0 | - |
| | PLANT RELATED | | | | | | | | |
| 18 | Property (Note P) | (Worksheet P-2, line 20) | | | - | | GP | 0.0000 0 | - |
| 19 | Gross Receipts | (Worksheet P-2, line 21) | | | - | | NA | 0.0000 0 | - |
| 20 | Other | (Worksheet P-2, line 22) | | | - | | GP | 0.0000 0 | - |
| 21 | Payments in lieu of taxes | (Worksheet P-2, line 23) | | | - | | GP | 0.0000 0 | - |
| 22 | TOTAL OTHER TAXES | (sum lines 16 - 21) | | | $ - | | | | $ - |
| | **INCOME TAXES** | (Note H) | | | | | | | |
| 23 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | | | 0.00% | | | |
| 24 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 5, line 21) and R= (page 5, line 24) and FIT, SIT & p are as given in Note H. | | | | | 0.00% | | | |
| 25 | 1 / (1 - T) = (from line 23) | | | | | - | | | |
| 26 | Amortized Investment Tax Credit | (Actual Gross Rev Req, Page 2, line 26) | $ - | $ - | $ - | | | | |
| *26a* | *(Excess)/Deficient Deferred Income Taxes* | *(Actual Gross Rev Req, Page 2, line 26a)* | *$-* | *$-* | *$-* | | | | |
| 27 | Income Tax Calculation = line 24 * line 30 | | | | $ - | | NA | | $ - |
| 28 | ITC adjustment (line 25 * line 26) | | | | - | | NP | 0.0000 0 | - |
| *28a* | *(Excess)/Deficient Deferred Income Tax Adjustment* | *(line 25 * line 26a)* | | | - | | *DA* | *1.0000 0* | - |
| 29 | Total Income Taxes | (line 27 plus line 28 *plus line 28a*) | | | | $ - | | | $ - |
| 30 | **RETURN** [ Rate Base (page 1, line 16) * Rate of Return (page 5, line 24) plus Incentive Return (page 5, line 29)] | | | | | | NA | | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 3 | | (Actual Gross Rev Req, Page | | | | | |
| 1 | Interest on Network Credits | 2, line 31) | | 0 | DA | | 0 |
| 3 | **GROSS REV. REQUIREMENT** | | | $ | | | $ |
| 2 | **(sum lines 11, 15, 22, 29, 30 & 31)** | | | 16,339,609 | | | - |

Rate Formula Template

Utilizing FERC Form 1 Data

Projected Gross Revenue Requirements

For the 12 months ended - December 31, 20xx

Projected



EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.

**SUPPORTING CALCULATIONS**

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| Line No | | **Form No. 1 Page, Line, Col.** | **Evergy Kansas Central, Inc (EKC)** | **Evergy Kansas South, Inc. (EKS)** | **Company Total** | **Allocator** | **Transmission (5)*(6)** |
| | **TRANSMISSION PLANT INCLUDED IN FORMULA** | | | | | | |
| 1 | Total transmission plant | (page 3, Line 13, col. 5) | | | | | $ - |
| 2 | Less transmission plant excluded from ISO rates | (Note I)(Actual Gross Rev Req, Page 3, line 2) | $ - | $ - | $ - | | - |
| 3 | Less transmission plant included in OATT Anc. Srvc | (Notes J&K) (Actual Gross Rev Req, Page 3, line 3) | $ - | $ - | $ - | | - |
| 4 | Transmission plant included in rates | (line 1 less lines 2 & 3) | | | | | $ - |
| 5 | Percentage of transmission plant included in rates | (line 4 divided by line 1) | | | | TP = | 0.00000 |

**TRANSMISSION EXPENSES**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | $ |
| 6 | Transmission expenses | (Page 2, line 1, col 5) | | | | | | | - |
| 7 | Less transmission expenses included in OATT Anc. Srvc | (Note L) (Page 2, line 2, col 5) | | | | | | | - |
| 8 | Included transmission expenses (line 6 less line 7) | | | | | | | | $ - |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | | | | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | | | | | T P = | 0.00000 |
| 11 | Percentage of transmission expenses included in rates (line 9 times line 10) | | | | | | | T E = | 0.00000 |

**GROSS AND NET PLANT ALLOCATORS**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | | | | |
| 11 | | (Actual Gross Rev. Page 3, | $ | $ | $ | | | | |
| 12 | Production | line 12) | - | - | - | NA | | | 0 |
| 13 | Transmission | (Actual Gross Rev. Page 3, line 13) | - | - | $ - | TP | 0.0000 0 | | 0 |
| 14 | Distribution | (Actual Gross Rev. Page 3, line 14) | - | - | - | NA | | | 0 |
| 15 | General & Intangible | (Actual Gross Rev. Page 3, line 15) | - | - | - | W/S | 0.0000 0 | | 0 |
| 16 | Common | (Actual Gross Rev. Page 3, line 16) | - | - | - | CE | 0.0000 0 | | 0 |
| 17 | TOTAL GROSS PLANT (sum lines 12-16) | | $ - | $ - | $ - | GP = | 0.000 % | | $ - |
| | ACCUMULATED DEPRECIATION (ACTUAL HISTORICAL COST) (Note Q) | | | | | | | | |
| 18 | | (Actual Gross Rev. Page 3, | $ | $ | $ | | | | |
| 18 | Production | line 18) | - | - | - | NA | | | 0 |
| 19 | Transmission | (Actual Gross Rev. Page 3, line 19) | - | - | $ - | TP | 0.0000 0 | | 0 |
| 20 | Distribution | (Actual Gross Rev. Page 3, line 20) | - | - | - | NA | | | 0 |
| 21 | General & Intangible | (Actual Gross Rev. Page 3, line 21) | - | - | - | W/S | 0.0000 0 | | 0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 22 | Common | (Actual Gross Rev. Page 3, line 22) | - | - | - | CE | 0.0000 0 | | 0 |
| 23 | TOTAL ACCUM. DEPRECIATION (sum lines 18-22) | | $ - | $ - | $ - | | | $ - | |
| | NET PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | | | |
| 24 | | | $ | $ | $ | | | | |
| 25 | Production | (line 12 less line 18) | - | - | - | | | | 0 |
| 26 | Transmission | (line 13 less line 19) | - | - | - | | | | 0 |
| 27 | Distribution | (line 14 less line 20) | - | - | - | | | | 0 |
| 28 | General & Intangible | (line 15 less line 21) | - | - | - | | | | 0 |
| 29 | Common | (line 16 less line 22) | - | - | - | | | | 0 |
| 30 | TOTAL NET PLANT (sum lines 24-28) | | $ - | $ - | $ - | NP = | 0.000 % | $ - | |

Rate Formula Template

Utilizing FERC Form 1 Data

Projected Gross Revenue Requirements

For the 12 months ended - December 31, 20xx

Projected

Page 4 of 5

EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.

**SUPPORTING CALCULATIONS**

| Line No | (1) | (2) | (3) | (4) | (5) | | (6) | (7) |
|---|---|---|---|---|---|---|---|---|
| | | **Form No. 1** | **Evergy Kansas Central, Inc** | **Evergy Kansas South, Inc.** | | | | |
| | | **Page, Line, Col.** | **(EKC)** | **(EKS)** | **Company Total** | **Allocator** | | **Transmission (5)*(6)** |
| | **WAGES & SALARY ALLOCATOR (W&S)** | | | | | | | |
| | | | $ | $ | $ | TP | Allocation | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Production | (Worksheet A-10) | 0 | 0 | $ - | 0.00000 | 0 | | | | |
| 2 | Transmission | (Worksheet A-10) | 0 | 0 | - | 0.00000 | 0 | | | | |
| 3 | Distribution | (Worksheet A-10) | 0 | 0 | - | 0.00000 | 0 | | W&S Allocator | | |
| 4 | Other | (Worksheet A-10) | 0 | 0 | - | 0.00000 | 0 | | ($ / Allocation) | | |
| 5 | Total (sum lines 1-4) | | 0 | 0 | $ - | | 0 | = | 0.00000 | = | WS |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **COMMON PLANT ALLOCATOR (CE) (Note M)** | | | | | | | | | | | |
| 6 | Electric | (Actual Gross Rev., Page 4, line 6) | $ - | $ - | $ - | **$** | % Electric (line 6 / line 9) | | W&S Allocator (line 5) | | CE |
| 7 | Gas | (Actual Gross Rev., Page 4, line 7) | - | - | - | | 0.0000 0 | * | 0.00000 | = | 0.0000 |
| 8 | W ater | (Actual Gross Rev., Page 4, line 8) | - | - | - | | | | | | |
| 9 | Total (sum lines 6 - 8) | | $ - | $ - | $ - | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **RETURN (R)** | | | | | $ |
| 10 | Interest on Long-Term Debt | (Actual Gross Rev., Page 4, line 10) | $ - | $ - | $ - | |
| 11 | Amort. of Debt Disc. and Expense | (Actual Gross Rev., Page 4, line 11) | - | - | - | |
| 12 | Amortization of Loss on Reacquired Debt | (Actual Gross Rev., Page 4, line 12) | - | - | - | |
| 13 | Less: Amort. of Premium on Debt-Credit | (Actual Gross Rev., Page 4, line 13) | - | - | - | |
| 14 | Less: Amort. of Gain on Reacquired Debt-Credit | (Actual Gross Rev., Page 4, line 14) | - | - | - | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Long Term Interest (sum of lines | | $ | $ | $ | | | $ | |
| 15 | 10 - 12 less 13 and 14) | | - | - | - | | | - | |
| 16 | Preferred Dividends (positive number) | (Actual Gross Rev., Page 4, line 16) | $ - | $ - | $ - | | | $ - | |
| | Development of Common Stock: | | | | | | | | |
| 17 | Proprietary Capital | (Actual Gross Rev. Page 4, line 17) | $ - | | $ - | | | $ - | |
| 18 | Less Preferred Stock | (line 22) | | | | | | - | |
| 19 | Less Adjusted 216.1 Subsidiary Retained Earnings | (Actual Gross Rev. Page 4, line 19) | | | | | | - | |
| 20 | Common Stock | (Line 17 less line 18 less line 19) | | | | | | $ - | |
| | | | **EKC** | **EKS** | $ | % | Cost (Note O) | W eighted | |
| 21 | Long Term Debt | (Actual Gross Rev, page 4, line 21) | $ - | $ - | $ - | 0.00 % | - | 0.0000 | =WCLTD |
| 22 | Preferred Stock | (Actual Gross Rev. page 4, line 22) | - | N/A | - | 0.00 % | - | 0.0000 | |
| 23 | Common Stock | (line 20) | - | N/A | - | 0.00 % | 0.103 | 0.0000 | |
| 24 | Total | (sum lines 21-23) | | | $ - | 0.00 % | | 0.0000 | = R |
| | **Incentive Return** | | **Gross Plant (3)** | **Accum. Depreciation (4)** | **Net Plant (3) - (4)** | | | | |
| 25 | Incentive Plant: Actual Zonal Plant | (Worksheet A-11, page 1, Actual Year) | $0.00 | $0.00 | $ - | | | | |
| 26 | Incentive Plant: Actual Base Plan Funded | (Worksheet A-11, page 2, Actual Year) | $0.00 | $0.00 | $ - | | | | |
| 27 | Incentive Plant: Actual Economic Portfolio | (Worksheet A-11, page 3, Actual Year) | $0.00 | $0.00 | $ - | | | | |
| 28 | Incentive Plant: Projected | (Worksheet P-1, line 44) | $0.00 | $0.00 | $ - | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 28 | | | $ | $ | $ |
| a | Total Incentive Net Plant | | - | - | - |
| 29 | Incentive Return | (Worksheet P-1, page 1, line 35) | | | $ - |



Rate Formula Template

Utilizing FERC Form 1 Data

Projected Gross Revenue Requirements

For the 12 months ended - December 31, 20xx

EVERGY KANSAS CENTRAL, INC. and EVERGY KANSAS SOUTH, INC.

**NOTES**

A (Hold future use)

B (Hold future use)

C (Hold future use)

D (Hold future use)

E (Hold future use)

F (Hold future use)

G (Hold future use)

H The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 28).

Inputs Required:

FIT = (Federal Income Tax Rate)

SIT= (State Income Tax Rate or Composite SIT)

p = (percent of federal income tax deductible for state purposes)

**Worksheet P1 - Projected Transmission Plant**
For the 12 months ended - December 31, 20xx



| | Total Plant | Incentive | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | **Project:** | | | | -<br>**Project:** | Project X | | | -<br>**Project:** | Project Y Economic Portfolio | | | | |
| 2 | | | | | Type: | | | | Type: | Base Plan Funded | | | Type: | | | | | |
| 3 | | | | | Deprec. Rate:(A) | 0.5556 % | | | Deprec. Rate:(A) | | | | Deprec. Rate:(A) | | | | | |
| 4 | | | | | ROE Adder | 0.70% | | | ROE Adder | | | | ROE Adder | | | | | |
| 5 | | | | | Weighted ROE: | 0.00% | | | Weighted ROE: | 0.00% | | | Weighted ROE: | 0.00% | | | | |
| 6 | | | | | Beginning Bal: | $ - | | | Beginning Bal: | | | | Beginning Bal: | | | | | |
| 7 | | **Total** | | | Beginning Dep: | - | | | Beginning Dep: | | | | Beginning Dep: | | | | | |
| 8 | | | | | Beginning Year: | | | | Beginning Year: | | | | Beginning Year: | | | | | |
| | **Year** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Year** | Gross Plant $ - | Depreciation | Accum. Dep. | Net Plant | Gross Plant $ - | Depreciation | Accum. Dep. | Net Plant | Gross Plant $ - | Depreciation | Accum. Dep. | Net Plant | |
| | | | | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | | | | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 11 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 12 | | | | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 13 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | - | - | - | - | - | - | - | - | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 2 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 3 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 4 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 5 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 6 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 7 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 8 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 1 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 9 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 0 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 1 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 2 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 3 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 4 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 5 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 6 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 7 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 8 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 2 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 9 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 3 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 0 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 3 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 1 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 3 | | | | | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 2 | | $0 | $0 | $0 | Jan-00 | - | - | - | - | | - | - | - | - | | - | - | - | - |
| 3 | 12 Mon | | | | | | | | | | | | | | | | | | |
| 3 | Tot | | $0 | | | | $0 | | | | $0 | | | | | $0 | | | |
| 3 | 13 Mon | | | | | | | | | | | | | | | | | | |
| 4 | Avg | $0 | | $0 | | $0 | | $0 | $0 | | $0 | | $0 | $0 | | $0 | | $0 | $0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| 3 | Total Incentive | | | | | | Incentive Return | $ - | Incentive Return | $ - | Incentive Return | $ - |
| 5 | Return: | $0 | | | | | | | | | | |

(A) 15-year accelerated depreciation expenses authorized in Docket Nos. EL08-31-000 and ER08-396-000.

**Worksheet P1 - Projected Transmission Plant For the 12 months ended - December 31, 20xx**



**Total Incentive, non-incentive and BPF Plant**

**EKC & EKS**

| | **Year** | **Total Plant Additions: Gross Plant** | **Depreciation** | **Accum. Dep.** | | **Non-Incentive Plant: Projected Non-Incentive Plant Additions** | **Non-Incentive Plant in Service** | **Non-Incentive Plant Depreciation Accrual(A) 0.0000 %** | **Non-Incentive Plant Accumulated Depreciation** |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | |
| 2 | | | | | Plant Balances as of Dec 31, 20xx | | | | |
| 3 | | | | | Plant Additions: | | | | |
| 4 | | $0 | $0 | $0 | Jan-00 | | - | - | - |
| 5 | | $0 | $0 | $0 | Jan-00 | | - | - | - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 7 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 8 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 9 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 10 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 11 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 12 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 13 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 14 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 15 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 16 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 17 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 18 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 19 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 20 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 21 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 22 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 23 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 24 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 25 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 26 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 27 | | $0 | $0 | $0 | Jan-00 | | - | - | - | |
| 28 | 12 Mon Tot | | $ - | | 12-Month Depreciation Accrual | | | $ - | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | 13 Mon | | | 13-Month Average | | |
| 9 | Avg | $0 | $0 | Balance | $0 | $0 |

Notes:
(A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 10) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 1) divided by 12 months.

**Worksheet P2 - Projected Expenses and Revenue Credits**
For the 12 months ended - December 31,
20xx

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| Line | | | **EKC Actual Costs** | **EKS Actual Costs** | **Total Costs** | **Ratio of Expense To Net Plant in Service** (Ratio of Cost to total) | **Projected Costs** (Ratio * Proj. Net Plant) |
| 1 | Net Plant in Service (EKC and EKS) | (Actual Gross Rev, p. 1, ln 18, col 7) | | | $0 | | |
| 2 | Projected Net Plant in Service | (Projected Gross Rev, p 1, ln 8, c7) | | | | | $0.00 |
| | **Operation and Maintenance Expenses** | | | | | | |
| 3 | Transmission | (Actual Gross Rev, p2, ln 1, col 3 & 4) | $ - | $ - | $ - | - | - |
| 4 | Less Account 561 | (Actual Gross Rev, p2, ln 2, col 3 & 4) | - | - | $ - | - | - |
| 5 | Less Account 565 | (Actual Gross Rev, p2, ln 2a, col 3 & 4) | - | - | $ - | - | - |
| 6 | A&G | (Actual Gross Rev, p2, ln 3, col 3 & 4) | - | - | $ - | - | - |
| 7 | Less: Actual PBOP | (Actual Gross Rev, p2, ln 3a, col 3 & 4) | - | - | $ - | | - |
| 8 | Plus: PBOP adder | (Actual Gross Rev, p2, ln 4, col 3 & 4) | 9,697,558 | 6,642,051 | $ 16,339,609 | | 16,339,609 |
| 9 | Less FERC Annual Fees | (Actual Gross Rev, p2, ln 5, col 3 & 4) | - | - | $ - | - | - |
| 10 | Less EPRI | (Actual Gross Rev, p2, ln 6, col 3 & 4) | - | - | $ - | - | - |
| 11 | Less Total Advertising Costs | (Actual Gross Rev, p2, ln 6a, col 3 & 4) | - | - | $ - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 12 | Less Total Regulatory Commission Expenses | (Actual Gross Rev, p2, ln 6b, col 3 & 4) | - | - | $ - | - | - |
| 13 | Plus Transmission Related Reg. Comm. Exp. | (Actual Gross Rev, p2, ln 7, col 3 & 4) | - | - | $ - | - | - |
| 14 | Plus Safety Advertising | (Actual Gross Rev, p2, ln 8, col 3 & 4) | - | - | $ - | - | - |
| 15 | Common | (Actual Gross Rev, p2, ln 9, col 3 & 4) | - | - | $ - | - | - |
| 16 | Transmission Lease Payments | (Actual Gross Rev, p2, ln 10, col 3 & 4) | - | - | $ - | - | - |
| 17 | Total | (Sum lines 3,6,8,13,14,15&16 less lines 4,5,7,9,10,11,12) | $ 9,697,558 | $ 6,642,051 | $ 16,339,609 | | $ 16,339,609 |
| | **Other Taxes** | | | | | | |
| | LABOR RELATED | | | | | | |
| 18 | Payroll | (Actual Gross Rev, p2, ln 16, col 3 & 4) | $ - | $ - | $ - | - | - |
| 19 | Highway and vehicle | (Actual Gross Rev, p2, ln 17, col 3 & 4) | - | - | $ - | - | - |
| | PLANT RELATED | | | | | | |
| 20 | Property (Note P) | (Actual Gross Rev, p2, ln 18, col 3 & 4) | - | - | $ - | - | - |
| 21 | Gross Receipts | (Actual Gross Rev, p2, ln 19, col 3 & 4) | - | - | $ - | - | - |
| 22 | Other | (Actual Gross Rev, p2, ln 20, col 3 & 4) | - | - | $ - | - | - |
| 23 | Payments in lieu of taxes | (Actual Gross Rev, p2, ln 21, col 3 & 4) | - | - | $ - | - | - |
| 23a | Total | (Sum lines 18 thru 23) | | $ - | $ - | | $ - |

| | | | EKC and EKS |
|---|---|---|---|
| | **Revenue Credits (EKC and EKS)** | | |
| 24 | Account No. 454 | | $ - |
| 25 | Account No. 456 | | $ - |
| 26 | Revenues from Grandfathered Interzonal Transaction | | - |
| 27 | Revenues from service provided by the ISO at a discount | | - |
| | | | $ - |

**Worksheet P3 - Projected Transmission Network Load**

For the 12 months ended - December 31, 20xx

| Line No. | | | | |
|---|---|---|---|---|
| 1 | Maximum Trans Network Load During the Summer of | | | = MW |
| | a | b | c | |
| | | | | |
| | | | | |
| | | **Percentage of Maximum Transmission Network Load From 2007** | **Projected Transmission Network Load (Col 2** | |
| | **Month** | **(Worksheet B)** | **x Line 1)** | |
| 2 | January | 0.00% | - | |
| 3 | February | 0.00% | - | |
| 4 | March | 0.00% | - | |
| 5 | April | 0.00% | - | |
| 6 | May | 0.00% | - | |
| 7 | June | 0.00% | - | |
| 8 | July | 0.00% | - | |
| 9 | August | 0.00% | - | |
| 10 | September | 0.00% | - | |
| 11 | October | 0.00% | - | |
| 12 | November | 0.00% | - | |
| 13 | December | 0.00% | - | |
| 14 | Total | | - | |
| 15 | 12-CP | | - | |

Note: Maximum Transmission Network Load is the maximum hourly load measured on the Evergy Kansas Central, Inc. and Evergy Kansas South, Inc. transmission system as of September 30 of each year. The data will be obtained from the Energy Accounting System.

# Worksheet P4 - Projected Transmission Plant Related to Base Plan Funded Projects

For the 12 months ended - December 31, 20xx

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Total Base Plan Funded Projects ( C )** | | | | | | | | | | | | | | | | | |
| 1 | **Total Plant** | | | | **Project:** | | | **Project:** | | | **Project:** | | | **Project:** | | |
| 2 | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | Deprec. Rate: ( C ) | 0.0000% | (A) | Deprec. Rate: ( C ) | 0.0000% | (A) | Deprec. Rate: ( C ) | 0.0000% | (A) | Deprec. Rate: ( C ) | 0.0000% | (A) |
| 4 | | | | | Beginning Bal: | | | Beginning Bal: | $ - | | Beginning Bal: | $ - | | Beginning Bal: | $ - | |
| 5 | | **Total** | | | Beginning Dep: | | | Beginning Dep: | - | | Beginning Dep: | - | | Beginning Dep: | - | |
| 6 | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | 2008-12 | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 8 | Jan-08 | $0 | $0 | $0 | Jan-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | Feb-08 | $0 | $0 | $0 | Feb-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | Mar-08 | $0 | $0 | $0 | Mar-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Apr-08 | $0 | $0 | $0 | Apr-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | May-08 | $0 | $0 | $0 | May-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | Jun-08 | $0 | $0 | $0 | Jun-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | $ - | $ - |
| 1 | Jul-08 | $0 | $0 | $0 | Jul-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | Aug-08 | $0 | $0 | $0 | Aug-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | Sep-08 | $0 | $0 | $0 | Sep-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | Oct-08 | $0 | $0 | $0 | Oct-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | Nov-08 | $0 | $0 | $0 | Nov-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 1 | Dec-08 | $0 | $0 | $0 | Dec-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | Jan-09 | $0 | $0 | $0 | Jan-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | Feb-09 | $0 | $0 | $0 | Feb-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | Mar-09 | $0 | $0 | $0 | Mar-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | Apr-09 | $0 | $0 | $0 | Apr-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | May-09 | $0 | $0 | $0 | May-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | Jun-09 | $0 | $0 | $0 | Jun-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |
| 2 | Jul-09 | $0 | $0 | $0 | Jul-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | Aug-09 | $0 | $0 | $0 | Aug-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | Sep-09 | $0 | $0 | $0 | Sep-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | Oct-09 | $0 | $0 | $0 | Oct-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | Nov-09 | $0 | $0 | $0 | Nov-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | Dec-09 | $0 | $0 | $0 | Dec-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | 13 Mon Avg | $0 | $0 | $0 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

(A) Projected non-incentive transmission depreciation expense (P-1, page 2, line 28) divided by projected transmission plant in service (P-1, page 2, line 29) divided by 12.

Notes:

(B) 15-year accelerated depreciation expenses authorized in Docket Nos. EL08-31-000 and ER08-396-000.

( C) May also include Incentive Projects if Incentive Projects are also Base Plan Funded.

# Worksheet P4 - Projected Transmission Plant Related to Base Plan Funded Projects

For the 12 months ended - December 31, 20xx

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Project:** | | | **Project:** | | | **Project:** | | | **Project:** | | | **Project:** | | |
| 2 | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | Deprec. Rate: ( C ) | 0.0000 % | (A) | Deprec. Rate: ( C ) | 0.0000 % | (A) | Deprec. Rate: ( C ) | 0.0000 % | (A) | Deprec. Rate: ( C ) | 0.000 0% | (A) | Deprec. Rate: ( C ) | 0.000 0% | (A) |
| 4 | | Beginning Bal: | $ - | | Beginning Bal: | - | | Beginning Bal: | $ - | | Beginning Bal: | $ - | | Beginning Bal: | $ - | |
| 5 | | Beginning Dep: | - | | Beginning Dep: | - | | Beginning Dep: | - | | Beginning Dep: | - | | Beginning Dep: | - | |
| 6 | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | Gross Plant | Accm. Deprec | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant |
| 7 | | $ - | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 8 | Jan-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | Feb-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | Mar-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - |
| 11 | Apr-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | May-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | Jun-08 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | Jul-08 | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Aug-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Sep-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | Oct-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 18 | Nov-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 19 | Dec-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | Jan-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | Feb-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | Mar-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | Apr-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | May-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | Jun-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | Jul-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | Aug-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | Sep-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | Oct-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | Nov-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | Dec-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | 13 Mon Avg | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

# Worksheet P4 - Projected Transmission Plant Related to Base Plan Funded Projects



For the 12 months ended -
December 31, 20xx

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Project:** | | | | **Project:** | | | | **Project:** | | | | **Project:** | | | | **Project:** | | | |
| 2 | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | |
| 3 | | Deprec. Rate: ( C ) | 0.0000 % | (A) | | Deprec. Rate: ( C ) | 0.0000 % | (A) | | Deprec. Rate: ( C ) | 0.0000 % | (A) | | Deprec. Rate: ( C ) | 0.000 0% | (A) | | Deprec. Rate: ( C ) | 0.000 0% | (A) | |
| 4 | | Beginning Bal: | $ - | | | Beginning Bal: | $ - | | | Beginning Bal: | $ - | | | Beginning Bal: | | | | Beginning Bal: | | | |
| 5 | | Beginning Dep: | - | | | Beginning Dep: | - | | | Beginning Dep: | - | | | Beginning Dep: | - | | | Beginning Dep: | - | | |
| 6 | | Beg Year-Mo.: | | | | Beg Year-Mo.: | | | | Beg Year-Mo.: | | | | Beg Year-Mo.: | | | | Beg Year-Mo.: | | | |
| | **Year** | Gross Plant | Accm. Deprec | Net Plant | | Gross Plant | Accm. Deprec. | Net Plant | | Gross Plant | Accm. Deprec. | Net Plant | | Gross Plant | Accm Deprec. | Net Plant | | Gross Plant | Accm Deprec. | Net Plant | |
| 7 | | $ - | | | | $ - | | | | $ - | | | | $ - | | | | $ - | | | |
| 8 | Jan-08 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Feb-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | | | | | | | | | | | | | | | | | |
| 10 | Mar-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | Apr-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | May-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | Jun-08 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | Jul-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | Aug-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Sep-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | Oct-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 18 | Nov-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 19 | Dec-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | Jan-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | Feb-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | Mar-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | Apr-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | May-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | Jun-09 | | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | Jul-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | Aug-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Sep-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Oct-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 3 | Nov-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 3 | Dec-09 | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | $ - | $ - | | | $ - | $ - | | | |
| 13 Mon Avg | | $0 | $0 | $0 | | $0 | $0 | $0 | | $0 | $0 | $0 | | $0 | $0 | $0 | | $0 | $0 | $0 | | | |

# Worksheet P4 - Projected Transmission Plant Related to Base Plan Funded Projects



For the 12 months ended -
December 31, 20xx

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Project:** | | | | **Project:** | | | | **Project:** | | | | **Project:** | | | | **Project:** | | | | | |
| 2 | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | | | |
| 3 | | Deprec. Rate: ( C ) | 0.0000 % | (A) | | Deprec. Rate: ( C ) | 0.0000 % | (A) | | Deprec. Rate: ( C ) | 0.0000 % | (A) | | Deprec. Rate: ( C ) | 0.000 0% | (A) | | Deprec. Rate: ( C ) | 0.000 0% | (A) | | | |
| 4 | | Beginning Bal: | $ - | | | Beginning Bal: | | | | Beginning Bal: | | | | Beginning Bal: | $ - | | | Beginning Bal: | $ - | | | | |
| 5 | | Beginning Dep: | - | | | Beginning Dep: | | | | Beginning Dep: | - | | | Beginning Dep: | - | | | Beginning Dep: | - | | | | |

| | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | **Year** | Gross Plant | Accm. Deprec | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant |
| 7 | | $ - | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 8 | Jan-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | Feb-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | Mar-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | Apr-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | May-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | Jun-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | Jul-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | Aug-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Sep-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | Oct-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 18 | Nov-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 19 | Dec-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | Jan-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | Feb-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Mar-09 | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Apr-09 | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | May-09 | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Jun-09 | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Jul-09 | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Aug-09 | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Sep-09 | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 2 | Oct-09 | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 3 | Nov-09 | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 3 | Dec-09 | | $ - | $ - | | | $ - | $ - | | | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | | |
| 13 | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Mon | | | | | | | | | | | | | | | | | | | | | | |
| 2 | Avg | | $0 | $0 | $0 | | $0 | $0 | $0 | | $0 | $0 | $0 | | $0 | $0 | $0 | | $0 | $0 | $0 | | | |

**Worksheet P5 - Projected Transmission Plant Related to Economic Portfolio Projects**



For the 12 months ended - December 31, 20xx

**Total Economic Portfolio Funded Projects**

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Total Plant** | | | | | **Project:** | Project E6 | | **Project:** | Project E7 | | **Project:** | Project E8 | | **Project:** | Project E9 | | **Project:** | Project E10 | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant | Gross Plant | Accm Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 8 | Jan-08 | $0 | $0 | $0 | Jan-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | Feb-08 | $0 | $0 | $0 | Feb-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 10 | Mar-08 | $0 | $0 | $0 | Mar-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 11 | Apr-08 | $0 | $0 | $0 | Apr-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | May-08 | $0 | $0 | $0 | May-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | Jun-08 | $0 | $0 | $0 | Jun-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 14 | Jul-08 | $0 | $0 | $0 | Jul-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | Aug-08 | $0 | $0 | $0 | Aug-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Sep-08 | $0 | $0 | $0 | Sep-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | Oct-08 | $0 | $0 | $0 | Oct-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | Nov-08 | $0 | $0 | $0 | Nov-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 19 | Dec-08 | $0 | $0 | $0 | Dec-08 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | Jan-09 | $0 | $0 | $0 | Jan-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | Feb-09 | $0 | $0 | $0 | Feb-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | Mar-09 | $0 | $0 | $0 | Mar-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | Apr-09 | $0 | $0 | $0 | Apr-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | May-09 | $0 | $0 | $0 | May-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | Jun-09 | $0 | $0 | $0 | Jun-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | Jul-09 | $0 | $0 | $0 | Jul-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | Aug-09 | $0 | $0 | $0 | Aug-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | Sep-09 | $0 | $0 | $0 | Sep-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | Oct-09 | $0 | $0 | $0 | Oct-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | Nov-09 | $0 | $0 | $0 | Nov-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | Dec-09 | $0 | $0 | $0 | Dec-09 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | 13 Mon Avg | $0 | $0 | $0 | | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

Notes: (A) Projected transmission depreciation expense (Projected Gross Rev Req, page 1, line 10) divided by projected transmission plant in service (Projected Gross Rev Req, page 1, line 1) divided by 12.
(B) May also include Incentive Projects if
Incentive Projects are also Base Plan Funded.

# Formula Rate Implementation Protocols

## I. Annual True-Up and Annual Projection

1. The Evergy Kansas Central, Inc. ("Evergy") formula rate template in Attachment H-1 of Southwest Power Pool's ("Evergy") Open Access Transmission Tariff ("Formula Rate"), is Evergy's filed rate. Evergy shall follow the instructions specified in the Formula Rate to calculate annually its Annual Transmission Revenue Requirements ("ATRR") and the rates for its Network Integration Transmission Service and Point-to-Point transmission service. These protocols shall apply to Evergy's calculation of its ATRR, including the calculation of the Annual True-Up ("Annual True-Up") and the projected net revenue requirement ("Annual Projection").

2. The Formula Rate shall be applicable to service on and after January 1st of each calendar year through December 31st of the same calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, as provided herein.

3. On or before June 15th, Evergy shall provide its Annual True-Up to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, Evergy shall provide notice of such posting to all parties on the SPP exploder list titled "Service List". Interested Parties can contact SPP to subscribe to the SPP exploder list.

4. On or before October 15th, Evergy shall provide its Annual Projection to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, Evergy shall provide notice of such posting to all parties on the SPP exploder list titled "Service List". Interested Parties can contact SPP to subscribe to the SPP exploder list.

5. Evergy shall submit to FERC an Informational Filing as provided in Section V of these protocols.

6. If the date for posting the Annual True-Up or Annual Projection falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date". Any delay in the Publication Date or in the posting of the Annual True-Up or Annual Projection will result in an equivalent extension of time for the submission of Information Requests discussed in Section II of these protocols.

7. A change to the Formula inputs related to return on equity, revised depreciation rates or Post-Employment Benefits Other than

Pensions may not be made absent an appropriate filing with FERC.

8. The Annual True-Up shall

   (a) Be based on FERC Form No. 1 data for the prior calendar year, and, to the extent specified in the Formula, upon the books and records of Evergy consistent with FERC accounting policies and practices;

   (b) Identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to FERC Form No. 1 and any adjustments not shown in FERC Form No. 1.

9. The Annual True-Up and Annual Projection shall:

   (a) Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

   (b) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used that are not otherwise available in the FERC Form No. 1;

   (c) Provide sufficient information to enable Interested Parties (as defined in Section I.10 of these protocols) to replicate the calculation;

   (d) Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

   (e) With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

      (i) Identify any Accounting Changes, including

         - The initial implementation of an accounting standard or policy;

         - the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

- correction of errors and prior period adjustments that impact the calculation;
- the implementation of new estimation methods or policies that change prior estimates; and

changes to income tax elections;

(ii) Identify items included in the calculation at an amount other than on a historic cost basis (e.g., fair value adjustments);

(iii) Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs;

(iv) Provide, for each item identified pursuant to items I.9.e.i - I.9.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the calculation.

10. Evergy shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") after the Annual True-Up Publication Date but no sooner than seven (7) days from the Publication Date and no later than July 15th. No less than thirty (30) days prior to such Annual True-Up Meeting, Evergy shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual True-Up Meeting and Evergy shall provide notice of such meeting to the SPP email exploder list titled "Service List". For purposes of these protocols, the term Interested Party includes, but is not limited to customers under the SPP OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting will be hosted by Evergy in the forum of their choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. Evergy shall provide remote access for Interested Parties to participate in the meeting. The Annual True-Up Meeting shall (i) permit Evergy to explain and clarify its Annual True-Up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from Evergy about the Annual True-Up.

11. Evergy shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") after the Annual Projection Publication Date but no sooner than seven (7) days from the Publication Date and no later than October 30th. No less than thirty (30) days prior to such Annual Projected Rate Meeting, Evergy shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual Projected Rate Meeting and Evergy shall provide notice of such meeting to an email exploder list. The Annual Projected Rate Meeting will be hosted by Evergy in the forum of their choice which may include video

conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. Evergy shall provide remote access for Interested Parties to participate in the meeting. The Annual Projected Rate Meeting shall (i) permit Evergy to explain and clarify its Annual Projection and (ii) provide Interested Parties an opportunity to seek information and clarifications from Evergy about the Annual Projection.

12. Each year Evergy shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

## II. Information Exchange Procedures

Each Annual True-Up and Annual Projection shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have seventy-five (75) days following the Annual True-Up Meeting to serve reasonable information and document requests related to the Annual True-Up; and sixty (60) days following the Annual Projection Publication Date (unless such period is extended with the written consent of Evergy or by FERC order) to serve reasonable information and document requests on Evergy related to the Annual True-Up and the Annual Projection ("Information Exchange Period"). If either of these dates falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

   (a) the extent, effect or impact of an Accounting Change;

   (b) whether the Annual True-Up or Annual Projection fails to include data properly recorded in accordance with these protocols;

   (c) the proper application of the Formula Rate and procedures in these protocols;

(d) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual True-Up or Annual Projection;

(e) the prudence of actual costs and expenditures, including the prudence of Evergy's procurement methods and cost control methodologies;

(f) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

(g) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. Evergy shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

3. Evergy will cause to be posted on SPP's website and OASIS all information requests from Interested Parties and Evergy's response(s) to such requests; except, however, if responses to information and document requests include material deemed by Evergy to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Evergy and the requesting party.

4. Evergy shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing Evergy's Annual True-Up or Annual Projection.

## III. Challenge Procedures

1. Interested Parties shall have until January 31st following the Publication Date (unless such period is extended with the written consent of Evergy or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify Evergy in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or Annual Projection. The period of time from the Publication Date until January 31st shall be referred to as the Review Period. If January 31st falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual True-Up or Annual Projection as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual True-Up or Annual Projection. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual True-Up or Annual Projection, the Interested Party is barred from pursuing a Formal Challenge with respect to any issue for that Annual True-Up or Annual Projection but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or Annual Projection.

2. A party submitting an Informal Challenge to Evergy must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Evergy shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. Evergy, and where applicable, SPP, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If Evergy disagrees with such challenge, Evergy will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31st, and Evergy must respond to all Informal Challenges by no later than February 28th, unless the Review Period is extended by Evergy or FERC.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section III. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

   (a) A Formal Challenge shall:

      (i) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

      (ii) Explain how the action or inaction violates the filed rate formula or protocols;

(iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

- The extent or effect of an Accounting Change;
- Whether the Annual True-Up or Annual Projection fails to include data properly recorded in accordance with these protocols;
- The proper application of the Formula Rate and procedures in these protocols;
- The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual True-Up or Annual Projection;
- The prudence of actual costs and expenditures;
- The effect of any change to the underlying Uniform System of Accounts or FERC Form 1; or
- Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

(iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(v) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(viii) State whether the filing party utilized the Informal Challenge procedures described in these protocols with regard to any issue.

(b) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on Evergy. Service to Evergy must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on Evergy's Informational Filing required under Section V of these protocols.

4. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or Annual Projection fails to include data properly recorded in accordance with these protocols; (3) the proper application of the Formula Rate and procedures in these protocols; (4) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual True-Up and Annual Projection; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

5. Evergy will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and Evergy's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by Evergy to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Evergy and the requesting party.

6. Any changes or adjustments to the Annual True-Up or Annual Projection resulting from the Information Exchange and Informal Challenge processes that are agreed to by Evergy will be reported in the Informational Filing required pursuant to Section V of these protocols. Any such changes or adjustments agreed to by Evergy on or before November 30th will be reflected in the Annual Projection for the upcoming Rate Year. Any changes or adjustments agreed to by Evergy after November 30th will be reflected in the following year's Annual True-Up, as discussed in Section IV of these protocols.

7. An Interested Party shall have until March 31st following the Review Period (unless such date is extended with the written consent of Evergy to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on Evergy on the date of such filing as specified in Section III.3.b above. A Formal Challenge shall be filed in the same docket as Evergy's Informational Filing discussed in Section V of these protocols. Evergy shall respond to the Formal

Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit any Informal Challenge during the applicable Review Period.

8. In any proceeding initiated by FERC concerning the Annual True-Up or Annual Projection or in response to a Formal Challenge, Evergy shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

9. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Evergy to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

10. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these protocols and the Annual True-Up and Annual Projection shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

11. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with Evergy in accordance with this Section III before pursuing a Formal Challenge.

## IV. Changes to Annual True-Up or Annual Projection

1. Except as provided in Section III.6 of these protocols, any changes to the data inputs, including but not limited to revisions to Evergy's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-Up or Annual Projection, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Projection for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section

VI of these protocols.

2. In the event that Evergy identifies an error in the Annual True-Up (or its FERC Form No. 1 or successor form which is used as an input to the Formula), or is required by applicable law or a court or regulatory body to correct an error, Evergy shall correct such error in good faith and without regard to whether the correction increases or decreases Evergy's revenue requirements. Nothing in these protocols should or may be construed as preventing Interested Parties or the Commission from protesting such correction as inappropriate.

## V. Informational Filings

1. By March 15th of each year, Evergy shall submit to FERC an informational filing ("Informational Filing") of its Annual Projection for the Rate Year, including its Annual True-Up. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that Evergy has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect Formula Rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, Evergy shall provide notice of the Informational Filing via an email exploder list and by posting the docket number assigned to Evergy's Informational Filing on SPP's website and OASIS.

2. Any challenges to the implementation of the Attachment H-Evergy Formula Rate must be made through the Challenge Procedures described in Section III of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

## VI. Calculation of True-Up Adjustment for the Annual True-Up

The True-Up Adjustment for the Annual True-Up will be determined in the following manner:

1. The Projected Revenue Requirement for the previous year, not including any prior year True-Up Adjustment, shall be compared to the Actual Revenue Requirement calculated in accordance with Evergy's Formula Rate for the previous year using FERC Form No. 1 for that same year, and, to the extent specified in the Formula, upon the books and records of Evergy consistent with FERC accounting policies and practices, to determine any over or under recovery plus interest ("True-Up Adjustment"). The True-Up Adjustment and related calculations shall be posted as part of Evergy's Annual True-Up to SPP's website and OASIS no later than June 15th (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the FERC Form No. 1 for the previous year.

   (a) Interest on any over recovery of the net revenue requirement shall be determined based on the Commission's regulations at 18 C.F.R § 35.19a. Interest on any under recovery of the net revenue requirement shall be determined using the interest rate equal to Evergy's actual short-term debt costs, calculated as Evergy's actual weighted average annual short-term interest rate for the twenty-four (24) months ended August 31st of the current Rate Year ("S-T Debt Cost Period"), capped at the applicable FERC refund interest rate for the same twenty-four (24) month period. In either case, the interest rate to be applied to the over- or under-recovery amounts will be determined using the average rate for the twenty-four (24) months preceding September of the current year. The interest amount will be included in the Annual Projection made available on October 15th. For purposes of the foregoing, short-term debt interest expense annual rate for refund purposes shall be as follows:

   STIR = (STIEXP / SDSTDB) x N where

   STIR = the annual short term interest rate on notes payable excluding notes with Associated Companies) for the S-T Debt Cost Period,

   STIEXP = the interest expense on such notes payable recorded in Account 431 and Account 428 for the S-T Debt Cost Period,

   SDSTDB = the sum of the outstanding daily balances of notes payable for such S-T Debt Cost Period recordable in Account 231, and

   N = the number of days in such S-T Debt Cost Period.

2. The Net Revenue Requirement for transmission services for the following year shall be the sum of the projected revenue

requirement for the following year and a True-Up Adjustment for the previous year, including interest as explained above.

# Addendum 4 to Attachment H Part 1

AEP West SPP Member Operating Companies

Calculation of Actual/ Projected Zonal Rate For Schedule 9

For the 2XXX Rate Year

**SPP Zone 1 Actual/ Projected AEP Revenue Requirements**

| Line No. | | | AEP Annual Revenue Requirement | PSO Annual Revenue Requirement | SWEPCO Annual Revenue Requirement |
|---|---|---|---|---|---|
| **A.** | **Network Service** | | | | |
| 1 | RATE YEAR REVENUE REQUIREMENT (w/o incentives) | (TCOS Line 1 ) | - | - | - |
| 2 | LESS: REVENUE CREDITS | (TCOS Line 2 ) | - | - | - |
| 3 | NETWORK CUSTOMER OWNED FACILITY CREDITS | (TCOS Line 3 ) | - | - | - |
| 4 | RATE YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT | (TCOS Line 4 ) | - | - | - |
| 5 | LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR: | | | | |
| 6 | BASE PLAN UPGRADES (W/O INCENTIVES) | (TCOS Line 5 ) | - | - | - |
| 7 | REQUESTED UPGRADES (W/O INCENTIVES) | (Worksheet F/G) | - | - | - |
| 8 | ECONOMIC UPGRADES (W/O INCENTIVES) | (Worksheet F/G) | - | - | - |
| 9 | SUBTOTAL | | - | - | - |
| 10 | EXISTING ZONAL ATRR (W/O INCENTIVES) | (Line 4- Line 9) | - | - | - |
| 11 | INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS | (TCOS Line 13 ) | - | - | - |
| 12 | **RATE YEAR ZONAL ATRR (W/ INCENTIVES)** | **(Line 10 + Line 11)** | **-** | **-** | **-** |
| 13 | Actual/Projected Rate Year AEP West Zone Average 12-Mo. Peak Demand, | (Load WS, ln 33) | | | |

| | | | | | |
|---|---|---|---|---|---|
| | MW | | - | - | - |
| 14 | **Monthly NITS Rate in $/MW - Month** | **(Line 12 / Line 13) /12** | - | - | - |

AEP West SPP Member Operating Companies

Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

**SPP SCHEDULE 1 AEP Revenue Requirements**

| Line No. | | | **AEP Annual Revenue Requirement** | **PSO Annual Revenue Requirement** | **SWEPCO Annual Revenue Requirement** |
|---|---|---|---|---|---|
| **A.** | **Schedule 1 ARR For 2XXX Rate Year** | | | | |
| 1 | Total Load Dispatch & Scheduling (Account 561) (TCOS Line 65) | | - | - | - |
| 2 | Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) | | - | | |
| 3 | Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) | | - | | |
| 4 | Total 561 Internally Developed Costs | (Line 1 - Line 2 - Line 3) | - | - | - |
| 5 | Less: PTP Service Credit (prior year Sched 1 revenue from PTP transactions) | | - | | |
| 6 | ZONAL ARR FOR RATE YEAR | (Line 4 - Line 5) | - | - | - |
| **B.** | **Schedule 1 2XXX Rate Year Calculations** | | | | |
| 7 | Rate Year AEP West Zone SPP Average 12-Mo. Peak Demand | (Load WS, ln 20) | - MW | | |
| 8 | Annual Point-to-Point Rate in $/MW - Year | (Line 6 / Line 7) | - | | |
| 9 | Monthly Point-to-Point Rate (ln 8 / 12) $/MW - Month | (Line 8 / 12) | - | | |
| 10 | Weekly Point-to-Point Rate (ln 8 / 52) $/MW - Weekly | (Line 8 / 52) | - | | |
| 11 | Daily Off-Peak Point-to-Point Rate (ln 8 / 365) $/MW - Day | (Line 8 / 365) | - | | |

12 Hourly Off-Peak Point-to-Point Rate (ln 8 / 8760) $/MW - Hour (Line 8 / 8760)

-

AEP Transmission
Calculation of Schedule 11 Revenue
Requirements For AEP Transmission Projects
For Projected Year 2XXX Including 2XXX-2
True-Up

**AEP Schedule 11 Revenue Requirement Including True-Up of Prior Collections**

**COMPANY NAME**

Note: Projects whose investment cost do NOT meet SPP's $100,000 threshold for 'regional' socialization are marked with an asterik "*" as SPP will only collect those ATRRs from the zone.

| (A) | (B) | (C ) | (D) | (E) | (F) | (G) = (E) + (F) | (H) | (I) | (J) = (H) - (I) | (K) | (L) | (M) = (K)-(L) | (N) | (O) | (P) = (J)+(M)+(N)+ (O) | (Q) = (G) + (P) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Projected ARR For 2XXX From WS-F** | | | **True-Up ARR From 2XXX-2 From Worksheet G** | | | | | | | | | |
| | | | | | | | **Base ARR** | | | **Incentive ARR** | | | | | | |
| **Sheet Name** | **Owner** | **Project Description** | **Year in Service** | **Base ARR** (WS-F) | **Incentive** | **Total** | **Actual Rate Year True Up Revenue Requirement** | **Projected Rate Year Revenue Requirement** | **TRUE-UP Adjustment** (WS-G) | **True-up** | **Projected** | **TRUE-UP Adjustment** (WS-G) | **Schedule 11 Revenue Credits and SPP Billing Adjustments** | **Interest** | **Total True Up net of revenue credits, including interest** | **Total ADJUSTED Revenue Requireme Effective 1/1/2XXX** |
| | | | | | | | | | | | | | | | | |
| | | **Company Total** | | | | | | | | | | | | | | |

**AEP West SPP Member Operating Companies**
**Network Load for January Through December 2XXX**
**Based on West Zone-SPP Monthly Transmission System Firm Peak Demands for the Twelve Months Ended December 31, 2XXX**

**Combined Load Worksheet**

Unless noted (e.g., PSO), the loads reported on lines 1 through 20 are the customer's schedule 9 and 11 load.

| Line No. | | | January | February | March | April | May | June | July | August | September | October | November | December | | | 12 Month Average MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Peak Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | | | |
| | | **Peak Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | | | |
| | **SPP Load Responsibility** | | | | | | | | | | | | | | | | |
| 1 | | **PSO (2)** | | | | | | | | | | | | | - | | 0 |
| 2 | | **SWEPCO excl Valley (2)** | | | | | | | | | | | | | - | | 0 |
| 3 | | **AECC (3)** | | | | | | | | | | | | | - | | 0 |
| 4 | | **AECC-MISO** | | | | | | | | | | | | | - | | 0 |
| 5 | | **WFEC (3)** | | | | | | | | | | | | | - | | 0 |
| 6 | | **OMPA (3)** | | | | | | | | | | | | | - | | 0 |
| 7 | | **OG&E - LSE** | | | | | | | | | | | | | - | | 0 |
| 8 | | **OG&E - TALL BEAR (3)** | | | | | | | | | | | | | - | | 0 |
| 9 | | **ETEC (3)** | | | | | | | | | | | | | - | | 0 |
| 10 | | **GREENBELT (3)** | | | | | | | | | | | | | - | | 0 |
| 11 | | **LIGHTHOUSE (3)** | | | | | | | | | | | | | - | | 0 |
| 12 | | **BENTONVILLE, AR (3)** | | | | | | | | | | | | | - | | 0 |
| 13 | | **PRESCOTT, AR (3)** | | | | | | | | | | | | | - | | 0 |
| 14 | | **MINDEN, LA (3)** | | | | | | | | | | | | | - | | 0 |
| 15 | | **HOPE, AR (3)** | | | | | | | | | | | | | - | | 0 |
| 16 | | **COFFEYVILLE, KS (3)** | | | | | | | | | | | | | - | | 0 |
| 17 | | **SWEPCO - VALLEY** | | | | | | | | | | | | | - | | 0 |
| 18 | | **AECI** | | | | | | | | | | | | | - | | 0 |
| 19 | | | | | | | | | | | | | | | | | |
| 20 | **System Firm Peak Demands** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | 0.000 | Sched - 9 12CP | **0** |
| | **Supporting Data** | | | | | | | | | | | | | | | | |
| 21 | **PSO:** | PSO Native Load (2) (4) | | | | | | | | | | | | | | | |
| 22 | | KAMO | | | | | | | | | | | | | | | |
| 23 | | GRDA load on PSO no longer used as of Dec 2015 (5) | | | | | | | | | | | | | | | |
| 24 | | PSO E&W portion allocated to WFEC zone | | | | | | | | | | | | | | | |
| 25 | | 100% PSO E&W included in PSO native load | | | | | | | | | | | | | | | |
| 26 | | Allen Holdenville | | | | | | | | | | | | | | | |
| 27 | | **PSO OATT Load Responsibility** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | 0.000 | | 0 |
| 28 | **SWEPCO:** | | | | | | | | | | | | | | | | |
| 29 | | SWEPCO Native Load (2)(5) | | | | | | | | | | | | | | | |
| 30 | | Dolet Hills Aux. Load (not self-generated) | | | | | | | | | | | | | | | |
| 31 | | Less: VALLEY | | | | | | | | | | | | | | | |
| 32 | | **SWEPCO OATT Load Responsibility** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | 0.000 | | 0 |
| 33 | **TOTAL AEP Affiliate Schedule 11 Load** | | | | | | | | | | | | | pr yr | | Sched - 11 12CP | **0** |
| | **AEP Schedule 11 Worksheet** | | | | | | | | | | | | | | | | |
| 34 | | PSO OATT Sched 9 load, Ln 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 35 | | less GRDA load on PSO Jan-Nov(b) 2015 no longer used | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 36 | | WFEC load already subtracted from PSO schedule 9 load line 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 37 | | Subtotal PSO Schedule 11 load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 38 | | SWEPCO Sched 11 load, Ln 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 39 | | TOTAL AEP Affiliate Schedule 11 Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 40 | | **TOTAL AEP ZONAL SCHEDULE 11** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | |

NOTES:

(1) Amounts are MW at the time of the AEP-SPP Internal (MLR) Peak

(2) At the generator, includes transmission losses.

(3) At the generator. Transmission losses added to metered values which include appropriate dist.& xfmr losses.

[4] PSO Native load includes PSO load on GRDA

(5) SWEPCO Native Load includes Valley

AEP West SPP Member Operating Companies

Transmission Cost of Service Formula Rate

Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

**COMPANY NAME**

| Line No. | | | Total | Allocator | | Transmission Amount |
|---|---|---|---|---|---|---|
| 1 | REVENUE REQUIREMENT (w/o incentives) | (ln 117) | | | | - |
| 2 | REVENUE CREDITS | (Note A) (Worksheet H) | - | DA | 1.00000 | $ - |
| 3 | Network Customer Owned Facility Credits | Worksheet B | | | | - |
| 4 | REVENUE REQUIREMENT For All Company Facilities | (ln 1 less ln 2 plus ln 3) | | | | - |

**MEMO: The Carrying Charge Calculations on lines 7 to 12 below are used in calculating project revenue requirements billed through SPP Schedule 11. The total non-incentive revenue requirement for these projects shown on line 5 is included in the total on line 4.**

| | | | | | | |
|---|---|---|---|---|---|---|
| 5 | Trued-Up / Projected Revenue Requirement for SPP BPU Regional Facilities (w/o incentives) (Worksheet F/G) | | - | DA | 1.00000 | $ - |
| 6 | NET PLANT CARRYING CHARGE (w/o incentives) (Note B) | | | | | |
| 7 | Annual Rate | (ln 1/ ln 37 x 100%) | | | | - |
| 8 | Monthly Rate | (ln 7 / 12) | | | | - |

| | | | |
|---|---|---|---|
| 9 | NET PLANT CARRYING CHARGE ON LINE 7 , W/O DEPRECIATION (w/o incentives) (Note B) | | |
| 10 | Annual Rate | ( (ln 1 - ln 86) / ln 37 x 100%) | - |
| 11 | NET PLANT CARRYING CHARGE ON LINE 9, W/O INCOME TAXES, RETURN (Note B) | | |
| 12 | Annual Rate | ( (ln 1 - ln 86 - ln 111 - ln 112) / ln 37 x 100%) | - |
| 13 | ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C) (Worksheet F/G) | | - |

AEP West SPP Member Operating Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

COMPANY NAME

| Line No. | (1) RATE BASE CALCULATION | (2) Data Sources (See "General Notes") | (3) TO Total NOTE D | (4) Allocator | | (5) Total Transmission |
|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | |
| 14 | Production | (Worksheet A-1 ln 14.B) | - | NA | 0.00000 | - |
| 15 | Less: Production ARO (Enter Negative) | (Worksheet A-1 ln 14.C) | - | NA | 0.00000 | - |
| 16 | Transmission | (Worksheet A-1 ln 14.D & Ln 121 | - | DA | | - |
| 17 | Less: Transmission ARO (Enter Negative) | (Worksheet A-1 ln 14.E) | - | TP | 1.00000 | - |
| 18 | Distribution | (Worksheet A-1 ln 14.F) | - | NA | 0.00000 | - |
| 19 | Less: Distribution ARO (Enter Negative) | (Worksheet A-1 ln 14.G) | - | NA | 0.00000 | - |
| 20 | General Plant | (Worksheet A-1 ln 28.B) | - | W/S | 0.00000 | - |
| 21 | Less: General Plant ARO (Enter Negative) | (Worksheet A-1 ln 28.C) | - | W/S | 0.00000 | - |
| 22 | Intangible Plant | (Worksheet A-1 ln 28.D) | - | W/S | 0.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | TOTAL GROSS PLANT | (sum lns 14 to 22) | - | GP= **GTD=** | **1.00000** **1.00000** | - |
| 24 | ACCUMULATED DEPRECIATION AND AMORTIZATION | | | | | |
| 25 | Production | (Worksheet A-2 ln 14.B) | - | NA | 0.00000 | - |
| 26 | Less: Production ARO (Enter Negative) | (Worksheet A-2 ln 14.C) | - | NA | 0.00000 | - |
| 27 | Transmission | (Worksheet A-2 ln 14.D less 29.F) | - | **TP1=** | 0.00000 | - |
| 28 | Less: Transmission ARO (Enter Negative) | (Worksheet A-2 ln 14.E) | - | **TP1=** | 0.00000 | - |
| 29 | Distribution | (Worksheet A-2 ln 14.F) | - | NA | 0.00000 | - |
| 30 | Less: Distribution ARO (Enter Negative) | (Worksheet A-2 ln 14.G) | - | NA | 0.00000 | - |
| 31 | General Plant | (Worksheet A-2 ln 28.B) | - | W/S | 0.00000 | - |
| 32 | Less: General Plant ARO (Enter Negative) | (Worksheet A-2 ln 28.C) | - | W/S | 0.00000 | - |
| 33 | Intangible Plant | (Worksheet A-2 ln 28.D) | - | W/S | 0.00000 | - |
| 34 | TOTAL ACCUMULATED DEPRECIATION | (sum lns 25 to 33) | - | | | - |
| 35 | NET PLANT IN SERVICE | | | | | |
| 36 | Production | (ln 14 + ln 15 - ln 25 - ln 26) | - | | | - |
| 37 | Transmission | (ln 16 + ln 17 - ln 27 - ln 28) | - | | | - |
| 38 | Distribution | (ln 18 + ln 19 - ln 29 - ln 30) | - | | | - |
| 39 | General Plant | (ln 20 + ln 21 - ln 31 - ln 32) | - | | | - |
| 40 | Intangible Plant | (ln 22 - ln 33) | - | | | - |
| 41 | TOTAL NET PLANT IN SERVICE | (sum lns 36 to 40) | - | **NP=** | **1.00000** | - |
| 42 | DEFERRED TAX ADJUSTMENTS TO RATE BASE | (Note E) | | | | |
| 43 | Account No. 281.1 (enter negative) | 272-273.8.k | - | NA | | - |
| 44 | Account No. 282.1 (enter negative) | (Worksheet C, ln 4 C & ln 8 J) | - | DA | | - |
| 45 | Account No. 283.1 (enter negative) | (Worksheet C, ln 12 C & ln 14 J) | - | DA | | - |
| 46 | Account No. 190.1 | (Worksheet C, ln 18 C & ln 22 J) | - | DA | | - |
| 47 | Account No. 255 (enter negative) | (Worksheet C, ln 26 C & ln 28 J) | - | DA | | - |
| 48 | TOTAL ADJUSTMENTS | (sum lns 43 to 47) | - | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 49 | PLANT HELD FOR FUTURE USE | (Worksheet A-1 ln 30.F) | - | DA | | - |
| 50 | REGULATORY ASSETS | (Worksheet S ln 10 cols. G and J) (Note W) | - | DA | | - |
| 51 | UNFUNDED RESERVES (ENTER NEGATIVE) (NOTE U) | (Worksheet R, ln 6 F) | - | W/S | 0.00000 | - |
| 52 | WORKING CAPITAL | (Note F) | | | | |
| 53 | Cash Working Capital | (1/8 * (ln 70 - Ln 69)) (Note G) | - | | | - |
| 54 | Transmission Materials & Supplies | (Worksheet D, pg 1 ln 1 E) | - | TP | 1.00000 | - |
| 55 | A&G Materials & Supplies | (Worksheet D, pg 1 ln 2 E) | - | W/S | 0.00000 | - |
| 56 | Stores Expense | (Worksheet D, pg 1 ln 3 E) | - | GP | 1.00000 | - |
| 57 | Prepayments (Account 165) - Labor Allocated | (Worksheet D, pg 1 ln 29 G) | - | W/S | 0.00000 | - |
| 58 | Prepayments (Account 165) - Gross Plant | (Worksheet D, pg 1 ln 29 F) | - | GP | 1.00000 | - |
| 59 | Prepayments (Account 165) - Transmission Only | (Worksheet D, pg 1 ln 29 E) | - | DA | 1.00000 | - |
| 60 | Prepayments (Account 165) - Unallocable | (Worksheet D, pg 1 ln 29 D) | - | NA | 0.00000 | - |
| 61 | TOTAL WORKING CAPITAL | (sum lns 53 to 60) | - | | | - |
| 62 | IPP CONTRIBUTIONS FOR CONSTRUCTION | (Note H) (Worksheet E, ln 8 B) | - | DA | 1.00000 | - |
| 63 | RATE BASE (sum lns 41, 48, 49, 50, 51, 61, 62) | | - | | | - |

AEP West SPP Member Operating Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

COMPANY NAME

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| Line No. | **EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION** | **Data Sources (See "General Notes")** | **TO Total** | **Allocator** | **Total Transmission** |
| | OPERATION & MAINTENANCE EXPENSE | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 64 | Transmission | 321.112.b | | | | |
| 65 | Less: Total Account 561 | (Note I) 321.84-92.b | | | | |
| 66 | Less: Account 565 | (Note J) 321.96.b | | | | |
| 67 | Less : Regulatory Amortizations / (Deferrals) | Worksheet S ln 2 (Note V) | - | | | |
| 68 | Plus: Includable 561 and 565 Expenses | Worksheet I ln 10 | - | | | |
| 69 | Plus : Approved Regulatory Amortizations / (Deferrals) | Worksheet S ln 4 (Note V) | - | | | |
| 70 | Total O&M Allocable to Transmission | (lns 64 - 65 - 66 - 67 + 68 + 69) | - | TP | 1.00000 | - |
| 71 | Administrative and General | 323.197.b (Note K, M) | | | | |
| 72 | Less: Acct. 924, Property Insurance | 323.185.b | | | | |
| 73 | Acct. 928, Reg. Com. Exp. | 323.189.b | - | | | |
| 74 | Acct. 930.1, Gen. Advert. Exp. | 323.191.b | - | | | |
| 75 | Acct. 930.2, Misc. Gen. Exp. | 323.192.b | - | | | |
| 76 | Regulatory Asset Amortizations / (Deferrals) | Worksheet S ln 6 (Note V) | - | | | |
| 77 | Balance of A & G | (ln 71 - sum ln 72 to ln 76) | - | W/S | 0.00000 | - |
| 78 | Plus: Acct. 924, Property Insurance | (ln 72) | - | GP | 1.00000 | - |
| 79 | Acct. 928 - Transmission Specific | Worksheet J ln 16.(E) (Note L) | - | TP | 1.00000 | - |
| 80 | Acct 930.1 - Only safety related ads -Direct | Worksheet J ln 22.(E) (Note L) | - | GP | 1.00000 | - |
| 81 | Acct 930.2 - Misc Gen. Exp. - Trans | Worksheet J ln 28.(E) (Note L) | - | DA | 1.00000 | - |
| 82 | Approved A&G Reg. Asset Amort. / (Deferrals) | Worksheet S ln 8 (Note V) | - | W/S | 0.00000 | - |
| 83 | A & G Subtotal | (sum lns 77 to 82) | - | | | - |
| 84 | TOTAL O & M EXPENSE | (ln 70 + ln 83) | - | | | - |
| 85 | DEPRECIATION AND AMORTIZATION EXPENSE | | | | | |
| 86 | Transmission | 336.7.b | | TP | 1.00000 | - |
| 87 | General | 336.10.b | | W/S | 0.00000 | - |
| 88 | Intangible | 336.1.d | | W/S | 0.00000 | - |
| 89 | TOTAL DEPRECIATION AND AMORTIZATION | (sum lns 86 to 88) | - | | | - |
| 90 | TAXES OTHER THAN INCOME | (Note N) | | | | |
| 91 | Labor Related | | | | | |
| 92 | Payroll | Worksheet L, Col. D | - | W/S | 0.00000 | - |
| 93 | Plant Related | | | | | |
| 94 | Property | Worksheet L, Col. C | - | GP | 1.00000 | - |
| 95 | Non-Allocable Taxes | Worksheet L, Col. F | - | NA | 0.00000 | - |
| 96 | Other | Worksheet L, Col. E | - | GP | 1.00000 | - |
| 97 | TOTAL OTHER TAXES | (sum lns 92 to 96) | - | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 98 | INCOME TAXES | (Note O) | | | | |
| 99 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | - | | | |
| 100 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | | - | | | |
| 101 | where WCLTD=(ln 141) and WACC = (ln 144) | | | | | |
| 102 | and FIT, SIT & p are as given in Note O. | | | | | |
| 103 | GRCF=1 / (1 - T) = (from ln 99) | | - | | | |
| 104 | Amortized Investment Tax Credit (enter negative) | (FF1 p.114, ln 19.c) | | | | |
| 105 | Excess / (Deficit) Deferred Income Tax | Company Records (Note O) and WS C-4 Ln 24 | | DA | | - |
| 106 | Tax Effect of Permanent and Flow Through Differences | Company Records (Note O) | | DA | | |
| 107 | Income Tax Prior to Adjustments | (ln 100 * ln 112) | - | | | - |
| 108 | ITC adjustment | (ln 103 * ln 104) | - | GP | 1.00000 | - |
| 109 | Excess / (Deficit) Deferred Income Tax | (ln 103 * ln 105) | - | DA | | - |
| 110 | Tax Effect of Permanent and Flow Through Differences | (ln 103 * ln 106) | - | DA | | - |
| 111 | TOTAL INCOME TAXES | (sum lns 107 to 110) | - | | | - |
| 112 | RETURN ON RATE BASE (Rate Base*WACC) | (ln 63 * ln 144) | - | | | - |
| 113 | INTEREST ON IPP CONTRIBUTION FOR CONST. (Note E) (Worksheet E, ln 2) | | - | DA | 1.00000 | - |
| 114 | REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX | | - | | | - |
| 115 | (sum lns 84, 89, 97, 111, 112, 113) | | | | | |
| 116 | TEXAS GROSS MARGIN TAX (Note P) (Worksheet K) | | - | DA | | - |
| 117 | REVENUE REQUIREMENT INCL GROSS MARGIN TAX | (ln 114 + 116) | - | | | - |

AEP West SPP Member Operating Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

COMPANY NAME

**SUPPORTING CALCULATIONS**

| ln No. | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN SPP TARIFF (Note W) | | | | | | | | |
| 118 | Total transmission plant | (ln 16) | | | | | | | - |
| 119 | Less transmission plant excluded from SPP Tariff (Worksheet A-1, ln 28 Col. (F)) (Note Q) | | | | | | | | - |
| 120 | Less transmission plant included in OATT Ancillary Services (Worksheet A-1, ln 28, Col. (E)) (Note R) | | | | | | | | - |
| 121 | Transmission plant included in SPP Tariff | (ln 118 - ln 119 - ln 120) | | | | | | | - |
| 122 | Percent of transmission plant in SPP Tariff | (ln 121 / ln 118) | | | | | | **TP =** | **1.00000** |
| 123 | WAGES & SALARY ALLOCATOR (W/S) | (Note S) | Direct Payroll | Payroll Billed from AEP Service Corp. | Total | | | | |
| 124 | Production | 354.20.b | | | - | NA | 0.00000 | | - |
| 125 | Transmission | 354.21.b | | | - | TP | 1.00000 | | - |
| 126 | Regional Market Expenses | 354.22.b | | | - | NA | 0.00000 | | - |
| 127 | Distribution | 354.23.b | | | - | NA | 0.00000 | | - |
| 128 | Other (Excludes A&G) | 354.24,25,26.b | | | - | NA | 0.00000 | | - |
| 129 | Total | (sum lns 124 to 128) | - | - | 0 | | | | - |
| 130 | Transmission related amount | | | | | | | **W/S =** | **0.00000** |
| 131 | WEIGHTED AVERAGE COST OF CAPITAL (WACC) (Note T, Note X) | | | | | | | | $ |
| 132 | Long Term Interest | Long Term Interest (Worksheet M, ln. 37, col. (d)) | | | | | | | - |
| 133 | Preferred Dividends | Preferred Stock Dividends (Worksheet M, ln. 57, col. (d)) | | | | | | | - |
| 134 | Development of Common Stock: | | | | | | | | Average |
| 135 | Proprietary Capital | (Worksheet M, ln. 14, col. (b)) | | | | | | | - |
| 136 | Less Preferred Stock (ln 142) | (Worksheet M, ln. 14, col. (c)) | | | | | | | - |
| 137 | Less Account 216.1 | (Worksheet M, ln. 14, col. (d)) | | | | | | | - |
| 138 | Less Account 219 | (Worksheet M, ln. 14, col. (e)) | | | | | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 139 | Common Stock | (ln 135 - ln 136 - ln 137 - ln 138) | | | | - |
| | | | **Capital Structure Percentage** | Cost | | |
| 140 | | Rate Year Average Balances | | (Note T) | | Weighted |
| 141 | Avg Long Term Debt (Worksheet M, ln. 28, col. (g)) | - | 0.00% | 0.00% | | 0.0000 |
| 142 | Avg Preferred Stock (Worksheet M, ln. 14, col. (c)) | - | 0.00% | 0.00% | | 0.0000 |
| 143 | Avg Common Stock (ln 139) | - | 0.00% | 10.50% | | 0.0000 |
| 144 | Total (sum lns 141 to 143) | - | | | **WACC =** | **0.0000** |

AEP West SPP Member Operating Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year
COMPANY NAME

**Letter** **Notes**

General Note: True Up References to data from FERC Form 1 are indicated as: page#.line#.col.#. Rate Year Projections from Company forecasts.

A The revenue credits shall include a) amounts received directly from the SPP for PTP transmission services, b) direct assignment charges for transmission facilities, the cost of which has been included in the TCOS, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the TCOS are not included as revenue credits. Revenue from Transmission Customers whose coincident peak loads are included in the DIVISOR of the load-ratio share calculation are not included as revenue credits. See Worksheet H for details.

B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for facilities and any upgrades.

C This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet G shows the calculation of the trued-up revenue requirement for each project, based on an FCR rate calculated from inputs on this TCOS. Line 13 shows the incremental ARR for projects receiving incentives as accepted by FERC. These individual additional revenue requirements are summed for the true-up year, and included here.

D The gross plant, accumulated depreciation, and deferred tax balances included in rate base and depreciation expense are reduced by the removal of amounts related to
Asset Retirement Obligations (AROs). This is to comply with the requirements of FERC Rulemaking RM02-7-000.

E The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by

prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense as discussed in Note N. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated to transmission. Transmission allocations are shown on Worksheet C.

F Identified as being transmission related or functionally booked to transmission.

G Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 70.

H Consistent with Paragraph 657 of Order 2003-A, the amount on line is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 113.

I Line 65 Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.

J Removes cost of transmission service provided by others to the extent such service is not incurred to provide the SPP service at issue.

K General Plant and Administrative & General expenses may be functionalized based on allocators other than the W/S allocator. Full documentation must be provided.

L Expense reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable or allocable to transmission service. Worksheet J allocates
these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet H.

M Recoverable PBOP expense is based on actual annual PBOP costs, including charges from the AEP Service Corporation. The PBOP amounts are included in the
Administrative and General total, and are based on current year expenses. The annual actuarial valuation report supporting the derivation of the PBOP expense,
along with an explanation of PBOP derivation process, is submitted during the formula rate annual update.

N Includes only FICA, unemployment, property and other assessments charged in the current year. Gross Receipts tax, Sales & Use taxes, local franchise taxes, and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 99) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | | |
| | SIT= | - | (State Income Tax Rate or Composite SIT. Worksheet K) |

p = - (percent of federal income tax deductible for state purposes)

Excess / (Deficit) Deferred Income Taxes will be amortized over the average remaining life of the assets to which it relates, unless the Commission requires a different amortization period. Recovery of permanent and flow through differences is limited to only the transmission functional portion of the tax difference related to capitalized AFUDC Equity.

P The Texas Gross Margin tax is calculated on the Texas allocated revenue of the Company, reduced by cost of goods sold deduction to derive a "Gross Margin" for the Company. The tax rate of one percent is assessed on the resulting amount. The jurisdictional allocator is based on transmission demand allocators.

Q Removes plant excluded from the OATT because it does not meet the SPP's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

R Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note Q.

S Includes functional wages & salaries incurred by parent company service corporation for support of the operating company.

T Long Term Debt cost rate = Long-Term Interest (ln 132) / Long Term Debt (ln 141). Preferred Stock cost rate = preferred dividends (ln 133) / preferred outstanding (ln 142). Common Stock cost rate (ROE) = 10.5%, the rate accepted by FERC pursuant to the settlement filed in Docket Nos.EL17-76 / EL18-199. It includes an additional 50 basis points for remaining a member of the SPP RTO.

The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the capital structure. Details and calculations of the weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are computed on Worksheet M. The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.

U The cost of service will make a rate base adjustment to remove unfunded reserves associated with contingent liabilities recorded to Accounts 228.1-228.4 from rate base.

V O&M and A&G shall be adjusted to remove all regulatory asset deferrals and amortizations that have not been approved by FERC for inclusion in cost of service, and then to add back in FERC approved amortizations and deferrals. Negative amounts in O&M or A&G represent deferrals. See Worksheet S.

W If the company submits a Section 205 filing proposing to make adjustments to this formula rate cost of service template to remove assets and costs related to transmission facilities constructed and operated specifically for the purpose of delivering the output of generation facilities, including generation tie-lines, which do not qualify under the SPP OATT for inclusion in transmission cost of service, challenges to such filing(s) shall be limited to the justness and reasonableness of such proposal.

X If the company submits a Section 205 filing proposing to make adjustments to this formula rate cost of service template to remove from the cost of capital the debt and related interest costs incurred in connection with financing specifically dedicated to non-transmission-related assets, such as securitization financing, challenges to such filing(s) shall be limited to the justness and reasonableness of such proposal's impacts on the Company's cost of capital.

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet A-1** - Detailed Plant Balances
**COMPANY NAME**

| | | **Gross Plant In Service - Production** | | | | | |
|---|---|---|---|---|---|---|---|
| Line No | **Month** | **Production** | **Production ARO** | **Transmission** | **Transmission ARO** | **Distribution** | **Distribution ARO** |
| | **(a)** | **(b)** FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46 | **(c)** FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44 | **(d)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58 | **(e)** Acct. 359.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57 | **(f)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75 | **(g)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74 |
| 1 | December Prior to Rate Year | | | | | | |
| 2 | January | | | | | | |
| 3 | February | | | | | | |
| 4 | March | | | | | | |
| 5 | April | | | | | | |
| 6 | May | | | | | | |
| 7 | June | | | | | | |
| 8 | July | | | | | | |
| 9 | August | | | | | | |
| 10 | September | | | | | | |
| 11 | October | | | | | | |
| 12 | November | | | | | | |
| 13 | December of Rate Year | | | | | | |
| 14 | Average of the 13 Monthly Balances | - | - | - | - | - | - |

| | | **Gross Plant In Service - Distribution, General and Intangible, GSU, Excluded Plant** | | | | |
|---|---|---|---|---|---|---|
| Line No | **Month** | **General** | **General ARO** | **Intangible** | **OATT Ancillary Services (GSU)** | **Excluded Plant** |
| | **(a)** | **(b)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99 | **(c)** Acct. 399.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98 | **(d)** FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5 | **(e)** Company Records | **(f)** Company Records |
| 15 | December Prior to Rate Year | | | | | |
| 16 | January | | | | | |
| 17 | February | | | | | |
| 18 | March | | | | | |
| 19 | April | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 20 | May | | | | | | | |
| 21 | June | | | | | | | |
| 22 | July | | | | | | | |
| 23 | August | | | | | | | |
| 24 | September | | | | | | | |
| 25 | October | | | | | | | |
| 26 | November | | | | | | | |
| 27 | December of Rate Year | | | | | | | |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | | | - |

**Transmission Functional Plant Held For Future Use (Notes A and B)**

| Line No | Asset Description | Definite Plan for Future Use | Estimated in Service Year | 2XXX Rate Year Beginning balance | 2XXX Rate Year Ending balance | 2XXX Rate Year Average |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 29A | | | | | | |
| 29B | | | | | | |
| 29C | | | | | | |
| 30 | Total | | | - | - | - |

Notes:

(A) Per the general instruction for Account No. 105 in 18 CFR Part 101.

(B) Include only the Transmission functional component of amounts reported page 214 of the FERC Form 1.

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet A-2** - Detailed Accumulated Depreciation Balances
**COMPANY NAME**

| | | Accumulated Depreciation - Production | | | | | |
|---|---|---|---|---|---|---|---|
| Line No | Month | Production | Production ARO | Transmission | Transmission ARO | Distribution | Distribution ARO |
| | (a) | (b) FF1, page 219, lns 20-24, Col. (b) | (c) Company Records (Included in total in Column (b)) | (d) FF1, page 219, ln 25, Col. (b) | (e) Company Records (Included in total in Column (b)) | (f) FF1, page 219, ln 26, Col. (b) | (g) Company Records (Included in total in Column (b)) |
| 1 | December Prior to Rate Year | | | | | | |
| 2 | January | | | | | | |
| 3 | February | | | | | | |
| 4 | March | | | | | | |
| 5 | April | | | | | | |
| 6 | May | | | | | | |
| 7 | June | | | | | | |
| 8 | July | | | | | | |
| 9 | August | | | | | | |
| 10 | September | | | | | | |
| 11 | October | | | | | | |
| 12 | November | | | | | | |
| 13 | December of Rate Year | | | | | | |
| 14 | Average of the 13 Monthly Balances | - | - | - | - | - | - |

| | | Accumulated Depreciation- Distribution, General and Intangible, GSU, Excluded Plant | | | | |
|---|---|---|---|---|---|---|
| Line No | Month | General | General ARO | Intangible | OATT Ancillary Services (GSU) | Excluded Plant |
| | (a) | (b) FF1, page 219, ln 28, Col. (b) | (c) Company Records (Included in total in Column (d)) | (d) FF1, page 200, ln 21, Col. (b) | (e) Company Records | (f) Company Records |
| 15 | December Prior to Rate Year | | | | | |
| 16 | January | | | | | |
| 17 | February | | | | | |
| 18 | March | | | | | |
| 19 | April | | | | | |
| 20 | May | | | | | |
| 21 | June | | | | | |
| 22 | July | | | | | |
| 23 | August | | | | | |
| 24 | September | | | | | |
| 25 | October | | | | | |
| 26 | November | | | | | |
| 27 | December of Rate Year | | | | | |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | - |

| | | |
|---|---|---|
| 29 | Transmission Accumulated, net of GSU and Excluded- Ln 14 Col (d) less Ln 28 Cols. (e) & (f) | $0 |

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet B** - Third Party Facility Credits
**COMPANY NAME**

| Line No. | | Source | Amount |
|---|---|---|---|
| 1 | Facility Credits under the SPP OATT | | - |

Note: Under Section 30.9 of the SPP OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet C** - ADIT and ADITC Balances

**COMPANY NAME**

| Line No. | (A) Acc. No. | (B) Description | (C) YE Balance | (E) Exclusions * | (F) 100% Transmission Related | (G) PTD Plant Related | (H) Transmission & Distribution Plant Related | (I) Labor Related | (J) Total Included in Rate base (E)+(F)+(G)+(H) |
|---|---|---|---|---|---|---|---|---|---|
| | | **Note: Account 281 is not allocated to Transmission** | | | | | | | |
| | | **Account 282 - Form-1 page 274.2.b and 275.2.k** | | | | | | | |
| 1 | 282.1 | 2XXX Year End Tax Deferrals - WS C-1 | - | - | - | - | - | - | |
| 2 | 282.1 | 2XXX-1 Year End Tax Deferrals - WS C-2 | - | - | - | - | - | - | |
| 3 | | **Subtotal** | - | - | - | - | - | - | |
| 4 | | **Average Balance before Proration** | - | - | - | - | - | - | |
| 5 | | **Proration Adjustment - WS C-3, Ln 19** | | | | - | | | |
| 6 | | **Prorated Average balance** | - | - | - | - | - | - | |
| 7 | | **Transmission Allocator from TCOS** | | 0.0000% | 100.0000% | 100.0000% | 100.0000% | 0.0000% | |
| 8 | | **Allocated Total** | | - | - | - | - | - | - |
| | | **Account 283 - Form-1 page 276.9.b and 277.9.k** | | | | | | | |
| 9 | 283.1 | 2XXX Year End Tax Deferrals - WS C-1 | - | - | - | - | - | - | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 10 | 283.1 | 2XXX-1 Year End Tax Deferrals - WS C-2 | - | - | - | - | - | - | |
| 11 | | **Subtotal** | - | - | - | - | - | - | |
| 12 | | **Average Balance** | - | - | - | - | - | - | |
| 13 | | **Transmission Allocator from TCOS** | | 0.0000% | 100.0000% | 100.0000% | 100.0000% | 0.0000% | |
| 14 | | **Allocated Total** | | - | - | - | - | - | - |
| | | **Account 190 - Form-1 page 234, Ln 8, Col. (b) & ( c)** | | | | | | | |
| 15 | 190.1 | 2XXX Year End Tax Deferrals - WS C-1 | - | - | - | - | - | - | |
| 16 | 190.1 | 2XXX-1 Year End Tax Deferrals - WS C-2 | - | - | - | - | - | - | |
| 17 | | **Subtotal** | - | - | - | - | - | - | |
| 18 | | **Average Balance before Proration** | - | - | - | - | - | - | |
| 19 | | **Proration Adjustment - WS C-3, Ln 38** | | | - | | | | |
| 20 | | **Prorated Average balance** | - | - | - | - | - | - | |
| 21 | | **Transmission Allocator from TCOS** | | 0.0000% | 100.0000% | 100.0000% | 100.0000% | 0.0000% | |
| 22 | | **Allocated Total** | | - | - | - | - | - | - |
| | | | | | | Pre 1971 ITC Includable in Rate Base | | | |
| | | **Account 255 - Form-1 page 266-267** | | | | | | | |
| 23 | 255.0 | Acc Defrd ITC - Federal - 12/31/2XXX (FF1 p. 267, Ln 2.h) | | | | - | | | |
| 24 | 255.0 | Acc Defrd ITC - Federal - 12/31/2XXX-1 (FF1 p. 266, Ln 2.b) | | | | - | | | |
| 25 | | **Subtotal** | - | | | - | | | |
| 26 | | **Average Balance** | - | | | - | | | |
| 27 | | **Transmission Allocator from TCOS** | | | | 100.0000% | | | |
| 28 | | **Allocated Total** | | N/A | N/A | - | N/A | N/A | - |

* Exclusions: Non-utility, fuel supply, off-system sales and other items as specified related to costs not included in rates.

AEP West SPP Member Operating Companies

COMPANY
NAME

**WORKSHEET C-1** - END OF YEAR DETAIL OF DEFERRED INCOME TAX BALANCES

**AS OF DECEMBER 31, 2XXX**

| | | | | | Allocation Method | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Account** | **Line #** | **Description** | **Balance** | **Allocation Basis** | **Exclusions** | **100% Transmission** | **PTD Plant** | **T&D** | **Labor** |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 PROTECTED | | WS C-4 | | | | | |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 UNPROTECTED | | WS C-4 | | | | | |
| | | Forecast Adjustment to 282 | | | | | | | |
| **282.1** | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** (absolute value Total Company Amount Ties to FF1 p.275(k) -- Acct 282 Electric) | - | | - | - | - | - | - |
| 2831001 | 960F | 960F-XS EXCESS ADFIT 283 UNPROTECTED | | WS C-4 | | | | | |
| | | Forecast Adjustment to 283 | | | | | | | |
| **283.1** | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** (absolute value Total Company Amount Ties to FF1 p.277(k) -- Acct 283 Electric) | - | | - | - | - | - | - |
| | | Forecast Adjustment to 190 | | | | | | | |
| **190.1** | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** (Total Company Amount Ties to FF1 p.234(c) -- Electric) | - | | - | - | - | - | - |

AEP West SPP Member Operating Companies

COMPANY NAME

**WORKSHEET C-2** -BEGINNING OF YEAR DETAIL OF DEFERRED INCOME TAX BALANCES

**AS OF DECEMBER 31, 2XXX -1**

| Account | Line # | Description | Balance | Allocation Basis | Allocation Method Exclusions | 100% Transmission | PTD Plant | T&D | Labor |
|---|---|---|---|---|---|---|---|---|---|
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 PROTECTED | | WS C-4 | | | | | |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 UNPROTECTED | | WS C-4 | | | | | |
| | | Forecast Adjustment to 282 | | | | | | | |
| 282.1 | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** | - | | - | - | - | - | - |
| | | (absolute value Total Company Amount Ties to FF1 p.275(k) -- Acct 282 Electric) | | | | | | | |
| 2831001 | 960F | 960F-XS EXCESS ADFIT 283 UNPROTECTED | | WS C-4 | | | | | |
| | | Forecast Adjustment to 283 | | | | | | | |
| 283.1 | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** | - | | - | - | - | - | - |
| | | (absolute value Total Company Amount Ties to FF1 p.277(k) -- Acct 283 Electric) | | | | | | | |
| | | Forecast Adjustment to 190 | | | | | | | |
| 190.1 | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** | - | | - | - | - | - | - |
| | | (Total Company Amount Ties to FF1 p.234(c) -- Electric) | | | | | | | |

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet C-4 - Excess Deferred Federal Income Taxes**

**COMPANY NAME**

NOTES

Include only excess DFIT recorded in accounts which are included in the formula rate cost of service. These include one or more subaccounts within accounts 190.1, 282.1, and 283.1.

*NOTE A: Unprotected balances of excess/deficient ADIT will be amortized over five years, starting the year after the change is effective, consistent with the settled process approved in Docket ER18-195 (167 FERC ¶ 61,272 at 6.) for the excess and deficient ADIT caused by the TCJA of 2017. Additional columns will be added to reflect future tax changes.*

*NOTE B: In the event that an initial unprotected, excess or deficient ADIT amount changes due to adjustments, residual balances will be amortized in the final year of the amortization period. In that case this line will be a manual input.*

| Line | (A) | (B) | | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|---|
| | | | | Account | | | | |
| | **Unprotected ADIT Balances** | Source | Total | *XXXXXX X* | *XXXXXXX* | *XXXXXXX* | XXXXXXX | XXXXXXX |
| | *Tax Rate Change Legislation Act* | | | | | | | |
| 1 | Balance per Books- Transmission Function only (190 enter positive, 282/283 enter negative) | Company records | - | - | | | | |
| 2 | Settlement Amortization period | | | 5 | 5 | 5 | 5 | 5 |
| 3 | Annual Transmission Function Amortization | Line 1 / Line 2 *NOTE B* | - | - | - | - | - | - |
| 4 | Rate Year Beginning Accumulated Amortization | Company records | - | - | | | | |
| 5 | Rate year Ending Accumulated Amortization | Line 3 + Line 4 | - | - | - | - | - | - |
| 6 | Rate Year Beginning Balance Per Books - Total Company | WS C-2 960F XS Unprotected | - | - | - | - | | |
| 7 | Rate Year Beginning Included Balance - 100% Transmission Function net of amortization | Line 1 - Line 4 | - | - | - | - | - | - |
| 8 | Worksheet C-2 Rate Base Excluded Balance | Line 6 - Line 7 | - | - | - | - | - | - |
| 9 | Rate Year Ending Balance Per Books - Total Company | WS C-1 960F XS Unprotected | - | - | - | - | | |
| 10 | Rate Year Ending Included Balance - 100% Transmission Function net of amortization | Line 1 - Line 5 | - | - | - | - | - | - |
| 11 | Worksheet C-1 Rate Base Excluded Balance | Line 9 - Line 10 | - | - | - | - | - | - |
| | | | | Account | | | | |
| | **Protected ADIT Balances** | Source | Total | 2821001 | XXXXXXX | XXXXXXX | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | *Tax Rate Change Legislation Act* | | | | | |
| 12 | Balance per Books- Transmission Function only (190 enter positive, 282/283 enter negative) | Company records | - | | | |
| 13 | Annual Transmission Function Amortization | Company records | - | | | |
| 14 | Beginning Accumulated Amortization | Company records | - | | | |
| 15 | Ending Accumulated Amortization | Line 13 + Line 14 | - | - | - | |
| 16 | WS C-2 Beginning Balance Per Books - Total Company | WS C-2 960F XS Protected | - | | | |
| 17 | Rate Year Ending Included Balance - 100% Transmission Function net of amortization | Line 12 - Line 14 | - | - | - | - |
| 18 | Worksheet C-2 Rate Base Excluded Balance | Line 16 - Line 17 | - | - | - | - |
| 19 | WS C-1 Ending Balance Net of Accumulated Amortization Per Books - Total Company | WS C-1 960F XS Protected | - | | | |
| 20 | Rate Year Ending Included Balance - 100% Transmission Function net of amortization | Line 12 - Line 15 | - | - | - | - |
| 21 | Worksheet C-1 Rate Base Excluded Balance | Line 19 - Line 20 | - | - | - | - |
| | **Annual Amortization of Excess ADIT** | | Transmission Function | | | |
| 22 | Unprotected | Line 3 | - | | | |
| 23 | Protected | Line 13 | - | | | |
| 24 | Total | Line 22 + Line 23 | - | *TCOS Col (5) Ln 105* | | |

*COMPANY NAME HERE*
*Worksheet C-5*
*Excess/ Deficient ADIT Worksheet for Total Company and Functional Balances*
*For Year Ended December 31, 20__*
*Debit/(Credit)*

| *A* | *B* | *C* | *D* | *E* | *F* | *G* | *H* |
|---|---|---|---|---|---|---|---|
| ***TOTAL COMPANY BALANCES*** | | | | | | | |
| *Line No.* | ***Account (NOTE A)*** | ***Description of Account*** | ***Protected Unprotected*** | ***Tax Rate Change Act*** | ***(Excess)/Deficient Balance at Remeasurement (NOTE C)*** | ***Amortization Methodology (NOTE D)*** | ***Amortization Period*** |
| | ***Deferred Tax Account (NOTE B)*** | | | | | | |
| *1a* | | | | | | | |
| *1b* | | | | | | | |
| *1c* | | | | | | | |
| *1d* | | | | | | | |
| *1e* | | | | | | | |
| *1f* | | | | | | | |
| *1g* | | | | | | | |
| *1h* | | | | | | | |
| *1i* | | | | | | | |
| *1j* | ***NOTE E*** | | | | | | |
| | ***Regulatory Deferral Accounts*** | | | | | | |
| *2a* | *182.3* | *Regulatory Asset* | | | | | |
| *2b* | *254####* | *Regulatory Liability* | | | | | |
| *2c* | ***NOTE E*** | | | | | | |
| *3* | *Total For Accounting Entries (Sum of Lines 1a through 2_)* | | | | - | | |
| ***TRANSMISSION FUNCTION BALANCES (NOTE J)*** | | | | | | | |
| | ***Deferred Tax Account (NOTE*** | | | | | | |

***B)***

*4a*

*4b*

*4c*

*4d*

*4e*

*4f*

*4g*

*4h* ***NOTE E***

***Regulatory Deferral Accounts***

| | | | | |
|---|---|---|---|---|
| *5a* | *182.3* | *Regulatory Asset* | | |
| *5b* | *254####* | *Regulatory Liability* | | |
| *5c* | ***NOTE E*** | | | |
| *6* | *Total For Accounting Entries (Sum of Lines 4a through 5_)* | | | - |

| *I* | *J* | *K* | *L* | *M* | *N* | *O* | *P* | *Q* | *R* |
|---|---|---|---|---|---|---|---|---|---|
| *1/1/20__ Beginning Balances* | | | *Balance Sheet Entries* | | *Tax Expense Entries* | | *12/31/20__ Ending Balance* | | |
| ***Excess/(Deficient) ADIT Regulatory Offset*** | ***(Excess)/Deficient ADIT in Utility Deferrals*** | ***Balance Sheet Account Reclassifications NOTE I*** | ***182.3*** | ***254*** | ***410/411 Excess/(Deficient) Amortization NOTE G/H*** | ***410/411 Deferred Tax Expense/ (Benefit)*** | ***Excess/(Deficient) ADIT Regulatory Offset Sum of Cols (I) - (O)*** | ***(Excess)/Deficient ADIT in Utility Deferrals*** | ***Reference*** |
| | | | | | | | | | |
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| - | - | - | - | - | - | - | - | - |

*NOTE F/G*

| | | | | | | | ***Sum of Cols (I) - (O)*** | |
|---|---|---|---|---|---|---|---|---|
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| - | - | - | - | - | - | - - - |

*NOTE F/G*

*GENERAL NOTE:*
*The information provided on this worksheet reflects the activity on the books of the Company, which maintains these records on both a total company and transmission functional basis. Because of the required exclusion of certain excess and deficient balances that relate to ADIT differences that aren't recoverable in the formula, the Company will use WS C-4 for determining the amortization recoverable in the formula, as opposed to using the transmission functional book amounts that are shown on this work sheet. See NOTE E and NOTE G below for a further description on how the Company will track future tax rate changes and ensure the proper net amount is recorded on line 105 in the TCOS of the formula.*
*NOTE A: In order to ensure ratebase neutrality, AEP utilizes the fourth digit of its seven digit FERC tax subaccount numbers to identify balances associated with utility operations vs. regulatory reporting requirements. A "1" in the fourth digit of a FERC tax account refers to the utility operations balances or activity. Accounts with the "1" designation will be included in the determination of ratebase to be recovered in the formula rate. A "4" in the fourth position of the account number indicates accounts used to track regulatory accounting requirements. The excess ADIT amounts recorded in accounts with the "4" designation will be contra to the "1" balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, but at the total FERC account level the tax liability or asset will be recorded at the current Federal FIT rate. The amounts recorded in the "4" accounts will be offset on a net basis in the regulatory asset or liability subaccount established for this purpose.*
*NOTE B: The amount of the FIT gross up to recorded on regulatory assets and liabilities will be reported on the first line of ADIT accounts provided for each specific change in tax rates.*
*NOTE C: The amounts of the remeasurement shown here are as of the effective date of the change in tax rates and will remain static on this workpaper. The derivation of this amount, along with the pre-remeasurement and post-remeasurement balances of ADIT, are presented in formula wokpaper(s) C-5-X.*
*NOTE D: {REFERENCE OR CITES TO APPROVAL OF AMORTIZATION PERIOD FOR UNPROTECTED EXCESS/DEFICIENT ADIT}*
*NOTE E: In the event of future tax rate changes, additional lines will be inserted in both the total company and transmission functional sections above as required to reflect any new ADIT or regulatory deferral accounts that may be necessary to track that tax rate change.*
*NOTE F: The amount of excess amortization entries shown in lines 1a through 1j and 4a through 4h are shown as a debit or credit to the ADIT account from which it is being amortized. The totals in line 3 and 6 is the offset recorded to the 410/411 tax expense account.*
*NOTE G: Transmission functional amortization expense determined on WS C-4 will supersede the amortization of excess and deficient ADIT included in Column N, Ln 6 of this worksheet, due to ratemaking adjustments required in the formula that are not reflected in the books.*
*NOTE H: Deficient remeasurement amounts will be recorded in 410.1 as a debit (expense) to cost of service; excess remeasurement amounts will be recorded in 411.1 as a credit to cost of service.*
*NOTE I. In the event that there are adjustments reported in column K of this worksheet that would result in changes to the initial unprotected excess or deficient ADIT amounts, AEP will provide supporting documentation for those adjustments to customers as a part of its annual update process.*
*NOTE J: The West Operating Companies maintain accounting records at the total company and functional basis and have done so since 2002. The total company and transmission functional excess and deficient balances are derived from the underlying total company and functional transactions recorded on the books and records of the West Operating Companies. Therefore, functional ADIT balances are based on the functional book balances that underlie them. The determination of excess and deficient balances on both a total company and transmission functional basis are based on a remeasurement of the individual component ADIT balances making up those total ADIT balances, which is performed at the time of the tax change. The sum of the individual re-measurements comprise the total amount of net excess or deficient ADIT on a total company and transmission functional basis. While the ADIT worksheets C-1 and C-2 utilize the total company ADIT balances and allocate them using formula-developed allocators, the related excess/deficient ADIT balances reflect the transmission functional book balances and do not rely on allocation in the formula.*

*AEP WEST OPERATING COMPANIES*

*ADDENDUM 4 TO ATTACHMENT H OF THE SPP OATT*
*WORKSHEET C-5-X*
*TAX REMEASUREMENT WORKSHEET*
*Debit/(Credit)*
***{TAX CHANGE LEGISLATION}***
***NOTE 1***

| *A* | *B* | *C* | *D* | *E* | *F=E/C* | *G* | *H = E + G* | *I* | *J = H + I* | *K* | *L = C - J* |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *Line No.* | *Utility Account* | *XX/XX/XX Pre-remeasurement Balance* | *Description / Reference* | *Remeasurement Amount (NOTE 2)* | *Remeasurement Percentage (NOTE 3)* | *Adjustments (NOTE 4)* | *Sub-total (NOTE 5)* | *Exclusions (NOTE 6)* | *Total Excess/Deficiency by Account (NOTE 7)* | *Protected/ Unprotected* | *ADIT Deferral After Remeasurement* |
| ***TOTAL COMPANY*** | | | | | | | | | | | |
| *1* | *List ADIT Accounts* | *$* | *{DESCRIPTION OF LINE ITEMS}* | *$* | *%* | *$* | *$* | *$* | *$* | *(PROTECTED OR UNPROTECTED* | *$* |
| *2* | | | | | | | | | | | |
| *3* | | | | | | | | | | | |
| *4* | | | | | | | | | | | |
| *5* | | | | | | | | | | | |
| *6* | | | | | | | | | | | |
| *7* | | | | | | | | | | | |
| *8* | | | | | | | | | | | |
| *9* | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | |
| 14 | *Total* | *$* | *(Sum of Lns. )* | *$* | | *$* | *$* | | *$* | | *$* | |

***TRANSMISSION FUNCTION***

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | *List ADIT Accounts* | *$* | *{DESCRIPTION OF LINE ITEMS}* | *$* | *%* | *$* | *$* | *$* | *$* | *(PROTECTED OR UNPROTECTED* | *$* | |
| 16 | | | | | | | | | | | | |
| 17 | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | |
| 19 | | | | | | | | | | | | |
| 20 | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | |
| 24 | | | | | | | | | | | | |
| 25 | | | | | | | | | | | | |
| 26 | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | |
| 28 | *Total* | *$* | *(Sum of Lns. )* | *$* | | *$* | | | *$* | | *$* | |

*GENERAL*

*NOTE:*

*This worksheet will summarize remeasurement adjustments in ADIT Accounts for both the total company and transmission function required by changes in either federal or state income tax rates and/or apportionment factors that give rise to Excess/Deficient ADIT. A new sheet will be included in the working formula for each change to tax rates or apportionment factors that may occur while this formula rate is in effect. New pages will be designated by incrementing the suffix letter in the workpaper name (i.e. C-5-A, C-5-B, etc.). Lines may be added as necessary to reflect the specifics of the remeasurement required by the tax change.*

*NOTE 1* *___{TAX CHANGE LEGISLATION}_____ required {PROVIDE DESCRIPTION OF CHANGE IN TAX RATE OR OTHER CHANGE}.*

*NOTE 2:* *Amount of Remeasurement in Column E will be based on supporting workpapers showing the initial remeasurement of individual ADIT items in each tax deferral account, and will indicate whether each remeasured ADIT item will be treated as protected or unprotected. The resulting totals will be shown on this worksheet for each ADIT account.*

*NOTE 3:* *The remeasurement calculation may not equal ___% of the _{DATE OF REMEASUREMENT}_____ deferral balance because of specific ADIT items that are not subject to remeasurement, are excludable from the excess/deficient balances recoverable in this formula, and/or the impact of apportionment factors in the calculation,*

*NOTE 4:* *[NOTES/EXPLANATIONS OF AMOUNTS REPORTED IN COLUMN G IF NECESSARY.]*

*NOTE 5:* *Ties to each Operating Companies' Worksheet C-5, Column F, showing the initial remeasurement value determined as a result of the _(TAX CHANGE LEGISLATION).*

*NOTE 6:* *This column represents the total of specific ADIT balances in each ADIT account that are included in the initial remeasurement but which are then excluded from the recoverable excess or deficient balances because the underlying ADIT item is not allocated in the formula. It will also include adjustments made after the initial remeasurement as identified by the AEP tax department.*

*NOTE 7:* *The transmission functional amount in this column will be the amount that is recoverable in the formula rate, based on the book remeasurement recorded on books and then adjusted for the excess or deficient amounts of excludable ADIT differences. This net total will be recorded on worksheet C-4.*

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet D** - Materials and Supplies and Prepayments
**COMPANY NAME**

| | (A) | (B) | ( C ) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|
| | **Materials & Supplies** | | | | | | | |
| **Line Number** | | | **Source** | | **13 Month Average Balance for Rate Year** | | | |
| 1 | | Transmission Materials & Supplies | WS D, p. 2 of 2, Col. (D), line 1 | | - | | | |
| 2 | | General Materials & Supplies | WS D, p. 2 of 2, Col. (D), line 2 | | - | | | |
| 3 | | Stores Expense (Undistributed) - Account 163 | WS D, p. 2 of 2, Col. (D), line 3 | | - | | | |
| | **Prepayments Account 165** | | | | | | | |
| **Line Number** | **Acc. No.** | **Description** | **13 Month Average Balance Source - Page 2 of 2. Col (D)** | **Excludable Balances** | **100% Transmission Related** | **Plant Related** | **Labor Related** | **Explanation** |
| 4 | 1650001 | Prepaid Insurance | - | | | | | |
| 5 | 1650004 | Prepaid Interest | - | | | | | |
| 6 | 1650005 | Prepaid Employee Benefits | - | - | | | | |
| 7 | 1650006 | Other Prepayments | - | - | | | | |
| 8 | 1650009 | Prepaid Carry Cost-Factored | - | - | | | | |
| 9 | 1650010 | Prepaid Pension Benefits | - | | | | - | |
| 10 | 165001116 | Prepaid Sales Taxes | - | | | - | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 11 | 165001216 | Prepaid Use Taxes | - | - | | | |
| 12 | 1650014 | FAS 158 Qual Contra Asset | - | - | | | |
| 13 | 1650016 | FAS 112 ASSETS | - | - | | | |
| 14 | 1650021 | Prepaid Insurance - EIS | - | | | | |
| 15 | 1650023 | Prepaid Leases | - | - | | | |
| 16 | 1650028 | Trinity Rail Car Lease - Non-current | - | - | | | |
| 17 | 1650031 | Prepaid OCIP Work Comp | - | | | | - |
| 18 | 1650032 | Prepaid OCIP Work Comp-Long Term | - | | | | - |
| 19 | 1650033 | Prepaid OCIP Work Comp-Affiliated | - | | | | - |
| 20 | 1650034 | Prepaid OCIP Work Comp-Affiliated Long Term | - | | | | - |
| 21 | 1650035 | PRW Without MED-D Benefits | - | | | | - |
| 22 | 1650036 | PRW for Med-D Benefits | - | | | | - |
| 23 | 1650037 | FAS158 Contra-PRW Exclude Med-D | - | - | | | |
| 24 | | | - | | | | - |
| 25 | | | - | - | | | |
| 26 | | | - | | | | |
| 27 | | | - | | | | |
| 28 | | | - | | | | |
| 29 | | | - | - | - | - | - |

Note 1: Prepayment Balance will not include: (i) federal and state income tax payments made to offset additional tax liabilities resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; (ii) outstanding income tax refunds due to the company resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; or (iii) prepayments of federal or state income taxes which are attributable to income earned during periods prior to January 1 of the year depicted in the Balance Sheet (as described in USofA Account 236).

| | (A) | (B) | ( C ) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) | (N) | (O) | (P) | (Q) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Materials & Supplies** | | | | | | | | | | | | | | | | |
| | | | | | **Monthly Balances** | | | | | | | | | | | | |
| **Line Number** | **Description** | | **Source - December Balances** | **13 Month Average** | December 2XXX-1 | January 2XXX | February 2XXX | March 2XXX | April 2XXX | May 2XXX | June 2XXX | July 2XXX | August 2XXX | September 2XXX | October 2XXX | November 2XXX | December 2XXX |
| 1 | Transmission Materials & Supplies | | FF1, p. 227, ln 8, Col. (c & b) | - | | | | | | | | | | | | | |
| 2 | General Materials & Supplies | | FF1, p. 227, ln 11, Col. (c & b) | - | | | | | | | | | | | | | |
| 3 | Stores Expense (Undistributed) - Account 163 | | FF1, p. 227, ln 16, Col. (c & b) | - | | | | | | | | | | | | | |
| | **Prepayments Account 165** | | | | | | | | | | | | | | | | |
| | Line item balances obtained from Company Records | | | | **Monthly Balances** | | | | | | | | | | | | |
| **Line Number** | **Acc. No.** | **Description** | | **13 Month Average** | December 2XXX-1 | January 2XXX | February 2XXX | March 2XXX | April 2XXX | May 2XXX | June 2XXX | July 2XXX | August 2XXX | September 2XXX | October 2XXX | November 2XXX | December 2XXX |
| 4 | 1650001 | Prepaid Insurance | | - | | | | | | | | | | | | | |
| 5 | 1650004 | Prepaid Interest | | - | | | | | | | | | | | | | |
| 6 | 1650005 | Prepaid Employee Benefits | | - | | | | | | | | | | | | | |
| 7 | 1650006 | Other Prepayments | | - | | | | | | | | | | | | | |
| 8 | 1650009 | Prepaid Carry Cost-Factored | | - | | | | | | | | | | | | | |
| 9 | 1650010 | Prepaid Pension Benefits | | - | | | | | | | | | | | | | |
| 10 | 165001116 | Prepaid Sales Taxes | | - | | | | | | | | | | | | | |
| 11 | 165001216 | Prepaid Use Taxes | | - | | | | | | | | | | | | | |
| 12 | 1650014 | FAS 158 Qual Contra Asset | | - | | | | | | | | | | | | | |
| 13 | 1650016 | FAS 112 ASSETS | | - | | | | | | | | | | | | | |
| 14 | 1650021 | Prepaid Insurance - EIS | | - | | | | | | | | | | | | | |
| 15 | 1650023 | Prepaid Leases | | - | | | | | | | | | | | | | |
| 16 | 1650028 | Trinity Rail Car Lease - Non-current | | - | | | | | | | | | | | | | |
| 17 | 1650031 | Prepaid OCIP Work Comp | | - | | | | | | | | | | | | | |
| 18 | 1650032 | Prepaid OCIP Work Comp-Long Term | | - | | | | | | | | | | | | | |
| 19 | 1650033 | Prepaid OCIP Work Comp-Affiliated | | - | | | | | | | | | | | | | |
| 20 | 1650034 | Prepaid OCIP Work Comp-Affiliated Long Term | | - | | | | | | | | | | | | | |
| 21 | 1650035 | PRW Without MED-D Benefits | | - | | | | | | | | | | | | | |
| 22 | 1650036 | PRW for Med-D Benefits | | - | | | | | | | | | | | | | |
| 23 | 1650037 | FAS158 Contra-PRW Exclude Med-D | | - | | | | | | | | | | | | | |
| 24 | 0 | 0 | | - | | | | | | | | | | | | | |
| 25 | 0 | 0 | | - | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 26 | 0 | 0 | - | |
| 27 | 0 | 0 | - | |
| 28 | 0 | 0 | - | |
| 29 | **Total - December Balances tie to Form 1, p 111.57.c and d** | | - | - - -

| | | |
|---|---|---|
| 6 | | |
| 7 | Net Funds from IPP Customers 12/31/2XXX (2XXX FORM 1, P269, (F)) | - |
| 8 | Average Balance for 2XXX ((ln 1 + ln 7)/2) | - |

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet F** - Calculation of PROJECTED Annual Revenue Requirement for Base Plan and Special-Billed Projects

**COMPANY NAME**

| Line Number | | | | | | |
|---|---|---|---|---|---|---|
| | **I.** | **Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Incentive.** | | | | |
| | | **A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects** | | | | |
| 1 | | ROE w/o incentives (TCOS, ln 143) | | 10.50% | | |
| 2 | | Project ROE Incentive Adder (Enter as whole number) | | - | basis points | |
| 3 | | ROE with additional 0 basis point incentive | | 10.50% | **<==Incentive ROE** | |
| 4 | | Determine R (cost of long term debt, cost of preferred stock and percent is from TCOS, lns 141 through 143) | | | | |
| 5 | | | % | Cost | Weighted cost | |
| 6 | | Long Term Debt | - | - | - | |
| 7 | | Preferred Stock | - | - | - | |

Note: Worksheets F and G are both populated from the TCOS worksheet every update.

Worksheet F is only used in Projections. Worksheet G is used only in True-Ups.
These worksheets add up all of the individual SPP Base Plan projects, Requested Upgrades,
Economic Upgrades, or any other projects billed by SPP through other than the NITS rate.

| SUMMARY OF PROJECTED ANNUAL BASE PLAN AND NON-BASE PLAN REVENUE REQUIREMENTS | | | |
|---|---|---|---|
| | Rev Require | With Incentives | Incentive Amount |

| | | | | |
|---|---|---|---|---|
| 8 | Common Stock | 10.50% | - | |
| 9 | | R = | - | |

**B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | | |
|---|---|---|---|
| 10 | Rate Base (TCOS, ln 63) | - | |
| 11 | R (from A. above) | - | |
| 12 | Return (Rate Base x R) | - | |

**C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | | |
|---|---|---|---|
| 13 | Return (from B. above) | | - |
| 14 | Tax Rate (TCOS, ln 99) | | - |
| 15 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | | - |
| 16 | Income Tax Calculation (Return x EIT) | | - |
| 17 | ITC Adjustment (TCOS, ln 108) | | - |
| 18 | Excess DFIT Adjustment (TCOS, ln 109) | - | |
| 19 | Tax Effect of Permanent and Flow Through Differences (TCOS, ln 110) | - | |
| 20 | Income Taxes | - | |

**II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.**

**A. Determine Net Revenue Requirement less return and Income Taxes.**

| | | |
|---|---|---|
| 21 | Net Revenue Requirement (TCOS, ln 117) | - |
| 22 | Return (TCOS, ln 112) | - |
| 23 | Income Taxes (TCOS, ln 111) | - |
| 24 | Gross Margin Taxes (TCOS, ln 116) | - |
| 25 | Net Revenue Requirement, Less Return and | |

s

| | | | | |
|---|---|---|---|---|
| ∑ Projected Year | 2XXX | - | - | $ - |

**NOTE:** **PART IV ---Projected Base Plan Project Tables are contained in a separate file**

| | | | |
|---|---|---|---|
| | Taxes | - | |
| | **B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.** | | |
| 26 | Net Revenue Requirement, Less Return and Taxes | - | |
| 27 | Return (from I.B. above) | - | |
| 28 | Income Taxes (from I.C. above) | - | |
| 29 | Net Revenue Requirement, with 0 Basis Point ROE increase | - | |
| 30 | Gross Margin Tax with Basis Point ROE Increase (II C. below) | - | |
| 31 | Revenue Requirement w/ Gross Margin Taxes | - | |
| 32 | Less: Depreciation (TCOS, ln 86) | - | |
| 33 | Net Rev. Req, w/0 Basis Point ROE increase, less Depreciation | - | |
| | **C. Determine Gross Margin Tax with hypothetical 0 basis point increase in ROE.** | | |
| 34 | Net Revenue Requirement before Gross Margin Taxes, with 0 | | - |
| 35 | Basis Point ROE increase (II B. above) | | |
| 36 | Apportionment Factor to Texas (Worksheet K, ln 12) | | - |
| 37 | Apportioned Texas Revenues | | - |
| 38 | Taxable Percentage of Revenue | | |
| 39 | Taxable, Apportioned Margin | | - |
| 40 | Texas Gross Margin Tax Rate | | |
| 41 | Texas Gross Margin Tax Expense | | - |
| 42 | Gross-up Required for Gross Margin Tax Expense | | - |
| 43 | Total Additional Gross Margin Tax Revenue Requirement | | - |
| | **D. Determine FCR with hypothetical 0 basis point ROE increase.** | | |
| 44 | Net Transmission Plant (TCOS, ln 37) | | - |
| 45 | Net Revenue Requirement, with 0 Basis Point ROE increase | | - |
| 46 | FCR with 0 Basis Point increase in ROE | | - |
| 47 | Net Rev. Req, w / 0 Basis Point ROE increase, less Dep. | | - |
| 48 | FCR with 0 Basis Point ROE increase, less Depreciation | | - |
| 49 | FCR less Depreciation (TCOS, ln 10) | | - |
| 50 | Incremental FCR with 0 Basis Point ROE increase, less Depreciation | | - |
| | **III. Calculation of Composite Depreciation Rate** | | |
| 51 | Transmission Plant Average Balance for 2XXX (WS A-1 Ln 14 Col (d)) | | - |

| | | |
|---|---|---|
| 52 | Annual Depreciation Expense (TCOS, ln 86) | - |
| 53 | Composite Depreciation Rate | - |
| 54 | Depreciable Life for Composite Depreciation Rate | - |
| 55 | Round to nearest whole year | - |

**'Worksheet F -- COMPANY NAME -- Calculation of Projected ARR for SPP Base Plan Upgrade Projects**

**IV. Determine the Revenue Requirement & Additional Revenue Requirement for facilities receiving incentives.**

**A. Facilities receiving incentives accepted by FERC in Docket No.**

**Project Description:**

| | |
|---|---|
| **Current Projected Year ARR** | |
| **Current Projected Year ARR w/ Incentive** | |
| **Current Projected Year Incentive ARR** | - |

| **DETAILS** | Project Number | |
|---|---|---|
| Investment (EOY) | Projected Year | **2XXX** |

CUMMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:

| | | | |
|---|---|---|---|
| Service Year (yyyy) | | ROE increase accepted by FERC (Basis Points) | - |
| Service Month (1-12) | - | FCR w/o incentives, less depreciation | 0.00% |
| Useful life | - | FCR w/incentives approved for these facilities, less dep. | 0.00% |
| CIAC (Yes or No) | | Annual Depreciation Expense | - |

INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR
TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE
LIFE OF THE PROJECT.

| Year | Investment Beginning Balance | Depreciation Expense | Ending Balance | Annual Revenue Requirement | Annual Revenue Req't. with Incentives | Additional Rev. Requirement ** |
|---|---|---|---|---|---|---|
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| Project Totals | | - | | - | - | - |

| PROJECTED Rev. Req't From Prior Year Template w/o Incentives | Project Rev Req't True-up w/o Incentives | PROJECTED Rev. Req't From Prior Year Template with Incentives ** | Project Rev Req't True-up with Incentives ** | True-up of Incentive with Incentives** |
|---|---|---|---|---|
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |

**** This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.**

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet G** - Calculation of TRUED-UP Annual Revenue Requirement for Base Plan and Special-Billed Projects

**COMPANY NAME**

**Line Number** **I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Incentive.**

**A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects**

1 ROE w/o incentives (TCOS, 10.50%

Note: Worksheets F and G are both populated from the TCOS worksheet every update.
Worksheet F is only used in Projections. Worksheet G is used only in True-Ups.
These worksheets add up all of the individual SPP Base Plan projects, Requested Upgrades,
Economic Upgrades, or any other projects billed by SPP through other than the

| | | | | | |
|---|---|---|---|---|---|
| | ln 143) | | | | NITS rate. |
| 2 | Project ROE Incentive Adder (Enter as whole number) | | - | basis points | |
| 3 | ROE with additional 0 basis point incentive | | 10.50% | **<==Incentive ROE** | |
| 4 | Determine R (cost of long term debt, cost of preferred stock and percent is from TCOS, lns 141 through 143) | | | | |
| 5 | | % | Cost | Weighted cost | |
| 6 | Long Term Debt | - | - | - | |
| 7 | Preferred Stock | - | - | - | |
| 8 | Common Stock | - | 10.50% | - | |
| 9 | | | R = | - | |

**B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | | |
|---|---|---|---|
| 10 | Rate Base (TCOS, ln 63) | - | |
| 11 | R (from A. above) | - | |
| 12 | Return (Rate Base x R) | - | |

**C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | |
|---|---|---|
| 13 | Return (from B. above) | - |
| 14 | Tax Rate (TCOS, ln 99) | - |
| 15 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | - |

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR SPP BPU & NON-BPU PROJECTS

| | Rev Require | With Incentives | Incentive Amounts |
|---|---|---|---|
| True-Up Rate Year 2XXX | | | |
| ∑ True Up Year Projected WS-F | $ - | $ - | $ - |
| ∑ True-Up Year True-Up WS-G | $ - | $ - | $ - |
| True-up Adjustment For 2XXX | - | - | - |

**NOTE:** **PART IV --- True-Up Base Plan Project Tables are contained in a separate file**

| | | |
|---|---|---|
| 16 | Income Tax Calculation (Return x EIT) | - |
| 17 | ITC Adjustment (TCOS, ln 108) | - |
| 18 | Excess DFIT Adjustment (TCOS, ln 109) | - |
| 19 | Tax Effect of Permanent and Flow Through Differences (TCOS, ln 110) | - |
| 20 | Income Taxes | - |

**II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.**

**A. Determine Net Revenue Requirement less return and Income Taxes.**

| | | |
|---|---|---|
| 21 | Net Revenue Requirement (TCOS, ln 117) | - |
| 22 | Return (TCOS, ln 112) | - |
| 23 | Income Taxes (TCOS, ln 111) | - |
| 24 | Gross Margin Taxes (TCOS, ln 116) | - |
| 25 | Net Revenue Requirement, Less Return and Taxes | - |

**B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.**

| | | |
|---|---|---|
| 26 | Net Revenue Requirement, Less Return and Taxes | - |
| 27 | Return (from I.B. above) | - |
| 28 | Income Taxes (from I.C. above) | - |
| 29 | Net Revenue Requirement, with 0 Basis Point ROE increase | - |
| 30 | Gross Margin Tax with Basis Point ROE Increase (II C. below) | - |
| 31 | Revenue Requirement w/ Gross Margin Taxes | - |
| 32 | Less: Depreciation (TCOS, ln 86) | - |
| 33 | Net Rev. Req, w/0 Basis Point ROE increase, less Depreciation | - |

**C. Determine Gross Margin Tax with hypothetical 0 basis point increase in ROE.**

| | | |
|---|---|---|
| 34 | Net Revenue Requirement before Gross Margin Taxes, with 0 | - |
| 35 | Basis Point ROE increase (II B. above) | |
| 36 | Apportionment Factor to Texas (Worksheet K, ln 12) | - |
| 37 | Apportioned Texas Revenues | - |
| 38 | Taxable Percentage of Revenue | |
| 39 | Taxable, Apportioned Margin | - |
| 40 | Texas Gross Margin Tax Rate | |
| 41 | Texas Gross Margin Tax Expense | - |
| 42 | Gross-up Required for Gross Margin Tax Expense | - |
| 43 | Total Additional Gross Margin Tax Revenue Requirement | - |

**D. Determine FCR with hypothetical 0 basis point ROE increase.**

| | | |
|---|---|---|
| 44 | Net Transmission Plant (TCOS, ln 37) | - |
| 45 | Net Revenue Requirement, with 0 Basis Point ROE increase | - |
| 46 | FCR with 0 Basis Point increase in ROE | - |
| 47 | Net Rev. Req, w / 0 Basis Point ROE increase, less Dep. | - |
| 48 | FCR with 0 Basis Point ROE increase, less Depreciation | - |
| 49 | FCR less Depreciation (TCOS, ln 10) | - |
| 50 | Incremental FCR with 0 Basis Point ROE increase, less Depreciation | - |

**III. Calculation of Composite Depreciation Rate**

| | | |
|---|---|---|
| 51 | Transmission Plant Average Balance for 2XXX (WS A-1 Ln 14 Col (d)) | - |
| 52 | Annual Depreciation Expense (TCOS, ln 86) | - |
| 53 | Composite Depreciation Rate | - |
| 54 | Depreciable Life for Composite Depreciation Rate | - |
| 55 | Round to nearest whole year | - |

**Worksheet G -- COMPANY NAME-- Calculation of Trued-Up ARR for SPP Base Plan Upgrade Projects**

**IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.**

**A. Facilities receiving incentives accepted by FERC in Docket No.**

| | **2XXX** | Rev Require | w/Incentives | Incentive Amounts |
|---|---|---|---|---|
| | Rate Year Projected (WS-F) | | | - |
| | Rate Year True-Up (WS-G) | | | - |
| | True-Up Adjustment | | | **-** |

**Project Description :**

| Details | Project Number | |
|---|---|---|
| Investment (EOY) | True-Up Year | **2XXX** |
| Service Year (yyyy) | ROE increase accepted by FERC (Basis Points) | - |
| Service Month (1-12) | FCR w/o incentives, less depreciation | 0.00% |
| Useful life | FCR w/incentives approved for these facilities, less dep. | 0.00% |
| CIAC (Yes or No) | Annual Depreciation Expense | |

CUMMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:
INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR
TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE LIFE OF THE PROJECT.

| **Investment Year** | **Beginning Balance** | **Depreciation Expense** | **Ending Balance** | **Average Balance** | **Annual Revenue Requirement** | **Annual Revenue Req't. with Incentives** | **Incentive Rev. Requirement **** |
|---|---|---|---|---|---|---|---|
| | - | - | - | - | $0 | $0 | $ - |
| | - | - | - | - | | | $ - |
| | - | - | - | - | - | - | |
| | - | - | - | - | | | $ - |
| | - | - | - | - | - | - | |
| | - | - | - | - | | | $ - |
| | - | - | - | - | - | - | |
| Project Totals | | | | | | | |

| **BPU Rev. Req't.From Prior Year Template w/o Incentives** | **BPU Rev Req't True-up w/o Incentives** | **BPU Rev. Req't.From Prior Year Template with Incentives **** | **BPU Rev Req't True-up with Incentives **** | **True-up of Incentive with Incentives **** |
|---|---|---|---|---|
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |

** This is the total amount that needs to be reported to SPP for billing to all regions.

** **This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.**

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

Worksheet H - Revenue Credits

**COMPANY NAME**

| Line: | | Total Company | Non-Transmission | Transmission |
|---|---|---|---|---|
| 1 | **Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)** | | - | - |
| 2 | **Account 451, Misc. Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)** | | - | |
| | **Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)** | | | |
| | Account 4540001 - Rent from Elect Property-Aff | | - | |
| | Account 4540002 - Rent from Elect Property - Non-Aff | | - | |
| | Account 4540005 - Rent from Elect Property - Pole Attach | | - | |
| | Account 4540004 - Rent from Elect Property - ABD - Non-Aff | | - | |
| | Other 454 Accounts | | | |
| 3 | Total Rents from Electric Property | - | | - |
| | **Account 456.0 Other Operating Revenues (FF1 p.300.21.(b); Company Records - Note 1)** | | | |
| | 1 Account 4560015, Revenues from Associated Business Development | | - | |
| | 2 All Other 456.0 Revenues | | - | |
| 4 | Total 456.0 Other Operating Revenues | - | | - |
| | **Account 456.1, Revenues from Transmission of Electricity of Others (FF1 p.300.22.(b); Company Records - Note 1)** | | | |
| | **Less:** | | | |
| | **Transmission Direct Assignment Revenue (if costs not in the ARR)** | | | |
| | **Sponsored Upgrade Revenue** | | | |
| | **Credits against Transmission Service Revenue related to Generation Interconnections** | | | |
| | **Revenue for GFA's (Relative to SPP OATT) Associated with Load Included in the Divisor** | | | |
| | **Network Service Revenue (SPP Schedule 9) Associated with Load included in the Divisor** | | | |
| | **Revenue Associated with Transmission Plant Excluded From SPP Tariff** | | | |
| | **Distribution and Other Non-Transmission Revenue** | | | |
| | **Revenue from SPP Ancillary Services Provided** | | | |
| | **Base Plan Revenue (from SPP)** | | | |
| | **Flow Through of ERCOT Ancillary Charges** | | | |
| | **Other** | | | |

| | | | |
|---|---|---|---|
| 5 | | **Net 456.1 Transmission Credits** | - |
| 6 | **Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)** | | |
| 7 | **Account 457.2, Miscellaneous Revenues (FF1p.300.24.(b); Company Records - Note 1)** | | |
| 8 | **Total Revenue Credits - Sum lines 1 through 7** | | - |

Note 1: Data for this worksheet came from the FERC Form 1 and the Company's General Ledger.

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet I** - Supporting Transmission Expense Adjustments
**COMPANY NAME**

Note: This worksheet is used to include any FERC jurisdictional transmission-related (i.e. non-retail) expenses recorded in Accounts 561 or 565 which are includable in the formula on TCOS line 66, and make any other necessary FERC jursdictional adjustments to Transmission O&M.

| **Line Number** | **(A) Description** | **(B) 2XXX** |
|---|---|---|
| 1 | | |
| 2 | | |
| 3 | | |
| 4 | | |

| | | | | |
|---|---|---|---|---|
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | Total | ( sum of lines 2 through 9 ) | | - |

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet J** - Allocation of Specific O&M or A&G Expenses

**COMPANY NAME**

| Line Number | (A) FERC Acct No. | (B) Description | (C) 2XXX Expense | (D) 100% Non-Transmission | (E) 100% Transmission Specific | (F) Explanation of Transmission Specific Items |
|---|---|---|---|---|---|---|
| | | **Account 928** | | | | |
| 1 | | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |

| | | | | |
|---|---|---|---|---|
| 16 | **Total (FERC Form 1 p.323.189.b)** | - | - | - |
| | **Account 930.1** | | | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | | | | |
| 21 | | | | |
| 22 | **Total (FERC Form 1 p.323.191.b)** | - | - | - |
| | **Account 930.2** | | | |
| 23 | | | | |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | **Total (FERC Form 1 p.323.192.b)** | - | - | - |

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet K** - Development of Composite State Income Tax Rate
**COMPANY NAME**

**I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES FOR 2XXX**

| | | |
|---|---|---|
| State Income Tax Rate - Oklahoma | Note 1 | |
| Apportionment Factor | | |
| Effective State Income Tax Rate | | - |
| State Income Tax Rate - | | |
| Apportionment Factor | | |
| Effective State Income Tax Rate | | - |
| State Income Tax Rate - | | |
| Apportionment Factor | | |
| Effective State Income Tax Rate | | - |
| State Income Tax Rate - | | |
| Apportionment Factor | | |
| Effective State Income Tax Rate | | - |
| State Income Tax Rate - | | |
| Apportionment Factor | | |
| Effective State Income Tax Rate | | - |
| Total Effective State Income Tax Rate | | - |

Note 1 --- The Oklahoma State Income Tax Rate of 6% is reduced to 5.66% due to the deductibility of Oklahoma State Income Taxes on the Oklahoma State Income Tax Return.

**II. CALCULATION OF TEXAS GROSS MARGIN TAX**

| Line # | | | Projected / Actual Total Company | Trans. Only |
|---|---|---|---|---|
| | REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX (TCOS ln 116) | | - | - |
| 1 | Apportionment Factor to Texas (ln12) | | - | - |
| 2 | Apportioned Texas Revenues | | - | - |
| 3 | Taxable Percentage of Revenue | | | |
| 4 | Taxable, Apportioned Margin | | - | - |
| 5 | Texas Gross Margin Tax Rate | | | |
| 6 | Texas Gross Margin Tax Expense | | - | - |
| 7 | Gross-up Required for Texas Gross Margin Expense | | - | - |
| 8 | Total Additional Gross Margin Tax Revenue Requirement | ((ln 6 * ln 3 * ln 1)/(1- ln 5) * ln 5) | - | - |

| | | | | |
|---|---|---|---|---|
| 9 | WHOLESALE LOAD ALLOCATOR (For Use in Gross Margin Tax Allocator) | | | |
| 10 | Texas Jurisdictional Load | | - | KW |
| 11 | Total Load | | - | KW |
| 12 | Allocation Percentage | (ln 10 / ln 11) | - | |

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet L** - Taxes Other than Income

**COMPANY NAME**

| Line No. | (A) Account | (B) Total Company | (C) Property | (D) Labor | (E) Other | (F) Non-Allocable |
|---|---|---|---|---|---|---|
| 1 | **Revenue Taxes** | | | | | |
| 2 | | | | | | - |
| 3 | | | | | | |
| 4 | **Real Estate and Personal Property Taxes** | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | - |
| 10 | **Payroll Taxes** | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | **Production Taxes** | | | | | |
| 16 | | | | | | - |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | **Miscellaneous Taxes** | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | | | | | | |
| 30 | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | Total Taxes by Allocable Basis<br>(Total Company Amount Ties to FFI p.114, Ln 14,(c)) | - | - | - | - | - |

**NOTE: As a check, the difference between the total from Ln 35 above and the total on FF1 p.263 line 41(i) should equal the sum of the 'income' tax line items within FF1 p262.x-263.x**

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service
Formula Rate
**Worksheet M - Cost of Capital**
**COMPANY NAME**

| | | **Average Balance of Common Equity** | | | | |
|---|---|---|---|---|---|---|
| Line No | **Month** | **Proprietary Capital** | **Less: Preferred Stock** | **Less Undistributed Sub Earnings (Acct 216.1)** | **Less AOCI (Acct 219.1)** | **Average Balance of Common Equity** |
| | **(a)**<br>**(Note A)** | **(b)**<br>(FF1 112.16) | **(c)**<br>(FF1 250-251) | **(d)**<br>(FF1 112.12) | **(e)**<br>(FF1 112.15) | **(f)=(b)-( c)-(d)-( e)** |
| 1 | December Prior to Rate Year | | | | | - |
| 2 | January | | | | | - |
| 3 | February | | | | | - |
| 4 | March | | | | | - |
| 5 | April | | | | | - |
| 6 | May | | | | | - |
| 7 | June | | | | | - |
| 8 | July | | | | | - |
| 9 | August | | | | | - |
| 10 | September | | | | | - |
| 11 | October | | | | | - |
| 12 | November | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 13 | December of Rate Year | | | | | - | - |
| 14 | Average of the 13 Monthly Balances | - | - | - | - | - | - |

| | | Average Balance of Long Term Debt | | | | | |
|---|---|---|---|---|---|---|---|
| Line No | **Month** | **Acct 221 Bonds** | **Less: Acct 222 Reacquired Bonds** | **Acct 223 LT Advances from Assoc. Companies** | **Acct 224 Senior Unsecured Notes** | **Less: Fair Value Hedges** | **Gross Proceeds Outstanding Long-Term Debt** |
| | **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)=(b)-( c)+(d)+( e)-(f)** |
| | **(Note A)** | (FF1 112.18) | (FF1 112.19) | (FF1 112.20) | (FF1 112.21) | FF1, page 257, Col. (h) - Note 1 | |
| 15 | December Prior to Rate Year | | | | | | - |
| 16 | January | | | | | | - |
| 17 | February | | | | | | - |
| 18 | March | | | | | | - |
| 19 | April | | | | | | - |
| 20 | May | | | | | | - |
| 21 | June | | | | | | - |
| 22 | July | | | | | | - |
| 23 | August | | | | | | - |
| 24 | September | | | | | | - |
| 25 | October | | | | | | - |
| 26 | November | | | | | | - |
| 27 | December of Rate Year | | | | | | - |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | - | - |

NOTE 1: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Page 257 Column H of the FF1)

***Development of Cost of Long Term Debt Based on Average Outstanding Balance***

| Line No | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|
| 29 | **Annual Interest Expense for 2XXX** | | | | | | |
| 30 | Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i) | | | | | | |
| 31 | Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 50 below. | | | - | | | |
| 32 | Plus: Allowed Hedge Recovery From Ln 55 below. | | | - | | | |
| 33 | Amort of Debt Discount & Expense - Acct 428 (117.63.c) | | | | | | |
| 34 | Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c) | | | | | | |
| 35 | Less: Amort of Premium on Debt - Acct 429 (117.65.c) | | | | | | |
| 36 | Less: Amort of Gain on Reacquired Debt - Acct 429.1 (117.66.c) | | | | | | |
| 37 | **Total Interest Expense (Ln 30 - 31 + 33 + 34 - 35 - 36)** | | | - | | | |
| 38 | **Average Cost of Debt for 2XXX (Ln 37/ ln 28 (g))** | | | **-** | | | |

***CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES***

39 NOTE: The net amount of hedging gains or losses recorded in account 427 to be recovered in this formula rate should be limited to the effective portion of pre-issuance cash flow hedges that are amortized over the life of the underlying debt issuances. The recovery of a net loss or passback of a net gain will be limited to five basis points of the total Capital Structure. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the "Excludable" column below.

| | **HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)** | **Total Hedge (Gain)/Loss for 2XXX** | **Less Excludable Amounts (See NOTE on Line 39)** | **Net Includable Hedge Amount** | **Remaining Unamortized Balance** | **Amortization Period Beginning** | **Ending** |
|---|---|---|---|---|---|---|---|
| 40 | | | - | - | | | |
| 41 | | | - | - | | | |
| 42 | | | | - | | | |
| 43 | | | | - | | | |
| 44 | | | | | | | |

| | | | |
|---|---|---|---|
| 45 | | | - |
| 46 | | | - |
| 47 | | | - |
| 48 | | | - |
| 49 | | | - |
| 50 | Total Hedge Amortization | - | - |
| 51 | Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48) | | - |
| 52 | Total Average Capital Structure Balance for 2XXX (TCOS, Ln 144) | | - |
| 53 | Financial Hedge Recovery Limit - Five Basis Points of Total Capital | | 0.0005 |
| 54 | Limit of Recoverable Amount | | - |
| 55 | **Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)** | | **-** |

***Development of Cost of Preferred Stock***

| | | |
|---|---|---|
| 56 | 13 Month Average Balance of Preferred Stock (Ln 14 Col. (c)) | - |
| 57 | Dividends on Preferred Stock | |
| 58 | Average Cost of Preferred Stock (Ln 57/ Ln 56) | **-** |

**AEP West SPP Member Operating Companies**

**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**

**Worksheet N - Schedule 11 True-up With Interest**

**COMPANY NAME**

| True up Revenue Requirement For Year 2XXX Available May, 2XXX+1 Net of Schedule 11 Revenue Credits | | Cash Revenue Collections for True-up Year, Net of Schedule 11 Revenue Credits | | True-up Adjustment - Over (Under) Recovery | True Up Year: | 2XXX |
|---|---|---|---|---|---|---|
| | | | | | Intermediate Year: | 2XXX+1 |
| | **-** | | **=** | $0 | Rate Year: | 2XXX+2 |

| Month | Refunds/ (Surcharges) | Cumulative Refunds/(Surcharges) | Base for Quarterly | Base for Monthly | Monthly Interest | Calculated | Amortization | Cumulative Refunds |
|---|---|---|---|---|---|---|---|---|

| | | - Beginning of Month (Without Interest) | Compound Interest | Interest | Rate (Worksheet Q) | Interest | and Interest - End of Month |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest** | | | | | | | |
| ***True-Up Year*** | | | | | | | |
| 1/1/2XXX | - | - | - | - | - | - | - |
| 2/1/2XXX | - | - | - | - | - | - | - |
| 3/1/2XXX | - | - | - | - | - | - | - |
| 4/1/2XXX | - | - | - | - | - | - | - |
| 5/1/2XXX | - | - | - | - | - | - | - |
| 6/1/2XXX | - | - | - | - | - | - | - |
| 7/1/2XXX | - | - | - | - | - | - | - |
| 8/1/2XXX | - | - | - | - | - | - | - |
| 9/1/2XXX | - | - | - | - | - | - | - |
| 10/1/2XXX | - | - | - | - | - | - | - |
| 11/1/2XXX | - | - | - | - | - | - | - |
| 12/1/2XXX | - | - | - | - | - | - | - |
| ***Intermediate Year*** | | | | | | | |
| 1/1/2XXX+1 | - | - | - | - | - | - | - |
| 2/1/2XXX+1 | - | - | - | - | - | - | - |
| 3/1/2XXX+1 | - | - | - | - | - | - | - |
| 4/1/2XXX+1 | - | - | - | - | - | - | - |
| 5/1/2XXX+1 | - | - | - | - | - | - | - |
| 6/1/2XXX+1 | - | - | - | - | - | - | - |
| 7/1/2XXX+1 | - | - | - | - | - | - | - |
| 8/1/2XXX+1 | - | - | - | - | - | - | - |
| 9/1/2XXX+1 | - | - | - | - | - | - | - |
| 10/1/2XXX+1 | - | - | - | - | - | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 11/1/2XXX+1 | - | - | - | - | - | - | | - |
| 12/1/2XXX+1 | - | - | - | - | - | - | | - |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| ***Rate Year*** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 2/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 3/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 4/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 5/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 6/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 7/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 8/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 9/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 10/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 11/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 12/1/2XXX+2 | - | - | - | - | - | - | - | - |

| | |
|---|---|
| True-Up Adjustment with Interest | - |
| Less Over (Under) Recovery | - |
| Total Interest | - |

**Note 1:** The monthly interest rates to be applied to the over recovery or under recovery amounts during the true-up year and the intermediate year will be determined using the monthly FERC interest rates (as determined pursuant to 18 C.F.R. Section 35.19a) posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp. The monthly interest rate to be applied to the over recovery or under recovery amounts each month during the rate year will equal a simple average of the 12 monthly interest rates for the intermediate year.

Note 2: An over or under collection for the Schedule 11 charge will be recovered prorata over the true-up year, held for the intermediate year and returned prorata over the rate year.

**AEP West SPP Member Operating Companies**
**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**
**Worksheet O - Schedule 9 NITS True-up With Interest**
**COMPANY NAME**

| True up Revenue Requirement For Year 2XXX Available May, 2XXX+1 Net of Schedule 9 Revenue Credits | - | Cash Revenue Collections for True-up Year, Net of Schedule 9 Revenue Credits | = | True-up Adjustment - Over (Under) Recovery |
|---|---|---|---|---|
| | | | | $0 |

True Up Year: 2XXX
Intermediate Year: 2XXX+1
Rate Year: 2XXX+2

| Month | Refunds/ (Surcharges) | Cumulative Refunds/(Surcharges) - Beginning of Month (Without Interest) | Base for Quarterly Compound Interest | Base for Monthly Interest | Monthly Interest Rate (Worksheet Q) | Calculated Interest | Cumulative Refunds and Interest - End of Month |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest** | | | | | | | |
| ***True-Up Year*** | | | | | | | |
| 1/1/2XXX | - | - | - | - | - | - | |
| 2/1/2XXX | - | - | - | - | - | - | |
| 3/1/2XXX | - | - | - | - | - | - | |
| 4/1/2XXX | - | - | - | - | - | - | |
| 5/1/2XXX | - | - | - | - | - | - | |
| 6/1/2XXX | - | - | - | - | - | - | |
| 7/1/2XXX | - | - | - | - | - | - | |
| 8/1/2XXX | - | - | - | - | - | - | |
| 9/1/2XXX | - | - | - | - | - | - | |
| 10/1/2XXX | - | - | - | - | - | - | |
| 11/1/2XXX | - | - | - | - | - | - | |
| 12/1/2XXX | - | - | - | - | - | - | |
| ***Intermediate Year*** | | | | | | | |
| 1/1/2XXX+1 | - | - | - | - | - | - | |
| 2/1/2XXX+1 | - | - | - | - | - | - | |
| 3/1/2XXX+1 | - | - | - | - | - | - | |
| 4/1/2XXX+1 | - | - | - | - | - | - | |
| 5/1/2XXX+1 | - | - | - | - | - | - | |
| 6/1/2XXX+1 | - | - | - | - | - | - | |

| | |
|---|---|
| True-Up Adjustment with Interest | - |
| Less Over (Under) Recovery | - |

Total Interest -

**Note 1:** The monthly interest rates to be applied to the over recovery or under recovery amounts during the true-up year and the intermediate year will be determined using the monthly FERC interest rates (as determined pursuant to 18 C.F.R. Section 35.19a) posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp.

**Note 2:** An over or under collection for the Schedule 9 charge will be recovered prorata over the true-up year, held through June of the intermediate year and charged/refunded in a lump sum during July of the intermediate year.

**AEP West SPP Member Operating Companies**
**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**
**Worksheet P - Schedule 1 NITS True-up With Interest**
**COMPANY NAME**

| True up Revenue Requirement For Year 2XXX Available May, 2XXX+1 Net of Schedule 1 Revenue Credits | | Cash Revenue Collections for True-up Year, Net of Schedule 1 Revenue Credits | | True-up Adjustment - Over (Under) Recovery | True Up Year: | 2XXX |
|---|---|---|---|---|---|---|
| | | | | | Intermediate Year: | 2XXX+1 |
| | - | | = | $0 | Rate Year: | 2XXX+2 |

| Month | Refunds/ (Surcharges) | Cumulative Refunds/(Surcharges) - Beginning of Month (Without Interest) | Base for Quarterly Compound Interest | Base for Monthly Interest | Monthly Interest Rate (Worksheet Q) | Calculated Interest | Cumulative Refunds and Interest - End of Month |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest** | | | | | | | |
| ***True-Up Year*** | | | | | | | |
| 1/1/2XXX | - | - | - | - | - | - | |
| 2/1/2XXX | - | - | - | - | - | - | |
| 3/1/2XXX | - | - | - | - | - | - | |
| 4/1/2XXX | - | - | - | - | - | - | |
| 5/1/2XXX | - | - | - | - | - | - | |
| 6/1/2XXX | - | - | - | - | - | - | |
| 7/1/2XXX | - | - | - | - | - | - | |
| 8/1/2XXX | - | - | - | - | - | - | |
| 9/1/2XXX | - | - | - | - | - | - | |
| 10/1/2XXX | - | - | - | - | - | - | |
| 11/1/2XXX | - | - | - | - | - | - | |
| 12/1/2XXX | - | - | - | - | - | - | |
| ***Intermediate Year*** | | | | | | | |
| 1/1/2XXX+1 | - | - | - | - | - | - | |
| 2/1/2XXX+1 | - | - | - | - | - | - | |
| 3/1/2XXX+1 | - | - | - | - | - | - | |
| 4/1/2XXX+1 | - | - | - | - | - | - | |
| 5/1/2XXX+1 | - | - | - | - | - | - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6/1/2XXX+1 | - | - | - | - | - | - |

| | |
|---|---|
| True-Up Adjustment with Interest | - |
| Less Over (Under) Recovery | - |
| Total Interest | - |

**Note 1:** The monthly interest rates to be applied to the over recovery or under recovery amounts during the true-up year and the intermediate year will be determined using the monthly FERC interest rates (as determined pursuant to 18 C.F.R. Section 35.19a) posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp.

**Note 2:** An over or under collection for the Schedule 1 charge will be recovered prorata over the true-up year, held through June of the intermediate year and charged/refunded In a lump sum during July of the intermediate year. Schedule 1 Point-to-Point rates are not subject to true-up.

**AEP West SPP Member Operating Companies**

**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**

**Worksheet Q - True-up Interest Rates**

**COMPANY NAME**

This Attachment is used to input and compute the interest rates to be applied to each year's revenue requirement true-ups.

| | | |
|---|---|---|
| | Applicable FERC Interest Rate (Note A): | |
| 1 | 1/1/2XXX | |
| 2 | 2/1/2XXX | |
| 3 | 3/1/2XXX | |
| 4 | 4/1/2XXX | |
| 5 | 5/1/2XXX | |
| 6 | 6/1/2XXX | |
| 7 | 7/1/2XXX | |
| 8 | 8/1/2XXX | |
| 9 | 9/1/2XXX | |
| 10 | 10/1/2XXX | |
| 11 | 11/1/2XXX | |
| 12 | 12/1/2XXX | |
| 13 | 1/1/2XXX+1 | |
| 14 | 2/1/2XXX+1 | |
| 15 | 3/1/2XXX+1 | |
| 16 | 4/1/2XXX+1 | |
| 17 | 5/1/2XXX+1 | |
| 18 | 6/1/2XXX+1 | |
| 19 | 7/1/2XXX+1 | |
| 20 | 8/1/2XXX+1 | |
| 21 | 9/1/2XXX+1 | |
| 22 | 10/1/2XXX+1 | |
| 23 | 11/1/2XXX+1 | |
| 24 | 12/1/2XXX+1 | |
| | Schedule 11 Base Plan True Up | |
| 25 | Average Monthly Rate - Lines 13- 24 | - |

Note A - Lines 1-20 are the FERC interest rates under section 35.19a of the regulations for the period shown,

as posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp.

AEP West SPP Member Operating Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet R** - Unfunded Reserves

**COMPANY NAME**

| Line Number | (A) Description | (B) Account | (C) Formula Expense Account | (D) Balances @ 12/31/2XXX | (E) Balances 12/31/2XXX-1 | (F) Average Balance for 2XXX |
|---|---|---|---|---|---|---|
| 1 | | | | | | - |
| 2 | | | | | | - |
| 3 | | | | | | - |
| 4 | | | | | | - |
| 5 | | | | | | - |
| 6 | Total | | | - | - | - |

Note - The cost of service will make a rate base adjustment to remove unfunded reserves associated with contingent liabilities recorded to Accounts 228.1-228.4 from rate base. Include only contingent liabilities which were expensed through accounts included in formula rate cost of service.

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet S** - Regulatory Assets
**COMPANY NAME**

| Line | (A) Description | (B) FERC Docket | (C) Source | (D) Amort. / Deferral Account | (E) 2XXX Amortization / (Deferral) |
|---|---|---|---|---|---|
| 1 | **Regulatory Asset Amortizations / (Deferrals) in O&M (Note 1)** | | | | |
| 1a | | | | | |
| 1b | | | | | |
| 1c | | | | | |
| 1d | | | | | |
| 1e | | | | | |
| 2 | Net Amortization / (Deferral) | | | | - |
| 3 | **FERC Approved Regulatory Amortizations / (Deferrals) in O&M (Note 2)** | | | | |
| 3a | | | | | |
| 3b | | | | | |
| 3c | | | | | |
| 3d | | | | | |
| 4 | Net Approved Amortization / (Deferral) | | | | - |
| 5 | **Reg Asset Amortizations / (Deferrals) in A&G (Note 3)** | | | | |
| 5a | | | | | |
| 5b | | | | | |
| 6 | Net Amortization / (Deferral) | | | | - |
| 7 | **FERC Approved Reg Amortizations / (Deferrals) in A&G (Note 4)** | | | | |
| 7a | | | | | |
| 7b | | | | | |
| 8 | Net Approved Amortization / (Deferral) | | | | - |

**Regulatory Assets Included in Rate Base (Note 5)**

| | (A) | | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | Description | FERC Approval Docket | Form 1 Reference | Recovery Start Date | Recovery Period (Months) | **Balance @ 12/31/2XXX** | **Balance @ 12/31/2XXX-1** | **Average Balance** | **Functional Allocator (Note 6)** | **Functional Allocator Value** | **Transmission Balance** |
| 9a | | | | | | | | - | | | - |
| 9b | | | | | | | | - | | | - |
| 9c | | | | | | | | - | | | - |
| 9d | | | | | | | | - | | | - |
| 9e | | | | | | | | - | | | - |
| 10 | Total | | | | | - | - | - | | | - |

Notes
1 Include all regulatory asset amortizations and deferrals included in accounts in Transmission O&M on FERC Form 1 p. 321, ln 122. Exclude all

| | |
|---|---|
| | Distribution and Production-related items. |
| 2 | Include only regulatory asset amortizations and deferrals included in accounts in Transmission O&M approved by FERC for inclusion in cost of service. |
| 3 | Include all amortizations and deferrals of regulatory assets included in accounts in A&G expense on FERC Form 1 p. 321, ln 197, except amounts in Account 928, 930.1, and 930.2, which are accounted for on Worksheet J. |
| 4 | Include only regulatory asset amortizations and deferrals included in accounts in A&G expense approved by FERC for inclusion in cost of service. |
| 5 | See referenced FERC docket for details of Regulatory Assets approved for inclusion in rate base. Include only the Transmission functional balance for assets which have both Transmission and Distribution components. |
| 6 | Balances direct assigned to Transmission except for payroll-related balances, which will be allocated using a wages and salaries allocator. |

AEP West SPP Member Operating Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet T** - Depreciation Rates
**PUBLIC SERVICE COMPANY OF OKLAHOMA**
**EFFECTIVE AS OF 11/01/2021**

**TRANSMISSION PLANT**

| Acct. No. | Account Title | Total Depr Rates |
|---|---|---|
| 350.1 | Land Rights | 1.18% |
| 352.0 | Structures & Improvements | 1.77% |
| 353.0 | Station Equipment | 1.81% |
| 354.0 | Towers & Fixtures | 2.71% |
| 355.0 | Poles & Fixtures | 4.06% |
| 356.0 | OH Conductor & Devices | 2.55% |
| 358.0 | Underground Conductor | 1.94% |

**GENERAL PLANT**

| Acct. No. | Account Title | Total Depr Rates |
|---|---|---|
| 390.0 | Structures & Improvements | 2.02% |
| 391.0 | Office Furniture | 5.70% |
| 391.11 | Office Equipment - Computers | 31.01% |
| 392.0 | Transportation Equipment | 7.18% |
| 393.0 | Stores Equipment | 3.86% |
| 394.0 | Tools Shop & Garage Equipment | 4.33% |
| 395.0 | Laboratory Equipment | 6.32% |
| 396.0 | Power Operated Equip | 7.93% |
| 397.0 | Communication Equip - Amortized | 6.97% |
| 397.16 | AMI - Communication Equipment | 7.18% |
| 398.0 | Miscellaneous Equipment | 5.65% |
| 399.3 | Alliance Rail | 2.50% |

**INTANGIBLE PLANT**

| Acct. No. | Account Title | Total Depr Rates |
|---|---|---|
| 303.0 | Intangible Plant | 10.00% |

Note 1 – These depreciation and amortization rates will not be changed absent a Section 205 or 206 filing at the Commission.
Note 2 – Oklahoma depreciation rates were approved in Cause No. PUD 202100055, the rates were made effective on November 1, 2021.

**Worksheet T** - Depreciation Rates

**SOUTHWESTERN ELECTRIC POWER COMPANY**

## CALCULATION WEIGHTED AVERAGE TOTAL COMPANY RATES
## TRANSMISSION, GENERAL AND INTANGIBLE PLANT
## EFFECTIVE AS OF 07/01/2022

| | | LOUISIANA | | | ARKANSAS | | | TEXAS | | | FERC - Wholesale | | | TOTAL COMPANY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | *PLANT ACCT.* | *LA RATES (2)* | *ALLOCATION FACTOR* | *WTD AVG. DEPREC. RATE* | *ARKANSAS RATES (3)* | *ALLOCATION FACTOR* | *WTD AVG. DEPREC. RATE* | *TEXAS RATES (4)* | *ALLOCATION FACTOR* | *WTD AVG. DEPREC. RATE* | *FERC RATES (1)* | *ALLOCATION FACTOR* | *WTD AVG. DEPREC. RATE* | *WTD AVG. DEPREC. RATE* |
| ***TRANSMISSION PLANT*** | | | | | | | | | | | | | | |
| | 350.1 | 1.6600% | 0.356325 | 0.5915% | 1.4800% | 0.201871 | 0.2988% | 1.3300% | 0.441804 | 0.5876% | 1.8200% | 0.00000 | 0.0000% | 1.48% |
| | 352.0 | 1.9100% | 0.356325 | 0.6806% | 1.3600% | 0.201871 | 0.2745% | 1.4600% | 0.441804 | 0.6450% | 1.8200% | 0.00000 | 0.0000% | 1.60% |
| | 353.0 | 2.1000% | 0.356325 | 0.7483% | 1.4200% | 0.201871 | 0.2867% | 1.5400% | 0.441804 | 0.6804% | 1.8900% | 0.00000 | 0.0000% | 1.72% |
| | 353.16 | 2.1000% | 0.356325 | 0.7483% | 1.4700% | 0.201871 | 0.2968% | 1.5400% | 0.441804 | 0.6804% | 1.8900% | 0.00000 | 0.0000% | 1.73% |
| | 354.0 | 2.7200% | 0.356325 | 0.9692% | 1.5900% | 0.201871 | 0.3210% | 1.1400% | 0.441804 | 0.5037% | 2.0000% | 0.00000 | 0.0000% | 1.79% |
| | 355.0 | 3.7200% | 0.356325 | 1.3255% | 3.5200% | 0.201871 | 0.7106% | 3.1800% | 0.441804 | 1.4049% | 2.7500% | 0.00000 | 0.0000% | 3.44% |
| | 356.0 | 2.6300% | 0.3563250.356325 | 0.9371% | 2.1600% | 0.2018710.201871 | 0.4360% | 2.0700% | 0.4418040.441804 | 0.9145% | 2.7500% | 0.00000 | 0.0000% | 2.29% |
| | 356.16 | 2.6300% | | 0.9371% | 1.8000% | | 0.3634% | 2.0700% | | 0.9145% | 2.7500% | 0.00000 | 0.0000% | 2.22% |
| | 357.0 | 1.0100% | 0.356325 | .03599% | 2.0200% | 0.201871 | 0.4078% | 1.9900% | 0.441804 | 0.8792% | 1.0100% | 0.00000 | 0.0000% | 1.65% |
| | 358.0 | 3.7500% | 0.3563250.356325 | 1.3362% | 1.0200% | 0.2018710.201871 | 0.2059% | 1.9900% | 0.4418040.441804 | 0.8792% | 1.8800% | 0.00000 | 0.0000% | 2.42% |
| | 358.16 | 3.7500% | | 1.3362% | 2.0000% | | 0.4037% | 1.9900% | | 0.8792% | 1.8800% | 0.00000 | 0.0000% | 2.62% |
| | 359.0 | 1.6700% | 0.356325 | 0.5951% | 0.0000% | 0.201871 | 0.0000% | 1.3500% | 0.441804 | 0.5964% | 0.7700% | 0.00000 | 0.0000% | 1.19% |
| ***GENERAL PLANT*** | | | | | | | | | | | | | | |
| | 390.0 | 2.9900% | 0.386080 | 1.1544% | 1.5400% | 0.198217 | 0.3053% | 1.86% | 0.368026 | 0.6845% | 1.62% | 0.047677 | 0.0772% | 2.22% |
| | 391.0 | 3.9000% | 0.386080 | 1.5057% | 5.1900% | 0.198217 | 1.0287% | 4.34% | 0.368026 | 1.5972% | 4.32% | 0.047677 | 0.2060% | 4.34% |
| | 391.1 | 20.8400% | 0.386080 | 8.0459% | 31.7400% | 0.198217 | 6.2914% | 16.55% | 0.368026 | 6.0908% | 10.69% | 0.047677 | 0.5097% | 20.94% |
| | 392.0 | 4.6000% | 0.386080 | 1.7760% | 1.8700% | 0.198217 | 0.3707% | 5.41% | 0.368026 | 1.9910% | 1.82% | 0.047677 | 0.0868% | 4.22% |
| | 393.0 | 3.6600% | 0.386080 | 1.4131% | 3.7900% | 0.198217 | 0.7512% | 3.91% | 0.368026 | 1.4390% | 3.94% | 0.047677 | 0.1878% | 3.79% |
| | 394.0 | 4.1400% | 0.386080 | 1.5984% | 3.0200% | 0.198217 | 0.5986% | 3.05% | 0.368026 | 1.1225% | 3.08% | 0.047677 | 0.1468% | 3.47% |
| | 395.0 | 3.8000% | 0.386080 | 1.4671% | 1.8400% | 0.198217 | 0.3647% | 3.72% | 0.368026 | 1.3691% | 1.52% | 0.047677 | 0.0725% | 3.27% |
| | 396.0 | 5.0600% | 0.386080 | 1.9536% | 14.4100% | 0.198217 | 2.8563% | 5.35% | 0.368026 | 1.9689% | 5.53% | 0.047677 | 0.2637% | 7.04% |
| | 397.0 | 7.2300% | 0.386080 | 2.7914% | 5.2800% | 0.198217 | 1.0466% | 5.31% | 0.368026 | 1.9542% | 8.79% | 0.047677 | 0.4191% | 6.21% |
| | 398.0 | 6.3200% | 0.386080 | 2.4400% | 6.1600% | 0.198217 | 1.2210% | 5.51% | 0.368026 | 2.0278% | 6.32% | 0.047677 | 0.3013% | 5.99% |
| | 399.3 | 0.0000% | 0.386080 | 0.0000% | 0.0000% | 0.198217 | 0.0000% | 0.00% | 0.368026 | 0.0000% | 0.00% | 0.047677 | 0.0000% | 0.00% |
| ***INTANGIBLE PLANT*** | | | | | | | | | | | | | | |
| | 303.0 | 12.7500% | 0.374489 | 4.7485% | 12.75000% | 0.203941 | 2.5860% | 12.75% | 0.358180 | 4.5417% | 12.75% | 0.063390 | 1.2678% | 12.75% |

1. FERC effective June 1, 2018 to match the Texas depreciation rates approved in PUC Docket No. 46449 in accordance with the settlement in FERC Docket ER18-195.

2. Louisiana transmission, distribution and general depreciation rates were approved at the LA Public Service Commission session dated November 17, 1999 as per Order U-23029-A.

3. Arkansas depreciation rates were approved in 2022 per Commission Order in Docket 21-070-U. Staff rates were approved and made effective on July 1, 2022.

4. Texas depreciation rates were approved on January 14, 2022 in PUC Docket 51415, the rates were made effective on March 18, 2021.

Note 1 - These depreciation and amortization rates will not be changed absent a Section 205 or 206 filing at the Commission.

## Addendum 4 to Attachment H – Part 2

## THE AEP WEST OPERATING COMPANIES FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Public Service Company of Oklahoma and Southwestern Electric Power Company (collectively "AEP West OpCos" or "AEP") for transmission revenue requirement determinations under the Southwest Power Pool ("SPP") Open Access Transmission Tariff ("SPP Tariff"). AEP shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth in the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Net Revenue Requirement will include revenue requirements and rate calculations for SPP Schedule 1 NITS, Schedule 9 Zonal NITS, and Schedule 11 (Base Plan). The Formula Rate shall become effective for recovery of AEP's Net Revenue Requirement upon the effective date for incorporation into the SPP Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

### Section 1. Annual Projection

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year, AEP shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection shall include the True-Up Adjustment described and defined in Section 2 below, if applicable. Upon determining the Annual Projection, AEP shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format

("PDF") and a data-populated formula rate in native format with all formulae/links intact at a publicly accessible location on SPP's internet website and OASIS, and make a corresponding informational filing at FERC. The date on which the posting occurs shall be that year's "True-Up Publication Date."

b. The posting of the Annual Projection shall:

(i.) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;

(ii.) Include all inputs in sufficient detail to identify the components of AEP's projected Net Revenue Requirement, explanations of the bases for the projections and input data, including workpapers in native software application format, to enable Interested Parties[1] to replicate the calculation of the projected Net Revenue Requirement;

(iii.) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)

A. Identify any Accounting Changes including:

i. The initial implementation of an accounting standard or policy;

ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;

iv. The implementation of new estimation methods or policies that

change prior estimates; and

v. Changes to income tax elections;

B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and

D. Provide, for each item identified pursuant to Section 1.b.iii.A - C of these Protocols, a narrative explanation of the individual impact of such changes on the projected Net Revenue Requirement.

(iv.) Include the following information related to affiliate cost allocation:

A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and

B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.

c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the

next business day.[2] Within five (5) calendar days of the posting, AEP shall provide notice of such posting via the SPP email subscription ("SPP Exploder List"). Interested Parties can subscribe to the SPP Exploder List on the SPP website.

d. Together with the posting of the Annual Projection, AEP shall cause to be posted on the SPP internet website and OASIS, and distributed to the SPP Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the SPP Exploder List no less than seven (7) calendar days prior to the meeting. AEP will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e. To the extent AEP agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on SPP's internet website and OASIS, and e-mailed to the SPP Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under SPP's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.

f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

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1 As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the SPP Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

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2 For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to the next business day.

**Section 2. True-Up Adjustment**

AEP will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEP's projected Net Revenue Requirement collected during the previous Rate Year[3] will be compared to AEP's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEP's Formula Rate and based upon (i) AEP's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEP's calculation of its annual revenue requirement, (iii) the books and records of AEP (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices

applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the SPP Tariff Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates,[4] to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").

b. Interest on any True-Up Adjustment Over/Under Recovery shall be calculated separately for the SPP Zonal NITS Annual Transmission Revenue Requirement (ATRR), Base Plan ATRR (Base Plan Upgrades) and Schedule 1 Scheduling, System Control, and Dispatch Service (Schedule 1). For the Zonal NITS ATRR and Schedule 1 NITS True-Up Adjustments, monthly interest will be calculated on the Over/Under Recovery during each month of the True-Up Year and for the first six months following the True-Up Year (during the Intermediate Year). The Zonal NITS ATRR and Schedule 1 NITS True-Up adjustments, along with the interest calculated during the eighteen (18) months as described above will be invoiced or refunded to customers all at once during the July billing. For the Base Plan ATRR True-Up Adjustment, monthly interest will be calculated on the Over/Under Recovery during each month of the True-Up Year, during each month of the succeeding year ("Intermediate Year") (12 months-True-up Year plus one), and during each month of the year in which the true-up will be billed and collected ("Projection Year") (True-Up Year plus two). The total true-up adjustment and interest for the 36 months described above will be added to (or deducted from) each Base Plan Project on a pro rata basis for determination of the Base Plan ATRR during the 12 months of the Projection Year.

For example, the 2018 True-Up adjustment will be calculated in 2019 and will be billed or credited to customers during 2020. The True-Up adjustments will include interest calculations over a 36-month period, including the 12 months during the True-Up year (2018), the 12 months during the Intermediate Year (2019) and the 12 months during the Projection Year (2019) in which the True-Up Adjustment is remitted to customers.

c. The rates used to calculate interest for True-Up Adjustments will be sourced directly from the FERC website in accordance with 18 C.F.R. § 35.19a. The monthly interest rate used to calculate interest during each month of the Projection Year will be based on an average of the 12 monthly interest rates during the Intermediate Year. Interest True-up adjustments will be compounded quarterly in accordance with 18 C.F.R. § 35.19a.

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[3] If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month, or portion thereof, it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

[4] SPP Tariff Governing Documents include the SPP Tariff, Bylaws, Criteria, and Membership Agreements.

**Section 3. Annual Update**

a. On or before May 25 following each Rate Year, AEP shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and a data-populated formula rate in native format with all formulae/links intact, at a publicly accessible location on SPP's internet website and OASIS, and make a corresponding informational filing at FERC. Within five (5) calendar days of such posting, SPP shall provide notice of such posting via the SPP Exploder List.

b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c. The date on which the posting occurs shall be that year's "Annual Update Publication Date."

d. Together with the posting of the Annual Update, AEP shall cause to be posted on the SPP website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update Meeting"). Notice of the Annual Update Meeting shall be provided via the SPP Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business

days after the Annual Update Publication Date. AEP will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e. The Annual Update posting for the Rate Year:

(i.) Shall provide, via the Formula Rate worksheets and associated workpapers in native software application format, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[5]

(ii.) Shall provide sufficient detail and sufficient explanation to enable Interested Parties to replicate the calculation of the Annual Update results from the FERC Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii.) Shall identify:

A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:

i. The initial implementation of an accounting standard or policy;

ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv. The implementation of new estimation methods or policies that change prior estimates; and

v. Changes to income tax elections;

B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);

C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;

D. For each item identified pursuant to Sections 3.e.iii.A - C of these Protocols, the individual impact (in narrative format) of such changes on the Annual Update.

(iv.) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(v.) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vi.) Shall not seek to modify the Formula Rate and shall not be subject to

challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).

f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); and (ii) the depreciation and/or amortization rates as set forth in Worksheet T included with the Formula Rate template.

g. **Example - Timelines for 2018 Annual Projection and 2019 Annual Update**: On or before October 31, 2017, AEP will determine the projected Net Revenue Requirement for the 2018 Rate Year. AEP will post the Annual Projection for the 2018 Rate Year in accordance with Section 1 above. On or before May 25, 2019, AEP will post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment for the Zonal NITS ATRR and Schedule 1 NITS will be reflected in July 2019 bill. The Base Plan True-Up will be reflected in the Annual Projection of the Base Plan Project Revenue Requirements for the 2020 Rate Year posted on or before October 31, 2019.

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5 It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the

referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

**Section 4. Annual Review Procedures**

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEP or by FERC order) ("Review Period"), to review the calculations and to notify AEP in writing, which may be made electronically, of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Upon receipt of a Preliminary Challenge, AEP will endeavor to send the Preliminary Challenge to SPP within five (5) business days. AEP shall request that SPP post all Preliminary Challenges at a publicly accessible location on SPP's internet website and OASIS, and that a link to the website will be e-mailed to the SPP Exploder List.

b. In the event of a Preliminary Challenge, AEP will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

c. AEP shall respond in writing to a Preliminary Challenge(s) within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEP agrees or disagrees with the challenge. If AEP disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEP shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on SPP's internet website and OASIS, and a link to the website will be e-mailed to the SPP Exploder List. Provided however, that Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party.

d. AEP shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.

e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEP or by FERC order) to serve reasonable information requests on AEP ("Discovery Period").

f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols (as provided above in Section 2.a); (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency

with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate in a final order issued by the Commission or by delegation in the context of prior AEP Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.

g. AEP shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEP shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEP will cause to be posted on the SPP website and OASIS all information requests from Interested Parties and AEP's response(s) to such requests, and a link to the website will be e-mailed to the SPP Exploder List. Provided however, that information and document requests and responses to information and document requests that include material deemed by AEP to be confidential information will

not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party. Voluminous materials that are unduly burdensome to provide by other means may be made available at a physical AEP site.

h. AEP shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEP's Annual Update or Annual Projection.

i. To the extent AEP and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.

k. If a change made by AEP to its accounting policies, practices, or procedures, or the

application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

**Section 5. Resolution of Challenges**

a. Interested Parties shall have up to two-hundred-seventy (270) calendar days following the applicable Publication Date (unless such period is extended with the written consent of AEP or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEP informational filing and shall be served on AEP by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by AEP pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate. This Section 5.a in no way shall affect a party's rights under section 206 of the Federal Power Act as set forth in Section 5.g of these Protocols.

b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:

(i.) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;

(ii.) Explain how the action or inaction violates the filed rate Template or Protocols;

(iii.) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including

A. The extent or effect of an Accounting Change;

B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;

C. The proper application of the Template and procedures in these Protocols;

D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;

E. The prudence of actual costs and expenditures;

F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.

(iv.) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(v.) State whether the issues presented are pending in an existing Commission proceeding in which the filing party is a party, or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi.) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(vii.) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise reasonably attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(viii.) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii)

any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party from raising that issue in a Formal Challenge, provided the Interested Party submitted a Preliminary Challenge during the Review Period with respect to one or more other issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

e. Any response by AEP to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the SPP Exploder List on the date of such filing.

f. In any Formal Challenge proceeding concerning a given year's Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEP shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating, with respect to the issue being challenged, that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEP to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.

h. AEP may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, or (ii) to correct obvious errors or omissions in the Formula Rate such as would result from changes to the FERC Form No. 1. The sole issue in any such limited section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEP any burden with respect to such other aspects of the Formula Rate.

**Section 6. Changes to Annual Updates**

If AEP determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

**Section 7. Joint Meeting of Transmission Owners**

Each year AEP shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members in order to arrange a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

## Addendum 5 To Attachment H Part 1

## Monthly Demand Charge Calculation For Zone 11
## Network Integration Transmission Service

This Addendum to Attachment H sets forth the component of the monthly Demand Charge for SPS' revenue requirement, which is applicable in Zone 11 for Network Customers taking Network Integration Transmission Service ("NITS") under Schedule 9 to this Tariff.

### Charges for Compensation to SPS

The monthly NITS Demand Charge to Network Customers for compensation to SPS shall be determined by multiplying the Network Customer's Monthly Network Load, determined in accordance with the provisions of Section 34.4, expressed in MW, by the rate for NITS then in effect pursuant to the Formula Rate as set out in this Addendum 5 to Attachment H. All capacity quantities used in determining the Network Customer's Monthly Network Load shall be adjusted to the transmission system input level, i.e., shall include the transmission capacity amount associated with any applicable losses.

Rate Formula Template
Utilizing Projected Data
For rates effective
01/01/20yy

Table 1

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | | | Transmission Amount |
| 1 | PROJECTED REVENUE REQUIREMENT | (ln 45 ) | | | $ - |
| 2 | PRIOR YEAR TRUE UP ADJUSTMENT | Input | | | $ - |
| 3 | INTEREST ON PRIOR YEAR TRUE UP ADJUSTMENT - Input | | | | $ - |
| 4 | PRIOR PERIOD CORRECTION TRUE UP ADJUSTMENT - (Worksheet A.1) | | | | $ - |
| 5 | INTEREST ON PRIOR PERIOD CORRECTION TRUE UP ADJUSTMENT - (Worksheet A.1) | | | | $ - |
| 6 | PROJECTED REVENUE REQUIREMENT WITH TRUE UP & PRIOR PERIOD CORRECTION (ln 1 + sum lines 2 through 5) | | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 7 | DIVISOR | | | | |
| 8 | Transmission Network Load | (Worksheet C) | | | - |
| 9 | RATES | | | | |
| 10 | Annual Cost ($/kW/Yr) | (ln 6 / ln 8) | - | | |
| 11 | Network & P-to-P Rate ($/kW/Mo) | (ln 10 / 12) | - | | |
| | | | Peak | | Off-Peak |
| 12 | Weekly P-To-P Rate ($/kW/Wk) | (ln 10 / 52; ln 10 / 52) | - | | - |
| 13 | Daily P-To-P Rate ($/kW/Day) | (ln 12 / 6; ln 12 / 7) | - | Capped at weekly rate | - |
| 14 | Hourly P-To-P Rate ($/MWh) | (ln 13 / 16; ln 13 / 24 both x 1,000) | - | Capped at weekly & daily rate | - |
| 15 | | | | | |
| 15 | METER CHARGE | | | | Charge |
| 16 | Revenue Requirement | (Worksheet N) | | | $0 |
| 17 | Number of Delivery Points | (Worksheet N) | | | 0 |
| 18 | Annual Meter Charge ($ per delivery point) | (ln 16 / ln 17) | | | $0 |
| 19 | Monthly Meter Charge ($ per delivery point) | (ln 18 / 12) | | | $0 |

| | | | |
|---|---|---|---|
| 220 | RADIAL LINE CHARGE (Worksheet A.2) | (Annual Charge) | Monthly Charge |
| 221 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |
| 222 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |
| 223 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |
| 224 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |
| 225 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |
| 226 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |
| 227 | (Worksheet A.2, Ln xx, Col m) | $0 | $0 |

| | | |
|---|---|---|
| 227a | ONE-TIME REFUND (NOTE 1) | Total One-Time Refund |
| 227 | | |
| b | | $ |
| 227c | | $ |
| 227 | | |
| d | | $ |
| 227e | | $ |
| 228 | | $ |

| | | | |
|---|---|---|---|
| 7f | | | |
| 27g | | $ | |
| 27h | | $ | |

27i (Note 1:)

27j One-time refund of the Lubbock Power and Light Hold Harmless Payment in October of 2021.

Rate Formula Template
**Utilizing Projected Data**
For the Billing Period 01/01/yy to 12/31/yy

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

Table 2

****PROJECTED****

| Li | (1) | (2) | (3) | (4) | (5) Transmissio |
|---|---|---|---|---|---|

| n e No. | | | | | n Amount |
|---|---|---|---|---|---|
| 28 | PROJECTED REVENUE REQUIREMENT (w/o incentives) | (ln 141) | | | $ - |
| 29 | REVENUE CREDITS | (Note A) | Total | Allocator | |
| 30 | Account No. 454 | (Worksheet B) | - | 1.000 DA | $ - |
| 31 | Account No. 456.1 | (Worksheet B) | - | 1.000 DA | - |
| 31.1 | Account No. 421.1 (or other applicable acct) | Worksheet B | - | 1.000 DA | |
| *31.2* | *Account No 456.0* | *(Worksheet B)* | - | *1.000 DA* | |
| 32 | Total Revenue Credits | | | | $ - |
| 33 | NET REVENUE REQUIREMENT (w/o incentives) | (ln 28 less ln 32) | | | $ - |

| | | | |
|---|---|---|---|
| 33 | NET PLANT CARRYING CHARGE (w/o incentives) (Note B) | | |
| 35 | Annual Rate | (ln 33 / ln 62 x 100) | 0.00% |
| 36 | Monthly Rate | (ln 35 / 12) | 0.00% |
| 37 | GROSS PLANT CARRYING CHARGE (w/o incentives) (Note B) | | |
| 38 | Annual Rate | (ln 33 / ln 48 x 100) | 0.00% |
| 39 | NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B) | | |
| 40 | Annual Rate | ( (ln 33 - ln 114 ) / ln 62 x 100) | 0.00% |
| 40.1 | BPU Depreciation Rate | (ln 114 / ln 48 ) | 0.00% |
| 41 | NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B) | | |
| 42 | Annual Rate | ( (ln 33 - ln 114 - ln 138 - ln 139) / ln 62 x 100) | 0.00% |
| 43 | ADDITIONAL REVENUE REQUIREMENT (w/incentives) (Note C - Worksheet R) | | $ - |

| | | | |
|---|---|---|---|
| 4 | Projected SPP Base Plan Upgrades Revenue Requirement | (WsP BPU Summary col (c) total and Note I) | $ - |
| 4 a | SPP Base Plan Upgrades Revenue Requirement Prior Year True-up Adjustment (Input) | | $ - |
| 4 b | SPP Base Plan Upgrades Revenue Requirement Interest on Prior Year True-up Adjustment (Input) | | $ - |
| 4 c | SPP Base Plan Upgrades Revenue Requirement (Amount Provided to SPP for Next Billing Period)(sum lines 44, 44a ,and 44b) | | $ - |
| 45 | PROJECTED REVENUE REQUIREMENT | (ln 33 + ln 43 - ln 44c) | $ - |

Rate Formula Template **Utilizing Projected Data** For the Billing Period 01/01/yy to 12/31/yy

Table 3

****PROJECTED****

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

| **RATE BASE** | **Data Sources (See** | **Total** | **Allocator** | **Total Transm** |
|---|---|---|---|---|

| Line No. | CALCULATION (1) | "General Notes") (2) | (3) | (4) | | ission (5) |
|---|---|---|---|---|---|---|
| 46 | GROSS PLANT IN SERVICE | | | | | |
| 47 | Production | WsD.1 , ln 6, col (n) | - | NA | | |
| 48 | Transmission | WsD.1 , ln 11, col (n) | - | TP | 0.00000 | - |
| 49 | Distribution | WsD.1 , ln 16, col (n) | - | NA | | |
| 50 | General Plant | WsD.1 , ln 21, col (n) | - | W/S | 0.00000 | - |
| 51 | Intangible Plant | WsD.1 , ln 25, col (n) | - | W/S | 0.00000 | - |
| 52 | TOTAL GROSS PLANT | (sum lns 47 to 51) | - | | | - |
| 53 | ACCUMULATED DEPRECIATION | | | | | |
| 54 | Production | WsD.1 , ln 41, col (n) | - | NA | | |
| 55 | Transmission | WsD.1 , ln 46, col (n) | - | TP | 0.00000 | - |
| 56 | Distribution | WsD.1 , ln 51, col (n) | - | NA | | |
| 57 | General Plant | WsD.1 , ln 56, col (n) | - | W/S | 0.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 58 | Intangible Plant | WsD.1 , ln 60, col (n) | - | W/S | 0.000 | - |
| 59 | TOTAL ACCUMULATED DEPRECIATION | (sum lns 54 to 58) | - | | | - |
| 60 | NET PLANT IN SERVICE | | | | | |
| 61 | Production | (ln 47 - ln 54) | - | NA | | |
| 62 | Transmission | (ln 48 - ln 55) | - | | | - |
| 63 | Distribution | (ln 49 - ln 56) | - | NA | | |
| 64 | General Plant | (ln 50 - ln 57) | - | | | - |
| 65 | Intangible Plant | (ln 51 - ln 58) | - | | | - |
| 66 | TOTAL NET PLANT IN SERVICE | (sum lns 61 to 65) | - | | | - |
| 67 | ADJUSTMENTS TO RATE BASE | (Note D) | | | | |
| 68 | Account No. 281 (enter negative) | (Worksheet E) | - | NA | | |
| 69 | Account No. 282 (enter negative) | (Worksheet E) | - | DA | | - |
| 70 | Account No. 283 (enter negative) | (Worksheet E) | - | DA | | - |
| 71 | Account No. 190 | (Worksheet E) | - | DA | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 72 | Account No. 255 (enter negative) | | | DA | | - |
| 72.1 | Account No. 254 Excess ADIT | (Worksheet E) | - | DA | | - |
| 72.2 | Account No. 182.3 Deficient ADIT | (Worksheet E) | - | DA | | - |
| 73 | Account No. 107 | WsQ , ln 15, col (c) | - | TP | 0.00000 | - |
| 74 | Net Pre-Funded AFUDC on CWIP included in Rate Base (enter negative) | (Note E) (Worksheet Q, ln 30) | - | TP | 0.00000 | - |
| 75 | Unamortized Balance of Abandoned Incentive Plant | (Note E) (Worksheet E) | - | TP | 0.00000 | - |
| 76 | Unamortized Balance of Extraordinary Property Loss | (Note E) (Worksheet E) | - | TP | 0.00000 | - |
| 77 | TOTAL ADJUSTMENTS | (sum lns 68 to 76) | - | | | - |
| 78 | LAND HELD FOR FUTURE USE (Note F) | WsD , ln 136, col (d) | - | TP | 0.00000 | - |
| 79 | WORKING CAPITAL | | | | | |
| 80 | CWC | (Note G) | | | | - |
| 81 | Materials & Supplies - Transmission | WsF , ln 102, col (d) | - | TP | 0.00000 | - |
| 82 | Materials & Supplies - Other | WsF , ln 103, col (d) | - | GP | 0.00000 | - |
| 83 | Prepayments (Account 165) Plant Related | WsF , ln 15, col (d) | - | GP | 0.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 84 | Prepayments (Account 165) Labor Related | WsF , ln 24, col (d) | - | W/S | 0.00000 | - |
| 85 | Prepayments (Account 165) Transmission Related | WsF , ln 32, col (d) | - | TP | 0.00000 | - |
| 86 | Prepayments (Account 165) Other Not Allocated | WsF , ln 46, col (d) | - | NA | 0.00000 | - |
| 87 | TOTAL WORKING CAPITAL | (sum lns 80 to 86) | - | | | - |
| 87.1 | UNFUNDED RESERVES | | | | | |
| 87.2 | Unfunded Reserves | WsF.1. Total Proj., col 11 | - | DA | | - |
| 88 | BALANCE OF NETWORK CREDITS (enter negative) (Note H) | | - | TP | 0.00000 | - |
| 89 | RATE BASE (sum lns 66, 77, 78, 87, 87.2, 88) | | - | | | - |

****PROJECTED****

Rate Formula Template **Utilizing Projected Data** For the Billing Period 01/01/yy to 12/31/yy

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

Table 4

| Line No. | EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION | Data Sources (See "General Notes") | Total | Allocator | Total Transmission |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |
| | OPERATION & | | | | |
| 90 | MAINTENANCE EXPENSE | | | | |
| 91 | Transmission | WsG , ln 36, col (c) | - | | |
| 92 | Less Total Account 561 | WsG , ln 38, col (c) | - | | |
| 93 | Add Back Account 561.6 | WsG , ln 39, col (c) | - | | |
| 94 | Add Back Account 561.7 | WsG , ln 40, col (c) | - | | |
| 95 | Less Total Account 565 | WsG , ln 41, col (c) | - | | |
| 96 | Transmission O&M Expense Adjustment | WsG , ln 42, col (c) | - | | |
| 97 | Transmission Subtotal | (ln 91 - ln 92 + ln 93 + ln 94 - ln 95 + ln 96 ) | - | TP 0.00000 | - |
| 98 | Administrative and General | WsG , ln 71, col (c) | - | | |
| 99 | Less: Acc. 928, Reg. Com. Exp. | WsG , ln 55, col (c) | - | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 10 | Acct. 930.1, Gen. | WsG , ln 57, | | | | |
| 0 | Advert. Exp. | col (c) | - | | | |
| 10 | Acct. 930.2, | WsG , ln 58, | | | | |
| 1 | Miscellaneous Gen. Exp. | col (c) | - | | | |
| 10 | Acc. 924, Property | WsG , ln 52, | | | | |
| 2 | Insurance | col (c) | - | | | |
| 10 | | (ln 98 - sum ln | | W/ | 0.00 | |
| 3 | Balance of A & G | 99 to ln 102) | - | S | 000 | - |
| 10 | Plus: Acct. 924, Property | | | | 0.00 | |
| 4 | Insurance | (ln 102) | - | GP | 000 | - |
| 10 | Acct. 928 - | (Note K) WsH | | | 1.00 | |
| 5 | Transmission Specific | ln 10, col (d) | - | DA | 000 | - |
| 10 | Acct. 928 - | (Note K) WsH | | | 0.00 | |
| 6 | Transmission Allocated | ln 10, col (e) | - | TP | 000 | - |
| 10 | Acct. 930.2 - | (Note K) WsH | | | 0.00 | |
| 7 | Transmission Specific | ln 21, col (d) | - | TP | 000 | - |
| 10 | Acct. 930.2 - | (Note K) WsH | | W/ | 0.00 | |
| 8 | Transmission Allocated | ln 21, col (e) | - | S | 000 | - |
| 10 | Transmission Safety | (Note K) WsH | | | 0.00 | |
| 9 | and Siting Advertising | ln 30, col (b) | - | TP | 000 | - |
| 11 | | | | | | |
| 0 | | | | | | - |
| 11 | | | | | | |
| 1 | A & G Subtotal | (sum lns 103 to 109) | - | | | - |
| 11 | | (ln 97 + ln 111 | | | | |
| 2 | TOTAL O & M EXPENSE | ) | - | | | - |
| 11 | DEPRECIATION AND | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 3 | AMORTIZATION EXPENSE | | | | | |
| 114 | Transmission | WsI, ln 8, col (e) | - | TP | 0.000 | - |
| 115 | Plus: Pre-Funded AFUDC Amortization | (Note E) (Worksheet Q, ln 31) | - | TP | 0.000 | - |
| 116 | Plus: Recovery of Abandoned Incentive Plant | (Note E) (Worksheet E) | - | TP | 0.000 | - |
| 117 | Plus: Recovery of Extraordinary Property Loss | (Note E) (Worksheet E) | - | TP | 0.000 | - |
| 118 | General | WsI, ln 16, col (e) | - | W/S | 0.000 | - |
| 119 | Intangible | WsI, ln 20, col (e) | - | W/S | 0.000 | - |
| 120 | TOTAL DEPRECIATION AND AMORTIZATION | (sum lns 114 to 119) | - | | | - |
| 121 | TAXES OTHER THAN INCOME | (Note L) | | | | |
| 122 | Labor Related | | | | | |
| 123 | Payroll | (Worksheet J) | - | W/S | 0.000 | - |
| 124 | Plant Related | | | | | |
| 125 | Property | (Worksheet J) | - | GP | 0.000 | - |
| 126 | Franchise & Gross Receipts | (Worksheet J) | - | NA | | - |
| 127 | Other Tax | (Worksheet J) | - | GP | 0.000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 128 | TOTAL OTHER TAXES | (sum lns 123 to 127) | - | | | | - |
| 129 | | | | | | | |
| 130 | INCOME TAXES | (Note M) | | | | | |
| 131 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | 0.00% | | | |
| 132 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | | 0.00% | | | |
| 133 | where WCLTD=(ln 160) and R= (ln 163) | | | | | | |
| 134 | and FIT, SIT & p are as given in Note M. | | | | | | |
| 135 | 1 / (1 - T) = (from ln 130) | | | - | | | |
| 135.1 | Amortized Investment Tax Credit (enter negative) | (Worksheet J) | - | | | | |
| 135.2 | (Excess)/Deficient ADIT Amortization - Plant | (Note P) (Worksheet D.4) | - | | | | |
| 135.3 | (Excess)/Deficient ADIT Amortization - Non-Plant | (Note P) (Worksheet D.4) | - | | | | |
| 136 | Income Tax Calculation | (ln 131 * ln 139) | - | | | | - |
| 137 | ITC adjustment | (ln 134 * ln 135) | - | | NP | 0.00 000 | - |
| 137.1 | (Excess)/Deficient ADIT Amortization - Plant | (ln 134 * ln 135.1) | - | | DA | 0.00 000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 137. | (Excess)/Deficient ADIT Amortization – Non-Plant | (ln 134 * 135.2) | - | DA | 0.00000 | - | |
| 138 | TOTAL INCOME TAXES | (sum lns 136 to 137.2) | - | | | | - |
| 139 | RETURN (Rate Base * Rate of Return) | (ln 89 * ln 179) | - | | | - | |
| 140 | INTEREST ON NETWORK CREDITS | (Note H) | - | TP | 0.00000 | - | |
| 141 | REVENUE REQUIREMENT | (sum lns 112, 120, 128, 138, 139, 140) | - | | | - | |

Rate Formula Template **Utilizing Projected Data**

Table 5

****PROJECTED****

For the Billing Period 01/01/yy to 12/31/yy

**SOUTHWESTERN PUBLIC**

**SERVICE COMPANY**

**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| 142 | TRANSMISSION PLANT INCLUDED IN OATT Transmission Rate (Note N) | | | | |
| 143 | Total transmission plant | (ln 48) | | | - |
| 144 | Less Generator Step-up facilities | WsD.1, ln 153, col (n) | | | - |
| 145 | Less Radial Line facilities | (Worksheet O) | | | - |
| 146 | Transmission plant included in OATT Trans Rate | (ln 143 - ln 144 - ln 145) | | | - |
| 147 | Percent of transmission plant in OATT Trans Rate | (ln 146 / ln 143) | | | **T 0.0 P 00 = 00** |

| | | | | | | |
|---|---|---|---|---|---|---|
| 148 | WAGES & SALARY ALLOCATOR (W/S) | (Note O) | | | | |
| 149 | Production | WsG, ln 77, col (e) | - | NA | | - |
| 150 | Transmission | WsG, ln 78, col (e) | - | TP | 0.000 | - |
| 151 | Regional Market | WsG, ln 79, col (e) | - | NA | | - |
| 152 | Distribution | WsG, ln 80, col (e) | - | NA | | - |
| 153 | Other | WsG, ln 81, col (e) | - | NA | | - |
| 154 | Total | (sum lns 149 to 153) | - | | | - |
| 155 | W/S Allocator | | | | | **W/S = 0.000** |
| 156 | | | | | | |
| 157 | GROSS PLAN ALLOCATOR (GP) | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 157 | Production | WsD.1, ln 6 – WsD.1, ln 5 | - | (ln 47) | - |
| 158 | Transmission | WsD.1, ln 11 – WsD.1, ln 10 | - | (ln 48) | |
| 159 | Distribution | WsD.1, ln 16 – WsD.1, ln 15 | - | (ln 49) | - |
| 160 | General | WsD.1, ln 21 – WsD.1, ln 20 | - | (ln 50) | - |
| 161 | Intangible | WsD.1, ln 25 – WsD.1, ln 24 | - | (ln 51) | - |
| 162 | TOTAL GROSS PLANT (Less Adjustments) | (sum lns 157 to 161) | - | | - |
| 163 | Gross Plant Allocator | | - | **GP=** | **0.000000** |
| 164 | NET PLANT ALLOCATOR (NP) | | | | |
| 165 | Production | ln 157 – (WsD.1, ln 41 – WsD.1, ln 40) | - | (ln 61) | - |
| 166 | Transmission | ln 158 – (WsD.1, ln 46 – WsD.1, ln | - | (ln 62) | - |

| | | | | | |
|---|---|---|---|---|---|
| | | 45) | | | |
| 166 | Distribution | ln 159 – (WsD.1, ln 51 – WsD.1, ln 50) | - | (ln 63) | - |
| 166 | General | ln 160 – (WsD.1, ln 56 – WsD.1, ln 55) | - | (ln 64) | - |
| 166 | Intangible | ln 161 – (WsD.1, ln 60 – WsD.1, ln 59 | - | (ln 65) | - |
| 170 | TOTAL NET PLANT (Less Adjustments) | (sum lns 165 to 169) | - | | - |
| 171 | Net Plant Allocator | | | **NP=** | **0.000000** |
| 172 | RETURN (R) | | | | $ |
| 173 | Long Term Interest | WsK, ln 51, col (d) | | | - |
| 174 | Preferred Dividends | WsK, ln 56, col (d) | | | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 175 | | | | $ | % | Cost | | Weighted |
| 176 | Long Term Debt | WsK, ln 17, col (o) | | - | 0.00% | 0.00 | | 0.000 |
| 177 | Preferred Stock | WsK, ln 5, col (o) | | - | 0.00% | 0.00 | | 0.000 |
| 178 | Common Stock | (WsK, ln 9, col (o) | | - | 0.00% | 0.10 | | 0.000 |
| 179 | Total | sum lns 176 to 178 | | - | | | R | **0.000** |
| | | | Rate Formula Template **Utilizing Projected Data** | | | | | Table 6 |
| | ****PROJECTED**** | | For the Billing Period 01/01/yy to 12/31/yy | | | | | |
| | | | **SOUTHWESTERN** | | | | | |

**PUBLIC SERVICE COMPANY**

**General Notes: a) References to data from FERC Form 1 are indicated as: page#.line#.col#.**

| Note Letter | |
|---|---|
| A | The revenues credited shall include amounts received directly from the SPP for service under this tariff reflecting SPS's integrated transmission facilities. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or other facilities revenues shall be excluded from the definition of transmission facilities under this tariff shall not be included as revenue credits. Revenue from coincident peak loads included in the DIVISOR are also not included as revenue credits unless this revenue is offset by a corresponding expense. See Worksheet B for details. |
| B | The annual and monthly net and gross plant carrying charges on page 2 are to be used to compute the revenue requirement for directly assigned facilities, any Base Plan Upgrades, distribution facilities, |

and radial lines.

C This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet R shows the calculation of the additional revenue requirements for each project receiving incentive rate treatment, as accepted by FERC by a separate docket. These individual additional revenue requirements shall be summed, for the then current year, and included here.

D Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190, and 255 as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106, 109, 133,158 or FASB Interpretation No. 48. Balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M.

The calculation of ADIT for both the true-up and the annual projection will be performed in accordance with IRS regulation Section 1.167(l)-1(h)(6). The Annual True-Up for a given year will use the same methodology that was used to project that year's rates. *(Except for ADIT Proration which is described on Table 21A of the template.)*

E Includes any incentive Construction Work in Progress (CWIP), any related Allowance for Funds Used During Construction (AFUDC), any unamortized balances related to the recovery of abandoned incentive plant costs, any extraordinary property losses and any related depreciation and amortization expense amounts.

Formula amounts for all of the foregoing items will remain at $0 until approved by FERC under a separate docket.

F Includes only transmission related or functionally booked as transmission land held for future use.

G Cash Working Capital will be set at and remain $0 until such time as SPS files and receives

| | |
|---|---|
| | FERC approval for a lead/lag study. |
| H | Equal to the balance of Network Facilities Upgrades Credits, net of accumulated depreciation, due transmission customers that made lump-sum payments towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Excludes interest since interest is added to the revenue requirement on line 140. |
| I | The base plan upgrade revenue requirement will be updated annually in the Annual Update. The BPU revenue requirement will be a projected amount with a true-up to actual adjustment. The updated revenue requirement will be provided to the SPP no later than November 15 for billings effective January 1. |
| J | (Reserved for future use) |
| K | Includes all Regulatory Commission expense itemized in FERC Form 1 at p. 350-351(h). Show in Worksheet H how these expense items are assigned to transmission. FERC Assessment Fees, General Advertising, and Industry Association Dues and Research and Developments costs recorded in 930.2 shall not be assigned to transmission. A & G expenses shall Include specific transmission safety-related advertising and transmission siting advertising costs. The annual PBOP expense amount will be based on the PBOP expense amount reported in SPS's most recent annual actuarial valuation report as of the date of SPS's Annual Update. SPS will provide a copy of that actuarial report as part of its Annual Update and its Annual Informational Filing to the Commission. NERC fees recorded in Acct. 928, Regulatory Commission Expenses, or in Acct. 165, Prepayments, shall be excluded from the formula. |
| L | Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts tax, taxes related to income, retail and non-transmission related taxes are excluded. |
| M | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = |

"the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state, it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 135) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00% | |
| | SIT= (Worksheet L) | 0.00% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.00% | (percent of FIT deductible for state purposes) |

N Removes the dollars of plant booked to transmission plant that is excluded from the Tariff because it does not meet the Tariff's definition of Transmission Facilities, or is booked to transmission (e.g. step-up transformers) that is included in the development of OATT ancillary service rates, or is otherwise not eligible to be recovered under this Tariff.

O Enter dollar amounts. Includes service company labor. Does not include contract labor.

P Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/(1-T)).

****ACTUAL****

Rate Formula Template Utilizing FERC Form 1 Actual Data For the Billing Period 01/01/yy to 12/31/yy

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

Table 7

| Line N | (1) | (2) | (3) | (4) | (5) Transmission Am |
|---|---|---|---|---|---|

| No. | | | | | Amount |
|---|---|---|---|---|---|
| 180 | REVENUE REQUIREMENT (w/o incentives) | (ln 293) | | | $ - |
| 181 | REVENUE CREDITS | (Note A) | Total | Allocator | |
| 182 | Account No. 454 | (Worksheet B) | - | DA | 1.0000 $ - |
| 183 | Account No. 456.1 | (Worksheet B) | - | DA | 1.0000 - |
| 183.1 | Account No. 421.1 (or other applicable acct) | Worksheet B | - | DA | 1.0000 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | *1.000* | |
| *183.2* | *Account No. 456.0* | *(Worksheet B)* | *-* | *DA* | *1.000* | |
| 184 | Total Revenue Credits | | | | | $ - |
| 185 | NET REVENUE REQUIREMENT (w/o incentives) | (ln 180 less ln 184) | | | | $ - |
| 186 | | | | | | |
| 187 | NET PLANT CARRYING CHARGE (w/o incentives) (Note B) | | | | | |
| 188 | Annual Rate | (ln 185 / ln 214 x 100) | | | | 0.00% |
| 189 | Monthly Rate | (ln 187 / 12) | | | | 0.00% |
| 190 | | | | | | |
| 191 | GROSS PLANT CARRYING CHARGE (w/o incentives) (Note B) | | | | | |
| 192 | Annual Rate | (ln 185 / ln 200 x 100) | | | | 0.00% |

| | | | |
|---|---|---|---|
| 191 | NET PLANT CARRYING CHARGE, W/O DEPRECIATION (w/o incentives) (Note B) | | |
| 192 | Annual Rate | ( (ln 185 - ln 266 ) / ln 214 x 100) | 0.00% |
| 192.1 | BPU Depreciation Rate | (ln 266 / ln 200) | 0.00% |
| 193 | NET PLANT CARRYING CHARGE, W/O DEPRECIATION, INCOME TAXES AND RETURN (Note B) | | |
| 194 | Annual Rate | ( (ln 185 - ln 266 - ln 290 - ln 291) / ln 217 x 100) | 0.00% |
| 195 | ADDITIONAL REVENUE REQUIREMENT (w/incentives) (Note C - Worksheet R) | | $ - |
| 196 | LESS SPP Base Plan Upgrades Revenue Requirement | (WsP BPU Summary cold (d) total and | $ - |

| | | | | | |
|---|---|---|---|---|---|
| | | Note I) | | | |
| 197 | ACTUAL REVENUE REQUIREMENT | (ln 185 + ln 195 - ln 196) | | | $ - |
| | ****ACTUAL**** | Rate Formula Template Utilizing FERC Form 1 Actual Data For the Billing Period 01/01/yy to 12/31/yy | | | Table 8 |
| | | **SOUTHWESTERN PUBLIC SERVICE COMPANY** | | | |
| | **RATE BASE CALCULATION** | **Data Sources (See** | **Tot** | **Allo** | **Total Tra** |

| Line No. | (1) | "General Notes") | al | cator | nsmission |
|---|---|---|---|---|---|
| | | | (3) | (4) | (5) |
| 198 | GROSS PLANT IN SERVICE | | | | |
| 199 | Production | WsD.1, ln 82, col (n) | - | NA | 0.000 |
| 200 | Transmission | WsD.1, ln 87, col (n) | - | TP | - |
| 201 | Distribution | WsD.1, ln 92, col (n) | - | NA | 0.000 |
| 202 | General Plant | WsD.1, ln 97, col (n) | - | W/S | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 0.00000 | |
| 203 | Intangible Plant | WsD.1, ln 101, col (n) | - | W/S | 0.00000 | - |
| 204 | TOTAL GROSS PLANT | (sum lns 199 to 203) | - | **GP=** | **0.00000** | - |
| 205 | ACCUMULATED DEPRECIATION | | | | | |
| 206 | Production | WsD.1, ln 116, col (n) | - | NA | | |
| 207 | Transmission | WsD.1, ln 121, col (n) | - | TP | 0.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 208 | Distribution | WsD.1, ln 126, col (n) | - | NA | 0.0000 | |
| 209 | General Plant | WsD.1, ln 131, col (n) | - | W/S | 0.0000 | - |
| 210 | Intangible Plant | WsD.1, ln 135, col (n) | - | W/S | 0.0000 | - |
| 211 | TOTAL ACCUMULATED DEPRECIATION | (sum lns 206 to 210) | - | | | - |
| 212 | | | | | | |
| 212 | NET PLANT IN SERVICE | | | | | |
| 213 | Production | (ln 199 - ln 206) | - | NA | | |
| 214 | Transmission | (ln 200 - ln 207) | - | | | - |
| 2 | Distribution | (ln 200 - | | N | | |

| | | | | | |
|---|---|---|---|---|---|
| 15 | | ln 208) | - | A | |
| 16 | General Plant | (ln 202 - ln 209) | - | | - |
| 17 | Intangible Plant | (ln 203 - ln 210) | - | | - |
| 18 | TOTAL NET PLANT IN SERVICE | (sum lns 213 to 217) | - | | - |
| 19 | ADJUSTMENTS TO RATE BASE | (Note D) | | | |
| 20 | Account No. 281 (enter negative) | (Worksheet E) | - | NA | |
| 21 | Account No. 282 (enter negative) | (Worksheet E) | - | DA | - |
| 22 | Account No. 283 (enter negative) | (Worksheet E) | - | DA | - |
| 23 | Account No. 190 | (Worksheet E) | - | DA | - |
| 24 | Account No. 255 (enter negative) | FF1, p. 266-267, ln 8 (h) | - | DA | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 224.1 | Account No. 254 Excess ADIT | | (Worksheet E) | - | DA | | - |
| 224.2 | Account No. 182.3 Deficient ADIT | | (Worksheet E) | - | DA | 0.000 | - |
| 225 | Account No. 107 | | WsQ , ln 46, col (c) | - | TP | 0.000 | - |
| 226 | Net Pre-Funded AFUDC on CWIP included in Rate Base (enter negative) | | (Note E) (Worksheet Q, ln 61) | - | TP | 0.000 | - |
| 227 | Unamortized Balance of Abandoned Incentive Plant | | (Note E) (Worksheet E) | - | TP | 0.000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 228 | Unamortized Balance of Extraordinary Property Loss | (Note E) (Worksheet E) | - | | | - |
| 229 | TOTAL ADJUSTMENTS | (sum lns 220 to 228) | - | | | - |
| 230 | LAND HELD FOR FUTURE USE (Note F) | WsD, ln 136, col (h) | - | TP | 0.000 | - |
| 231 | | | | | | |
| 232 | WORKING CAPITAL | | | | | |
| 233 | | | | | | |
| 234 | CWC | (Note G) | | | | - |
| 235 | Materials & Supplies - Transmission | WsF, ln 110, col (d) | - | TP | 0.000 | - |
| 236 | Materials & Supplies - Other | WsF, ln 111, col | - | GP | 0.000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 4 | | | (d) | | | 0.000000000 | |
| 2 | | | | | | 0.000 | |
| 3 | | | | | | 0.000 | |
| 5 | Prepayments (Account 165) Plant Related | WsF, ln 60, col (d) | - | GP | 0.000 | - | |
| 2 | | | | | | 0.000 | |
| 3 | | | | | | 0.000 | |
| 6 | Prepayments (Account 165) Labor Related | WsF, ln 70, col (d) | - | W/S | 0.000 | - | |
| 2 | | | | | | 0.000 | |
| 3 | | | | | | 0.000 | |
| 7 | Prepayments (Account 165) Transmission Related | WsF, ln 78, col (d) | - | TP | 0.000 | - | |
| 2 | | | | | | 0.000 | |
| 3 | | WsF, ln | | | | 0.000 | |
| 8 | Prepayments (Account 165) Other Not Allocated | 92, col (d) | - | NA | 0.000 | - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 0 | |
| | | | | | 0 | |
| 239 | TOTAL WORKING CAPITAL | (sum lns 232 to 238) | - | | | - |
| 239.1 | UNFUNDED RESERVES | | | | | |
| 239.2 | Unfunded Reserves | WsF.1, Total Actual, col (11) | - | DA | | - |
| | | | | | 0.0000 | |
| 240 | BALANCE OF NETWORK CREDITS (enter negative) (Note H) | | - | TP | 0 | - |
| 241 | RATE BASE (sum lns 218, 229, 230, 239, 239.2, 240) | | - | | | - |

****ACTUAL****

Rate Formula Template Utilizing Table 9

FERC Form 1 Actual Data For the Billing Period 01/01/yy to 12/31/yy

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

| Line No. | EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION | Data Sources (See "General Notes") | Total | Allocator | Total Transmission |
|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) |

| | | | | | |
|---|---|---|---|---|---|
| 242 | OPERATION & MAINTENANCE EXPENSE | | | | |
| 243 | Transmission | WsG, ln 36, col (e) | - | | |
| 244 | Less Total Account 561 | WsG, ln 38, col (e) | - | | |
| 245 | Add Back Account 561.6 | WsG, ln 39, col (e) | - | | |
| 246 | Add Back Account 561.7 | WsG, ln 40, col (e) | - | | |
| 247 | Less Total Account 565 | WsG, ln 41, col (e) | - | | |
| 248 | Transmission O&M Expense Adjustment | WsG, ln 42, col (e) | - | | |
| 249 | Transmission Subtotal | (ln 243 - ln 244 + ln 245 + ln 246 - ln 247 + ln 248 ) | - | TP 0.0000 | - |
| 250 | Administrative and General | WsG, ln | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 250 | | 71, col (e) WsG, ln 55, col | - | | | |
| 251 | Less: Acc. 928, Reg. Com. Exp. | (e) WsG, ln 57, col | - | | | |
| 252 | Acct. 930.1, Gen. Advert. Exp. | (e) WsG, ln 58, col | - | | | |
| 253 | Acct. 930.2, Miscellaneous Gen. Exp. | (e) WsG, ln 52, col | - | | | |
| 254 | Acc. 924, Property Insurance | (e) | - | | | |
| 255 | Balance of A & G | (ln 250 - sum ln 251 to ln 254) | - | W/S | 0.0000000 | - |
| 256 | Plus: Acct. 924, Property Insurance | (ln 254) | - | GP | 0.0000000 | - |
| 257 | Acct. 928 - Transmission Specific | (Note K) WsH, ln 10, col (h) | - | DA | 1.0 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 0.0000000 | |
| 258 | Acct. 928 - Transmission Allocated | (Note K) WsH, ln 10, col (i) | - | TP | 0.0000000 | - |
| 259 | Acct. 930.2 - Transmission Specific | (Note K) WsH, ln 21, col (h) | - | TP | 0.0000000 | - |
| 260 | Acct. 930.2 - Transmission Allocated | (Note K) WsH, ln 21, col (i) | - | W/S | 0.0000000 | - |
| 261 | Transmission Safety and Siting Advertising | (Note K) WsH, ln 30, col (f) | - | TP | 0.0000000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 0 | |
| 262 | | | | | | - |
| 263 | A & G Subtotal | (sum lns 255 to 261) | - | | | - |
| 264 | TOTAL O & M EXPENSE | (ln 249 + ln 263 ) | - | | | - |
| 265 | DEPRECIATION AND AMORTIZATION EXPENSE | | | | | |
| 266 | Transmission | Wsl, ln 36, col (e) | - | TP | 0.00000000 | - |
| 267 | Plus: Pre-Funded AFUDC Amortization | (Note E) (Worksheet Q, ln 62) | - | TP | 0.00000000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 268 | Plus: Recovery of Abandoned Incentive Plant | (Note E) (Worksheet E) | - | TP | 0.0000 | - |
| 269 | Plus: Recovery of Extraordinary Property Loss | (Note E) (Worksheet E) | - | TP | 0.0000 | - |
| 270 | General | WsI, ln 44, col (e) | - | W/S | 0.0000 | - |
| 271 | Intangible | WsI, ln 48, col (e) | - | W/S | 0.0000 | - |
| 272 | TOTAL DEPRECIATION AND AMORTIZATION | (sum lns 266 to 271) | - | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 273 | TAXES OTHER THAN INCOME | (Note L) | | | | |
| 274 | Labor Related | | | | | |
| 275 | Payroll | (Worksheet J) | - | W/S | 0.0000 | - |
| 276 | Plant Related | | | | | |
| 277 | Property | (Worksheet J) | - | GP | 0.0000 | - |
| 278 | Franchise & Gross Receipts | (Worksheet J) | - | NA | | - |
| 279 | Other Tax | (Worksheet J) | - | GP | 0.0000 | - |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 0 | |
| | | | | 0 | |
| | | | | 0 | |
| 280 | TOTAL OTHER TAXES | (sum lns 275 to 279) | - | | - |
| 281 | | | | | |
| 282 | | | | | |
| 283 | INCOME TAXES | (Note M) | | | |
| 284 | | | | | |
| 285 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00 % | | |
| 286 | | | | | |
| 287 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.00 % | | |
| 288 | | | | | |
| 289 | where WCLTD=(ln 296) and R= (ln 299) | | | | |
| 290 | | | | | |
| 291 | and FIT, SIT & p are as given in Note M. | | | | |
| 292 | | | | | |
| 293 | 1 / (1 - T) = (from ln 328) | | - | | |
| 294 | | | | | |
| 295 | Amortized Investment Tax Credit (enter negative) | (Worksheet J) | - | | |
| 296 | | (Note P) | | | |
| 297 | (Excess)/Deficient ADIT Amortization - Plant | Worksheet D.4) | - | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 287.2 | (Excess)/Deficient ADIT Amortization - Non-Plant | (Note P) Worksheet D.4) | - | | | | |
| 288 | Income Tax Calculation | (ln 283 * ln 291) | - | | | | - |
| 289 | ITC adjustment | (ln 286 * ln 287) | - | | 0.0000 NP | 0 | - |
| 289.1 | (Excess)/Deficient ADIT Amortization - Plant | (ln 286 * ln 287.1) | - | | 0.0000 DA | 0 | - |
| 289.2 | (Excess)/Deficient ADIT Amortization - Non-Plant | (ln 286 * ln 287.2) | - | | 0.0000 DA | 0 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 0 | |
| 290 | TOTAL INCOME TAXES | (sum lns 288 to 289.2) | - | | | - |
| 291 | RETURN (Rate Base * Rate of Return) | (ln 288 * ln 331) | - | | | - |
| 292 | INTEREST ON NETWORK CREDITS | (Note H) | - | TP | 0.0000 | - |
| 293 | REVENUE REQUIREMENT (sum lns 264, 272, 280, 290, 291, 292) | | - | | | - |

Rate Formula Template Utilizing FERC Form 1 Actual Data For the Billing

Table 10

****ACTUAL****

Period 01/01/yy to 12/31/yy

**SOUTHWESTERN PUBLIC SERVICE COMPANY**

**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| 294 | TRANSMISSION PLANT INCLUDED IN OATT Transmission Rate (Note N) | | | | |
| 295 | Total transmission plant | (ln 200) WsD.1, ln 155, col (n) (Workshe et O) | | | - |
| 296 | Less Generator Step-up facilities | | | | - |
| 297 | Less Radial Line facilities | | | | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 297.a | Plus Radial Line facilities true-up | (Worksheet M) | | | | | - |
| 298 | Transmission plant included in OATT Trans Rate | (ln 295 - ln 296 - ln 297 - ln 297.a) | | | | | - |
| 299 | Percent of transmission plant in OATT Trans Rate | (ln 298 / ln 295) | | | | TP = | 0.0000 |
| 300 | WAGES & SALARY ALLOCATOR (W/S) | (Note O) | | | | | |
| 301 | Production | WsG, ln 77, col (i) | - | NA | 0.0000 | | - |
| 302 | Transmission | WsG, ln 78, col (i) | - | TP | 0.0000 | | - |
| 303 | Regional Market | WsG, ln 79, col (i) | - | NA | | | - |

| | | | | | |
|---|---|---|---|---|---|
| 304 | Distribution | WsG, ln 80, col (i) | - | NA | - |
| 305 | Other | WsG, ln 81, col (i) | - | NA | - |
| 306 | Total | (sum lns 285 to 289) | - | | - |
| 307 | W/S Allocator | | | | **W/S = 0.0000** |
| 308 | GROSS PLAN ALLOCATOR (GP) | - | | | - |
| 309 | Production | WsD.1, ln 82 – WsD.1, ln – 81 | | (ln 199) | -- |
| 310 | Transmission | WsD.1, ln 87 – WsD.1, ln – 86 | | (ln 200) | - |

| | | | | | |
|---|---|---|---|---|---|
| | | | | ) | |
| | | | | (l | |
| | | | | n | |
| 3 | | | WsD.1, ln | 2 | |
| 1 | | | 92 – | 0 | |
| 1 | | | WsD.1, ln | 1 | |
| 1 | Distribution | | – 91 | ) | - |
| | | | | (l | |
| | | | | n | |
| | | | WsD.1, ln | 2 | |
| 3 | | | 97 – | 0 | |
| 1 | | | WsD.1, ln | 2 | |
| 2 | General | | – 96 | ) | - |
| | | | | (l | |
| | | | | n | |
| | | | WsD.1, ln | 2 | |
| 3 | | | 101 – | 0 | |
| 1 | | | WsD.1, ln | 3 | |
| 3 | Intangible | | – 100 | ) | - |
| 3 | | | | | |
| 1 | TOTAL GROSS PLANT (Less(sum lns 309 to 313) | | | | |
| 4 | Adjustments) | - | | | |
| 3 | | | | **G** | **0.0** |
| 1 | | | | **P** | **000** |
| 5 | Gross Plant Allocator | | | **=** | **0** |
| 3 | | | | | |
| 1 | | | | | |
| 6 | NET PLANT ALLOCATOR (NP) | | | | |
| 3 | | | ln 309 – | (l | |
| 1 | | | (WsD.1, | n | |
| 7 | Production | | ln 116 – | 2 | |

| | | | |
|---|---|---|---|
| | | WsD.1, ln 115) | 13) |
| 318 | Transmission | ln 310 – (WsD.1, ln 121 – WsD.1, ln 120) | (ln 214) |
| 319 | Distribution | ln 311 – (WsD.1, ln 126 – WsD.1, ln 125) | (ln 215) |
| 320 | General | ln 312 – (WsD.1, ln 131 – WsD.1, ln 130) | (ln 216) |
| 321 | Intangible | ln 313 – (WsD.1, ln 135 – WsD.1, ln 134) | (ln 217) |
| 322 | | | |
| 322 | TOTAL NET PLANT (Less (sum Lns 317 to 321) Adjustments) | | |
| 323 | Net Plant Allocator | | **N 0.0** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2 | | | | | | | **P 000** |
| 3 | | | | | | | **= 0** |
| 3 | | | | | | | |
| 2 | | | | | | | |
| 4 | RETURN (R) | | | | | | $ |
| 3 | | | | | | | |
| 2 | | | | | | | |
| 5 | Long Term Interest | WsK, ln 51, col (h) | | | | | - |
| 3 | | | | | | | |
| 2 | | | | | | | |
| 6 | Preferred Dividends | WsK, ln 56, col (h) | | | | | - |
| 3 | | | | | | | |
| 2 | | | | | | Cost | Weighted |
| 7 | | | | $ | % | | |
| | | | | | 0.000% | 0.00 | |
| 3 | | WsK, ln | | | 0.00 | 0.00 | |
| 2 | | 36, col | | | 0.00 | 0.00 | 0.0000 |
| 8 | Long Term Debt | (o) | - | | % | 0.00 | |
| | | | | | 0.000% | 0.00 | |
| 3 | | WsK, ln | | | 0.00 | 0.00 | |
| 2 | | 23, col | | | 0.00 | 0.00 | 0.0000 |
| 9 | Preferred Stock | (o) | - | | % | 0.00 | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 330 | Common Stock | WsK, ln 27, col (o) | | - | 0.00% | 0.1050 | 0.0000 |
| 331 | Total | (sum lns 328 to 300) | | - | | | **R 0.0000** |
| | | | Rate Formula Template Utilizing FERC Form 1 Actual Data For the Billing Period 01/01/yy to 12/31/yy | | | | Table 11 |
| | ****ACTUAL**** | | **SOUTHWESTERN PUBLIC SERVICE COMPANY** | | | | |

**General Notes: a) References to data from FERC Form 1 are indicated as: page#.line#.col#.**

| Note Letter | |
|---|---|
| A | The revenues credited shall include amounts received directly from the SPP for service under this tariff reflecting SPS's integrated transmission facilities. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or other facilities revenues shall be excluded from the definition of transmission facilities under this tariff shall not be included as revenue credits. Revenue from coincident peak loads included in the DIVISOR are also not included as revenue credits unless this revenue is offset by a corresponding expense. See Worksheet B for details. |
| B | The annual and monthly net and gross plant carrying charges on page 7 are to be used to compute the revenue requirement for directly assigned facilities, any Base Plan Upgrades, distribution facilities, and radial lines. This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. |
| C | Worksheet R shows the calculation of the additional revenue requirements for each project receiving incentive rate treatment, as accepted by FERC by a separate docket. These individual |

additional revenue requirements shall be summed, for the then current year, and included here.

D Reflects the transmission related portion of balances in Accounts 281, 282, 283, 190, and 255 as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106, 109, 133,158 or FASB Interpretation No. 48. Balance of Account 255 is reduced by prior flow throughs and completely excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note M.

The calculation of ADIT for both the true-up and the annual projection will be performed in accordance with IRS regulation Section 1.167(l)-1(h)(6). The Annual True-Up for a given year will use the same methodology that was used to project that year's rates. *(Except for ADIT Proration which is described on Table 21A of the template.)*

E Includes any incentive Construction Work in Progress (CWIP), any related Allowance for Funds Used During Construction (AFUDC), any unamortized balances related to the recovery of abandoned incentive plant costs, any extraordinary property losses and any related depreciation and amortization expense amounts.

Formula amounts for all of the foregoing items will remain at $0 until approved by FERC under a separate docket.

F Includes only transmission related or functionally booked as transmission land held for future use.

G Cash Working Capital will be set at and remain $0 until such time as SPS files and receives FERC approval for a lead/lag study.

H Equal to the balance of Network Facilities Upgrades Credits, net of accumulated depreciation, due transmission customers that made lump-sum payments towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Excludes interest since interest is added to the revenue requirement on line 276.

I The base plan upgrade revenue requirement will be updated annually in the Annual Update. The BPU revenue requirement will be a projected amount with a true-up to actual adjustment. The updated revenue requirement will be provided to the SPP no later than November 15 for billings effective

January 1.

J (Reserved for future use)

K Includes all Regulatory Commission expense itemized in FERC Form 1 at 350-351(h). Show in Worksheet H how these expense items are assigned to transmission.
FERC Assessment Fees, General Advertising, and Industry Association Dues and Research and Developments costs recorded in 930.2 shall not be assigned
to transmission. A & G expenses shall Include specific transmission safety-related advertising and transmission siting advertising costs.
The annual PBOP expense amount will be based on the PBOP expense amount reported in SPS's most recent annual actuarial valuation report as of the date of SPS's Annual Update. SPS will provide a copy of that actuarial report as part of its Annual Update and its Annual Informational Filing to the Commission.
NERC fees recorded in Acct. 928, Regulatory Commission Expenses, or in Acct. 165, Prepayments, shall be excluded from the formula.
Includes only FICA, unemployment, highway, property and other assessments charged in the current year.

L Gross receipts tax, taxes related to income, retail and non-transmission related taxes are excluded.

M The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =
"the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state, it must attach a
work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that
elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce
rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)
(ln 271) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

Inputs Required: FIT = 0.00 %

| | | | |
|---|---|---|---|
| | SIT= (Worksheet L) | 0.00 % | (State Income Tax Rate or Composite SIT) |
| | p = | 0.00 % | (percent of FIT deductible for state purposes) |

| | |
|---|---|
| N | Removes the dollars of plant booked to transmission plant that is excluded from the Tariff because it does not meet the Tariff's definition of Transmission Facilities, or is booked to transmission (e.g. step-up transformers) that is included in the development of OATT ancillary service rates, or is otherwise not eligible to be recovered under this Tariff. |
| O | Enter dollar amounts. Includes service company labor. Does not include contract labor. |
| P | Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/(1-T)). Amoritizations of excess/deficient deferred income taxes resulting from the enactment of the Tax Reform and Jobs Act will be included beginning January 1, 2018 (with the 2018 True-Up) |

Table 12

Schedule 1 Rate Formula Template
Southwestern Public Service Company

A. Schedule 1 - Projected ARR for Billing Period 01/01/20yy to 12/31/20yy

| | | | | |
|---|---|---|---|---|
| 1 | Total Load Dispatch and Scheduling (Account 561) | WsG OM - WS | $0 | |
| 2 | Less: Load Dispatch - Scheduling, System Control and Dispatch Services | WsG - Acct 561.4 | $0 | |
| 3 | Less: Transmission Service Studies | WsG - Acct 561.6 | $0 | |
| 4 | Less: Generation Interconnection Studies | WsG - Acct 561.7 | $0 | |
| 5 | Less: Load Dispatch - Reliability, Planning & Standards Development Services | WsG - Acct 561.8 | $0 | |
| 6 | Total 561 Costs for Projected Schedule 1 ARR | (ln 1 - Sum of ln 2 through 5) | $0 | |
| 7 | Less: Schedule 1 Point to Point Projected Revenues | WsB Rev Credits | $0 | |
| 8 | Projected Schedule 1 ARR Without True-up Adjustments | (ln 6 - ln 7) | $0 | |
| 9 | Prior Year True-up Adjustment | Input from Prior Year True-up | | |
| 10 | Interest On Prior Year True-up Adjustment | Input from Prior Year | | |
| 11 | Projected Schedule 1 ARR | ( ln 8 + ln 9 + ln 10) | $0 | |

B. Schedule 1 Rate Calculations

| | | | | |
|---|---|---|---|---|
| 12 | Projected Average 12-Mo. Demand | WsC Divisor | 0 | kW |
| 13 | Monthly Point to Point Rate in $/kW - Month | ((ln 11 /ln 12) /12) | $0.000 | kW |
| 14 | Weekly Point to Point Rate in $/kW - Weekly | ((ln 11 /ln 12) /52) | $0.000 | kW |
| 15 | Daily Point to Point Rate in $/kW - Day | ((ln 11 /ln 12) /365) | $0.000 | kW |
| 16 | Hourly Point to Point Rate in $/mW - Hourly | ((ln 11 /ln 12) /8760 * 1000) | $0.000 | mW |

1 ****SECTIONS C AND D USED ONLY FOR TRUE-UP, ANNUAL UPDATE WILL**

7 **BE BLANK****

C. Schedule 1 - Actual ARR for the Billing Period 01/01/20yy to 12/31/20yy

| | | | | |
|---|---|---|---|---|
| 18 | Total Load Dispatch and Scheduling (Account 561) | WsG OM - WS | $0 | |
| 19 | Less: Load Dispatch - Scheduling, System Control and Dispatch Services | WsG - Acct 561.4 | $0 | |
| 20 | Less: Transmission Service Studies | WsG - Acct 561.6 | $0 | |
| 21 | Less: Generation Interconnection Studies | WsG - Acct 561.7 | $0 | |
| 22 | Less: Load Dispatch - Reliability, Planning & Standards Development Services | WsG - Acct 561.8 | $0 | |
| 23 | Total 561 Costs for Actual Schedule 1 ARR | (ln 18 - Sum of ln 19 through 22) | $0 | |
| 24 | Less: Schedule 1 Point to Point Actual Revenues Billed | WsB Rev Credits | $0 | |
| 25 | Actual Schedule 1 ARR | (ln 23 - ln 24) | $0 | |

True Up from Billing Period to be Included in Projected Schedule 1 ARR:

| | | | | |
|---|---|---|---|---|
| 26 | Revenue Requirement True-Up: | | | |
| 27 | Actual Schedule 1 ARR calculated above | (ln 25) | $0 | |
| 28 | Projected Schedule 1 ARR calculated above | (ln 8) | $0 | |
| 29 | ARR True-up Amount (Over recovery = credit; under recovery = debit) | (ln 27 - ln 28) | $0 | |
| 30 | Volume True-Up: | | | |
| 31 | Actual Divisor Load for the Billing Period | WsC Divisor | 0 | kW |

| | | | | |
|---|---|---|---|---|
| 132 | Projected Divisor Load for the Billing Period | (ln 12) | 0 | kW |
| 133 | Volume Adjustment | (ln 32 - ln 31) | 0 | |
| 134 | Projected Zonal Rate per kw-yr for the Billing Period | (ln 28 / ln 32) | $0.0000 | |
| 135 | Actual Zonal Rate per kw-yr for the Billing Period | (ln 27 / ln 31) | $0.0000 | |
| 136 | Volume Revenue Adjustment (Over recovery = credit; under recovery = debit) | (ln 33 * ln 34) | $0 | |
| 137 | Net Schedule 1 True-up Adjustment (Over Recovery = credit; under recovery = debit) | (ln 29 + ln 36) | $0 | |
| 138 | Interest True-up Amount | (ln 68) | $0 | |

D. Interest Calculation:

| | Months | FERC Quarterly Interest Rates | Monthly Interest Rate |
|---|---|---|---|
| 142 | January - Projected Yr 20yy | 0.00% | 0.0000 |
| 143 | February | 0.00% | 0.0000 |
| 144 | March | 0.00% | 0.0000 |
| 145 | April | 0.00% | 0.0000 |

| | | | |
|---|---|---|---|
| 46 | May | 0.00% | 0.0000 |
| 47 | June | 0.00% | 0.0000 |
| 48 | July | 0.00% | 0.0000 |
| 49 | August | 0.00% | 0.0000 |
| 50 | September | 0.00% | 0.0000 |
| 51 | October | 0.00% | 0.0000 |
| 52 | November | 0.00% | 0.0000 |
| 53 | December | 0.00% | 0.0000 |
| 54 | January - True-up Yr 20yy | 0.00% | 0.0000 |
| 55 | February | 0.00% | 0.0000 |
| 56 | March | 0.00% | 0.0000 |
| 57 | April | 0.00% | 0.0000 |
| 58 | May | 0.00% | 0.0000 |
| 59 | June | 0.00% | 0.0000 |
| 60 | July | 0.00% | 0.0000 |
| 61 | August | 0.00% | 0.0000 |
| 62 | September | 0.00% | 0.0000 |
| 63 | Average Monthly Interest Rate | | 0.0000 |

| | | | |
|---|---|---|---|
| 64 | Over/Under Recovery Amount | (ln 37) | $0 |
| 65 | Average Monthly Interest Rate | (ln 63) | 0.0000 |
| 66 | Monthly Interest Recovery Amount | (ln 64 * ln 65) | $0 |
| 67 | Number of Months for Interest Recovery Amount | | 24 |
| 68 | Interest Recovery Amount | (ln 67 * ln 66) | $0 |

69 Note:

70 The interest is calculated using the interest rate posted on the FERC website.

71 See link to website below.

72 http://www.ferc.gov/legal/acct-matts/interest-rates.asp#skipnavsub

**Southwestern Public Service Company** **Worksheet A**
**Worksheet A - Projected Billing Year True-Up Adjustment and Interest Calculation** **Table 13**

Line No

| | | | | | |
|---|---|---|---|---|---|
| . | | | | | |
| 1 | I. Revenue Requirement True-up: | | | | |
| 2 | Projected Revenue Requirement for the Prior Rate Year - (ARR Projected Data ln 33+ ln 43) | $ | - | | |
| 3 | Actual Revenue Requirement for the True-Up Year - (ARR Actual Data ln 169 + ln 179) | | | | |
| 4 | Revenue Requirement True-Up Year ( ln 3 - ln 2) | $ | - | | |
| | II. SPP Base Plan Upgrades Revenue | | | | |
| 5 | Requirement True-up: | | | | |
| 6 | Projected BPU Revenue Requirement for the Prior Rate Year (ARR – Projected Data ln 44 col (5)) | | $ - | | |
| 7 | Actual BPU Revenue Requirement for the True-up Rate Year (ARR – Actual Data ln 180 col (5)) | | $ - | | |
| 8 | SPP BPU True-up (ln 7 – ln 6) | | $ - | | |
| 9 | Total Revenue Requirement True-up Adjustment (ln 4 – ln 8) | | | $0.0000 | |
| 10 | III. Volume True-up: | | | | |
| 11 | Projected Divisor Load for the Prior Rate Year, - (WsC Divisor ln 14 * 1,000) | | | 0 | kw |
| 12 | Actual Divisor Load for the Prior Rate Year, - (WsC Divisor ln 28 * 1,000) | | | 0 | kw |
| 13 | Volume Adjustment (ln 11 – ln 12) | 0 | | | kw |
| 14 | Projected Zonal Rate per kw-yr for the Prior Rate Year - 20yy ( (ln 2 - ln 6 ) / ln 11) | $0.0000 | | | |

| | | | | |
|---|---|---|---|---|
| 115 | Actual Zonal Rate per kw-yr for the Prior Rate Year - 20yy ((ln 3 / line 7) / ln 12) | | | $0.0000 |
| 116 | Volume Revenue Adjustment (ln 13 x ln 14) | | | $0 |
| 117 | Net True-up Adjustment (ln 9 + ln 16) | | | $0 |
| 118 | III. Interest Calculation: | | | |
| 119 | | Projected Billing Year FERC Quarterly Interest Rates | Monthly Interest Rate | |
| 124 | January - Projected Yr 20yy | 0.00% | 0.0000 | |
| 125 | February | 0.00% | 0.0000 | |
| 126 | March | 0.00% | 0.0000 | |
| 127 | April | 0.00% | 0.0000 | |
| 128 | May | 0.00% | 0.0000 | |
| 129 | June | 0.00% | 0.0000 | |
| 130 | July | 0.00% | 0.0000 | |
| 131 | August | 0.00% | 0.0000 | |
| 132 | September | 0.00% | 0.0000 | |
| 133 | October | 0.00% | 0.0000 | |

| | | | | | |
|---|---|---|---|---|---|
| 33 | | | | | |
| 34 | November | | 0.00% | 0.0000 | |
| 35 | December | | 0.00% | 0.0000 | |
| 36 | January - True-up Yr 20yy | | 0.00% | 0.0000 | |
| 37 | February | | 0.00% | 0.0000 | |
| 38 | March | | 0.00% | 0.0000 | |
| 39 | April | | 0.00% | 0.0000 | |
| 40 | May | | 0.00% | 0.0000 | |
| 41 | June | | 0.00% | 0.0000 | |
| 42 | July | | 0.00% | 0.0000 | |
| 43 | August | 0.00% | | 0.0000 | |
| 44 | September | 0.00% | | 0.0000 | |
| 45 | Average Monthly Interest Rate | | | 0.0000 | |

| | | Annual Revenue Requirement (ARR) True-up | SPP BPU Revenue Requirement True-up |
|---|---|---|---|
| 46 | Over/Under Recovery Amount (ARR sum of lines 4 and 16; BPU line 8 amount) | **$0** | **$0** |
| 47 | Average Monthly Interest Rate (ln 45) | 0.0000 | 0.0000 |

| | | | | |
|---|---|---|---|---|
| 48 | Monthly Interest Recovery Amount (ln 46 x ln 47) | $0 | $0 | |
| 49 | Number of Months for Interest Recovery Amount | 24 | 24 | |
| 50 | Interest Recovery Amount (ln 49 x ln 48) | $0 | $0 | |
| 51 | Prior Year True-up Adjustment (ln 46) | **(Input to Annual Update)** $0 | | $0 |
| 52 | Interest on Prior Year True-up Adjustment (ln 50) | **(Input to Annual Update)** $0 | | $0 |
| 53 | Note: | | | |
| 54 | The interest is calculated using the interest rate posted on the FERC website. | | | |
| 55 | See link to website below. | | | |
| 56 | http://www.ferc.gov/legal/acct-matts/interest-rates.asp#skipnavsub | | | |

**Southwestern Public Service Company** **Worksheet A.1**
**Worksheet A.1 - Prior Period Correction True-Up with Interest Calculation** **Table 14**

| Line No. | |
|---|---|
| 1 | Explanation of Prior Period Correction: |
| 2 | |
| 3 | |

| | | | |
|---|---|---|---|
| 4 | Rate Year Prior Period Correction Applicable to (input year) | | |
| 5 | Effective True-up Year for Rate Year Prior Period Correction (line 4 year + 2 years) | 0 | |
| 6 | Year Prior Period Correction Settled/Agreed (input) | | |
| 7 | Rate Year Prior Period Correction Will be Included in ATRR (line 6 year + 1 year) | 0 | |
| 8 | Number of Months Prior Period Correction Subject to Interest ((ln 7 year - ln 4 year) * 12) | 0 | |
| 9 | I. Revenue Requirement True-up: | | |
| 10 | Revenue Requirement for Prior Period Correction True-up Year without Prior Period Correction (input) | | |
| 11 | Revised Revenue Requirement for True-up Year with Prior Period Correction (input) | | |
| 12 | Revenue Requirement True-up Adjustment (Over Recovery is a Credit, Under Recovery is a Debit) (ln 11 - ln 10) | $0 | |
| 13 | II. Volume True-up: | | |
| 14 | Divisor for Prior Period Correction True-up Year without Prior Period Correction (input) | | kw |
| 15 | Divisor for True-up Year with Prior Period Correction (input) | | kw |
| 16 | Volume Adjustment (line 14 - line 15) | 0 | kw |
| 17 | Actual Zonal Rate (line 10 / line 14) | $0.0000 | |
| 18 | Revised Zonal Rate (line 11 / line 15) | $0.0000 | |
| 19 | Volume Revenue Adjustment (Over Recovery is a Credit, Under Recovery is a Debit) (line 16 x line 17) | $0 | |
| 20 | Net Prior Period Correction True-up Adjustment (Over Recovery is a Credit, Under Recovery is a Debit) (line 12 + line 19) | $0 | |
| 21 | III. Interest Calculation: | | |

| | | FERC Quarterly | Number of Days | Monthly Interest | |
|---|---|---|---|---|---|
| | Month/Year | Interest Rates | in Month | Rate | |
| 25 | | | | 0.0000 | |
| 26 | | | | 0.0000 | |
| 27 | | | | 0.0000 | |
| 28 | | | | 0.0000 | |
| 29 | | | | 0.0000 | |
| 30 | | | | 0.0000 | |
| 31 | | | | 0.0000 | |
| 32 | | | | 0.0000 | |
| 33 | | | | 0.0000 | |
| 34 | | | | 0.0000 | |
| 35 | | | | 0.0000 | |
| 36 | | | | 0.0000 | |
| 37 | | | | 0.0000 | |
| 38 | | | | 0.0000 | |
| 39 | | | | 0.0000 | |
| 40 | | | | 0.0000 | |
| 41 | | | | 0.0000 | |
| 42 | | | | 0.0000 | |
| 43 | | | | 0.0000 | |
| 44 | | | | 0.0000 | |
| 45 | | | | 0.0000 | |
| 46 | Average Monthly Interest Rate | | | 0.0000 | |
| 47 | Over/Under Recovery Amount (ln 20 amount) | | | | $0 |
| | | | | | 0.000 |
| 48 | Average Monthly Interest Rate (ln 46) | | | | 0 |
| 49 | Monthly Interest Recovery Amount (ln 47 x ln 48) | | | | $0 |
| 50 | Number of Months for Interest Recovery Amount (from line 8) | | | | 0 |
| 51 | Interest Recovery Amount (ln 50 times ln 49) | | | | $0 |

| | | | |
|---|---|---|---|
| 52 | Prior Period Correction Adjustment (ln 20) | **$0** | **(Input to Annual Update)** |
| 53 | Interest on Prior Period Correction Adjustment (ln 51) | **$0** | **(Input to Annual Update)** |

54 Note:
55 The interest is calculated using the interest rate posted on the FERC website.
56 See link to website below.
57 http://www.ferc.gov/legal/acct-matts/interest-rates.asp#skipnavsub

**Southwestern Public Service Company** **Worksheet A.2**
**Worksheet A.2 - Radial Line True-Up with Interest Calculation** **Table 14.1**

| Line No. | | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|
| 1 | I. Radial Line Interest on True-Up Calculation | | | | | | |
| 2 | | | | | | | |
| 3 | | Revenue | Month Radial | Months | Average | | Interest |
| 4 | | Requirement | Line | Subject to | Interest | Monthly | Recovery |
| 5 | | True-Up | Changed | Interest | Rate | Interest (Col a * Col d) | Amount |
| 6 | | (Worksheet M) | (Input) | (12 - Col b) | (Col i) | | (Col c * Col e) |
| 7 | | | | | 0.0000 | $0 | $0 |
| 8 | | | | | 0.0000 | $0 | $0 |
| 9 | | | | | 0.0000 | $0 | $0 |
| 10 | | | | | 0.0000 | $0 | $0 |
| 11 | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 12 | | | | | | | | | |
| 13 | Total | $0 | | | | | | | $0 |
| 14 | | | | | | | | | |
| 15 | II. Interest Rates: | | | | | | | | |
| 16 | | (g) | (h) | (i) | | | | | |
| 17 | | FERC | Number | Monthly | | | | | |
| 18 | | Quarterly | of Days | Interest | | | | | |
| 19 | Month/Year | Interest Rates | in Month | Rate | | | | | |
| 20 | | | | 0.0000 | | | | | |
| 21 | | | | 0.0000 | | | | | |
| 22 | | | | 0.0000 | | | | | |
| 23 | | | | 0.0000 | | | | | |
| 24 | | | | 0.0000 | | | | | |
| 25 | | | | 0.0000 | | | | | |
| 26 | | | | 0.0000 | | | | | |
| 27 | | | | 0.0000 | | | | | |
| 28 | | | | 0.0000 | | | | | |
| 29 | Average Monthly Interest Rate | | | 0.0000 | | | | | |
| 30 | | | | | | | | | |
| 31 | III. Total Radial Line Charges | | | | | | | | |
| 32 | | | | (j) | (k) | (l) | (m) | | |
| 33 | | | | Annual | | Interest on | Total Annual | | |
| 34 | | | | Charge | True-Up | True-Up | Charge | | |
| 35 | | | | (Worksheet M) | (Col a) | (Col f) | (Sum Col j - l) | | |
| 36 | | | | | $0 | $0 | $0 | | |
| 37 | | | | | $0 | $0 | $0 | | |
| 38 | | | | | $0 | $0 | $0 | | |
| 39 | | | | | $0 | $0 | $0 | | |
| 40 | | | | | $0 | $0 | $0 | | |
| 41 | | | | | $0 | $0 | $0 | | |
| 42 | | | | | $0 | $0 | $0 | | |

| | | | | | |
|---|---|---|---|---|---|
| 43 | | | | | |
| 44 | Total | $0 | $0 | $0 | $0 |

Note:
The interest is calculated using the interest rate posted on the FERC website.
See link to website below.
http://www.ferc.gov/legal/acct-matts/interest-rates.asp#skipnavsub

# Addendum 5 To Attachment H Part 2

**Southwestern Public Service Company** **Worksheet B**
**Worksheet B - Revenue Credits** **Table 15**

**Gain on Disposition of Property, Projected for Billing Year =** **20yy**
( Revenue related to sale of transmission assets)

| Line No. | | (a) Total | (b) Adjustments | (c) Adjusted Total Amount |
|---|---|---|---|---|
| 1 | Amortization of Gain on the Sale (Allocated to Transmission) (Note 1) | | | $ - |
| 2 | Gain on disposition of property (Other Related) | | | $ - |
| 3 | Total 421.1 (or other applicable acct) | $ - | $ - | **$ -** |

**Gain on Disposition of Property, Actual for Billing Year =** **20yy**
( Revenue related to sale of transmission assets)

| Line No. | | (a) Total | (b) Adjustments | (c) Adjusted Total Amount |
|---|---|---|---|---|
| 4 | Amortization of Gain on the Sale (Allocated to Transmission) (Note 1) | | | $ - |
| 5 | Gain on disposition of property (Other Related) | | | $ - |
| 6 | Total 421.1 (FF1, p. 114-117, ln 40. (c) (or other applicable acct) | $ - | $ - | **$ -** |

Note 1: In prior transactions, on a case-by-case basis, the Public Utilities Commission of Texas (PUCT) has required SPS to credit to SPS's Texas retail ratepayers a specified percentage of gains on SPS's disposition of certain property. Effective January 1, 2016, for each transmission sale or transfer transaction resulting in a gain recorded in Account 421.1 (gain on disposition of property) or other applicable account, the amount of the gain included in Column (c) on Lines 1 and 4 for that transaction will equal the (i) total amount of the gain for that transaction recorded in Account 421.1 or other applicable account, (ii) multiplied by the Texas retail gain sharing percentage specified by the PUCT for that transaction.

**Account 454, Rent from Electric Property, Projected for Billing Year = 20yy**

( Revenue related to transmission facilities for pole attachments, rentals, etc.)

Total Company: $

| Line No. | | (a) Amount | (b) Allocator | (c) | (d) Allocated Amount |
|---|---|---|---|---|---|
| 1 | Rent from Electric Property Classified as General | $ | W/S | 0.000 | $ - |
| 2 | Rent from Electric Property Classified as Distribution | $ | NA | | |
| 3 | Rent from Electric Property Classified as Transmission | | | | |
| 3a | Related to Network Transmission Facilities | $ | DA | 1.000 | $ - |
| 3b | Related to Non-Network Transmission Facilities | $ | NA | | |
| 4 | Rent from Electric Property Classified as Production | $ | NA | | |
| 5 | Total Account 454 Rent from Electric Property | $ - | | | $ - **Net Transmission Credits** |

**Account 454, Rent from Electric Property, Actual for Billing Year = 20yy**

Total Company

y

( Revenue related to transmission facilities for pole attachments, rentals, etc.)

(FF1, p. 300-301, ln 19 (b)

| Line No. | | (a) Amount | (b) Allocator | (c) | (d) Allocated Amount | |
|---|---|---|---|---|---|---|
| 6 | Rent from Electric Property Classified as General | | W/S | 0.000 | $ - | |
| 7 | Rent from Electric Property Classified as Distribution | | NA | | | |
| 8 | Rent from Electric Property Classified as Transmission | | | | | |
| 8a | Related to Network Transmission Facilities | | D A | 1.000 | $ - | |
| 8b | Related to Non-Network Transmission Facilities | | NA | | | |
| 9 | Rent from Electric Property Classified as Production | | NA | | | |
| 10 | Total Account 454 Rent from Electric Property | $ - | | | $ - | **Net Transmission Credits** |

Data Source - Account 454 General Ledger Detail Analysis

## Southwestern Public Service Company

**Wor kshe**

**et B**

# Worksheet B - Revenue Credits

**Tabl e 16**

## Account 456.0, Other Electric Revenue, Projected for Billilng Year =

20yy $-

| Line No. | | (a) Amount | (b) Allocator | (c) | (d) Allocated Amount |
|---|---|---|---|---|---|
| 1 | Schedule 18- Annual Interconnection Customer O&M Charge | $ | DA | 1.00000 | $ |
| 2 | Other Electric Revenue | | NA | | |
| 3 | Total Account 456.0 Other Electric Revenue | $ | | | $ |

**Account 456.0, Other Electric Revenue, Actuals for Billing Year =** 20yy $ -

| Line No. | | (a) Amount | (b) Allocator | (c) | (d) Allocated Amount |
|---|---|---|---|---|---|
| 4 | Schedule 18- Annual Interconnection Customer O&M Charge | $ | DA | 1.00000 | $ |
| 5 | Other Electric Revenue | | NA | | |
| 6 | Total Account 456.0 Other Electric Revenue | $ | | | $ |

## Account 456.1, Revenues from Transmission of Electricity of Others, Projected for Billing Year =

20yy $ -

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|
| | | Scheduling, System | Reactive Supply & | Regulation | Network & | Network & Interco. | Supplemental | FERC Assess | Total Of |

| Line No. | Type | Description | RTO | Network Transmission | Control & Dispatch | Voltage Control | and Frequency | Energy Imbalance | Spinning Reserve | Spinning Reserve | Pass Through | Line Items |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | 0.00 |
| 2 | | | | | | | | | | | | 0.00 |
| 3 | | | | | | | | | | | | 0.00 |
| 4 | | | | | | | | | | | | 0.00 |
| 5 | | | | | | | | | | | | 0.00 |
| 6 | | | | | | | | | | | | 0.00 |
| 7 | | | | | | | | | | | | 0.00 |
| 8 | | | | | | | | | | | | 0.00 |
| 9 | | | | | | | | | | | | 0.00 |
| 10 | | | | | | | | | | | | 0.00 |
| 11 | | | | | | | | | | | | 0.00 |
| 12 | | | | | | | | | | | | 0.00 |
| 13 | | | | | | | | | | | | 0.00 |
| 14 | | | | | | | | | | | | 0.00 |
| 15 | | | | | | | | | | | | 0.00 |
| 16 | | | | | | | | | | | | |
| 17 | | | | | | | | | | | | 0.00 |
| 18 | | | | | | | | | | | | 0.00 |
| 19 | | | | | | | | | | | | 0.00 |
| 20 | | | | | | | | | | | | 0.00 |
| 21 | | | | | | | | | | | | 0.00 |
| 22 | | | | | | | | | | | | 0.00 |
| 23 | | | | | | | | | | | | 0.00 |
| 24 | | | | | | | | | | | | 0.00 |
| 25 | | | | | | | | | | | | 0.00 |
| 26 | | | | | | | | | | | | 0.00 |
| 27 | | | | | | | | | | | | 0.00 |
| 28 | | | | | | | | | | | | 0.00 |
| 29 | | | | | | | | | | | | 0.00 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | | | | | | | | | | | 0.00 |
| 31 | | | | | | | | | | | |
| 32 | | | | | | | | | | | |
| 33 | Total | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 34 | | | | | | | | | | | |
| 35 | **Summarized by Type: Note 2** | | | | | | | | | | |
| **36** | **Credit** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** |
| 37 | Divisor | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 38 | Ancillary | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 39 | Other | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 40 | Total | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

| | | |
|---|---|---|
| 41 | Description of Revenue Types: | |
| 42 | Ancillary | Ancillary services includes regulation & frequency, control & dispatch, voltage |
| 43 | | control, reactive, spinning reserve, scheduling and generation step-up. |
| 44 | Divisor | Load associated with these revenues are included in the formula divisor. |
| 45 | Credit | Revenue credit because load not included in divisor. |

46 Note 2 - SPP point to point revenues are being revenue credited here because SPP will not revenue credit these revenues to LSEs.

**Southwestern Public** **Wor**

# Service Company

# Worksheet B - Revenue Credits

kshe et B

Tabl e 17

**Account 456.1, Revenues from Transmission of Electricity of Others, Actual for Billing Year =** 20yy $ - (Total Company - FF1, p 330, col. n)

| Line No. | Type | Description | (a) RTO | (b) Network Transmission | (c) Scheduling, System Control & Dispatch | (d) Reactive Supply & Voltage Control | (e) Regulation and Frequency | (f) Network & Energy Imbalance | (g) Network & Interco. Spinning Reserve | (h) Supplemental Spinning Reserve | (i) FERC Assess Pass Through | (j) Total Of Line Items | (k) Total Per FERC Form No. 1 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 47 | | | | | | | | | | | | | |
| 48 | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | |
| 50 | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 52 | | | | | | | | | | | |
| 53 | | | | | | | | | | | |
| 54 | | | | | | | | | | | |
| 55 | | | | | | | | | | | |
| 56 | | | | | | | | | | | |
| 57 | | | | | | | | | | | |
| 58 | | | | | | | | | | | |
| 59 | | | | | | | | | | | |
| 60 | | | | | | | | | | | |
| 61 | | | | | | | | | | | |
| 62 | | | | | | | | | | | |
| 63 | | | | | | | | | | | |
| 64 | | | | | | | | | | | |
| 65 | | | | | | | | | | | |
| 66 | | | | | | | | | | | |
| 67 | | | | | | | | | | | |
| 68 | | | | | | | | | | | |
| 69 | | | | | | | | | | | |
| 70 | | | | | | | | | | | |
| 71 | | | | | | | | | | | |
| 72 | | | | | | | | | | | |
| 73 | | | | | | | | | | | |
| 74 | | | | | | | | | | | |
| 75 | Total | 0.00 | 0.00 | 0.00 | 0.00 | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 76 | | | | | | | | | | | |
| 77 | **Summarized by Type: Note 2** | | | | | | | | | | |
| **78** | **Credit** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** |
| 79 | Divisor | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 80 | Ancillary | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 81 | Other | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 82 | Total | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

83 Description of Revenue Types:

| | | |
|---|---|---|
| 84 | Ancillary | Ancillary services includes regulation & frequency, control & dispatch, voltage |
| 85 | | control, reactive, spinning reserve, scheduling and generation step-up. |
| 86 | Divisor | Load associated with these revenues are included in the formula divisor. |
| 87 | Credit | Revenue credit because load not included in divisor. |

88 Note 2 - SPP point to point revenues are being revenue credited here because SPP will not revenue credit these revenues to LSEs.

# Southwestern Public Service Company
# Worksheet C - Divisor

**Worksheet C**

**Table 18**

## I. Transmission Network Load (mW) Projected for Billing Year = 20yy

| Line No. | Month | Network Load[1] | Plus: Intertie Demand[2] | TO's Transmission Network Load |
|---|---|---|---|---|
| 1 | | | | 0 |
| 2 | | | | 0 |

| | | | | |
|---|---|---|---|---|
| 3 | | | | 0 |
| 4 | | | | 0 |
| 5 | | | | 0 |
| 6 | | | | 0 |
| 7 | | | | 0 |
| 8 | | | | 0 |
| 9 | | | | 0 |
| 10 | | | | 0 |
| 11 | | | | 0 |
| 12 | | | | 0 |
| 13 | Total | 0 | 0 | 0 |
| 14 | 12-CP | 0 | 0 | 0 |

## II. Transmission Network Load (mW) Actual for Billing Year = 20 yy

| Line No. | Month, Day and Year[1] | Hour Ending[1] | Network Load[1] | Plus: Intertie Demand[2] | TO's Transmission Network Load |
|---|---|---|---|---|---|
| 15 | | | | | 0 |
| 16 | | | | | 0 |
| 17 | | | | | 0 |
| 18 | | | | | 0 |
| 19 | | | | | 0 |
| 20 | | | | | 0 |
| 21 | | | | | 0 |
| 22 | | | | | 0 |
| 23 | | | | | 0 |
| 24 | | | | | 0 |
| 25 | | | | | 0 |
| 26 | | | | | 0 |

| | | | | |
|---|---|---|---|---|
| 27 | Total | 0 | 0 | 0 |
| 28 | 12-CP | 0 | 0 | 0 |

## III. Notes

1 These are the dates, hour ending and loads at the time of the transmission peak, as reported in FF1, p. 400.

2 Reserved capacity associated with SPS-Public Service Company of Colorado Intertie.

IV. Firm Network Service for Othes (mW) for Billing Year= 20yy

| Line No. | Month | Projected Wholesale Load | Actual Wholesale Load[3] |
|---|---|---|---|
| 29 | January | | |
| 30 | February | | |
| 31 | March | | |
| 32 | April | | |
| 33 | May | | |
| 34 | June | | |
| 35 | July | | |
| 36 | August | | |
| 37 | September | | |
| 38 | October | | |
| 39 | November | | |
| 40 | December | | |
| 41 | Total | | |
| 42 | 12 Month Average | | |

**V. Notes**

3 These are the Wholesale Loads by month, as reported in FF1, p. 400.

**Workshe et D**
**Table 19**

Southwestern Public Service Company
Worksheet D Average Rate Base
Inputs for Average Rate Base Calculations

| Line No. | (a) | Year = 20yy (b) Projected Beg of Year Balance | (c) Projected End of Year Balance | (d) Projected Average Balance (b+c)/2 | (e) References for Actual Data | Year = 20yy (f) Actual Beg of Year Balance | (g) Actual End of Year Balance | (h) Actual Average Balance (f+g)/2 |
|---|---|---|---|---|---|---|---|---|
| 1 | Deferred Taxes - Account 281 | | | | | | | |
| 2 | | | | 0 | | | | 0 |
| 3 | | | | 0 | | | | 0 |
| 4 | | | | 0 | | | | 0 |
| 5 | | | | 0 | | | | 0 |
| 6 | Total Account 281 | 0 | 0 | 0 | FF1, p. 272-273, ln 8 (b) and (k) | 0 | 0 | 0 |
| 7 | | | | | | | | |
| 8 | Deferred Taxes - Account 282 | | | | | | | |
| 9 | | | | | | | | |
| 10 | | | | 0 | | | | 0 |
| 11 | | | | 0 | | | | 0 |
| 12 | | | | 0 | | | | 0 |
| 13 | | | | 0 | | | | 0 |
| 14 | | | | 0 | | | | 0 |
| 15 | | | | 0 | | | | 0 |
| 16 | | | | 0 | | | | 0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 17 | Subtotal Liberalized Depreciation | | | 0 | | | | 0 |
| 18 | | | | | | | | |
| 19 | | | | | | | | |
| 20 | | | | | | | | |
| 21 | Excess ADIT | | | 0 | | | | 0 |
| 22 | FAS 109 Plant Excess ADIT - Protected | | | 0 | FF1, p. 274-275, ln 6 (k) footnote | | | 0 |
| 23 | FAS 109 Plant Excess ADIT - Uprotected | | | 0 | FF1, p. 274-275, ln 6 (k) footnote | | | 0 |
| 24 | Total Account 282 | 0 | 0 | 0 | FF1, p. 274-275, ln 9 (b) and (k) | 0 | 0 | 0 |
| 25 | | | | | | | | |
| 26 | Deferred Taxes - Account 283 | | | | | | | |
| 27 | | | | 0 | | | | 0 |
| 28 | | | | 0 | | | | 0 |
| 29 | | | | 0 | | | | 0 |
| 30 | | | | 0 | | | | 0 |
| 31 | | | | 0 | | | | 0 |
| 32 | | | | 0 | | | | 0 |
| 33 | | | | 0 | | | | 0 |
| 34 | | | | 0 | | | | 0 |
| 35 | | | | 0 | | | | 0 |
| 36 | | | | 0 | | | | 0 |
| 37 | | | | 0 | | | | 0 |
| 38 | | | | 0 | | | | 0 |
| 39 | | | | 0 | | | | 0 |
| 40 | | | | 0 | | | | 0 |
| 41 | | | | 0 | | | | 0 |
| 42 | | | | 0 | | | | 0 |
| 43 | | | | 0 | | | | 0 |
| 44 | | | | 0 | | | | 0 |
| 45 | | | | 0 | | | | 0 |
| 46 | | | | 0 | | | | 0 |
| 47 | | | | 0 | | | | 0 |
| 48 | | | | 0 | | | | 0 |
| 49 | | | | 0 | | | | 0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 50 | Total Account 283 | 0 | 0 | 0 | FF1, p. 276-277, ln 19 (b) and (k) | 0 | 0 | 0 |
| 51 | | | | | | | | |
| 52 | Deferred Taxes - Account 190 | | | | | | | |
| 53 | | | | 0 | | | | 0 |
| 54 | | | | 0 | | | | 0 |
| 55 | | | | 0 | | | | 0 |
| 56 | | | | 0 | | | | 0 |
| 57 | | | | 0 | | | | 0 |
| 58 | | | | 0 | | | | 0 |
| 59 | | | | 0 | | | | 0 |
| 60 | Subtotal Basis Difference | | | 0 | | | | 0 |
| 61 | | | | 0 | | | | 0 |
| 62 | | | | 0 | | | | 0 |
| 63 | | | | 0 | | | | 0 |
| 64 | | | | 0 | | | | 0 |
| 65 | | | | 0 | | | | 0 |
| 66 | | | | 0 | | | | 0 |
| 67 | | | | 0 | | | | 0 |
| 68 | | | | 0 | | | | 0 |
| 69 | | | | 0 | | | | 0 |
| 70 | | | | 0 | | | | 0 |
| 71 | | | | 0 | | | | 0 |
| 72 | | | | 0 | | | | 0 |
| 73 | | | | 0 | | | | 0 |
| 74 | | | | 0 | | | | 0 |
| 75 | | | | 0 | | | | 0 |
| 76 | | | | 0 | | | | 0 |
| 77 | | | | 0 | | | | 0 |
| 78 | | | | 0 | | | | 0 |
| 79 | | | | 0 | | | | 0 |
| 80 | | | | 0 | | | | 0 |
| 81 | | | | 0 | | | | 0 |
| 82 | | | | 0 | | | | 0 |
| 83 | | | | 0 | | | | 0 |
| 84 | | | | 0 | | | | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 85 | | 0 | | | 0 |
| 86 | | 0 | | | 0 |
| 87 | | 0 | | | 0 |
| 88 | | 0 | | | 0 |
| 89 | | 0 | | | 0 |
| 90 | | 0 | | | 0 |
| 91 | | 0 | | | 0 |
| 92 | | 0 | | | 0 |
| 93 | | 0 | | | 0 |
| 94 | | 0 | | | 0 |
| 95 | | 0 | | | 0 |
| 96 | | 0 | | | 0 |
| 97 | | 0 | | | 0 |
| 98 | | 0 | | | 0 |
| 99 | | 0 | | | 0 |
| 100 | | 0 | | | 0 |
| 101 | | 0 | | | 0 |
| 102 | | 0 | | | 0 |
| 103 | | 0 | | | 0 |
| 104 | | 0 | | | 0 |
| 105 | | 0 | | | 0 |
| 106 | | 0 | | | 0 |
| 107 | | 0 | | | 0 |
| 108 | | 0 | | | 0 |
| 109 | | 0 | | | 0 |
| 110 | | 0 | | | 0 |
| 111 | | 0 | | | 0 |
| 112 | | 0 | | | 0 |
| 113 | | 0 | | | 0 |
| 114 | | 0 | | | 0 |
| 115 | | 0 | | | 0 |
| 116 | | 0 | | | 0 |
| 117 | | 0 | | | 0 |
| 118 | Deficient ADIT | 0 | | | 0 |
| 119 | FAS 109 Plant Deficient ADIT -Protected | 0 | FF1, p. 234, ln 5 (c) footnote | | 0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 120 | FAS 109 Plant Deficient ADIT - Uprotected | | | 0 | FF1, p. 234, ln 5 (c) footnote | | | 0 |
| 121 | Total Account 190 | 0 | 0 | 0 | FF1, p. 234, ln 18 (b) and (c) | 0 | 0 | 0 |
| 122 | | | | | | | | |
| 123 | Total Deferred Taxes | | | 0 | | | | 0 |
| 124 | | | | | | | | |
| 125 | Unamortized Balance of Abandoned Incentive Plant | | | | | | | |
| 126 | (See Formula Template Note E found on pages 6 and 11.) | | | | | | | |
| 127 | | | | 0 | | | | 0 |
| 128 | Total Abandoned Incentive Plant | 0 | 0 | 0 | Company Records | 0 | 0 | 0 |
| 129 | | | | | | | | |
| 130 | Unamortized Balance of Extraordinary Property Loss (Note E) | | | | | | | |
| 131 | (See Formula Template Note E found on pages 6 and 11.) | | | | | | | |
| 132 | | | | 0 | | | | 0 |
| 133 | Total Extraordinary Property Loss | 0 | 0 | 0 | Company Records | 0 | 0 | 0 |
| 134 | | | | | | | | |
| 135 | | | | | | | | |
| 136 | Land Held for Future Use | | | 0 | FF1, p. 214 | | | 0 |

Southwestern Public Service Company
Worksheet D.1 Rate Base - 13 Month Average
Input for 13 Month Average Rate Base Calculations

**Workshe et D.1**

**Table 20**

| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **PROJECTED** | | | | | **PROJECTED BALANCES PLANT IN SERVICE** | | | | | | | | | |
| Line | Plant in Service | | | | | | | | | | | | | | 13 Mo Average |

| No. | Function | 01/01/yy | 01/31/yy | 02/28/yy | 03/31/yy | 04/30/yy | 05/31/yy | 06/30/yy | 07/31/yy | 08/31/yy | 09/30/yy | 10/31/yy | 11/30/yy | 12/31/yy | Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Production Steam | | | | | | | | | | | | | | 0 |
| 2 | Less Asset Retirement Costs (Note 1) | | | | | | | | | | | | | | 0 |
| 3 | Production Other | | | | | | | | | | | | | | 0 |
| 4 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 5 | Adjustment to Production (WsD.5, lns 1+2) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 6 | Production Net of ARC and Adj | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | | | | | | | | | | | | | | | |
| 8 | Transmission | | | | | | | | | | | | | | 0 |
| 9 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 10 | Adjustment to Transmission (WsD.5, ln 3) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | Transmission Net of ARC and Adj | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | | | | | | | | | | | | | | | |
| 13 | Distribution | | | | | | | | | | | | | | 0 |
| 14 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 15 | Adjustment to Distribution (WsD.5, ln 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | Distribution Net of ARC and Adj | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | | | | | | | | | | | | | | | |
| 18 | General | | | | | | | | | | | | | | 0 |
| 19 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 20 | Adjustment to General (WsD.5, ln 5) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | General Net of ARC and Adj | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | | | | | | | | | | | | | | | |
| 23 | Intangible | | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24 | Adjustment to Intangible (WsD.5, ln 6) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 25 | Total Intangible Net of Adj | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 26 | | | | | | | | | | | | | | | |
| 27 | Total Gross Plant In Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 28 | Less Total Asset Retirment Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 29 | | | | | | | | | | | | | | | |
| 30 | Total Gross Plant in Service Net of ARC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 31 | | | | | | | | | | | | | | | |
| 32 | (Note 1 - ARC not included in projected balance amounts.) | | | | | | | | | | | | | | |
| 33 | | | | | | | | | | | | | | | |
| 34 | **PROJECTED** | **PROJECTED BALANCES DEPRECIATION & AMORTIZATION** | | | | | | | | | | | | | |
| 35 | Accumulated Depreciation & Amortization | | | | | | | | | | | | | | 13 Mo Average |
| 36 | Function | 01/01/yy | 01/31/yy | 02/28/yy | 03/31/yy | 04/30/yy | 05/31/yy | 06/30/yy | 07/31/yy | 08/31/yy | 09/30/yy | 10/31/yy | 11/30/yy | 12/31/yy | Balance |
| 37 | Production Steam | | | | | | | | | | | | | | 0 |
| 38 | Production Other | | | | | | | | | | | | | | 0 |
| 39 | Production - Intangible Amortization | | | | | | | | | | | | | | 0 |
| 40 | Adjustment to Production (WsD.5, lns 11+12) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 41 | Total Production | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 42 | | | | | | | | | | | | | | | |
| 43 | Transmission | | | | | | | | | | | | | | 0 |
| 44 | Transmission - Intangible Amortization | | | | | | | | | | | | | | 0 |
| 45 | Adjustment to Transmission (WsD.5, ln 13) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 46 | Total Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 47 | | | | | | | | | | | | | | | |
| 48 | Distribtution | | | | | | | | | | | | | | 0 |
| 49 | Distribtution - Intangible Amortization | | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 50 | Adjustment to Distribution (WsD.5, ln 14) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 51 | Total Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 52 | | | | | | | | | | | | | | | |
| 53 | General | | | | | | | | | | | | | | 0 |
| 54 | General - Intangible Amortization | | | | | | | | | | | | | | 0 |
| 55 | Adjustment to General (WsD.5, ln 15) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 56 | Total General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 57 | | | | | | | | | | | | | | | |
| 58 | Intangible - Software | | | | | | | | | | | | | | 0 |
| 59 | Adjustment to Intangible (WsD.5, ln 16) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 60 | Total Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 61 | | | | | | | | | | | | | | | |
| 62 | Total Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 63 | Total Accumulated Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 64 | | | | | | | | | | | | | | | |
| 65 | Total Accumulated Depr & Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 66 | | | | | | | | | | | | | | | |
| 67 | **PROJECTED NET PLANT IN SERVICE** | | | | | | | | | | | | | | |
| 68 | Production | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 69 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 70 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 71 | General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 72 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 73 | | | | | | | | | | | | | | | |
| 74 | Total Projected Net Plant in Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 75 | | | | | | | | | | | | | | | |
| 76 | Net Plant in Service Check Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Southwestern Public Service Company
Worksheet D.1 Rate Base - 13 Month Average
Input for 13 Month Average Rate Base Calculations

**Workshe et D.1**

**Table 21**

| Line No. | Plant in Service Function | (a) 01/01/yy | (b) 01/31/yy | (c) 02/28/yy | (d) 03/31/yy | (e) 04/30/yy | (f) 05/31/yy | (g) 06/30/yy | (h) 07/31/yy | (i) 08/31/yy | (j) 09/30/yy | (k) 10/31/yy | (l) 11/30/yy | (m) 12/31/yy | (n) 13 Mo Average Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **ACTUAL** | **ACTUAL BALANCES PLANT IN SERVICE** | | | | | | | | | | | | | |
| 77 | Production Steam | | | | | | | | | | | | | | 0 |
| 78 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 79 | Production Other | | | | | | | | | | | | | | 0 |
| 80 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 81 | Adjustment to Production (WsD.5, Lns 27+28) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 82 | Production Net of ARC and Adj. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 83 | | | | | | | | | | | | | | | |
| 84 | Transmission | | | | | | | | | | | | | | 0 |
| 85 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 86 | Adjustment to Transmission (WsD.5, ln 29) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 87 | Transmission Net of ARC and Adj. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 88 | | | | | | | | | | | | | | | |
| 89 | Distribution | | | | | | | | | | | | | | 0 |
| 90 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 91 | Adjustment to Distribution (WsD.5, ln 30) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 92 | Distribution Net of ARC and Adj. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 93 | | | | | | | | | | | | | | | |
| 94 | General | | | | | | | | | | | | | | 0 |
| 95 | Less Asset Retirement Costs | | | | | | | | | | | | | | 0 |
| 96 | Adjustment to General (WsD.5, Ln 31) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 97 | General Net of ARC and Adj. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 98 | | | | | | | | | | | | | | | |
| 99 | Intangible - Software | | | | | | | | | | | | | | 0 |
| 100 | Adjustment to Intangible (WsD.5, ln 32) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 101 | Total Intangible Net of Adj. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 102 | | | | | | | | | | | | | | | |
| 103 | Total Gross Plant In Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 104 | Less Total Asset Retirement Costs | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 105 | | | | | | | | | | | | | | | |
| 106 | Total Gross Plant in Service Net of ARC | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 107 | | | | | | | | | | | | | | | |
| 108 | | | | | | | | | | | | | | | |
| 109 | | | | | | | | | | | | | | | |
| 110 | **ACTUAL** | **ACTUAL BALANCES DEPRECIATION & AMORTIZATION** | | | | | | | | | | | | | |
| 111 | Accumulated Depreciation & Amortization | | | | | | | | | | | | | | 13 Mo Average |
| 112 | Function | 01/01/yy | 01/31/yy | 02/28/yy | 03/31/yy | 04/30/yy | 05/31/yy | 06/30/yy | 07/31/yy | 08/31/yy | 09/30/yy | 10/31/yy | 11/30/yy | 12/31/yy | Balance |
| 113 | Production Steam | | | | | | | | | | | | | | 0 |
| 114 | Production Other | | | | | | | | | | | | | | 0 |
| 115 | Production - Intangible | | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Amortization | | | | | | | | | | | | | | |
| 11 | Adjustment to Production | | | | | | | | | | | | | | |
| 5 | (WsD.5, lns 38+39) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | | | | | | | | | | | | | | | |
| 6 | Total Production | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 11 | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | |
| 8 | Transmission | | | | | | | | | | | | | | 0 |
| 11 | Transmission - Intangible | | | | | | | | | | | | | | |
| 9 | Amortization | | | | | | | | | | | | | | 0 |
| 12 | Adjustment to Transmission | | | | | | | | | | | | | | |
| 0 | (WsD.5, ln 40) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | | | | | | | | | | | | | | | |
| 1 | Total Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | | |
| 3 | Distribution | | | | | | | | | | | | | | 0 |
| 12 | Distribution - Intangible | | | | | | | | | | | | | | |
| 4 | Amortization | | | | | | | | | | | | | | 0 |
| 12 | Adjustment to Distribution | | | | | | | | | | | | | | |
| 5 | (WsD.5, ln 41) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | | | | | | | | | | | | | | | |
| 6 | Total Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 12 | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | | |
| 8 | General | | | | | | | | | | | | | | 0 |
| 12 | General - Intangible | | | | | | | | | | | | | | |
| 9 | Amortization | | | | | | | | | | | | | | 0 |
| 13 | Adjustment to General | | | | | | | | | | | | | | |
| 0 | (WsD.5, ln 42) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | | | | | | | | | | | | | | | |
| 1 | Total General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | |
| 3 | Intangible - Software | | | | | | | | | | | | | | 0 |
| 13 | Adjustment to General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | (WsD.5, ln 43) | | | | | | | | | | | | | | |
| 135 | Total Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 136 | | | | | | | | | | | | | | | |
| 137 | Total Accumulated Depreciation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 138 | Total Accumulated Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 139 | | | | | | | | | | | | | | | |
| 140 | Total Accumulated Depr & Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 141 | | | | | | | | | | | | | | | |
| 142 | **ACTUAL NET PLANT IN SERVICE** | | | | | | | | | | | | | | |
| 143 | Production | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 144 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 145 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 146 | General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 147 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 148 | | | | | | | | | | | | | | | |
| 149 | Total Projected Net Plant in Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 150 | | | | | | | | | | | | | | | |
| 151 | Net Plant in Service Check Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 152 | | | | | | | | | | | | | | | |
| 153 | GSU PLANT IN SERVICE PROJECTED | | | | | | | | | | | | | | 0 |
| 154 | | | | | | | | | | | | | | | |

| | | | |
|---|---|---|---|
| 4 | | | |
| 15 | GSU PLANT IN SERVICE | | |
| 5 | ACTUAL | | 0 |

Southwestern Public Service Company

**Worksheet D.5**

Worksheet D.5 Adjustments to Rate Base

**Table 21D**

| Line No. | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **PROJECTED BALANCES** | | | | | | | | | | | | | |
| | **Plant in Service Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |
| 1 | Production Steam | | | | | | | | | | | | | | 0 |
| 2 | Production Other | | | | | | | | | | | | | | 0 |
| 3 | Transmission | | | | | | | | | | | | | | 0 |
| 4 | Distribution | | | | | | | | | | | | | | 0 |
| 5 | General | | | | | | | | | | | | | | 0 |
| 6 | Intangible | | | | | | | | | | | | | | 0 |
| 7 | Total Gross Plant in Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 8 | | | | | | | | | | | | | | | |
| 9 | **Accumulated Depreciation & Amortization Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| 10 | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |
| 11 | Production Steam | | | | | | | | | | | | | | 0 |
| 12 | Production Other | | | | | | | | | | | | | | 0 |
| 13 | Transmission | | | | | | | | | | | | | | 0 |
| 14 | Distribution | | | | | | | | | | | | | | 0 |
| 15 | General | | | | | | | | | | | | | | 0 |
| 16 | Intangible | | | | | | | | | | | | | | 0 |
| 17 | Total Accumulated Depr & Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | | | | | | | | | | | | | | | |
| 19 | **PROJECTED NET PLANT IN SERVICE** | | | | | | | | | | | | | | |
| 20 | Production Steam | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | Production Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 22 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 23 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 24 | General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 25 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 26 | Total Projected Net Plant In Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**ACTUAL BALANCES**

| Line No. | **Plant in Service Adjustments** **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | 13 Mo Average Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | Production Steam | | | | | | | | | | | | | | 0 |
| 28 | Production Other | | | | | | | | | | | | | | 0 |
| 29 | Transmission | | | | | | | | | | | | | | 0 |
| 30 | Distribution | | | | | | | | | | | | | | 0 |
| 31 | General | | | | | | | | | | | | | | 0 |
| 32 | Intangible | | | | | | | | | | | | | | 0 |
| 33 | Total Gross Plant in Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 34 | | | | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | | | |
| 36 | **Accumulated Depreciation & Amortization Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| 37 | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |
| 38 | Production Steam | | | | | | | | | | | | | | 0 |
| 39 | Production Other | | | | | | | | | | | | | | 0 |
| 40 | Transmission | | | | | | | | | | | | | | 0 |
| 41 | Distribution | | | | | | | | | | | | | | 0 |
| 42 | General | | | | | | | | | | | | | | 0 |
| 43 | Intangible | | | | | | | | | | | | | | 0 |
| 44 | Total Accumulated Depr & Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 45 | | | | | | | | | | | | | | | |
| 46 | **ACTUAL NET PLANT IN SERVICE** | | | | | | | | | | | | | | |
| 47 | Production Steam | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 48 | Production Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 49 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 50 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 51 | General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 52 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 53 | Total Actual Net Plant in Service | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 54 | | | | | | | | | | | | | | | |

| Line No. | **Accumulated Deferred Income Tax Adjustment** | **PROJECTED BALANCES** Beginning Balance | Ending Balance | Average Balance | **ACTUAL BALANCES** Beginning Balance | Ending Balance | Average Balance |
|---|---|---|---|---|---|---|---|
| 55 | | | | | | | |
| 56 | | | | | | | |
| 57 | **Account 281** | | | 0 | | | 0 |
| 58 | | | | | | | |
| 59 | | | | | | | |

**Depreciation and Amortization Expense Adjustment**

| | PROJECTED BALANCES Depreciation Expense | ACTUAL BALANCES Depreciation Expense |
|---|---|---|
| Production Steam | | |
| Production Other | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 60 | **Account 282** | 0 | 0 | Transmission | | |
| 61 | | 0 | 0 | Distribution | | |
| 62 | | 0 | 0 | General | | |
| 63 | | 0 | 0 | Intangible - Software | | |
| 64 | | 0 | 0 | Total Depreciation Expense | 0 | 0 |
| 65 | | 0 | 0 | | | |
| 66 | | 0 | 0 | | Amortization Expense | Amortization Expense |
| 67 | | | | Production Steam | | |
| 68 | **Account 283** | | | Production Other | | |
| 69 | | 0 | 0 | Transmission | | |
| 70 | | 0 | 0 | Distribution | | |
| 71 | | 0 | 0 | General | | |
| 72 | | 0 | 0 | Intangible - Software | | |
| 73 | | 0 | 0 | Total Amortization Expense | 0 | 0 |
| 74 | | 0 | 0 | | | |
| 75 | | 0 | 0 | | | |
| 76 | | 0 | 0 | | | |
| 77 | | 0 | 0 | | | |
| 78 | | 0 | 0 | | | |
| 79 | | 0 | 0 | | | |
| 80 | | 0 | 0 | | | |
| 81 | | 0 | 0 | | | |
| 82 | | 0 | 0 | | | |
| 83 | | 0 | 0 | | | |
| 84 | | 0 | 0 | | | |
| 85 | | 0 | 0 | | | |
| 86 | | 0 | 0 | | | |
| 87 | | | | | | |
| 88 | **Account 190** | | | | | |
| 89 | | 0 | 0 | | | |
| 90 | | 0 | 0 | | | |
| 91 | | 0 | 0 | | | |
| 92 | | 0 | 0 | | | |
| 93 | | 0 | 0 | | | |
| 94 | | 0 | 0 | | | |
| 95 | | 0 | 0 | | | |

| | | | | |
|---|---|---|---|---|
| 96 | | 0 | | 0 |
| 97 | | 0 | | 0 |
| 98 | | 0 | | 0 |
| 99 | | 0 | | 0 |
| 100 | | 0 | | 0 |
| 101 | | 0 | | 0 |
| 102 | | 0 | | 0 |
| 103 | | 0 | | 0 |
| 104 | | 0 | | 0 |
| 105 | | 0 | | 0 |
| 106 | | 0 | | 0 |
| 107 | | 0 | | 0 |
| 108 | | 0 | | 0 |
| 109 | | 0 | | 0 |
| 110 | | 0 | | 0 |
| 111 | | 0 | | 0 |
| 112 | | 0 | | 0 |
| 113 | | 0 | | 0 |
| 114 | | 0 | | 0 |
| 115 | | 0 | | 0 |
| 116 | | 0 | | 0 |
| 117 | | 0 | | 0 |
| 118 | | 0 | | 0 |
| 119 | | 0 | | 0 |
| 120 | | 0 | | 0 |
| 121 | | 0 | | 0 |
| 123 | | 0 | | 0 |
| 124 | | 0 | | 0 |
| 125 | | 0 | | 0 |
| 126 | | 0 | | 0 |
| 127 | | 0 | | 0 |
| 128 | | 0 | | 0 |
| 129 | | 0 | | 0 |
| 130 | | 0 | | 0 |
| 131 | | 0 | | 0 |
| 132 | | 0 | | 0 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 133 | | | | 0 | | | | 0 |
| 134 | | | | 0 | | | | 0 |
| 135 | | | | 0 | | | | 0 |
| 136 | | | | 0 | | | | 0 |
| 137 | | | | 0 | | | | 0 |
| 138 | | | | 0 | | | | 0 |
| 139 | | | | 0 | | | | 0 |
| 140 | | | | 0 | | | | 0 |
| 141 | | | | 0 | | | | 0 |
| 142 | | | | 0 | | | | 0 |
| 143 | | | | | | | | |
| 144 | Total Adjustments to ADIT | 0 | 0 | 0 | | 0 | 0 | 0 |

Southwestern Public Service Company

**Workpaper 1 - AGIS**

Workpaper 1 - AGIS

**Table 21E**

| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | **PROJECTED BALANCES** | | | | | | | |
| Line | **Plant in Service Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| No. | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |
| 1 | Transmission | | | | | | | | | | | | | | 0 |
| 2 | Distribution | | | | | | | | | | | | | | 0 |
| 3 | General | | | | | | | | | | | | | | 0 |
| 4 | Intangible | | | | | | | | | | | | | | 0 |
| 5 | | | | | | | | | | | | | | | |
| 6 | **Accumulated Depreciation & Amortization Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| 7 | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |
| 8 | Transmission | | | | | | | | | | | | | | 0 |
| 9 | Distribution | | | | | | | | | | | | | | 0 |
| 10 | General | | | | | | | | | | | | | | 0 |
| 11 | Intangible - Software | | | | | | | | | | | | | | 0 |
| 12 | | | | | | | | | | | | | | | |
| 13 | **PROJECTED NET PLANT IN SERVICE** | | | | | | | | | | | | | | |
| 14 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 16 | General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| | | | | | | | | **ACTUAL BALANCES** | | | | | | | |
| Line | **Plant in Service Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| No. | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |
| 18 | Transmission | | | | | | | | | | | | | | 0 |
| 19 | Distribution | | | | | | | | | | | | | | 0 |
| 20 | General | | | | | | | | | | | | | | 0 |
| 21 | Intangible | | | | | | | | | | | | | | 0 |
| 22 | | | | | | | | | | | | | | | |
| 23 | **Accumulated Depreciation & Amortization Adjustments** | | | | | | | | | | | | | | 13 Mo Average |
| 24 | **Function** | 1/1/20yy | 1/31/20yy | 2/29/20yy | 3/31/20yy | 4/30/20yy | 5/31/20yy | 6/30/20yy | 7/31/20yy | 8/31/20yy | 9/30/20yy | 10/31/20yy | 11/30/20yy | 12/31/20yy | Balance |

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| 25 | Transmission | | | | | | | | | | | | | | 0 |
| 26 | Distribution | | | | | | | | | | | | | | 0 |
| 27 | General | | | | | | | | | | | | | | 0 |
| 28 | Intangible - Software | | | | | | | | | | | | | | 0 |
| 29 | | | | | | | | | | | | | | | |
| 30 | **ACTUAL NET PLANT IN SERVICE** | | | | | | | | | | | | | | |
| 31 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 32 | Distribution | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 33 | General | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 34 | Intangible | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

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| 35 | | | | | | | | | | |
| 36 | **Accumulated Deferred Income Tax Adjustment** | **PROJECTED BALANCES** | | | **ACTUAL BALANCES** | | | **Depreciation and Amortization Expense Adjustment** | | |
| 37 | | **Beginning Balance** | **Ending Balance** | **Average Balance** | **Beginning Balance** | **Ending Balance** | **Average Balance** | | PROJECTED BALANCES | ACTUAL BALANCES |
| 38 | **Account 282** | | | 0 | | | 0 | | Depreciation Expense | Depreciation Expense |
| 39 | Electric Distribution | | | 0 | | | 0 | Transmission | | |
| 40 | Electric Transmission | | | | | | | Distribution | | |
| 41 | **Account 283** | | | 0 | | | 0 | | | |
| 42 | Liberalized Depreciation – Software | | | 0 | | | 0 | | Amortization Expense | Amortization Expense |
| 43 | Liberalized Depreciation – Software Electric Intangible | | | 0 | | | 0 | General | | |
| 44 | | | | 0 | | | 0 | Intangible - Software | | |

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| Southwestern Public Service Company | | | | | | WsD.2 ADIT Proration Factor | | | | | | | | | | | |
| Accumulated Deferred Income Taxes Proration Factor | | | | | | Table 21A | | | | | | | | | | | |
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| | Rate Year = | | | | | | | | | | | | | | | | |
| Line No. | | | | | | | | | | | | | | | | | |
| 1 | **Account 282 - Liberalized Depreciation-Transmission** | | | | | | | | | | | | | | | | |
| 2 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | | | |
| 3 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** | |
| 4 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (see Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) | |
| 5 | | | | | | | | | | | | | | | | | |
| 6 | December 31st balance Prorated Items | | | | | | | | | | | | | | | | |
| 7 | January | | | | | | | | | | | | | | | | |
| 8 | February | | | | | | | | | | | | | | | | |
| 9 | March | | | | | | | | | | | | | | | | |
| 10 | April | | | | | | | | | | | | | | | | |
| 11 | May | | | | | | | | | | | | | | | | |
| 12 | June | | | | | | | | | | | | | | | | |
| 13 | July | | | | | | | | | | | | | | | | |
| 14 | August | | | | | | | | | | | | | | | | |
| 15 | Septemb | | | | | | | | | | | | | | | | |

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| 16 | October | | | | | | | | | | | | | | | |
| 17 | November | | | | | | | | | | | | | | | |
| 18 | December | | | | | | | | | | | | | | | |
| 19 | Total | | | | | | | | | | | | | | | |
| 20 | | | | | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | | | | | |
| 24 | Ending Balance of Prorated items | | | | (Line 18, & Col H) | | | | | | | (Line 18, & Col N) | | | | |
| 25 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | From WsD and WsD.5Avg Rate Base | | | | |
| 26 | Proration Adjustment | | | | (Line 24 minus Line 25) | | | | | | | (Line 24 minus Line 25) | | | | |

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| 27 | | | | | | | | | | | | | | | | |
| 28 | | | | | | | | | | | | | | | | |
| 29 | **Account 282 - Liberalized Depreciation-General and Intangible** | | | | | | | | | | | | | | | |
| 30 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See note 6 and 7)** | | | | | |
| 31 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 32 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity(See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or | Difference between projected and actual activity when actual and projected activity are either both increases or | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is | Balance reflecting proration or averaging (See Note 5) |

| | | | | | | | | | | | | | decreases (See Note 2) | decreases (See Note 3) | an increase (See Note 4) | |
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| 33 | | | | | | | | | | | | | | | | |
| 34 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 35 | January | | | | | | | | | | | | | | | |
| 36 | February | | | | | | | | | | | | | | | |
| 37 | March | | | | | | | | | | | | | | | |
| 38 | April | | | | | | | | | | | | | | | |
| 39 | May | | | | | | | | | | | | | | | |
| 40 | June | | | | | | | | | | | | | | | |
| 41 | July | | | | | | | | | | | | | | | |
| 42 | August | | | | | | | | | | | | | | | |
| 43 | September | | | | | | | | | | | | | | | |
| 44 | October | | | | | | | | | | | | | | | |
| 45 | November | | | | | | | | | | | | | | | |
| 46 | December | | | | | | | | | | | | | | | |
| 47 | Total | | | | | | | | | | | | | | | |
| 48 | | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | |
| 50 | | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | |
| 52 | Ending Balance of Prorated items | | | | (Line 46, & Col H) | | | | | | | | (Line 46, & Col N) | | | |
| 53 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | | From WsD and WsD.5 | | | |
| 54 | Proration Adjustment | | | | (Line 52 minus Line 53) | | | | | | | | (Line 52 minus line 53) | | | |

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| 55 | | | | | | | | | | | | | | | | |
| 56 | | | | | | | | | | | | | | | | |
| 57 | **Account 283 - Liberalized Depreciation-Software** | | | | | | | | | | | | | | | |
| 58 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | | |
| 59 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 60 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | ADITWhen projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 61 | | | | | | | | | | | | | | | | |
| 62 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 63 | January | | | | | | | | | | | | | | | |
| 64 | February | | | | | | | | | | | | | | | |
| 65 | March | | | | | | | | | | | | | | | |
| 66 | April | | | | | | | | | | | | | | | |
| 67 | May | | | | | | | | | | | | | | | |
| 68 | June | | | | | | | | | | | | | | | |
| 69 | July | | | | | | | | | | | | | | | |
| 70 | August | | | | | | | | | | | | | | | |
| 71 | September | | | | | | | | | | | | | | | |
| 72 | October | | | | | | | | | | | | | | | |
| 73 | November | | | | | | | | | | | | | | | |
| 74 | December | | | | | | | | | | | | | | | |

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| 75 | Total | | | | | | | | | | | | | | | |
| 76 | | | | | | | | | | | | | | | | |
| 77 | | | | | | | | | | | | | | | | |
| 78 | | | | | | | | | | | | | | | | |
| 79 | | | | | | | | | | | | | | | | |
| 80 | Ending Balance of Prorated items | | | | (Line 74, & Col H) | | | | | | | | (Line 74, & Col N) | | | |
| 81 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | | From WsD and WsD.5 | | | |
| 82 | Proration Adjustment | | | | (Line 80 minus Line 81) | | | | | | | | (Line 80 minuse Line 81) | | | |

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| 83 | | | | | | | | | | | | | | | | |
| 84 | | | | | | | | | | | | | | | | |
| 85 | **Account 190 - Basis Difference-Transmission** | | | | | | | | | | | | | | | |
| 86 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | | |
| 87 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 88 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 89 | | | | | | | | | | | | | | | | |
| 90 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 91 | January | | | | | | | | | | | | | | | |
| 92 | Febr | | | | | | | | | | | | | | | |

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| | uary | | | | | | | | | | | | | | | |
| 93 | March | | | | | | | | | | | | | | | |
| 94 | April | | | | | | | | | | | | | | | |
| 95 | May | | | | | | | | | | | | | | | |
| 96 | June | | | | | | | | | | | | | | | |
| 97 | July | | | | | | | | | | | | | | | |
| 98 | August | | | | | | | | | | | | | | | |
| 99 | September | | | | | | | | | | | | | | | |
| 100 | October | | | | | | | | | | | | | | | |
| 101 | November | | | | | | | | | | | | | | | |
| 102 | December | | | | | | | | | | | | | | | |
| 103 | Total | | | | | | | | | | | | | | | |
| 104 | | | | | | | | | | | | | | | | |
| 105 | | | | | | | | | | | | | | | | |
| 106 | | | | | | | | | | | | | | | | |
| 107 | | | | | | | | | | | | | | | | |
| 108 | Ending Balance of Prorated items | | | | (Line 102, & Col H) | | | | | | | | (Line 102, & Col N) | | | |
| 109 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | | From WsD and WsD.5 | | | |
| 110 | Proration Adjustment | | | | (Line 108 minus Line 109) | | | | | | | | (Line 108 minus Line 109) | | | |

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| 111 | | | | | | | | | | | | | | | | |
| 112 | | | | | | | | | | | | | | | | |
| 113 | **Account 190 - Basis Difference-General and Intangible** | | | | | | | | | | | | | | | |

| 114 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 115 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 116 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity(See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 117 | | | | | | | | | | | | | | | | |
| 118 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 119 | January | | | | | | | | | | | | | | | |
| 120 | February | | | | | | | | | | | | | | | |
| 121 | March | | | | | | | | | | | | | | | |
| 122 | April | | | | | | | | | | | | | | | |
| 123 | May | | | | | | | | | | | | | | | |
| 124 | June | | | | | | | | | | | | | | | |
| 125 | July | | | | | | | | | | | | | | | |
| 126 | August | | | | | | | | | | | | | | | |
| 127 | September | | | | | | | | | | | | | | | |
| 128 | October | | | | | | | | | | | | | | | |
| 129 | November | | | | | | | | | | | | | | | |
| 130 | December | | | | | | | | | | | | | | | |
| 131 | Total | | | | | | | | | | | | | | | |
| 132 | | | | | | | | | | | | | | | | |
| 133 | | | | | | | | | | | | | | | | |
| 134 | | | | | | | | | | | | | | | | |
| 135 | | | | | | | | | | | | | | | | |

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| 136 | Ending Balance of Prorated items | | (Line 130, & Col H) | | | | | | (Line 130, & Col N) | | | | |
| 137 | Non-prorated Average Balance | | From WsD and WsD.5 | | | | | | From WsD and WsD.5 | | | | |
| 138 | Proration Adjustment | | (Line 136 minus Line 137) | | | | | | (Line 136 minus Line 137) | | | | |

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| 139 | | | | | | | | | | | | | | | | | |
| 140 | | | | | | | | | | | | | | | | | |
| 141 | **Account 190 - Basis Difference-CIAC Transmission** | | | | | | | | | | | | | | | | |
| 142 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | | | |
| 143 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** | |
| 144 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) | |
| 145 | | | | | | | | | | | | | | | | | |
| 146 | December 31st balance Prorated Items | | | | | | | | | | | | | | | | |
| 147 | January | | | | | | | | | | | | | | | | |
| 148 | February | | | | | | | | | | | | | | | | |
| 149 | March | | | | | | | | | | | | | | | | |

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| 150 | April | | | | | | | | | | | | | | | |
| 151 | May | | | | | | | | | | | | | | | |
| 152 | June | | | | | | | | | | | | | | | |
| 153 | July | | | | | | | | | | | | | | | |
| 154 | Aug ust | | | | | | | | | | | | | | | |
| 155 | Sept emb er | | | | | | | | | | | | | | | |
| 156 | Octo ber | | | | | | | | | | | | | | | |
| 157 | Nov emb er | | | | | | | | | | | | | | | |
| 158 | Dec emb er | | | | | | | | | | | | | | | |
| 159 | Total | | | | | | | | | | | | | | | |
| 160 | | | | | | | | | | | | | | | | |
| 161 | | | | | | | | | | | | | | | | |
| 162 | | | | | | | | | | | | | | | | |
| 163 | | | | | | | | | | | | | | | | |
| 164 | Ending Balance of Prorated items | | | | (Line 158, & Col H) | | | | | | | (Line 158, & Col N) | | | | |
| 165 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | From WsD and WsD.5 | | | | |
| 166 | Proration Adjustment | | | | (Line 164 minus Line 165) | | | | | | | (Line 164 minus Line 165) | | | | |

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| 167 | | | | | | | | | | | | | | | | |
| 168 | | | | | | | | | | | | | | | | |
| 169 | **Account 190 - Basis Difference-CIAC General** | | | | | | | | | | | | | | | |
| 170 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | |

| 171 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 172 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 173 | | | | | | | | | | | | | | | | |
| 174 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 175 | January | | | | | | | | | | | | | | | |
| 176 | February | | | | | | | | | | | | | | | |
| 177 | March | | | | | | | | | | | | | | | |
| 178 | April | | | | | | | | | | | | | | | |
| 179 | May | | | | | | | | | | | | | | | |
| 180 | June | | | | | | | | | | | | | | | |
| 181 | July | | | | | | | | | | | | | | | |
| 182 | August | | | | | | | | | | | | | | | |
| 183 | September | | | | | | | | | | | | | | | |
| 184 | October | | | | | | | | | | | | | | | |
| 185 | November | | | | | | | | | | | | | | | |
| 186 | December | | | | | | | | | | | | | | | |
| 187 | Total | | | | | | | | | | | | | | | |
| 188 | | | | | | | | | | | | | | | | |
| 189 | | | | | | | | | | | | | | | | |
| 190 | | | | | | | | | | | | | | | | |
| 191 | | | | | | | | | | | | | | | | |
| 192 | Ending Balance of Prorated items | | | | (Line 186, & Col H) | | | | | | | | (Line 186, & Col N) | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 193 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | | From WsD and WsD.5 | | | |
| 194 | Proration Adjustment | | | | (Line 192 minus Line 193) | | | | | | | | (Line 192 minus Line 193) | | | |

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| 195 | | | | | | | | | | | | | | | | |
| 196 | | | | | | | | | | | | | | | | |
| 197 | **Account 190 - Federal Only NOL-Transmission** | | | | | | | | | | | | | | | |
| 198 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6)** | | | | | |
| 199 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 200 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 201 | | | | | | | | | | | | | | | | |
| 202 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 203 | January | | | | | | | | | | | | | | | |
| 204 | February | | | | | | | | | | | | | | | |
| 205 | March | | | | | | | | | | | | | | | |
| 206 | April | | | | | | | | | | | | | | | |
| 207 | May | | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 208 | June | | | | | | | | | | | | | | | |
| 209 | July | | | | | | | | | | | | | | | |
| 210 | August | | | | | | | | | | | | | | | |
| 211 | September | | | | | | | | | | | | | | | |
| 212 | October | | | | | | | | | | | | | | | |
| 213 | November | | | | | | | | | | | | | | | |
| 214 | December | | | | | | | | | | | | | | | |
| 215 | Total | | | | | | | | | | | | | | | |
| 216 | | | | | | | | | | | | | | | | |
| 217 | | | | | | | | | | | | | | | | |
| 218 | | | | | | | | | | | | | | | | |
| 219 | | | | | | | | | | | | | | | | |
| 220 | Ending Balance of Prorated items | | | | (Line 214, & Col H) | | | | | | | | (Line 214, & Col N) | | | |
| 221 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | | From WsD and WsD.5 | | | |
| 222 | Proration Adjustment | | | | (Line 220 Minus Line 221) | | | | | | | | (Line 220 Minuse Line 221) | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 223 | | | | | | | | | | | | | | | | |
| 224 | | | | | | | | | | | | | | | | |
| 225 | **Account 190 - Federal Only NOL-General** | | | | | | | | | | | | | | | |
| 226 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration - True-up (See Note 6 and 7)** | | | | | |
| 227 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 228 | Month | Days in the | Number of Days | Total Days in | Proration Amount | | Projected Monthly | Prorated Projected | Prorated Projected | | Actual Monthly | Difference between | Preserve proration | Difference between | When projected | Balance reflecting |

| | | Month | Remaining in Year After Month's Accrual of Deferred Taxes | Future Portion of Test Period | (C / D) | | Activity | Monthly Activity (E x F) | Balance (Cumulative Sum of G) | | Activity | projected and actual activity (See Note 1) | when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | proration or averaging (See Note 5) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 229 | | | | | | | | | | | | | | | | |
| 230 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 231 | January | | | | | | | | | | | | | | | |
| 232 | February | | | | | | | | | | | | | | | |
| 233 | March | | | | | | | | | | | | | | | |
| 234 | April | | | | | | | | | | | | | | | |
| 235 | May | | | | | | | | | | | | | | | |
| 236 | June | | | | | | | | | | | | | | | |
| 237 | July | | | | | | | | | | | | | | | |
| 238 | August | | | | | | | | | | | | | | | |
| 239 | September | | | | | | | | | | | | | | | |
| 240 | October | | | | | | | | | | | | | | | |
| 241 | November | | | | | | | | | | | | | | | |
| 242 | December | | | | | | | | | | | | | | | |
| 243 | Total | | | | | | | | | | | | | | | |
| 244 | | | | | | | | | | | | | | | | |
| 245 | | | | | | | | | | | | | | | | |
| 246 | | | | | | | | | | | | | | | | |
| 247 | | | | | | | | | | | | | | | | |
| 248 | Ending Balance of Prorated items | | | | (Line 242, & Col H) | | | | | | | | (Line 242, & Col N) | | | |
| 249 | Non-prorated Average Balance | | | | From WsD and WsD.5 | | | | | | | | From WsD and WsD.5 | | | |
| 250 | Proration Adjustment | | | | (Line 248 minus Line 249) | | | | | | | | (Line 248 minus | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | line 249) | | | |
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| 251 | | | | | | | | | | | | | |
| 252 | | | | | | | | | | | | | |
| 253 | | | | | | | | | | | | | |

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| 254 | | | | | | | | | | | | | | | | |
| 255 | **Account 182 – Excess ADIT Federal Only NOL - Transmission** | | | | | | | | | | | | | | | |
| 256 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration – True-up (See Note 6 and 7)** | | | | | |
| 257 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 258 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 259 | | | | | | | | | | | | | | | | |
| 260 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 261 | January | | | | | | | | | | | | | | | |
| 262 | February | | | | | | | | | | | | | | | |
| 263 | March | | | | | | | | | | | | | | | |
| 264 | April | | | | | | | | | | | | | | | |
| 265 | May | | | | | | | | | | | | | | | |
| 266 | June | | | | | | | | | | | | | | | |
| 267 | July | | | | | | | | | | | | | | | |
| 268 | August | | | | | | | | | | | | | | | |
| 269 | September | | | | | | | | | | | | | | | |
| 270 | October | | | | | | | | | | | | | | | |
| 271 | November | | | | | | | | | | | | | | | |
| 272 | December | | | | | | | | | | | | | | | |
| 273 | Total | | | | | | | | | | | | | | | |
| 274 | | | | | | | | | | | | | | | | |
| 275 | | | | | | | | | | | | | | | | |
| 276 | | | | | | | | | | | | | | | | |
| 277 | | | | | | | | | | | | | | | | |
| 278 | Ending Balance of Prorated items | | | | (Line 272, & Col H) | | | | | | | | (Line 272, & Col N) | | | |
| 279 | Non-prorated Average Balance | | | | From WsD.3 Excess ADIT | | | | | | | | From WsD.3 Excess ADIT | | | |
| 280 | Proration Adjustment | | | | (Line 278 minus Line 279) | | | | | | | | (Line 278 minus Line 279) | | | |
| 281 | | | | | | | | | | | | | | | | |
| 282 | | | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 283 | **Account 182 – Excess ADIT Federal Only NOL - General** | | | | | | | | | | | | | | | |
| 284 | **Days in Period** | | | | | | **Averaging with Proration - Projected** | | | | **Averaging Preserving Projected Proration – True-up (See Note 6 and 7)** | | | | | |
| 285 | **A** | **B** | **C** | **D** | **E** | | **F** | **G** | **H** | | **I** | **J** | **K** | **L** | **M** | **N** |
| 286 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period | Proration Amount (C / D) | | Projected Monthly Activity | Prorated Projected Monthly Activity (E x F) | Prorated Projected Balance (Cumulative Sum of G) | | Actual Monthly Activity | Difference between projected and actual activity (See Note 1) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases (See Note 2) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases (See Note 3) | When projected activity is an increase while actual activity is a decrease or projected activity is a decrease while actual activity is an increase (See Note 4) | Balance reflecting proration or averaging (See Note 5) |
| 287 | | | | | | | | | | | | | | | | |
| 288 | December 31st balance Prorated Items | | | | | | | | | | | | | | | |
| 289 | January | | | | | | | | | | | | | | | |
| 290 | February | | | | | | | | | | | | | | | |
| 291 | March | | | | | | | | | | | | | | | |
| 292 | April | | | | | | | | | | | | | | | |
| 293 | May | | | | | | | | | | | | | | | |
| 294 | June | | | | | | | | | | | | | | | |
| 295 | July | | | | | | | | | | | | | | | |
| 296 | August | | | | | | | | | | | | | | | |
| 297 | September | | | | | | | | | | | | | | | |
| 298 | October | | | | | | | | | | | | | | | |
| 299 | November | | | | | | | | | | | | | | | |
| 300 | December | | | | | | | | | | | | | | | |
| 301 | Total | | | | | | | | | | | | | | | |
| 302 | | | | | | | | | | | | | | | | |
| 303 | | | | | | | | | | | | | | | | |
| 304 | | | | | | | | | | | | | | | | |
| 305 | | | | | | | | | | | | | | | | |
| 306 | Ending Balance of Prorated items | | | | (Line 300, & Col H) | | | | | | | | (Line 300, & Col N) | | | |
| 307 | Non-prorated Average Balance | | | | From WsD.3 Excess ADIT | | | | | | | | From WsD.3 Excess ADIT | | | |
| 308 | Proration Adjustment | | | | (Line 306 minus Line 307) | | | | | | | | (Line 306 minus Line 307) | | | |

Notes: 1) Column J is the difference between projected monthly and actual monthly activity (Column I minus Column F). Specifically, if projected and actual activity are both positive, a negative in Column J represents over-projection (amount of projected activity that did not occur) and a positive in Column J represents under-projection (excess of actual activity over projected activity). If projected and actual activity are both negative, a negative in Column J represents under-projection (excess of actual activity over projected activity) and a positive in Column J represents over-projection (amount of projected activity that did not occur).

2) Column K preserves proration when actual monthly and projected monthly activity are either both increases or decreases. Specifically, if Column J is over-projected, enter Column G x [Column I/Column F]. If Column J is under-projected, enter the amount from Column G and complete Column L). In other situations, enter zero.

3) Column L applies when (1) Column J is under-projected AND (2) actual monthly and projected monthly activity are either both increases or decreases. Enter the amount from Column J. In other situations, enter zero.

4) Column M applies when (1) projected monthly activity is an increase while actual monthly activity is a decrease OR (2) projected monthly activity is a decrease while actual monthly activity is an increase. Enter actual monthly activity (Col I). In other situations, enter zero.

5) Column N is computed by adding the prorated monthly activity, if any, from Column K to 50 percent of the portion of monthly activity, if any, from Column L or M to the balance at the end of the prior month. The activity in columns L and M is multiplied by 50 percent to reflect averaging of rate base to the extent that the proration requirement has not been applied to a portion of the monthly activity.

6) The methodology to remove double averaging from the true-up ADIT Proration calculation, is effective June 27, 2018.

7) Excess/deficient ADIT resulting from the enactment of the Tax Reform and Jobs Act is included beginning January 1, 2018 (with the 2018 True-Up)

Southwestern Public Service Company **Worksheet D.3**

Worksheet D.3 Non-Plant Excess ADIT **Table 21B**

Inputs for Average Rate Base Calculations

| Line No. | (a) | Year = 20yy (b) Projected Beg of Year Balance | (c) Projected End of Year Balance | (d) Projected Avg. Balance (b+c)/2 | (e) ADIT Amortization | (f) References for Actual Data | Year = 20yy (g) Actual Beg of Year Balance | (h) Actual End of Year Balance | (i) Actual Avg. Balance (f+g)/2 | (j) ADIT Amortization |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Excess Deferred Taxes - Liabilities Account 254 (Unprotected) | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | | | | | | | | | | |
| 4 | | | | | | | | | | |
| 5 | | | | | | | | | | |
| 6 | | | | | | | | | | |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | - | | | | | - | |
| 13 | **Excess ADIT Liabilities Account 254 Subject to Proration (Protected)** | | | | | | **Excess ADIT Liabilities Account 254 Subject to Proration (Protected)** | | | |
| 14 | | | | - | | | | | - | |
| 15 | | | | - | | | | | - | |

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|---|---|---|---|---|---|---|---|---|---|
| 16 | Total Account 254 | 0 | 0 | - | 0 | | 0 | 0 | 0 | 0 |
| 17 | | | | | | | | | |
| 18 | Acct 254 Gross Up | | | | | | | | |
| 19 | | | | | | | | | |
| 20 | Total Acct 254 Grossed Up | 0 | 0 | | | FF1, p 278, Footnote | 0 | 0 | | |
| 21 | | | | | | | | | |
| 22 | Excess Deferred Taxes - Assets Account 182.3 (Unprotected) | | | | | | | | | |
| 23 | | | | | | | | | |
| 24 | | | | | | | | | |
| 25 | | | | | | | | | |
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| 51 | | | | - | | | | | - | |
| 52 | | | | - | | | | | - | |
| 53 | **Excess ADIT Assets Account 182.3 Subject to Proration (Protected)** | | | | | | **Excess ADIT Assets Account 182.3 Subject to Proration (Protected)** | | | |
| 54 | | | | | | | | | | |
| 55 | | | | | | | | | | |
| 56 | | | | | | | | | | |
| 57 | | | | - | | | | | - | |
| 58 | | | | - | | | | | - | |
| 59 | | | | - | | | | | - | |
| 60 | | | | - | | | | | - | |
| 61 | Total Account 182.3 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 |
| 62 | | | | | | | | | | |
| 63 | Acct 182.3 Gross Up | | | | | | | | | |
| 64 | | | | | | | | | | |
| 65 | Total Acct 182.3 Grossed Up | 0 | 0 | | | FF1, p 278, Footnote | 0 | 0 | | |

Note 1: Excess/deficient ADIT and associated amortizations resulting from the enactment of the Tax Reform and Jobs Act is included beginning with the 2018 True-Up

**Southwestern Public Service Company** **Worksheet D.4**

**Worksheet D.4 - (Excess)/Deficient ADIT Amortization** **Table 21C**

Plant Excess ADIT Amortization, Projected for Billing Year = 20yy

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|
| **Identification** | **Total (Note 1)** | **Retail, Production & Other Related** | **Transmission Related** | **Plant Related** | **Labor Related** | **Total Included in Income Tax Expense (d)+(e)+(f)** | **Remaining Amortization Period (Note 2)** |
| | | | | | | | |
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| | | | | | | | |
| **Subtotal** | | | | | | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | - | - | - | - | | |
| **Total** | | | | | | | |

## Southwestern Public Service Company

## Worksheet D.4 - (Excess)/Deficient ADIT Amortization

Non-Plant Excess ADIT Amortization, Projected for Billing Year = 20yy

| (a)<br>Identification | (b)<br>Total (Note 1) | (c)<br>Retail, Production & Other Related | (d)<br>Transmission Related | (e)<br>Plant Related | (f)<br>Labor Related | (g)<br>Total Included in Income Tax Expense<br>(d)+(e)+(f) | (h)<br>Remaining Amortization Period (Note 2) |
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| **Subtotal** | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Transmission Allocator [ TP, GP or W/S ]** | | - | - | - | - | | |
| **Total** | | | | | | | |

## Southwestern Public Service Company

## Worksheet D.4 - (Excess)/Deficient ADIT Amortization

Plant Excess ADIT Amortization, Actual for Billing Year = 20yy

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|
| **Identification** | **Total (Note 1)** | **Retail, Production & Other Related** | **Transmission Related** | **Plant Related** | **Labor Related** | **Total Included in Income Tax Expense (d)+(e)+(f)** | **Remaining Amortization Period (Note 2)** |
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| **Subtotal** | | | | | | | |

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|---|---|---|---|---|---|---|---|
| **Transmission Allocator [ TP, GP or W/S ]** | | - | - | - | - | | |
| **Total** | | | | | | | |

## Southwestern Public Service Company

## Worksheet D.4 - (Excess)/Deficient ADIT Amortization

Non-Plant Excess ADIT Amortization, Actual for Billing Year = 20yy

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|
| **Identification** | **Total (Note 1)** | **Retail, Production & Other Related** | **Transmission Related** | **Plant Related** | **Labor Related** | **Total Included in Income Tax Expense (d)+(e)+(f)** | **Remaining Amortization Period (Note 2)** |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| **Subtotal** | | | | | | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | - | - | - | - | | |
| **Total** | | | | | | | |

Note 1: Excess and Deficient ADIT is amortized to FERC Accounts 410.1 and 411.1
Note 2: The amortization of Excess and Deficient ADIT balances began January 1, 2018 and are included in the 2018 True-Up

## Addendum 5 To Attachment H Part 3

# Southwestern Public Service Company
# Worksheet E - Rate Base Adjustments

**Worksheet E**

**Table 22**

**ADIT Account 281 Projected for Billing Year = 20yy**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail, Production & Other Related | Transmission Related | Plant Related | Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |
| 281 | | - | | | | | | |
| 281 | | - | | | | | | |
| 281 | | - | | | | | | |
| 281 | | - | | | | | | |
| 281 | | - | | | | | | |
| Subtotal | | | | | | | | |
| ADIT Adjustments (Avg Balance from WsD.5) | | | | | | | | |
| 281 | | | | | | | | |
| | | | | | | | | |
| | | - | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | - | - | - | - | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | |
| **Total** | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| **Total** | | 0 | 0 | 0 | 0 | 0 | |

## ADIT Account 282 Projected for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail, Production & Other Related | Transmission Related | Plant Related | Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |
| 282 | | - | | | | | | |
| 282 | | - | | | | | | |
| 282 | | - | | | | | | |
| 282 | | - | | | | | | |
| 282 | | - | | | | | | |
| 282 | | | | | | | | |
| 282 | | | | | | | | |
| 282 | | | | | | | | |
| 282 | FAS 109 Plant Excess ADIT – Protected | | | | | | | |
| 282 | FAS 109 Plant Excess ADIT – Unprotected | | | | | | | |
| | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Subtotal | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 282 | | | | | | | | |
| 282 | | | | | | | | |
| 282 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| | | - | - | - | - | - | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Proration Adjustment – Transmission (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General & Intangible (from WsD.2)** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| **Total** | | | 0 | 0 | 0 | 0 | 0 | |

## ADIT Account 283 Projected for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| | | Avg Balance | Retail, Production & Other | Transmissi | Plant | Labor | Total Included in Rate Base | |

| Acc. No. | Identification | from WsD | Related | on Related | Related | Related | (E)+(F)+(G) | Description |
|---|---|---|---|---|---|---|---|---|
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| Subtotal | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 283 | | | | | | | | |
| 283 | | | | | | | | |
| | | | | | | | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Proration Adjustment – Software (from WsD.2)** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| **Total** | | | 0 | 0 | 0 | 0 | 0 | |

**ADIT Account 254 Projected for Billing Year = 20yy**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail, Production & Other Related | Transmission Related | Plant Related | Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |
| 254 | | - | | | | | | |
| 254 | | - | | | | | | |
| 254 | | - | | | | | | |
| 254 | | - | | | | | | |
| 254 | | - | | | | | | |
| 254 | | - | | | | | | |
| 254 | | - | | | | | | |
| | | | | | | | | |
| Excess ADIT Liabilities subject to Proration | | - | - | - | - | - | | |
| | | - | | | | | | |
| | | - | | | | | | |
| | | - | | | | | | |
| | | - | | | | | | |
| Subtotal - Projected | | - | - | - | - | - | | |
| Proration Adjustment – (from WsD.2) | | - | - | - | - | - | | |
| Total | | - | - | - | - | - | | |
| Transmission Allocator [ TP, GP or W/S ] | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | | |
| Total | | 0 | 0 | 0 | 0 | 0 | | |
| | | | | | | | | |
| | | | | | | | | |

# Southwestern Public Service Company
# Worksheet E - Rate Base

Worksheet E Tabl

# Adjustments



**ADIT Account 190 Projected for Billing Year = 20yy**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail, Production & Other Related | Transmission Related | Plant Related | Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |

**ADIT Account 190 Projected for Billing Year = 20yy**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. | Identification | Avg Balance from WsD | Retail, Production & Other Related | Transmission Relat | Plant Rel | Labor Rel | Total Included in Rate Base (E)+(F)+(G) | Descr |

| No. | | | | ed | ate d | ate d | | iption |
|---|---|---|---|---|---|---|---|---|
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | FAS 109 Plant Deficient ADIT - Protected | | | | | | | |
| 190 | FAS 109 Plant Deficient ADIT - Unprotected | | | | | | | |
| Subtotal | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 190 | | | | | | | | |
| 190 | | | | | | | | |
| 190 | | | | | | | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Proration Adjustment – Transmission (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General & Intangible (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – Transmission NOL (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General NOL (from WsD.2)** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000 % | 0.00 00% | 0.00 00% | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Total** | | | 0 | 0 | 0 | 0 | 0 | | |

**ADIT Account 182.3 Projected for Billing Year = 20yy**

| (A) Acc. No. | (B) Identification | (C) Avg Balance from WsD | (D) Retail, Production & Other Related | (E) Transmission Related | (F) Plant Related | (G) Labor Related | (H) Total Included in Rate Base (E)+(F)+(G) | (I) Description |
|---|---|---|---|---|---|---|---|---|
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| | | | | | | | | |
| **Excess ADIT Assets Subject to Proration** | | - | - | - | - | - | | |
| | | - | | | | | | |
| | | - | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| **Subtotal - Projected** | | - | - | - | - | - | | |
| **Proration Adjustment – Transmission NOL (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General NOL (from WsD.2)** | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Total** | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| **Total** | | 0 | 0 | 0 | 0 | 0 | |

## Unamortized Balance of Abandoned Incentive Plant Projected for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|
| Acc. No. | Identification | Average Unamortized Balance from WsD | Current Year Amortization Expense | Unamortized Balance End of Current Year |
| | | - | | - |
| | | - | | - |
| | | | | |
| **Total** | | - | - | - |

## Unamortized Balance of Extraordinary Property Loss Projected for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|
| | | Average Unamortized Balance | Current Year Amortiz | Unamortized Balance End |

| Acc. No. | Identification | from WsD | ation Expense | of Current Year |
|---|---|---|---|---|
| | | - | | - |
| | | - | | - |
| | | | | |
| Total | | - | - | - |

# Southwestern Public Service Company
# Worksheet E - Rate Base Adjustments

**Worksheet E**

**Table 24**

**ADIT Account 281 Actual for Billing Year = 20yy**

| (A) Acc. No. | (B) Identification | (C) Avg Balance from WsD | (D) Retail Production & Other Related | (E) Transmission Related | (F) Plant Related | (G) Labor Related | (H) Total Included in Rate Base (E)+(F)+(G) | (I) Description |
|---|---|---|---|---|---|---|---|---|
| 281 | | - | | | | | | |
| 281 | | - | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 281 | | - | | | | | | |
| Subtotal – FF1, p. 272-273 | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 281 | | | | | | | | |
| | | | | | | | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000% | 0.00 00% | 0.00 00% | | |
| **Total** | | | 0 | 0 | 0 | 0 | 0 | |

## ADIT Account 282 Actual for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail Production & Other Related | Transmission Related | Plant Related | Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |
| 282 | | - | | | | | | |
| 282 | | - | | | | | | |
| 282 | | - | | | | | | |
| 282 | FAS 109 Plant Excess ADIT – Protected | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 282 | FAS 109 Plant Excess ADIT – Unprotected | | | | | | | |
| Subtotal – FF1, p. 274-275 | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 282 | | | | | | | | |
| | | | | | | | | |
| | | | | | | | | |
| 282 | | | | | | | | |
| | | | | | | | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Proration Adjustment – Transmission (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General & Intangible (from WsD.2)** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000 % | 0.00 00% | 0.00 00% | | |
| **Total** | | | 0 | 0 | 0 | 0 | 0 | |

## ADIT Account 283 Actual for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail Production & Other Related | Transmission Related | 0 Plant Related | 0 Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |
| | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| 283 | | - | | | | | | |
| Subtotal – FF1, p. 276-277 | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 283 | | | | | | | | |
| | | | | | | | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Proration Adjustment – Software (from WsD.2)** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | |
| **Total** | | | 0 | 0 | 0 | 0 | 0 | |

**ADIT Account 254 Actual for Billing Year = 20yy**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| | | Avg Balance | Retail, Production & Other | Transmission | Plant | Labor | Total Included in Rate Base | |

| Acc. No. | Identification | from WsD | Related | Related | Related | Related | (E)+(F)+(G) | Description |
|---|---|---|---|---|---|---|---|---|
| 254 | - | | | | | | | |
| 254 | - | | | | | | | |
| 254 | - | | | | | | | |
| 254 | - | | | | | | | |
| 254 | - | | | | | | | |
| 254 | - | | | | | | | |
| 254 | - | | | | | | | |
| | | | | | | | | |
| **Excess ADIT Liabilities Subject to Proration** - | | - | - | - | - | | | |
| | - | | | | | | | |
| | - | | | | | | | |
| | - | | | | | | | |
| | - | | | | | | | |
| **Subtotal-Actual** - | | - | - | - | - | | | |
| **Proration Adjustment – Software (from WsD.2)** - | | | | | | | | |
| **Total** | - | - | - | - | - | | | |
| **Transmission Allocator [ TP, GP or W/S ]** - | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | | | |
| **Total** | - | 0 | 0 | 0 | 0 | | | |

## ADIT Account 190 Actual for Billing Year = 20yy

| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) |
|---|---|---|---|---|---|---|---|---|
| Acc. No. | Identification | Avg Balance from WsD | Retail Production & Other Related | Transmission Related | Plant Related | Labor Related | Total Included in Rate Base (E)+(F)+(G) | Description |

| | | | | | d | d | | |
|---|---|---|---|---|---|---|---|---|
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | | - | | | | | | |
| 190 | FAS 109 Plant Deficient ADIT – Protected | | | | | | | |
| 190 | FAS 109 Plant Deficient ADIT – Unprotected | | | | | | | |
| Subtotal – FF1, p. 234 | | | | | | | | |
| ADIT Adjustments (Avg. Balance from WsD.5) | | | | | | | | |
| 190 | | | | | | | | |
| 190 | | | | | | | | |
| **Less FASB 109 Above if not separately removed** | | | | | | | | |
| **Less FASB 106 Above if not separately removed** | | | | | | | | |
| **Proration Adjustment – Transmission (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General & Intangible (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – Transmission NOL (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General NOL (from WsD.2)** | | | | | | | | |
| **Total** | | - | - | - | - | - | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | | 0.0000% | 0.0000 % | 0.00 00% | 0.00 00% | | |
| **Total** | | | 0 | 0 | 0 | 0 | 0 | |

**ADIT Account 182.3 Actual for Billing Year = 20yy**

| (A) | (B) | (C) | (D) Retail, Producti | (E) | (F) | (G) | (H) Total Included | (I) |
|---|---|---|---|---|---|---|---|---|

| Acc. No. | Identification | Avg Balance from WsD | on & Other Related | Transmission Related | Plant Related | Labor Related | in Rate Base (E)+(F)+(G) | Description |
|---|---|---|---|---|---|---|---|---|
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| 182.3 | | - | | | | | | |
| **Excess ADIT Assets Subject to Proration** - | | - | - | - | - | | | |
| | | - | | | | | | |
| | | - | | | | | | |
| | | - | | | | | | |
| | | | | | | | | |
| **Subtotal - Actual** - | | - | - | - | - | | | |
| **Proration Adjustment – Transmission NOL (from WsD.2)** | | | | | | | | |
| **Proration Adjustment – General NOL (from WsD.2)** | | | | | | | | |
| **Total** | - | - | - | - | - | | | |
| **Transmission Allocator [ TP, GP or W/S ]** | | 0.0000% | 0.0000% | 0.0000% | 0.0000% | 0 | | |
| **Total** | | 0 | 0 | 0 | 0 | 0 | | |

**Southwestern Public Service** **Worksh**

# Company

# Worksheet E - Rate Base Adjustments

eet E

Tabl e 25

## Unamortized Balance of Abandoned Incentive Plant Actual for Billing Year = 20yy

| (A) Acc. No. | (B) Identification | (C) Average Unamortized Balance from WsD | (D) Prior Year Amortization Expense | (E) Unamortized Balance End of Prior Year |
|---|---|---|---|---|
| | | - | | - |
| | | - | | - |
| | | | | |
| | Total | - | - | - |

## Unamortized Balance of Extraordinary Property Loss Actual for Billing Year = 20yy

| (A) | (B) | (C) Average | (D) | (E) Unamortized |
|---|---|---|---|---|

| Acc. No. | Identification | Unamortized Balance from WsD | Prior Year Amortization Expense | Balance End of Prior Year |
|---|---|---|---|---|
| | _ | - | | - |
| | | - | | - |
| | | | | |
| | Total | - | - | - |

**Southwestern Public Service Company** **Worksheet F**
**Worksheet F - Working Capital** **Table 26**

| Line No. | | | | | |
|---|---|---|---|---|---|
| 1 | **I. PREPAYMENTS:** | | | | |
| 2 | **Calculation of Projected Average Balances Based on Actual Prior Year Beginning & Ending** | | | | |
| 3 | **Balances** | | | | |
| 4 | **(a)** | **(b)** | **(c)** | | **(d)** |
| 5 | | | | | Projected |
| 6 | | Balance at | Balance at | | Average |
| 7 | | Jan 1, 20yy | Dec 31, 20yy | | Balance |
| 8 | Plant Related: | | | | |
| 9 | | | | | 0 |
| 10 | | | | | 0 |
| 11 | | | | | 0 |
| 12 | | | | | 0 |
| 13 | | | | | 0 |

| | | | | |
|---|---|---|---|---|
| 14 | | | | 0 |
| 15 | Total Plant Related: | 0 | 0 | 0 |
| 16 | | | | |
| 17 | Labor Related: | | | |
| 18 | | | | 0 |
| 19 | | | | 0 |
| 20 | | | | 0 |
| 21 | | | | 0 |
| 22 | | | | 0 |
| 23 | | | | 0 |
| 24 | Total Labor Related: | 0 | 0 | 0 |
| 25 | | | | |
| 26 | Transmission Related: | | | |
| 27 | | | | 0 |
| 28 | | | | 0 |
| 29 | | | | 0 |
| 30 | | | | 0 |
| 31 | | | | 0 |
| 32 | Total Transmission Related: | 0 | 0 | 0 |
| 33 | | | | |
| 34 | Other - Not Included: | | | |
| 35 | | | | 0 |
| 36 | | | | 0 |
| 37 | | | | 0 |
| 38 | | | | 0 |
| 39 | | | | 0 |
| 40 | | | | 0 |
| 41 | | | | 0 |
| 42 | | | | 0 |
| 43 | | | | 0 |
| 44 | | | | 0 |
| 45 | | | | 0 |
| 46 | Total Other Not Included: | 0 | 0 | 0 |
| 47 | | | | |
| 48 | Total Prepayments Balances: | 0 | 0 | 0 |

**Calculation of Actual Average Balances for the Billing Period 01/01/20yy to 12/31/20yy**

| | Beginning of Year Balance | End of Year Balance | Actual Average Balance |
|---|---|---|---|
| Plant Related: | | | |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| Total Plant Related: | 0 | 0 | 0 |
| Labor Related: | | | |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| Total Labor Related: | 0 | 0 | 0 |
| Transmission Related: | | | |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| | | | 0 |
| Total Transmission Related: | 0 | 0 | 0 |
| Other - Not Included: | | | |
| | | | 0 |
| | | | 0 |
| | | | 0 |

| | | | | |
|---|---|---|---|---|
| 84 | | | | 0 |
| 85 | | | | 0 |
| 86 | | | | 0 |
| 87 | | | | 0 |
| 88 | | | | 0 |
| 89 | | | | 0 |
| 90 | | | | 0 |
| 91 | | | | 0 |
| 92 | Total Other Not Included: | 0 | 0 | 0 |
| 93 | | | | |
| 94 | Total Prepayments Balances: | 0 | 0 | 0 |
| 95 | | | | |
| 96 | **II. MATERIALS AND SUPPLIES** | | | |
| 97 | | | | |
| 98 | **Calculation of Projected Average Balances Based on Actual from Prior Year FF1:** | | | |
| 99 | **(a)** | **(b)** | **(c)** | **(d)** |
| 100 | | FF1, 20yy | FF1, 20yy | Projected Average |
| 101 | | Beg of Year | End of Year | Balance |
| 102 | Materials and Supplies - Transmission - FF1, p. 227, ln 8 | | | 0 |
| 103 | Materials and Supplies - Other - FF1, p. 227, ln 11 | | | 0 |
| 104 | | | | |
| 105 | | | | |
| 106 | **Calculation of Actual Average Balances Based on Actual from FF1:** | | | |
| 107 | | | | |
| 108 | | FF1 20yy | FF120yy | Actual Average |
| 109 | | Beg of Year | End of Year | Balance |
| 110 | Materials and Supplies - Transmission - FF1, p. 227, ln 8 | | | 0 |
| 111 | Materials and Supplies - Other - FF1, p. 227, ln 11 | | | 0 |

**Southwestern Public Service Company** Table 26A

**Worksheet F.1 - Unfunded Reserves**

Projected for Billing Year = YYYY

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
|---|---|---|---|---|---|---|---|---|---|---|
| List of all reserves: | FERC Account for Accrual/Balance | Beginning Balance | Ending Balance | Average Balance | Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account | Enter 1 if the accrual account is included in the formula rate, enter (0) if the accrual account is NOT included in the formula rate | Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liability on the balance sheet | Allocation (Plant or Labor Allocator) | Allocation Factor | Allocated to Transmission |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| Total Proj. | | | | - | | | | | | - |

Notes:

The Formula Rate shall include a credit to rate base for each unfunded reserve. An unfunded reserve is a reserve where an escrow, trust, or restricted account has not been established for a fund whose balance is collected from customers through cost accruals to accounts that are recovered under the Formula Rate. Each unfunded reserve will be included on the lines above. The allocator in Col. (9) will be the same allocator used in the Formula Rate for the cost accruals to the account that is recovered under the Formula Rate

Actual for Billing Year = yyyy

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) |
|---|---|---|---|---|---|---|---|---|---|---|
| List of all reserves: | FERC Account for Accrual/Balance | Beginning Balance | Ending Balance | Average Balance | Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account | Enter 1 if the accrual account is included in the formula rate, enter (0) if the accrual account is NOT included in the formula rate | Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liability on the balance sheet | Allocation (Plant or Labor Allocator) | Allocation Factor | Allocated to Transmission |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| | | | | - | | | | | | - |
| Total Actual | | | | - | | | | | | - |

Notes:

A The Formula Rate shall include a credit to rate base for each unfunded reserve. An unfunded reserve is a reserve where an escrow, trust, or restricted account has not been established for a fund whose balance is collected from customers through cost accruals to accounts that are recovered under the Formula Rate. Each unfunded reserve will be included on the lines above. The allocator in Col. (9) will be the same allocator used in the Formula Rate for the cost accruals to the account that is recovered under the Formula Rate

**Southwestern Public Service Company** **Worksh**

**eet G**

**Worksheet G - O&M Expenses and Wages and Salaries** **Table 27**

| Line No. | (a) FERC Account No. | (b) Description | (c) Projected Amount | (d) FF1, Reference for Actual | (e) Actual Amount |
|---|---|---|---|---|---|
| 1 | | **TRANSMISSION EXPENSES** | | | |
| 2 | | *OPERATION* | | | |
| 3 | 560 | Supervision and Engineering | | p. 320-323, ln 83, (b) | |
| 4 | 561.0 | Load Dispatching | | p. 320-323, ln 84, (b) | |
| 5 | 561.1 | Load Dispatching - Reliability | | p. 320-323, ln 85, (b) | |
| 6 | 561.2 | Load Dispatching - Monitor & Operate Transmission System | | p. 320-323, ln 86, (b) | |
| 7 | 561.3 | Load Dispatching - Transmission Service & Scheduling | | p. 320-323, ln 87, (b) | |
| 8 | 561.4 | Scheduling, System Control & Dispatch Services | | p. 320-323, ln 88, (b) | |
| 9 | 561.5 | Reliability, Planning and Standards Development | | p. 320-323, ln 89, (b) | |
| 10 | 561.6 | Transmission Service Studies | | p. 320-323, ln 90, (b) | |
| 11 | 561.7 | Generation Interconnection Studies | | p. 320-323, ln 91, (b) | |
| 12 | 561.8 | Reliability, Planning and Standards Development Services | | p. 320-323, ln 92, (b) | |
| 13 | 562 | Station Expenses | | p. 320-323, ln 93, (b) | |
| 14 | 562.1 | Energy Storage Equipment | | p. 320-323, ln 93.1, (b) | |
| 15 | 563 | Overhead Line Expenses | | p. 320-323, ln 94, (b) | |

| | | | | | |
|---|---|---|---|---|---|
| 16 | 564 | Underground Line Expenses | | p. 320-323, ln 95, (b) | |
| 17 | 565 | Transmission of Electricity by Others | | p. 320-323, ln 96, (b) | |
| 18 | 566 | Miscellaneous Transmission Expenses | | p. 320-323, ln 97, (b) | |
| 19 | 567 | Rents | | p. 320-323, ln 98, (b) | |
| 20 | | Total Operation | 0 | | 0 |
| 21 | | | | | |
| 22 | | *MAINTENANCE* | | | |
| 23 | 568 | Supervision and Engineering | | p. 320-323, ln 101, (b) | |
| 24 | 569 | Structures | | p. 320-323, ln 102, (b) | |
| 25 | 569.1 | Computer Hardware | | p. 320-323, ln 103, (b) | |
| 26 | 569.2 | Computer Software | | p. 320-323, ln 104, (b) | |
| 27 | 569.3 | Communication Equipment | | p. 320-323, ln 105, (b) | |
| 28 | 569.4 | Miscellaneous Regional Transmission Plant | | p. 320-323, ln 106, (b) | |
| 29 | 570 | Station Equipment | | p. 320-323, ln 107, (b) | |
| 30 | 570.1 | Energy Storage Equipment | | p. 320-323, ln 107.1, (b) | |
| 31 | 571 | Overhead Lines | | p. 320-323, ln 108, (b) | |
| 32 | 572 | Underground Lines | | p. 320-323, ln 109, (b) | |
| 33 | 573 | Miscellaneous Transmission Plant | | p. 320-323, ln 110, (b) | |
| 34 | | Total Maintenance | 0 | | 0 |
| 35 | | | | | |
| 36 | | Total Transmission O&M | 0 | | 0 |
| 37 | | | | | |
| 38 | | Less: All 561 Accounts | 0 | | 0 |
| 39 | | Add Back: Account 561.6 - Transmission | 0 | | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | Service Studies | | | |
| 40 | | Add Back: Account 561.7 - Generation Interconnection Studies | 0 | | 0 |
| 41 | | Less: Account 565 - Transmission of Electricity by Others | 0 | | 0 |
| 42 | | Transmission O&M Expense Adjustment (Note 1) | | | |
| 43 | | | | | |
| 44 | | Total Net Transmission Expense | 0 | | 0 |
| 45 | | | | | |
| 46 | | **ADMINISTRATIVE AND GENERAL** | | | |
| 47 | | *OPERATION* | | | |
| 48 | 920 | Administrative and General Salaries | | p. 320-323, ln 181, (b) | |
| 49 | 921 | Office Supplies and Expense | | p. 320-323, ln 182, (b) | |
| 50 | 922 | (Less) Administrative Expense Transferred | | p. 320-323, ln 183, (b) | |
| 51 | 923 | Outside Services Employed | | p. 320-323, ln 184, (b) | |
| 52 | 924 | Property Insurance | | p. 320-323, ln 185, (b) | |
| 53 | 925 | Injury and Damages | | p. 320-323, ln 186, (b) | |
| 54 | 926 | Employee Pensions and Benefits | | p. 320-323, ln 187, (b) | |
| 55 | 928 | Regulatory Commission Expenses | | p. 320-323, ln 189, (b) | |
| 56 | 929 | (Less) Duplicate Charges-Cr. | | p. 320-323, ln 190, (b) | |
| 57 | 930.1 | General Advertising Expenses | | p. 320-323, ln 191, (b) | |
| 58 | 930.2 | Miscellaneous General Expenses | | p. 320-323, ln 192, (b) | |
| 59 | 931 | Rents | | p. 320-323, ln 193, (b) | |
| 60 | | Total Operation | 0 | | 0 |
| 61 | | | | | |
| 62 | | *MAINTENANCE* | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 63 | 935 | Maintenance of General Plant | | p. 320-323, ln 196, (b) | | | | | |
| 64 | | | | | | | | | |
| 65 | | Less: Account 926 Retail Pension Tracker | | p. 320-323 Footnote Data | | | | | |
| 66 | | Less: Account 926 Retail Pension Tracker Amortization | | p. 320-323 Footnote Data | | | | | |
| 67 | | Less: O&M Expenses (Note 1) | | | | | | | |
| 68 | | Less: Retail Advanced Grid A&G Costs (Note 2) | | | | | | | |
| 69 | | | | | | | | | |
| 70 | | | | | | | | | |
| 71 | | TOTAL ADMINISTRATIVE AND GENERAL | 0 | | 0 | | | | |
| 72 | | | | | | | | | |
| 73 | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| 74 | | | | **Projected** | | | | **Actual** | |
| 75 | | | Direct | Payroll Billed from | Total Projected | | Direct | Payroll Billed from | Total Actual |
| 76 | | Wages and Salaries Allocator | Payroll | Service Corp | Amount | | Payroll | Service Corp | Amount |
| 77 | | Production | | | 0 | p. 354-355, ln 20, (b) | | | 0 |
| 78 | | Transmission | | | 0 | p. 354-355, ln, 21, (b) | | | 0 |
| 79 | | Regional Market | | | 0 | p. 354-355, ln 22, (b) | | | 0 |
| 80 | | Distribution | | | 0 | p. 354-355, ln 23, (b) | | | 0 |
| 81 | | Other | | | 0 | p. 354-355, ln 24-26, (b) | | | 0 |
| 82 | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 83 | Total | 0 | 0 | 0 | 0 | 0 | 0 |
| 84 | | | | | | | |
| 85 | (Note 1: Eliminate Eddy County HVDC transmission O&M and A&G expenses.) | | | | | | |
| 86 | (Note 2: Source: Company books and records) | | | | | | |

**Southwestern Public Service Company**
**Worksheet H - Miscellaneous Expenses**

**Worksheet H**
**Table 28**

| Line No. | | | Projected | | | Actual | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | Acct 928 Projected for Billing Year = | | | Acct 928 Actual for Billing Year = | | | 20yy | |
| 2 | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 3 | | | 100% | 100% | | | 100% | 100% | | |
| 4 | | | Non- | Transmission | Transmission | | Non- | Transmission | Transmission | |
| 5 | Description | Expense | Transmission | Specific | Allocated | Expense | Transmission | Specific | Allocated | Explanation |
| 6 | | | | | | | | | | |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | Total 928 | | | | - | | | | | |
| | | - | - | - | | - | - | - | - | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
| 13 | | Acct 930.2 Projected for Billing Year = | | | 20yy | Acct 930.2 Actual for Billing Year = | | | 20yy | |
| 14 | | | | | | | | | | |
| 15 | | | | | | | | | | |
| 16 | | | | | | | | | | |
| 17 | | | | | | | | | | |
| 18 | | | | | | | | | | |
| 19 | | | | | | | | | | |
| 20 | | | | | | | | | | |
| 21 | Total 930.2 | | | | | | | | | |
| | | - | - | - | - | | - | - | - | |
| 22 | | | | | | | | | | |
| 23 | | | | | | | | | | |
| 24 | Transmission Safety & Siting Advertising (Other Than in Acct 930.1) Projected for Year = | | | | 20yy | Actual Transmission Safety & Siting for Year = | | | 20yy | |
| 25 | | | | | | | | | | |
| 26 | | | | | | | | | | |
| 27 | | | | | | | | | | |
| 28 | | | | | | | | | | |
| 29 | | | | | | | | | | |
| 30 | Total Transmission Safety & Siting Adv. | | | | | - | | | | |
| | - | | | | | | | | | |

**Southwestern Public Service Company** **Worksheet I**

**Worksheet I - Depreciation and Amortization Expense** **Table 29**

Projected Year = **20yy**

| Line No. | (a) Description | (b) Reference | (c) Projected Depreciation Expense | (d) Projected Amortization Expense | (e) Projected Total Depr. & Amort. Expense |
|---|---|---|---|---|---|
| 1 | Steam Production | | | | 0 |
| 2 | Other Production | | | | 0 |
| 3 | Adjustment to Production | WsD.5, lns 58 + 59, col (k) and WsD.5, lns 67 + 68, col (k) | | | 0 |
| 4 | Total Production | | 0 | 0 | 0 |
| 5 | | | | | |
| 6 | Transmission | | | | 0 |
| 7 | Adjustment to Transmission | WsD.5, ln 60, col (k) and WsD.5, ln 69, col (k) | | | 0 |
| 8 | Total Transmission | | 0 | 0 | 0 |
| 9 | | | | | |
| 10 | Distribution | | | | 0 |
| 11 | Adjustment to Distribution | WsD.5, ln 61, col (k) and WsD.5, ln 70, col (k) | | | 0 |
| 12 | Total Distribution | | 0 | 0 | 0 |
| 13 | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 14 | General | | | | | 0 | |
| 15 | Adjustment to General | WsD.5, ln 62, col (k) and WsD.5, ln 71, col (k) | | | 0 | | |
| 16 | Total General | | 0 | 0 | 0 | | |
| 17 | | | | | | | |
| 18 | Intangible - Computer Software | | | | | 0 | |
| 19 | Adjustment to Intangible | WsD.5, ln 63, col (k) and WsD.5, ln 72, col (k) | | | | 0 | |
| 20 | Total Intangible | | 0 | 0 | | 0 | |
| 21 | | | | | | | |
| 22 | Total | | | 0 | 0 | 0 | |
| 23 | | | | | | | |
| 24 | | | Actual Year = | **20yy** | | | |
| 25 | | | Actual | Actual | Actual Total Depr. & | | |
| 26 | | | | | | | |
| 27 | | | Depreciation Expense | Amortization Expense | Amort. Expense | | |
| 28 | | | | | | | |
| 29 | Steam Production | FF1, p. 336-337, footnote | | | | 0 | |
| 30 | Other Production | FF1, p. 336-337, footnote | | | | 0 | |
| 31 | Adjustment to Production | WsD.5, lns 58 + 59, col (m) and WsD.5, lns 67 + 68, col (m) | | | | 0 | 31 |
| 32 | Total Production | | | 0 | 0 | 0 | |
| 33 | | | | | | | |
| 34 | Transmission | FF1, p. 336-337, footnote | | | | 0 | |
| 35 | Adjustment to Transmission | WsD.5, ln 60, col (m) and WsD.5, ln 69, col (m) | | | 0 | | |
| 36 | Total Transmission | | 0 | 0 | 0 | | |
| 37 | | | | | | | |
| 38 | Distribution | FF1, p. 336-337, footnote | | | | 0 | |

| | | | | | |
|---|---|---|---|---|---|
| 39 | Adjustment to Distribution | WsD.5, ln 61, col (m) and WsD.5, ln 70, col (m) | | | 0 |
| 40 | Total Distribution | | 0 | 0 | 0 |
| 41 | | | | | |
| 42 | General | FF1, p. 336-337, footnote | | | 0 |
| 43 | Adjustment to General | WsD.5, ln 62, col (m) and WsD.5, ln 71, col (m) | 0 | | |
| 44 | Total General | | 0 | 0 | |
| 45 | | | | | |
| 46 | Intangible - Computer Software | FF1, p. 336-337, footnote | | | 0 |
| 47 | Adjustment to Intangible | WsD.5, ln 63, col (m) and WsD.5, ln 72, col (m) | | | 0 |
| 48 | Total Intangible | | 0 | 0 | 0 |
| 49 | | | | | |
| 50 | Total | | | 0 | 0 | 0 |

**Worksheet J**

**Table 30**

# Southwestern Public Service Company
# Worksheet J - Taxes Other Than Income & Investment Tax Credit

**Projected for Billing Year = 20yy**

| Line No. | (A) Description | (B) Expense | (C) Excluded from Rev Requirement | (D) Included in Rev Requirement |
|---|---|---|---|---|
| 1 | LABOR RELATED: | | | |

| | | | | | |
|---|---|---|---|---|---|
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | Subtotal Labor Related | - | - | | - |
| 6 | | | | | |
| 7 | PLANT RELATED: | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | Subtotal Plant Related - Property | - | - | | - |
| 13 | | | | | |
| 14 | OTHER: | | | | |
| 15 | | | | | |
| 16 | | | | | |
| 17 | FRANCHISE & GROSS RECEIPTS: | | | | |
| 18 | | | | | |
| 19 | | | | | |
| 20 | | | | | |
| 21 | | | | | |
| 22 | | | | | |
| 23 | | | | | |
| 24 | Subtotal Franchise & Gross Receipts | - | - | | - |
| 25 | | | | | |
| 26 | Total Taxes Other Than Income | - | - | | - |
| 27 | | | | | |
| 28 | | | | | |
| 29 | | | | | |
| 30 | Investment Tax Credit Amortized | | | | |
| 31 | | | | | |
| 32 | | | | **Actual for Billing Year =** | **20yy** |

| | (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|---|
| | | FF1 | | Excluded from | Included in |
| | Description | Reference | Expense | Rev Requirement | Rev Requirement |
| | LABOR RELATED: | | | | |
| | | | | | |
| | Subtotal Labor Related | | - | - | - |
| | PLANT RELATED: | | | | |
| | | | | | |
| | Subtotal Plant Related - Property | | - | - | - |
| | OTHER: | | | | |
| | - | - | | | |
| | FRANCHISE & GROSS RECEIPTS: | | | | |
| | | | | | |
| | Subtotal Franchise & Gross Receipts | | - | - | - |
| | Total Taxes Other Than Income | | | | |

| | | |
|---|---|---|
| 64 | FF1, p. 114-117, ln 14, (c): | |
| 65 | | |
| 66 | Investment Tax Credit Amortized FF1, p. 266-267, ln 8, (f) | |

**Southwestern Public Service Company**

**Worksheet K - Capital Structure**

**Worksheet K Table 31**

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | **PROJECTED BALANCES** | | | | | | | | |
| 2 | **Common Equity - Projected** | | | | | | | | | | | | | | 13 Month |
| 3 | | 01/01/yy | 01/31/yy | 02/28/yy | 03/31/yy | 04/30/yy | 05/31/yy | 06/30/yy | 07/31/yy | 08/31/yy | 09/30/yy | 10/31/yy | 11/30/yy | 12/31/yy | Average Balance |
| 4 | Proprietary Capital | | | | | | | | | | | | | | 0 |
| 5 | Less Preferred Stock | | | | | | | | | | | | | | 0 |
| 6 | Less Acct 216.1 Unapprop. Undist. Sub. Earnings | | | | | | | | | | | | | | 0 |
| 7 | Less Acct 219.1-Accum Other Compre. Income | | | | | | | | | | | | | | 0 |
| 8 | | | | | | | | | | | | | | | |
| 9 | **Common Equity Balances (ln 4 - ln 5 - ln 6 - n 7)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| 10 | | | | | | | | | | | | | | | |
| 11 | **Long Term Debt - Projected** | | | | | | **PROJECTED BALANCES** | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | Bonds | | | | | | | | | | | | | | 0 |
| 14 | Less Reacquired Bonds | | | | | | | | | | | | | | 0 |
| 15 | Other Long Term Debt | | | | | | | | | | | | | | 0 |
| 16 | | | | | | | | | | | | | | | |
| 17 | **Debt Balances (ln 13 - ln 14 + ln 15)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| 18 | | | | | | | | | | | | | | | |
| 19 | | | | | | | **ACTUAL BALANCES** | | | | | | | | |
| 20 | **Common Equity - Actual** | | | | | | | | | | | | | | 13 Month |
| 21 | | 01/01/yy | 01/31/yy | 02/28/yy | 03/31/yy | 04/30/yy | 05/31/yy | 06/30/yy | 07/31/yy | 08/31/yy | 09/30/yy | 10/31/yy | 11/30/yy | 12/31/yy | Average Balance |
| 22 | Proprietary Capital | | | | | | | | | | | | | | 0 |
| 23 | Less Preferred Stock | | | | | | | | | | | | | | 0 |
| 24 | Less Acct 216.1 Unapprop. Undist. Sub. Earnings | | | | | | | | | | | | | | 0 |
| 25 | Less Acct 219.1-Accum Other Compre. Income | | | | | | | | | | | | | | 0 |
| 26 | | | | | | | | | | | | | | | |
| 27 | **Common Equity Bal (ln 22 - ln 23 - ln 24 - ln 25)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| 28 | | | | | | | | | | | | | | | |
| 29 | | | | | | | **ACTUAL BALANCES** | | | | | | | | |
| 30 | **Long Term Debt - Actual** | | | | | | | | | | | | | | |
| 31 | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 32 | Bonds | | | | | | | | | | | | | | | 0 |
| 33 | Less Reacquired Bonds | | | | | | | | | | | | | | | 0 |
| 34 | Other Long Term Debt | | | | | | | | | | | | | | | 0 |
| 35 | | | | | | | | | | | | | | | | |
| 36 | **Debt Balances (ln 32 - ln 33 + ln 34)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| 37 | | | | | | | | | | | | | | | | |
| 38 | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | | | | | | | |
| 39 | | | | **Projected** | | | **FF1 Reference for Actual** | **Actual** | | | | | | | | |
| 40 | **Cost of Debt - Annual Interest Expense** | | | **20yy** | | | | **20yy** | | | | | | | | |
| 41 | | | | | | | | | | | | | | | | |
| 42 | Interest on Long Term Debt | | | | | | p. 114-117, ln 62 (c) | | | | | | | | | |
| 43 | Less: Financial Hedge Gain/Expense and Interest Rate Derivative(ln 62) | | | 0 | | | | 0 | | | | | | | | |
| 44 | Plus: Allowed Hedge and Interest Rate Derivative Recovery (ln 67) | | | 0 | | | | 0 | | | | | | | | |
| 45 | Amortization of Debt Discount and Expense | | | | | | p. 114-117, ln 63 (c) | | | | | | | | | |
| 46 | Amortization of Loss on Reacquired Debt | | | | | | p. 114-117, ln 64(c) | | | | | | | | | |
| 47 | Less: Interest on Long Term Credit Facility | | | | | | p. 256-257 (m) | | | | | | | | | |
| 48 | Less: Amort of Premium on Debt | | | | | | p. 114-117, ln 65 (c) | | | | | | | | | |
| 49 | Less: Amort of Gain on | | | | | | p. 114- | | | | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | Reacquired Debt | | | 117, ln 66 (c) | | |
| 50 | | | | | | |
| 51 | **Total Interest Expense (ln 42 - ln 43 + ln 44 + ln 45 + ln 46 - ln 47 – ln 48 - ln 49)** | **0** | | | **0** | |
| 52 | | | | | | |
| 53 | **Average Cost of Debt** | **0.00 %** | **(ln 51 / ln 17, col (o)** | | **0.0 0%** | **(ln 51 / ln 36, col (o)** |
| 54 | | | | | | |
| 55 | **Preferred Stock Cost** | | | | | |
| 56 | Dividends on Preferred Stock | | | p. 118-119, ln 29 (c) | | |
| 57 | **Average Cost of Preferred Stock** | **0.00 %** | **(ln 56 / ln 5 , col (o)** | | **0.0 0%** | **(ln 56 / ln 23, col (o)** |
| 58 | | | | | | |
| 59 | **Financial Hedge Amortization and Interest Rate Derivative (Enter Gains as a Negative Number)** | | | | | |
| 60 | | | | | | |
| 61 | | | | | | |
| 62 | Total Hedge Amortization and Interest Rate Derivative | 0 | | | 0 | |
| 63 | | | | | | |
| 64 | Total Average Capital Balance (ln 9 + ln 17) | 0 | | | 0 | |
| 65 | Financial Hedge Recovery Limit - 7.5 Basis Points of Total Capital | 0.00075 | | | 0.0007 5 | |
| 66 | Limit of Recoverable Amount | 0 | | | 0 | |
| 67 | **Recoverable Hedge Amortization & Interest Rate Derivative (Lesser of ln 62 or ln 66)** | 0 | | | 0 | |

**Southwestern Public Service Company** **Worksheet L**
**Worksheet L - Development of Composite State Income Tax Rate** **Table 32**

I. Development of **Projected** Composite State Income Tax Rate for Billing Period Beginning 01/01/yy

| | |
|---|---|
| State Income Tax Rate - New Mexico | |
| Apportionment Factor | |
| Projected Effective State Income Tax Rate | 0.0000% |
| State Income Tax Rate - Kansas | |
| Apportionment Factor | |
| Projected Effective State Income Tax Rate | 0.0000% |
| State Income Tax Rate - Oklahoma | |
| Apportionment Factor | |
| Projected Effective State Income Tax Rate | 0.0000% |
| State Income Tax Rate - Texas | |
| Apportionment Factor | |
| Projected Effective State Income Tax Rate | 0.0000% |
| Total Composite State Income Tax Rate | **0.0000%** |

II. Development of **Actual** Composite State Income Tax Rate for Billing Period Beginning 01/01/yy

| | |
|---|---|
| State Income Tax Rate - New Mexico | |
| Apportionment Factor | |
| Actual Effective State Income Tax Rate | 0.0000% |

| | | |
|---|---|---|
| State Income Tax Rate - Kansas | | |
| Apportionment Factor | | |
| Actual Effective State Income Tax Rate | | 0.0000% |
| State Income Tax Rate - Oklahoma | | |
| Apportionment Factor | | |
| Actual Effective State Income Tax Rate | | 0.0000% |
| State Income Tax Rate - Texas | | |
| Apportionment Factor | | |
| Actual Effective State Income Tax Rate | | 0.0000% |
| Total Composite State Income Tax Rate | | **0.0000%** |

# Southwestern Public Service Company Worksheet M - Direct Assigned Radial Lines

**Worksheet M**

**Table 33**

**Actual for Billing Year =** **20yy** (Note 1)

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|
| | | Last Actual | | Radial Line Reclassification | | | | ATRR - TP Allocator Adj. | |
| | | Net Plant | | Month/ Year | | Prorate | | Prorate | Gross |

| Line No. | | Gross Plant | Net Plant | Carrying Charge (Annual Rate) Input | Revenue Requirement Col (b) * Col (c) | In Service of Reclass Input | Prorate Input | Revenue Requirement Col (f) / 12 * Col (d) | True-Up Adjustment Col (g) - Col (d) | Gross Plant Col (f) /12 * Col (a) | Plant Adjustment Col (i) - Col (a) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Radial Line Direct Assignment (Worksheet O) | | | | | | | | | | |
| 2 | | - | - | - | $0 | - | | $0 | $0 | $0 | $0 |
| 3 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 4 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 5 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 6 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 7 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 8 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 9 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 10 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 11 | | | | | $0 | | | $0 | $0 | $0 | $0 |
| 12 | Total Plant Direct Assigned | $0 | $0 | | $0 | | | $0 | $0 | $0 | $0 |

Note 1 - Actual prior year end balances will be used for the Gross and Net Plant amounts.

**Southwestern Public Service Company**

**Worksheet N - Meter Investment**

**Worksheet N**
**Table 34**

**Projected (1) for Billing Year =** **20yy**

| Line No. | Meter Type | Number of Meters | Average Replacement Cost per Meter (2) | Total Replacement Cost | Allocated Meter Investment | Average Allocated Meter Investment | No. of Delivery Points | Total Meter Investment |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | $ - | $ - | $ - | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2 | | | $ - | $ - | $ - | | |
| 3 | | | $ - | $ - | $ - | | $ - |
| 4 | Total | - | $ - | $ | (3) | | |
| 5 | Gross Plant Carrying Charge (4) | | | | | | |
| 6 | Revenue Requirement | | | | | | $ - |

(1) Actual prior year end balances will be used for the projected amounts.
(2) Averages will be based on the most recent available study.
(3) From FF1, p. 204-207, ln 70, col (g).
(4) Based on the last actual amount.

# Addendum 5 To Attachment H Part 4

**Southwestern Public Service Company**
**Worksheet O - Radial Line Investment**

**Worksheet O**

## Table 35

| Line No. | Radial Line / Asset Location | Total Radial Gross Plant $ | Total Radial Net Plant $ | Wholesale Radial Gross Plant $ | Wholesale Radial Net Plant $ | Retail Radial Gross Plant $ | Retail Radial Net Plant $ | Customer | Reclass ? |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Projected for Billing Year =20yy (Note 1)** | | | | | | | | |
| 2 | **In Service Prior to October 1, 2005:** | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | | | | | | | | |
| 11 | | | | | | | | | |
| 12 | | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | **Total In Service Prior to October 1, 2005** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | | |
| 16 | Projected for Billing Year =20yy (Note 1) | | | | | | | | |
| 17 | **In Service October 1, 2005 and Later:** | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Total In Service October 1, 2005 and Later** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | | |
| **Total Projected SPS Radial Plant** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | | |

Note 1 – Actual Prior year end balances are used for the projected amounts.

| **Radial Line / Asset Location** | **Total Radial Gross Plant $** | **Total Radial Net Plant $** | **Wholesale Radial Gross Plant $** | **Wholesale Radial Net Plant $** | **Retail Radial Gross Plant $** | **Retail Radial Net Plant $** | **Customer** | **Reclass ?** |
|---|---|---|---|---|---|---|---|---|
| **Actual for Year = 20yy** | | | | | | | | |
| **In Service Prior to October 1, 2005:** | | | | | | | | |
| **Total In Service Prior to October 1, 2005** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | | |
| **In Service October 1, 2005 and Later:** | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 45 | | | | | | | |
| 46 | | | | | | | |
| 47 | **Total In Service October 1, 2005 and Later** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** |
| 48 | | | | | | | |
| 49 | **Total Actual SPS Radial Plant** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** | **$0.00** |

**Worksheet P**

**Southwestern Public Service Company**
**Worksheet P - Revenue Requirement for Base Plan Upgrades, Service Upgrades, Sponsored Upgrades and Generator Interconnection Facilities.**

**Table 36**

**Determine the Revenue Requirement for Base Plan Upgrades**

**I.**

| Line No. | | (a) Investment Year | (b) Project Description | (c) Projected Plant Investment Balance | (d) Projected Revenue Requirement | (e) Actual Plant Investment Balance | (f) Actual Revenue Requirement | (g) SPP Base Plan True-up Amount | (h) 20yy SPP Base Plan True-up Amount | (i) 20yy SPP Base Plan True-up Amount Int. | (j) 20yy Projected Revenue Req. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | SUMMARY OF BPU UPGRADES | | | | | | | | | | |
| 5 | | | Section A Base Plan Facilities in Service Project 1 | | - | | - | - | | | |
| 6 | | | Section A Base Plan Facilities in Service Project 2 | | - | | - | - | | | |
| 7 | | | Section A Base Plan Facilities in Service Project 3 | | - | | - | - | | | |
| 8 | | | | | - | | - | - | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | - | | - | - | | | |
| 10 | | | | - | | - | - | | | |
| 11 | | | | - | | - | - | | | |
| 12 | | | | | | | | | | |
| 13 | | | | | | | | | | |
| 14 | | | | | | | | | | |
| 15 | **Total Revenue Requirement and True-up Amount** | | | - | | - | - | | | |

**A. Base Plan facilities In**
16 **Service.**

**i. Project 1, Projected**
17 **(Describe)**

18 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year**
19 **matching Projected Year. Values prior and subsequent to the Projected Year will change as Attachment O is updated.**
20 **These changes will not result in a refund or additional charge related to years prior to the Projected Year.**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 21 | | | | | **Projected Details** | | |
| 22 | Beginning Investment Service Year (yyyy) | | | | | Projected Year (Input) | 20yy |
| 23 | | | | | | Projected Year FCR w/o incentives, less depreciation (From ARR – Projected Data, line 40 col (5)) | 0.00% |
| 24 | Billing Month (1-12) | | | | | | |
| 25 | | | | | | | |
| 26 | CIAC (Yes or No) | | | | | | |

| 27 | Investment | Beginning | Addition/(Ret) | Plant Investment | | Depreciation | Ending | Revenue |
|---|---|---|---|---|---|---|---|---|
| 28 | Year | Balance | Amount | Balance | Projected Depreciation Rate | Expense | Balance | Requirement |
| 29 | - | - | - | - | | - | - | - |
| 30 | - | - | - | - | | - | - | - |
| 31 | - | - | - | - | | - | - | - |
| 32 | - | - | - | - | | - | - | - |
| 33 | - | - | - | - | | - | - | - |
| 34 | - | - | - | - | | - | - | - |
| 35 | - | - | - | - | | - | - | - |
| 36 | - | - | - | - | | - | - | - |
| 37 | - | - | - | - | | - | - | - |
| 38 | - | - | - | - | | - | - | - |
| 39 | - | - | - | - | | - | - | - |
| 40 | - | - | - | - | | - | - | - |
| 41 | - | - | - | - | | - | - | - |
| 42 | - | - | - | - | | - | - | - |
| 43 | - | - | - | - | | - | - | - |
| 44 | - | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | | | | - | - | - | | |
| 45 | - | | - | - | - | | | | - | - | - | | |
| 46 | - | | - | - | - | | | | - | - | - | | |
| 47 | - | | - | - | - | | | | - | - | - | | |
| 48 | - | | - | - | - | | | | - | - | - | | |
| 49 | - | | - | - | - | | | | - | - | - | | |
| 50 | - | | - | - | - | | | | - | - | - | | |
| 51 | - | | - | - | - | | | | - | - | - | | |
| 52 | - | | - | - | - | | | | - | - | - | | |
| 53 | - | | - | - | - | | | | - | - | - | | |
| 54 | - | | - | - | - | | | | - | - | - | | |
| 55 | - | | - | - | - | | | | - | - | - | | |
| 56 | - | | - | - | - | | | | - | - | - | | |
| 57 | - | | - | - | - | | | | - | - | - | | |
| 58 | - | | - | - | - | | | | - | - | - | | |
| 59 | - | | - | - | - | | | | - | - | - | | |
| 60 | …. | | …. | ….. | ….. | | | | ….. | ….. | …. | | |
| 61 | | | | | | | | | | | | | |

**i. Project 1, Actual**

62 **(Describe)**

**The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | **Actual Details** | | | | |
| | Beginning Investment Service Year (yyyy) | | | | | True-up Year (Actual Year Used for Revenue Requirement - Input) | 20yy | | | |
| | Billing Month (1-12) | | | | | True-up Year (Actual FCR w/o incentives, less depreciation) (From ARR-Actual Data, line 176 col (5)) | 0.00% | | | |
| | CIAC (Yes or No) | | | | | | | | | |
| | **Investment Year** | **Beginning Balance** | **Addition/(Ret) Amount** | **Plant Investment Balance** | **Actual Depreciation Rate** | | **Depreciation Expense** | **Ending Balance** | **Revenue Requirement** | |
| | - | - | - | - | | | - | - | - | |
| | - | - | - | - | | | - | - | - | |
| | - | - | - | - | | | - | - | - | |
| | - | - | - | - | | | - | - | - | |
| | - | - | - | - | | | - | - | - | |
| | - | - | - | - | | | - | - | - | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 80 | - | - | - | - | - | - | - |
| 81 | - | - | - | - | - | - | - |
| 82 | - | - | - | - | - | - | - |
| 83 | - | - | - | - | - | - | - |
| 84 | - | - | - | - | - | - | - |
| 85 | - | - | - | - | - | - | - |
| 86 | - | - | - | - | - | - | - |
| 87 | - | - | - | - | - | - | - |
| 88 | - | - | - | - | - | - | - |
| 89 | - | - | - | - | - | - | - |
| 90 | - | - | - | - | - | - | - |
| 91 | - | - | - | - | - | - | - |
| 92 | - | - | - | - | - | - | - |
| 93 | - | - | - | - | - | - | - |
| 94 | - | - | - | - | - | - | - |
| 95 | - | - | - | - | - | - | - |
| 96 | - | - | - | - | - | - | - |
| 97 | - | - | - | - | - | - | - |
| 98 | - | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | | | - | - | - | |
| 99 | - | | - | - | - | | | - | - | - | |
| 100 | - | | - | - | - | | | - | - | - | |
| 101 | - | | - | - | - | | | - | - | - | |
| 102 | - | | - | - | - | | | - | - | - | |
| 103 | - | | - | - | - | | | - | - | - | |
| 104 | - | | - | - | - | | | - | - | - | |
| 105 | …. | | …. | ….. | ….. | | | ….. | ….. | …. | |
| 106 | | | | | | | | | | | |

107 **A. Base Plan facilities In Service.**

108 **i. Project 2, Projected (Describe)**

109 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year**
110 **matching Projected Year. Values prior and subsequent to the Projected Year will change as Attachment O is updated.**
111 **These changes will not result in a refund or additional charge related to years prior to the Projected Year.**

| 112 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | **Projected Details** | | |
| 113 | Beginning Investment Service Year | | | | | Projected Year (Input) | 20yy | |
| 114 | | | | | | Projected Year FCR w/o | 0.00% | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 114 | (yyyy) | | | | | incentives, less depreciation | | | |
| 115 | Billing Month (1-12) | | | | | (From ARR – Projected Data, line 40 col (5)) | | | |
| 116 | | | | | | | | | |
| 117 | CIAC (Yes or No) | | | | | | | | |
| 118 | **Investment Year** | **Beginning Balance** | **Addition/(Ret) Amount** | **Plant Investment Balance** | **Projected Depreciation Rate** | | **Depreciation Expense** | **Ending Balance** | **Revenue Requirement** |
| 120 | - | - | - | - | | | - | - | - |
| 121 | - | - | - | - | | | - | - | - |
| 122 | - | - | - | - | | | - | - | - |
| 123 | - | - | - | - | | | - | - | - |
| 124 | - | - | - | - | | | - | - | - |
| 125 | - | - | - | - | | | - | - | - |
| 126 | - | - | - | - | | | - | - | - |
| 127 | - | - | - | - | | | - | - | - |
| 128 | - | - | - | - | | | - | - | - |
| 129 | - | - | - | - | | | - | - | - |
| 130 | - | - | - | - | | | - | - | - |
| 131 | - | - | - | - | | | - | - | - |
| 132 | - | - | - | - | | | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2 | | | | | | | |
| 13 | | | | | | | |
| 3 | - | - | - | - | - | - | - |
| 13 | | | | | | | |
| 4 | - | - | - | - | - | - | - |
| 13 | | | | | | | |
| 5 | - | - | - | - | - | - | - |
| 13 | | | | | | | |
| 6 | - | - | - | - | - | - | - |
| 13 | | | | | | | |
| 7 | - | - | - | - | - | - | - |
| 13 | | | | | | | |
| 8 | - | - | - | - | - | - | - |
| 13 | | | | | | | |
| 9 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 0 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 1 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 2 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 3 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 4 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 5 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 6 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 7 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 8 | - | - | - | - | - | - | - |
| 14 | | | | | | | |
| 9 | - | - | - | - | - | - | - |
| 15 | | | | | | | |
| 0 | - | - | - | - | - | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 151 | …. | …. | ….. | ….. | | ….. | ….. | …. |

152

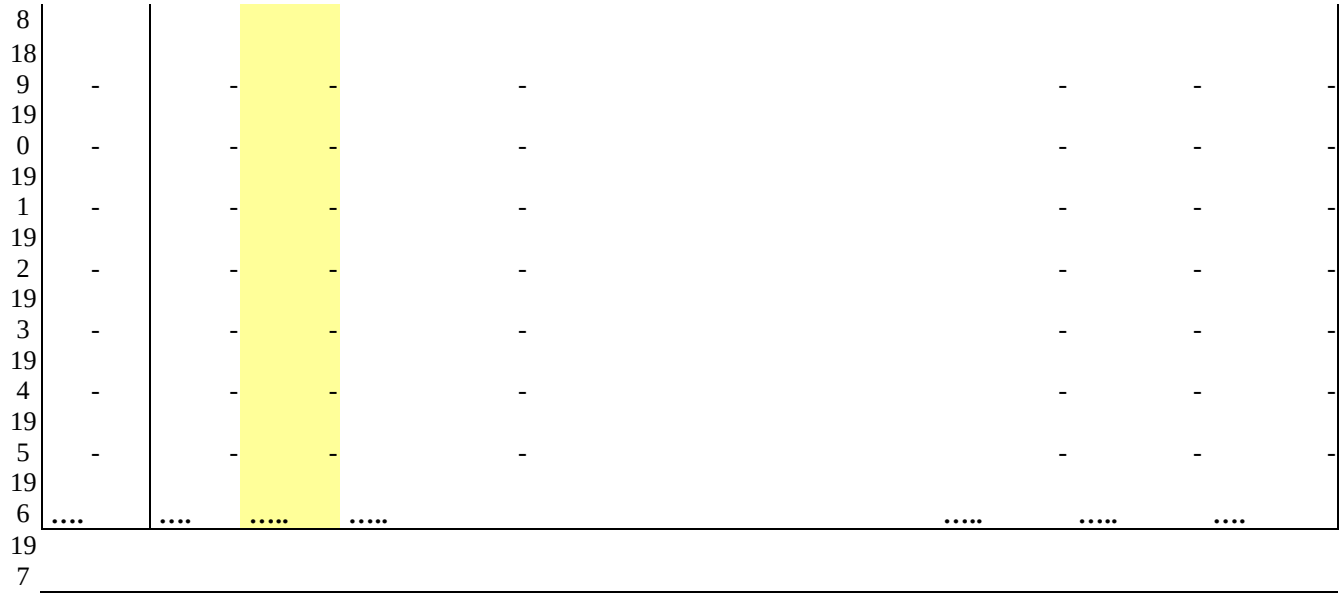
**i. Project 2, Actual (Describe)**

153 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 157 | | | | | **Actual Details** | | | |
| 158 | Beginning Investment | | | | | True-up Year (Actual Year Used for Revenue Requirement - Input) | | 20yy |
| 159 | Service Year | | | | | True-up Year (Actual FCR w/o incentives, less depreciation) (From ARR-Actual Data, line 176 col (5)) | | 0.00% |
| 160 | Billing Month | | | | | | | |
| 161 | | | | | | | | |
| 162 | CIAC (Yes or No) | | | | | | | |

| 163 | **Investment Year** | **Beginning Balance** | **Addition/(Ret) Amount** | **Plant Investment Balance** | **Actual Depreciation Rate** | **Depreciation Expense** | **Ending Balance** | **Revenue Requirement** |
|---|---|---|---|---|---|---|---|---|
| 165 | - | - | - | - | | - | - | - |
| 166 | - | - | - | - | | - | - | - |
| 167 | - | - | - | - | | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 168 | - | - | - | - | - | - | - |
| 169 | - | - | - | - | - | - | - |
| 170 | - | - | - | - | - | - | - |
| 171 | - | - | - | - | - | - | - |
| 172 | - | - | - | - | - | - | - |
| 173 | - | - | - | - | - | - | - |
| 174 | - | - | - | - | - | - | - |
| 175 | - | - | - | - | - | - | - |
| 176 | - | - | - | - | - | - | - |
| 177 | - | - | - | - | - | - | - |
| 178 | - | - | - | - | - | - | - |
| 179 | - | - | - | - | - | - | - |
| 180 | - | - | - | - | - | - | - |
| 181 | - | - | - | - | - | - | - |
| 182 | - | - | - | - | - | - | - |
| 183 | - | - | - | - | - | - | - |
| 184 | - | - | - | - | - | - | - |
| 185 | - | - | - | - | - | - | - |
| 186 | - | - | - | - | - | - | - |
| 187 | - | - | - | - | - | - | - |
| 188 | - | - | - | - | - | - | - |


8
18
9
19
0
19
1
19
2
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3
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4
19
5
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6
19
7

**II.** Determine the Revenue Requirement for Service Upgrades, Sponsored Upgrades and Generator Interconnection Facilities.

SUMMARY OF SERVICE, SPONSORED AND GENERATOR INTERCONNECTION UPGRADES

| Line No. | (a) Investment Year | (b) Project Description | (c) Projected Revenue Requirement | (d) Actual Revenue Requirement | (e) SPP Base Plan True-up Amount |
|---|---|---|---|---|---|
| 5 | | | - | - | - |
| 6 | | | - | - | - |
| 7 | | | - | - | - |
| 8 | | | - | - | - |
| 9 | | | - | - | - |
| 10 | | | - | - | - |
| 11 | | | - | - | - |
| 12 | | | | | |
| 13 | | | | | |
| 14 | | | | | |
| 15 | **Total Revenue Requirement and True-up Amount** | | - | - | - |

**Worksheet P - Revenue Requirement for Base Plan Upgrades, Service Upgrades, Sponsored Upgrades and Generator Interconnection Facilities.**

**III. Depreciation Rates**

| Year | Projected Worksheet P Depr Rate | Actual Worksheet P Depr Rate |
|---|---|---|
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |
| 20yy | | |

Projected Ref. Table 2, Line 40.1, col(5)  Actual Ref. Table 7, Line 176.1 col(5)

**Southwestern Public Service Company** **Worksheet P**
**Worksheet P - Revenue Requirement for Base Plan Upgrades** **Table 37**

198 **A. Base Plan facilities. In Service**

199 **i. Project 3, Projected (Describe)**

200 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching Projected Year. Values prior and subsequent to Projected Year will change as Attachment O**
201 **is updated.**
**These changes will not result in a refund or additional charge related to years prior to the Projected**
202 **Year.**

| 203 | Projected Details | | | | | |
|---|---|---|---|---|---|---|
| 204 | Beginning Investment Service Year (yyyy) | | Projected Year (Input) | | 20yy | |
| 205 | | | Projected Year FCR w/o incentives, less depreciation | | 0.00% | |
| 206 | Billing Month (1-12) | | (From ARR – Projected Data, line 40 col (5)) | | | |
| 207 | Depreciation Rate | | | | | |
| 208 | CIAC (Yes or No) | | | | | |
| 209 | **Investment** | **Beginning** | **Addition/(Ret)** | **Plant Investment** | **Depreciation** | **Ending** | **Revenue** |
| 210 | **Year** | **Balance** | **Amount** | **Balance** | **Expense** | **Balance** | **Requirement** |
| 211 | - | - | - | - | - | - | - |
| 212 | - | - | - | - | - | - | - |
| 213 | - | - | - | - | - | - | - |
| 214 | - | - | - | - | - | - | - |
| 215 | - | - | - | - | - | - | - |
| 216 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 217 | - | - | - | - | - | - | - |
| 218 | - | - | - | - | - | - | - |
| 219 | - | - | - | - | - | - | - |
| 220 | - | - | - | - | - | - | - |
| 221 | - | - | - | - | - | - | - |
| 222 | - | - | - | - | - | - | - |
| 223 | - | - | - | - | - | - | - |
| 224 | - | - | - | - | - | - | - |
| 225 | - | - | - | - | - | - | - |
| 226 | - | - | - | - | - | - | - |
| 227 | - | - | - | - | - | - | - |
| 228 | - | - | - | - | - | - | - |
| 229 | - | - | - | - | - | - | - |
| 230 | - | - | - | - | - | - | - |
| 231 | - | - | - | - | - | - | - |
| 232 | - | - | - | - | - | - | - |
| 233 | - | - | - | - | - | - | - |
| 234 | - | - | - | - | - | - | - |
| 235 | - | | | - | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | |
| 236 | - | - | - | - | - | - | - |
| 237 | - | - | - | - | - | - | - |
| 238 | - | - | - | - | - | - | - |
| 239 | - | - | - | - | - | - | - |
| 240 | - | - | - | - | - | - | - |
| 241 | - | - | - | - | - | - | - |
| 242 | …. | …. | ….. | ….. | ….. | ….. | …. |

243

244 **i. Project 3, Actual (Describe)**

245 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year**
246 **matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated.**
247 **These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

| 248 | True-up Year Actual Details | | | | | | |
|---|---|---|---|---|---|---|---|
| 249 | Beginning Investment Service Year (yyyy) | | True-up Year (Actual Year Used for Revenue Requirement - Input) | | 20yy | | |
| 250 | | | True-up Year (Actual FCR w/o incentives, less depreciation) | | 0.00% | | |
| 251 | Billing Month (1-12) | | (From ARR-Actual Data, line 176 col (5)) | | | | |
| 252 | Depreciation Rate | | | | | | |
| 253 | CIAC (Yes or No) | | | | | | |
| 254 | **Investment** | **Beginning** | **Addition/(Ret)** | **Plant Investment** | **Depreciation** | **Ending** | **Revenue** |
| 255 | **Year** | **Balance** | **Amount** | **Balance** | **Expense** | **Balance** | **Requirement** |
| 256 | - | - | - | - | - | - | - |
| 257 | - | - | - | - | - | - | - |
| 258 | - | - | - | - | - | - | - |
| 259 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 260 | - | - | - | - | - | - | - |
| 261 | - | - | - | - | - | - | - |
| 262 | - | - | - | - | - | - | - |
| 263 | - | - | - | - | - | - | - |
| 264 | - | - | - | - | - | - | - |
| 265 | - | - | - | - | - | - | - |
| 266 | - | - | - | - | - | - | - |
| 267 | - | - | - | - | - | - | - |
| 268 | - | - | - | - | - | - | - |
| 270 | - | - | - | - | - | - | - |
| 271 | - | - | - | - | - | - | - |
| 272 | - | - | - | - | - | - | - |
| 273 | - | - | - | - | - | - | - |
| 274 | - | - | - | - | - | - | - |
| 275 | - | - | - | - | - | - | - |
| 276 | - | - | - | - | - | - | - |
| 277 | .... | .... | ..... | ..... | ..... | ..... | .... |
| 288 | | | | | | | |

289 **B. Base Plan facilities. Construction Work in Progress**

290 **i. Project 1, Projected (Describe)**

291 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year**
292 **matching Projected Year. Values prior and subsequent to the Projected Year will change as Attachment O is updated.**
293 **These changes will not result in a refund or additional charge related to years prior to the Projected Year.**

| 294 | **Projected Details** | | | |
|---|---|---|---|---|
| 295 | Beginning Investment | | Projected Year (Input) | 20yy |
| 296 | Service Year (yyyy) | | Projected Year FCR w/o incentives, less depreciation | 0.00% |
| 297 | Billing Month (1-12) | | (From ARR – Projected Data, line 40 col (5)) | |
| 298 | Depreciation Rate | | | |
| 299 | CIAC (Yes or No) | | | |

| | Months | CWIP Balance | Revenue Requirement |
|---|---|---|---|
| 302 | Dec | - | |
| 303 | Jan | - | |
| 304 | Feb | - | |
| 305 | Mar | - | |
| 306 | Apr | - | |
| 307 | May | - | |
| 308 | Jun | - | |
| 309 | Jul | - | |
| 310 | Aug | - | |
| 311 | Sep | - | |
| 312 | Oct | - | |
| 313 | Nov | - | |
| 314 | Dec | - | |
| 315 | | | |
| 316 | 13 Mo Average | $ - | |

317 **i. Project 1, Actual (Describe)**

**The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

| True-up Year Actual Details | | | |
|---|---|---|---|
| Beginning Investment | | True-up Year (Actual Year Used for Revenue Requirement - Input) | 20yy |
| Service Year (yyyy) | | True-up Year (Actual FCR w/o incentives, less depreciation) | 0.00% |
| Billing Month (1-12) | | (From ARR-Actual Data, line 176 col (5)) | |
| Depreciation Rate | | | |
| CIAC (Yes or No) | | | |

| Months | CWIP Balance | Revenue Requirement |
|---|---|---|
| Dec | - | |
| Jan | - | |
| Feb | - | |
| Mar | - | |
| Apr | - | |
| May | - | |
| Jun | - | |
| Jul | - | |
| Aug | - | |
| Sep | - | |
| Nov | - | |
| Dec | - | |
| | | $ |
| 13 Mo Average | - | - |

**Southwestern Public Service Company** **Worksheet P**
**Worksheet P - Revenue Requirement for Base Plan Upgrades** **Table 38**

Line No.

**C. Service Upgrades.**

**i. Project 1, Projected (Describe)**

**The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year matching Projected Year. Values prior and subsequent to the Porojected Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the Projected Year.**

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Projected Details** | | | | | |
| Beginning Investment | | | Projected Year (Input) | | 20yy | |
| Service Year (yyyy) | | | Projected Year FCR w/o incentives, less depreciation | | 0.00% | |
| Billing Month (1-12) | | | (From ARR – Projected Data, line 40 col (5)) | | | |
| Depreciation Rate | | | | | | |
| CIAC (Yes or No) | | | | | | |

| **Investment Year** | **Beginning Balance** | **Addition/(Ret) Amount** | **Plant Investment Balance** | **Depreciation Expense** | **Ending Balance** | **Revenue Requirement** |
|---|---|---|---|---|---|---|
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - |
| 362 | - | - | - | - | - | - | - |
| 363 | - | - | - | - | - | - | - |
| 364 | - | - | - | - | - | - | - |
| 365 | - | - | - | - | - | - | - |
| 366 | - | - | - | - | - | - | - |
| 367 | - | - | - | - | - | - | - |
| 368 | - | - | - | - | - | - | - |
| 369 | - | - | - | - | - | - | - |
| 370 | - | - | - | - | - | - | - |
| 371 | - | - | - | - | - | - | - |
| 372 | - | - | - | - | - | - | - |
| 373 | - | - | - | - | - | - | - |
| 374 | - | - | - | - | - | - | - |
| 375 | - | - | - | - | - | - | - |
| 376 | - | - | - | - | - | - | - |
| 377 | - | - | - | - | - | - | - |
| 378 | - | - | - | - | - | - | - |
| 379 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 380 | - | - | - | - | - | - | - |
| 381 | - | - | - | - | - | - | - |
| 382 | - | - | - | - | - | - | - |
| 383 | - | - | - | - | - | - | - |
| 384 | - | - | - | - | - | - | - |
| 385 | - | - | - | - | - | - | - |
| 386 | - | - | - | - | - | - | - |
| 387 | - | - | - | - | - | - | - |
| 388 | .... | .... | ..... | ..... | ..... | ..... | .... |

389 **i. Project 1, Actual (Describe)**

390 **The calculated Rev. Req. from TO's and Other Zones shown below are only valid for Investment Year**
391 **matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated.**
392 **These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 393 | **True-up Year Actual Details** | | | | | | |
| 394 | Beginning Investment | | | True-up Year (Actual Year Used for Revenue Requirement - Input) | | 20yy | |
| 395 | Service Year (yyyy) | | | True-up Year (Actual FCR w/o incentives, less depreciation) | | 0.00% | |
| 396 | Billing Month (1-12) | | | (From ARR-Actual Data, line 176 col (5)) | | | |
| 397 | Depreciation Rate | | | | | | |
| 398 | CIAC (Yes or No) | | | | | | |
| 399 | | | | | | | |
| 400 | **Investment** | **Beginning** | **Addition/(Ret)** | **Plant Investment** | **Depreciation** | **Ending** | **Revenue** |
| 401 | **Year** | **Balance** | **Amount** | **Balance** | **Expense** | **Balance** | **Requirement** |
| 402 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 403 | - | - | - | - | - | - | - |
| 404 | - | - | - | - | - | - | - |
| 405 | - | - | - | - | - | - | - |
| 406 | - | - | - | - | - | - | - |
| 407 | - | - | - | - | - | - | - |
| 408 | - | - | - | - | - | - | - |
| 409 | - | - | - | - | - | - | - |
| 410 | - | - | - | - | - | - | - |
| 411 | - | - | - | - | - | - | - |
| 412 | - | - | - | - | - | - | - |
| 413 | - | - | - | - | - | - | - |
| 414 | - | - | - | - | - | - | - |
| 415 | - | - | - | - | - | - | - |
| 416 | - | - | - | - | - | - | - |
| 417 | - | - | - | - | - | - | - |
| 418 | - | - | - | - | - | - | - |
| 419 | - | - | - | - | - | - | - |
| 420 | - | - | - | - | - | - | - |
| 421 | - | - | - | - | - | - | - |
| 422 | - | - | - | - | - | - | - |
| 423 | - | - | - | - | - | - | - |
| 424 | - | - | - | - | - | - | - |
| 425 | - | - | - | - | - | - | - |
| 426 | - | - | - | - | - | - | - |
| 427 | - | - | - | - | - | - | - |
| 428 | - | - | - | - | - | - | - |
| 429 | - | - | - | - | - | - | - |
| 430 | - | - | - | - | - | - | - |
| 431 | - | - | - | - | - | - | - |
| 432 | - | - | - | - | - | - | - |
| 433 | .... | .... | ..... | ..... | ..... | ..... | .... |

**D. Sponsored Upgrades.**

**i. Project 1, Projected (Describe)**

**The calculated Rev. Req. from Sponsor and Credit shown below are only valid for Investment Year matching Projected Year. Values prior and subsequent to the Projected Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the Projected Year.**

| **Projected Details** | | | |
|---|---|---|---|
| Beginning Investment | | Projected Year (Input) | 20yy |
| Service Year (yyyy) | | Projected Year FCR w/o incentives, less depreciation | 0.00% |
| Billing Month (1-12) | | (From ARR – Projected Data, line 40 col (5)) | |
| Depreciation Rate | | | |
| CIAC (Yes or No) | | | |

| Investment Year | Beginning Balance | Addition/(Ret) Amount | Plant Investment Balance | Depreciation Expense | Ending Balance | Revenue Requirement |
|---|---|---|---|---|---|---|
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |
| - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 456 | - | - | - | - | - | - | - |
| 457 | - | - | - | - | - | - | - |
| 458 | - | - | - | - | - | - | - |
| 459 | - | - | - | - | - | - | - |
| 460 | - | - | - | - | - | - | - |
| 461 | - | - | - | - | - | - | - |
| 462 | - | - | - | - | - | - | - |
| 463 | - | - | - | - | - | - | - |
| 464 | - | - | - | - | - | - | - |
| 465 | - | - | - | - | - | - | - |
| 466 | - | - | - | - | - | - | - |
| 467 | - | - | - | - | - | - | - |
| 468 | - | - | - | - | - | - | - |
| 469 | - | - | - | - | - | - | - |
| 470 | - | - | - | - | - | - | - |
| 471 | - | - | - | - | - | - | - |
| 472 | - | - | - | - | - | - | - |
| 473 | - | - | - | - | - | - | - |
| 474 | - | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - |
| 475 | - | - | - | - | - | - | - |
| 476 | - | - | - | - | - | - | - |
| 477 | - | - | - | - | - | - | - |
| 478 | - | - | - | - | - | - | - |
| 479 | .... | .... | ..... | ..... | ..... | ..... | .... |

480 **i. Project 1, Actual (Describe)**

481 **The calculated Rev. Req. from Sponsor and Credit shown below are only valid for Investment Year**
482 **matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated.**
483 **These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

484 **True-up Year Actual Details**

| | | | | |
|---|---|---|---|---|
| 485 | Beginning Investment | | True-up Year (Actual Year Used for Revenue Requirement - Input) | 20yy |
| 486 | Service Year (yyyy) | | True-up Year (Actual FCR w/o incentives, less depreciation) | 0.00% |
| 487 | Billing Month (1-12) | | (From ARR-Actual Data, line 176 col (5)) | |
| 488 | Depreciation Rate | | | |
| 489 | CIAC (Yes or No) | | | |
| 490 | | | | |

| 491 / 492 | Investment Year | Beginning Balance | Addition/(Ret) Amount | Plant Investment Balance | Depreciation Expense | Ending Balance | Revenue Requirement |
|---|---|---|---|---|---|---|---|
| 493 | - | - | - | - | - | - | - |
| 494 | - | - | - | - | - | - | - |
| 495 | - | - | - | - | - | - | - |
| 496 | - | - | - | - | - | - | - |
| 497 | - | - | - | - | - | - | - |
| 498 | - | - | - | - | - | - | - |
| 499 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 500 | - | - | - | - | - | - | - |
| 501 | - | - | - | - | - | - | - |
| 502 | - | - | - | - | - | - | - |
| 503 | - | - | - | - | - | - | - |
| 504 | - | - | - | - | - | - | - |
| 505 | - | - | - | - | - | - | - |
| 506 | - | - | - | - | - | - | - |
| 507 | - | - | - | - | - | - | - |
| 508 | - | - | - | - | - | - | - |
| 509 | - | - | - | - | - | - | - |
| 510 | - | - | - | - | - | - | - |
| 511 | - | - | - | - | - | - | - |
| 512 | - | - | - | - | - | - | - |
| 513 | - | - | - | - | - | - | - |
| 514 | - | - | - | - | - | - | - |
| 515 | - | - | - | - | - | - | - |
| 516 | - | - | - | - | - | - | - |
| 517 | - | - | - | - | - | - | - |
| 518 | - | - | - | - | - | - | - |
| 519 | - | - | - | - | - | - | - |
| 520 | - | - | - | - | - | - | - |
| 521 | - | - | - | - | - | - | - |
| 522 | - | - | - | - | - | - | - |
| 523 | - | - | - | - | - | - | - |
| 524 | .... | .... | ..... | ..... | ..... | ..... | .... |

**Southwestern Public Service Company** **Worksheet P**
**Worksheet P - Revenue Requirement for Base Plan Upgrades** **Table 39**

Line No.

525 **E. Generator Interconnect Upgrades.**

526 **i. Project 1, Projected (Describe)**

527 **The calculated Rev. Req. from Generator and Credit shown below are only valid for Investment Year**
528 **matching Projected Year. Values prior and subsequent to the Projected Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the Projected**
529 **Year.**

| 530 | Projected Details | | | |
|---|---|---|---|---|
| 531 | Beginning Investment | | Projected Year (Input) | 20yy |
| 532 | Service Year (yyyy) | | Projected Year FCR w/o incentives, less depreciation | 0.00% |
| 533 | Billing Month (1-12) | | (From ARR – Projected Data, line 40 col (5)) | |
| 534 | Depreciation Rate | | | |
| 535 | CIAC (Yes or No) | | | |
| 536 | | | | |

| 537 / 538 | Investment Year | Beginning Balance | Addition/(Ret) Amount | Plant Investment Balance | Depreciation Expense | Ending Balance | Revenue Requirement |
|---|---|---|---|---|---|---|---|
| 539 | - | - | - | - | - | - | - |
| 540 | - | - | - | - | - | - | - |
| 541 | - | - | - | - | - | - | - |
| 542 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 543 | - | - | - | - | - | - | - |
| 544 | - | - | - | - | - | - | - |
| 545 | - | - | - | - | - | - | - |
| 546 | - | - | - | - | - | - | - |
| 547 | - | - | - | - | - | - | - |
| 548 | - | - | - | - | - | - | - |
| 549 | - | - | - | - | - | - | - |
| 550 | - | - | - | - | - | - | - |
| 551 | - | - | - | - | - | - | - |
| 552 | - | - | - | - | - | - | - |
| 553 | - | - | - | - | - | - | - |
| 554 | - | - | - | - | - | - | - |
| 555 | - | - | - | - | - | - | - |
| 556 | - | - | - | - | - | - | - |
| 557 | - | - | - | - | - | - | - |
| 558 | - | - | - | - | - | - | - |
| 559 | - | - | - | - | - | - | - |
| 560 | - | - | - | - | - | - | - |
| 561 | - | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - |
| 562 | - | - | - | - | - | - | - |
| 563 | - | - | - | - | - | - | - |
| 564 | - | - | - | - | - | - | - |
| 565 | - | - | - | - | - | - | - |
| 566 | - | - | - | - | - | - | - |
| 567 | - | - | - | - | - | - | - |
| 568 | - | - | - | - | - | - | - |
| 569 | - | - | - | - | - | - | - |
| 570 | …. | …. | ….. | ….. | ….. | ….. | …. |

571

572 **i. Project 1, Actual (Describe)**

573 **The calculated Rev. Req. from Generator and Credit shown below are only valid for Investment Year**
574 **matching True-up Year. Values prior and subsequent to the True-up Year will change as Attachment O is updated.**
575 **These changes will not result in a refund or additional charge related to years prior to the True-up Year.**

| 576 | True-up Year Actual Details | | | | | | |
|---|---|---|---|---|---|---|---|
| 577 | Beginning Investment | | | True-up Year (Actual Year Used for Revenue Requirement - Input) | | | 20yy |
| 578 | Service Year (yyyy) | | | True-up Year (Actual FCR w/o incentives, less depreciation) | | | 0.00% |
| 579 | Billing Month (1-12) | | | (From ARR-Actual Data, line 176 col (5)) | | | |
| 580 | Depreciation Rate | | | | | | |
| 581 | CIAC (Yes or No) | | | | | | |
| 582 | | | | | | | |
| 583 | **Investment** | **Beginning** | **Addition/(Re** | **Plant Investment** | **Depreciation** | **Ending** | **Revenue** |

| | | | t) | | | | |
|---|---|---|---|---|---|---|---|
| 584 | Year | Balance | Amount | Balance | Expense | Balance | Requirement |
| 585 | - | - | - | - | - | - | - |
| 586 | - | - | - | - | - | - | - |
| 587 | - | - | - | - | - | - | - |
| 588 | - | - | - | - | - | - | - |
| 589 | - | - | - | - | - | - | - |
| 590 | - | - | - | - | - | - | - |
| 591 | - | - | - | - | - | - | - |
| 592 | - | - | - | - | - | - | - |
| 593 | - | - | - | - | - | - | - |
| 594 | - | - | - | - | - | - | - |
| 595 | - | - | - | - | - | - | - |
| 596 | - | - | - | - | - | - | - |
| 597 | - | - | - | - | - | - | - |
| 598 | - | - | - | - | - | - | - |
| 599 | - | - | - | - | - | - | - |
| 600 | - | - | - | - | - | - | - |
| 601 | - | - | - | - | - | - | - |
| 602 | - | - | - | - | - | - | - |
| 603 | - | - | - | - | - | - | - |
| 604 | - | - | - | - | - | - | - |
| 605 | - | - | - | - | - | - | - |
| 606 | - | - | - | - | - | - | - |
| 607 | - | - | - | - | - | - | - |
| 608 | - | - | - | - | - | - | - |
| 609 | - | - | - | - | - | - | - |
| 610 | - | - | - | - | - | - | - |
| 611 | - | - | - | - | - | - | - |
| 612 | - | - | - | - | - | - | - |
| 613 | - | - | - | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 614 | - | | - | - | - | - | - |
| 615 | - | | - | - | - | - | - |
| 616 | .... | | .... | ..... | ..... | ..... | ..... | .... |

# Southwestern Public Service Company
# Worksheet Q - Forecasted Incentive CWIP (Note 1)

**Workshe et Q**

**Table 40**

## Projected for Billing Year = 20yy

| Line No. | | (A) Projected Incentive CWIP | (B) Projected Specific CWIP | (C) Accumulated Balance Projected Incentive CWIP |
|---|---|---|---|---|
| 1 | Dec | | | |
| 2 | Jan | | | - |
| 3 | Feb | | | - |
| 4 | Mar | | | - |
| 5 | Apr | | | - |
| 6 | May | | | - |
| 7 | Jun | | | - |
| 8 | Jul | | | - |

| | | | | |
|---|---|---|---|---|
| 9 | Aug | | | - |
| 10 | Sep | | | - |
| 11 | Oct | | | - |
| 12 | Nov | | | - |
| 13 | Dec | | | - |
| 14 | Total | - | - | - |

| | | | |
|---|---|---|---|
| 15 | 13 month avg of current year changes to CWIP = Col C | - | (Goes to Page 3, ln 73) |

| | | (D) Accumulated Pre-Funded AFUDC | (E) Pre-Funded AFUDC Amortization |
|---|---|---|---|
| 16 | Dec | | |
| 17 | Jan | | |
| 18 | Feb | | |
| 19 | Mar | | |
| 20 | Apr | | |
| 21 | May | | |
| 22 | Jun | | |
| 23 | Jul | | |
| 24 | Aug | | |
| 25 | Sep | | |
| 26 | Oct | | |
| 27 | Nov | | |
| 28 | Dec | | |
| 29 | Total | - | - |

| | | | |
|---|---|---|---|
| 30 | 13 Month Avg Accumulated Pre-Funded AFUDC = Col D | - | (Goes to Page 3, ln 74) |
| 31 | Pre-Funded AFUDC Amortization = Col E | - | (Goes to Page 4, ln 115) |

## Actual for Billing Year = 20yy

| | | (A) Actual Incentive CWIP | (B) Actual Other CWIP | (C) Accumulated **Balance** Actual Incentive CWIP |
|---|---|---|---|---|
| 32 | Dec | | | |
| 33 | Jan | | | - |
| 34 | Feb | | | - |
| 35 | Mar | | | - |
| 36 | Apr | | | - |
| 37 | May | | | - |
| 38 | Jun | | | - |
| 39 | Jul | | | - |
| 40 | Aug | | | - |
| 41 | Sep | | | - |
| 42 | Oct | | | |

| | | | | |
|---|---|---|---|---|
| | | | | - |
| 43 | Nov | | | - |
| 44 | Dec | | | - |
| 45 | Total | - | - | - |

| | | | |
|---|---|---|---|
| 46 | 13 month avg of prior year changes to CWIP = Col C | - | (Goes to Page 8, ln 209) |

| | | (D) Accumulated Pre-Funded AFUDC | (E) Pre-Funded AFUDC Amortization |
|---|---|---|---|
| 47 | Dec | | |
| 48 | Jan | | |
| 49 | Feb | | |
| 50 | Mar | | |
| 51 | Apr | | |
| 52 | May | | |
| 53 | Jun | | |
| 54 | Jul | | |
| 55 | Aug | | |
| 56 | Sep | | |
| 57 | Oct | | |
| 58 | Nov | | |
| 59 | Dec | | |
| 60 | Tot | - | - |

al

| | | | |
|---|---|---|---|
| 61 | 13 Month Avg Accumulated Pre-Funded AFUDC = Col D | - | (Goes to Page 8, ln 210) |
| 62 | Pre-Funded AFUDC Amortization = Col E | - | (Goes to Page 9, ln 251) |

63 Note 1: Worksheet Q will remain blank until such time that SPS files for and receives FERC approval
64 for including specific incentive CWIP projects in the formula rate. SPS accounting records will be the
65 source of this data.

**Worksheet R Table**

## Southwestern Public Service Company

## Worksheet R - Incentive Projects.

# I. Calculate Return and Income Taxes with hypothetical 100 basis point ROE increase.

## A. Determine "R" with hypothetical 100 basis point increase in ROE.

| Line No. | | | | | |
|---|---|---|---|---|---|
| 1 | ROE w/o incentives (From Page 5, ln 162) | | | | 10.50% |
| 2 | ROE with additional 100 basis point incentive | | | | 11.50% |
| 3 | Determine R ( cost of long term debt, cost of preferred stock and percent is from Page 5, lns 160 through162) | | | | |
| 4 | | | % | Cost | Weighted cost |
| 5 | | Long Term Debt | 0.00 % | 0.00 00 | 0.0000 |
| 6 | | Preferred Stock | 0.00 % | 0.00 00 | 0.0000 |
| 7 | | Common Stock | 0.00 % | 0.11 50 | 0.0000 |
| 8 | | | | R = | 0.0000 |

## B. Determine Return using "R" with hypothetical 100 basis point ROE increase.

| | | |
|---|---|---|
| 9 | Rate Base (From Page 3, ln 89) | - 0.00 |
| 10 | R (from A. above) | 00 |
| 11 | Return (Rate Base x R) | - |

### C. Determine Income Taxes using Return with hypothetical 100 basis point ROE increase.

| | | |
|---|---|---|
| 12 | Return (from B. above) | - |
| 13 | CIT (From Page 4, ln 131) | 0.00 % |
| 14 | Income Tax Calculation (Return x CIT) | - |
| 15 | ITC Adjustment (From Page 4, ln 137) | - |
| 16 | Income Taxes | - |

## II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 100 basis point ROE increase.

### A. Determine Net Revenue Requirement less return and Income Taxes.

| Line No. | | | |
|---|---|---|---|
| 17 | Net Revenue Requirement (From Page 2, ln 33) | - | |
| 18 | Return (From Page 4, ln 139) | | - |
| 19 | Income Taxes (From Page 4, ln 138) | - | |
| 20 | Net Revenue Requirement, Less Return and Taxes | | - |

## B. Determine Net Revenue Requirement with hypothetical 100 basis point increase in ROE.

| | | |
|---|---|---|
| 21 | Net Revenue Requirement, Less Return and Taxes | - |
| 22 | Return (from I.B. above) | - |
| 23 | Income Taxes (from I.C. above) | - |
| 24 | Net Revenue Requirement, with 100 Basis Point ROE increase | - |
| 25 | Depreciation (From Page 4, ln 114) | - |
| 26 | Net Rev. Req, w/100 Basis Point ROE increase, less Depreciation | - |

## C. Determine FCR with hypothetical 100 basis point ROE increase.

| | | | |
|---|---|---|---|
| 27 | Net Transmission Plant (From Page 3, ln 62) | - | |
| 28 | Net Revenue Requirement, with 100 Basis Point ROE increase | - | |
| 29 | FCR with 100 Basis Point increase in ROE | 0.00% | |
| 30 | Net Rev. Req, w/100 Basis Point ROE increase, less Dep. | - | |
| 31 | FCR with 100 Basis Point ROE increase, less Depreciation | 0.00% | (use when no CIAC is associated with facilities receiving incentives) |
| 32 | FCR w/o 100 Basis Point ROE increase, less | 0.00% | (From Page 2, ln 40) |

| | | | |
|---|---|---|---|
| 33 | Depreciation FCR w/o Return, Income Taxes and Depreciation | 0.00% | (use when CIAC is associated with facilities receiving incentives) |

# Southwestern Public Service Company

**Worksheet R Table 42**

# Worksheet R - Incentive Projects.

## III. Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives.

### A. Facilities receiving incentives accepted by FERC in Docket No.

**The calculated Additional Revenue Requirement and Revenue Credit shown below are only valid for Investment Years matching Current Year. Values prior and subsequent to the Current Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the Current Year.**

Beginning Balance = Investment in first year and prior year Ending Balance, thereafter
Depreciation Expense = Straight line depreciation equal to Investment divided by Useful Life
Ending Balance = Beginning Balance - Depreciation Expense
Revenue Requirement = FCR * Beginning Balance plus Depreciation Expense, adjusted by Service Month divided by 12 in the first year

Additional Rev. Requirement = Revenue Requirement w/incentives less w/o incentive for the year
Additional Revenue Credit = Revenue Requirement w/o incentives

| Line No. | | Details | | | |
|---|---|---|---|---|---|
| 34 | | Investment Service Year (yyyy) | | Current Year | |
| 35 | | Service Month (1-12) | | ROE increase accepted by FERC (Basis Points) | |
| 36 | | Useful life | | FCR w/o incentives, less depreciation | 0.00% |
| 37 | | CIAC (Yes or No) | | FCR w/incentives approved for these facilities, less dep. | 0.00% |
| 38 | | | | Annual Depreciation Expense | - |

| 39 | | Investment | Beginning | Depreciation | Ending | Revenue | Additional Rev. | Additional Rev. |
|---|---|---|---|---|---|---|---|---|
| 40 | | Year | Balance | Expense | Balance | Requirement | Requirement | Credit |
| 41 | w/o incentives | - | - | - | - | - | | $ - |
| 42 | w/incentives | - | - | - | - | - | $ - | |
| 43 | w/o | - | | | | | | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | incentives | | - | - | - | - | | | | |
| 44 | w/incentives | - | - | - | - | - | $ - | | | |
| 45 | w/o incentives | - | - | - | - | - | | $ | - | |
| 46 | w/incentives | - | - | - | - | - | $ - | | | |
| 47 | w/o incentives | - | - | - | - | - | | $ | - | |
| 48 | w/incentives | - | - | - | - | - | $ - | | | |
| 49 | w/o incentives | - | - | - | - | - | | $ | - | |
| 50 | w/incentives | - | - | - | - | - | $ - | | | |
| 51 | w/o incentives | - | - | - | - | - | | $ | - | |
| 52 | w/incentives | - | - | - | - | - | $ - | | | |
| 53 | w/o incentives | - | - | - | - | - | | $ | - | |
| 54 | w/incentives | - | - | - | - | - | $ - | | | |
| 55 | w/o incentives | - | - | - | - | - | | $ | - | |
| 56 | w/incentives | - | - | - | - | - | $ - | | | |
| 57 | w/o incentives | - | - | - | - | - | | $ | - | |
| 58 | w/incentives | - | - | - | - | - | $ - | | | |
| 59 | w/o incentives | - | - | - | - | - | | $ | - | |
| 60 | w/incentives | - | - | - | - | - | $ - | | | |
| 61 | w/o incentives | - | - | - | - | - | | $ | - | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 62 | w/incentives | - | - | - | - | - | $ - | | | |
| 63 | w/o incentives | - | - | - | - | - | | $ | - | |
| 64 | w/incentives | - | - | - | - | - | $ - | | | |
| 65 | w/o incentives | - | - | - | - | - | | $ | - | |
| 66 | w/incentives | - | - | - | - | - | $ - | | | |
| 67 | w/o incentives | - | - | - | - | - | | $ | - | |
| 68 | w/incentives | - | - | - | - | - | $ - | | | |
| 69 | w/o incentives | - | - | - | - | - | | $ | - | |
| 70 | w/incentives | - | - | - | - | - | $ - | | | |
| 71 | w/o incentives | - | - | - | - | - | | $ | - | |
| 72 | w/incentives | - | - | - | - | - | $ - | | | |
| 73 | w/o incentives | - | - | - | - | - | | $ | - | |
| 74 | w/incentives | - | - | - | - | - | $ - | | | |
| 75 | w/o incentives | - | - | - | - | - | | $ | - | |
| 76 | w/incentives | - | - | - | - | - | $ - | | | |
| 77 | w/o incentives | - | - | - | - | - | | $ | - | |
| 78 | w/incentives | - | - | - | - | - | $ - | | | |
| 79 | w/o incentives | - | - | - | - | - | | $ | - | |
| 80 | w/incentive | - | | | | | $ | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | s | | - | - | - | - | - | | |
| 81 | w/o incentives | - | - | - | - | - | | $ | - |
| 82 | w/incentive s | - | - | - | - | - | $ - | | |
| 83 | w/o incentives | - | - | - | - | - | | $ | - |
| 84 | w/incentive s | - | - | - | - | - | $ - | | |
| 85 | w/o incentives | - | - | - | - | - | | $ | - |
| 86 | w/incentive s | - | - | - | - | - | $ - | | |
| 87 | w/o incentives | - | - | - | - | - | | $ | - |
| 88 | w/incentive s | - | - | - | - | - | $ - | | |
| 89 | w/o incentives | - | - | - | - | - | | $ | - |
| 90 | w/incentive s | - | - | - | - | - | $ - | | |
| 91 | w/o incentives | - | - | - | - | - | | $ | - |
| 92 | w/incentive s | - | - | - | - | - | $ - | | |
| 93 | w/o incentives | - | - | - | - | - | | $ | - |
| 94 | w/incentive s | - | - | - | - | - | $ - | | |
| 95 | w/o incentives | - | - | - | - | - | | $ | - |
| 96 | w/incentive s | - | - | - | - | - | $ - | | |
| 97 | w/o incentives | - | - | - | - | - | | $ | - |
| 98 | w/incentive s | - | - | - | - | - | $ - | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 99 | w/o incentives | - | - | - | - | - | | $ | - |
| 10 0 | w/incentives | - | - | - | - | - | $ - | | |
| 10 1 | w/o incentives | - | - | - | - | - | | $ | - |
| 10 2 | w/incentives | - | - | - | - | - | $ - | | |
| 10 3 | w/o incentives | .... | .... | ..... | .... | | .... | | |
| 10 4 | w/incentives | .... | .... | ..... | ..... | .... | .... | | |
| | | | | | | | $ - | $ | - |

**Worksheet R Table 43**

# Southwestern Public Service Company

# Worksheet R - Incentive Projects.

## III. Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives. (cont.)

**B. Facilities receiving incentives accepted by FERC in Docket No.**

**The calculated Additional Revenue Requirement and Revenue Credit shown below are only valid for Investment Years matching Current Year. Values prior**

**and subsequent to the Current Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the Current Year.**

Beginning Balance = Investment in first year and prior year Ending Balance, thereafter
Depreciation Expense = Straight line depreciation equal to Investment divided by Useful Life
Ending Balance = Beginning Balance - Depreciation Expense
Revenue Requirement = FCR * Beginning Balance plus Depreciation Expense, adjusted by Service Month divided by 12 in the first year
Additional Rev. Requirement = Revenue Requirement w/incentives less w/o incentive for the year
Additional Revenue Credit = Revenue Requirement w/o incentives

| Line No. | | | Details | | | |
|---|---|---|---|---|---|---|
| 105 | | | Investment Service Year (yyyy) | | Current Year | **0** |
| 106 | | | Service Month (1-12) | | ROE increase accepted by FERC (Basis Points) | |
| 107 | | | | | FCR w/o incentives, less depreciation | 0.00% |
| 108 | | Useful life | | | FCR w/incentives approved for these facilities, less dep. | 0.00% |
| 109 | | CIAC (Yes or No) | | | Annual Depreciation Expense | - |
| 110 | | **Investme** | **Beginning** | **Ending** | **Revenue** | **Additi** **Addit** |

| 111 | | nt<br>Year | Balance | Depreciation Expense | Balance | Requirement | onal Rev.<br>Requirement | ional Rev.<br>Credit |
|---|---|---|---|---|---|---|---|---|
| 112 | w/o incentives | - | - | - | - | - | | $ - |
| 113 | w/ incentives | - | - | - | - | - | $ - | |
| 114 | w/o incentives | - | - | - | - | - | | $ - |
| 115 | w/ incentives | - | - | - | - | - | $ - | |
| 116 | w/o incentives | - | - | - | - | - | | $ - |
| 117 | w/ incentives | - | - | - | - | - | $ - | |
| 118 | w/o incentives | - | - | - | - | - | | $ - |
| 119 | w/ incentives | - | - | - | - | - | $ - | |
| 120 | w/o ince | - | - | - | - | - | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | ntives w/incentives w/o incentives | | | | | | | |
| 121 | | - | - | - | - | - | $ - | |
| 122 | ntives w/in | - | - | - | - | - | | $ - |
| 123 | centives w/o incentives | - | - | - | - | - | $ - | |
| 124 | ntives w/in | - | - | - | - | - | | $ - |
| 125 | centives w/o incentives | - | - | - | - | - | $ - | |
| 126 | ntives w/in | - | - | - | - | - | | $ - |
| 127 | centives w/o incentives | - | - | - | - | - | $ - | |
| 128 | ntives w/in | - | - | - | - | - | | $ - |
| 129 | centives w/o incentives | - | - | - | - | - | $ - | |
| 130 | ntives | - | - | - | - | - | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 131 | w/in cent ives | - | - | - | - | - | $ - | |
| 132 | w/o ince ntiv es | - | - | - | - | - | | $ - |
| 133 | w/in cent ives | - | - | - | - | - | $ - | |
| 134 | w/o ince ntiv es | - | - | - | - | - | | $ - |
| 135 | w/in cent ives | - | - | - | - | - | $ - | |
| 136 | w/o ince ntiv es | - | - | - | - | - | | $ - |
| 137 | w/in cent ives | - | - | - | - | - | $ - | |
| 138 | w/o ince ntiv es | - | - | - | - | - | | $ - |
| 139 | w/in cent ives | - | - | - | - | - | $ - | |
| 140 | w/o ince ntiv es | - | - | - | - | - | | $ - |
| 141 | w/in cent | - | - | - | - | - | $ - | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | ives w/o incentives | - | - | - | - | - | | $ - |
| 142 | w/in cent | | | | | | $ | |
| 143 | ives w/o incentives | - | - | - | - | - | | $ - |
| 144 | w/in cent | | | | | | $ | |
| 145 | ives w/o incentives | - | - | - | - | - | | $ - |
| 146 | w/in cent | | | | | | $ | |
| 147 | ives w/o incentives | - | - | - | - | - | | $ - |
| 148 | w/in cent | | | | | | $ | |
| 149 | ives w/o incentives | - | - | - | - | - | | $ - |
| 150 | w/in cent | | | | | | $ | |
| 151 | ives | - | - | - | - | - | | |
| 152 | w/o | - | | | - | | | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | incentives w/incentives | | - | - | | - | | - |
| 153 | w/o incentives | - | - | - | - | - | $ - | |
| 154 | w/incentives | - | - | - | - | - | | $ - |
| 155 | w/o incentives | - | - | - | - | - | $ - | |
| 156 | w/incentives | - | - | - | - | - | | $ - |
| 157 | w/o incentives | - | - | - | - | - | $ - | |
| 158 | w/incentives | - | - | - | - | - | | $ - |
| 159 | w/o incentives | - | - | - | - | - | $ - | |
| 160 | w/incentives | - | - | - | - | - | | $ - |
| 161 | w/o incentives | - | - | - | - | - | $ - | |
| 162 | | - | - | - | - | - | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | es w/in cent | | | | | | $ | |
| 163 | ives w/o ince ntiv | - | - | - | - | - | - | |
| 164 | es w/in cent | - | - | - | - | - | | $ - |
| 165 | ives w/o ince ntiv | - | - | - | - | - | $ - | |
| 166 | es w/in cent | - | - | - | - | - | | $ - |
| 167 | ives w/o ince ntiv | - | - | - | - | - | $ - | |
| 168 | es w/in cent | - | - | - | - | - | | $ - |
| 169 | ives w/o ince ntiv | - | - | - | - | - | $ - | |
| 170 | es w/in cent | - | - | - | - | - | | $ - |
| 171 | ives w/o ince ntiv | - | - | - | - | - | $ - | |
| 172 | es | - | - | - | - | - | | $ - |
| 173 | w/in | - | | | - | | $ | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | cent ives w/o ince ntiv | | - | | - | | | - | - | |
| 174 | es w/in cent | .... | | | .... | ..... | | .... | | .... |
| 175 | ives | .... | .... | | ..... | ..... | | .... | .... | |
| | | | | | | | | | $ - | $ - |

**Worksheet RTable 44**

## Southwestern Public Service Company

## Worksheet R - Incentive Projects.

**III. Determine the Additional Revenue Requirement and Revenue Credit for facilities receiving incentives. (cont.)**

**B. Facilities receiving incentives accepted by FERC**

**in Docket No.**

**The calculated Additional Revenue Requirement and Revenue Credit shown below are only valid for Investment Years matching Current Year. Values prior and subsequent to the Current Year will change as Attachment O is updated. These changes will not result in a refund or additional charge related to years prior to the Current Year.**

Beginning Balance = Investment in first year and prior year Ending Balance, thereafter
Depreciation Expense = Straight line depreciation equal to Investment divided by Useful Life
Ending Balance = Beginning Balance - Depreciation Expense
Revenue Requirement = FCR * Beginning Balance plus Depreciation Expense, adjusted by Service Month divided by 12 in the first year
Additional Rev. Requirement = Revenue Requirement w/incentives less w/o incentive for the year
Additional Revenue Credit = Revenue Requirement w/o incentives

| Line No. | Details | | | |
|---|---|---|---|---|
| 176 | Investment Service Year (yyyy) | | Current Year | **0** |
| 177 | Service Month (1-12) | | ROE increase accepted by FERC (Basis Points) | |
| 178 | Useful life | | FCR w/o incentives, less depreciation | 0.00% |
| 179 | | | FCR w/incentives approved for these facilities, less dep. | 0.00% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 180 | | CIAC (Yes or No) | | Annual Depreciation Expense | | | - | | |
| 181 | | **Investment** | **Beginning** | **Depreciation Expense** | **Ending** | | **Revenue** | **Additional Rev.** | **Additional Rev.** |
| 182 | | **Year** | **Balance** | | **Balance** | | **Requirement** | **Requirement** | **Credit** |
| 183 | w/o incentives | - | - | - | - | - | | | $ - |
| 184 | w/ incentives | - | - | - | - | - | | $ - | |
| 185 | w/o incentives | - | - | - | - | - | | | $ - |
| 186 | w/ incentives | - | - | - | - | - | | $ - | |
| 187 | w/o incentives | - | - | - | - | - | | | $ - |
| 188 | w/ incentives | - | - | - | - | - | | $ - | |
| 189 | w/o incentives | - | - | - | - | - | | | $ - |
| 190 | w/in | - | | | - | | | $ | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | cent ives w/o ince ntiv | | - | - | | - | - | |
| 191 | es w/in | - | - | - | - | - | | $ - |
| 192 | cent ives w/o | - | - | - | - | - | $ - | |
| 193 | ntiv es w/in | - | - | - | - | - | | $ - |
| 194 | cent ives w/o | - | - | - | - | - | $ - | |
| 195 | ntiv es w/in | - | - | - | - | - | | $ - |
| 196 | cent ives w/o | - | - | - | - | - | $ - | |
| 197 | ntiv es w/in | - | - | - | - | - | | $ - |
| 198 | cent ives w/o | - | - | - | - | - | $ - | |
| 199 | ntiv es w/in | - | - | - | - | - | | $ - |
| 200 | cent ives | - | - | - | - | - | $ - | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 201 | w/o incentives | - | - | - | - | - | | $ - |
| 202 | w/ incentives | - | - | - | - | - | $ - | |
| 203 | w/o incentives | - | - | - | - | - | | $ - |
| 204 | w/ incentives | - | - | - | - | - | $ - | |
| 205 | w/o incentives | - | - | - | - | - | | $ - |
| 206 | w/ incentives | - | - | - | - | - | $ - | |
| 207 | w/o incentives | - | - | - | - | - | | $ - |
| 208 | w/ incentives | - | - | - | - | - | $ - | |
| 209 | w/o incentives | - | - | - | - | - | | $ - |
| 210 | w/ incentives | - | - | - | - | - | $ - | |
| 211 | w/o ince | - | - | - | - | - | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 212 | ntives w/incentives w/o incentives | - | - | - | - | - | $ - | |
| 213 | ntives w/incentives | - | - | - | - | - | | $ - |
| 214 | ntives w/o incentives | - | - | - | - | - | $ - | |
| 215 | ntives w/incentives | - | - | - | - | - | | $ - |
| 216 | ntives w/o incentives | - | - | - | - | - | $ - | |
| 217 | ntives w/incentives | - | - | - | - | - | | $ - |
| 218 | ntives w/o incentives | - | - | - | - | - | $ - | |
| 219 | ntives w/incentives | - | - | - | - | - | | $ - |
| 220 | ntives w/o incentives | - | - | - | - | - | $ - | |
| 221 | ntives | - | - | - | - | - | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 222 | w/in incentives | - | - | - | - | - | $ - | |
| 223 | w/o incentives | - | - | - | - | - | | $ - |
| 224 | w/in incentives | - | - | - | - | - | $ - | |
| 225 | w/o incentives | - | - | - | - | - | | $ - |
| 226 | w/in incentives | - | - | - | - | - | $ - | |
| 227 | w/o incentives | - | - | - | - | - | | $ - |
| 228 | w/in incentives | - | - | - | - | - | $ - | |
| 229 | w/o incentives | - | - | - | - | - | | $ - |
| 230 | w/in incentives | - | - | - | - | - | $ - | |
| 231 | w/o incentives | - | - | - | - | - | | $ - |
| 232 | w/in cent | - | - | - | - | - | $ - | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | ives w/o incentives | - | - | - | - | - | $ - | |
| 233 | w/in cent | | | | | | | |
| 234 | ives w/o incentives | - | - | - | - | - | $ - | |
| 235 | w/in cent | | | | | | | |
| 236 | ives w/o incentives | - | - | - | - | - | $ - | |
| 237 | w/in cent | | | | | | | |
| 238 | ives w/o incentives | - | - | - | - | - | $ - | |
| 239 | w/in cent | | | | | | | |
| 240 | ives w/o incentives | - | - | - | - | - | $ - | |
| 241 | w/in cent | | | | | | | |
| 242 | ives | - | - | - | - | - | | |
| 243 | w/o | - | | | - | | $ | |

| | | |

**Southwestern Public Service Company** **Table 45**
**Transmission Formula Rate Template** **Worksheet S**
**Twelve Months Ended December 31, 20YY**
**Depreciation and Amortization Rates**

| FERC Account | Name | Depreciation/ Amortization Rate (%) |
|---|---|---|
| **Electric Intangible** | | |
| 303.40 | Electric Intangible Software 3 Yr | 33.33 |
| 303.40 | Electric Intangible Software 5 Yr | 20.00 |
| 303.40 | Electric Intangible Software 7 Yr | 14.29 |
| 303.40 | Electric Intangible Software 10 Yr | 10.00 |
| 303.40 | Electric Intangible Software 15 Yr | 6.67 |
| **Electric Transmission** | | |
| 350.2 | Land Rights | 1.13 |
| 352 | Structures & Improvements | 1.50 |
| 353 | Station Equipment | 1.83 |
| 354 | Towers & Fixtures | 1.51 |
| 355 | Poles & Fixtures | 3.12 |
| 356 | OH Conductors & Devices | 2.73 |
| 357 | UG Conduit | 1.10 |
| 358 | UG Conductors & Devices | 2.47 |
| 359 | Roads & Trails | 1.57 |
| **Electric General** | | |
| 389 | General Land Rights | 2.12 |
| 390 | Structures and Improvements | 2.36 |
| 391 | Office, Furniture and Equipment | 4.00 |
| 391.4 | Computer Hardware | 20.00 |

| | | |
|---|---|---|
| 392.1 | Transportation Equipment - Autos | 9.10 |
| 392.2 | Transportation Equipment - Light Trucks | 9.30 |
| 392.3 | Transportation Equipment - Trailers | 6.07 |
| 392.4 | Transportation Equipment - Heavy Trucks | 7.83 |
| 393 | Stores Equipment | 2.86 |
| 394 | Tools Shop Equipment | 2.86 |
| 395 | Laboratory Equipment | 4.00 |
| 396 | Power Operated Equipment | 4.74 |
| 397 | Communications Equipment | 6.93 |
| 397.3 | Communications Equipment - EMS | 6.93 |
| 398 | Miscellaneous Equipment | 4.17 |

**Notes:**

The Depreciation Rates were approved in Docket ER19-1888 (Transmission) and Docket ER15-949 (General and Intangible) and will not change absent a 205 or 206 filing.

## Addendum 5 To Attachment H Part 5

# ANNUAL FORMULA RATE IMPLEMENTATION PROCEDURES
# SOUTHWESTERN PUBLIC SERVICE COMPANY

## Section 1 Applicability

The formula rate template and these Annual Formula Rate Implementation Procedures (collectively, the "Formula Rate") comprise SPS's filed transmission rate. SPS shall follow the Formula Rate to calculate annually its Zonal Annual Transmission Revenue Requirement ("Zonal ATRR"), the monthly rate for Network Integration Transmission Service ("NITS Rate"), the rates for point-to-point transmission service ("PTP Rates"), the monthly meter charge ("Meter Charge"), the monthly radial line charge ("Radial Line Charge"), the ATRR for Base Plan Upgrades ("BPU ATRR"), and the ATRR and rates for Ancillary Services Schedule 1 – Scheduling, System Control and Dispatch Service ("Schedule 1 Rates") provided in the SPS rate zone under the Southwest Power Pool ("SPP") and Xcel Energy Operating Companies ("Xcel Energy") Open Access Transmission Tariffs ("OATTs") (collectively, the "Annual Update"). Recovery of costs associated with existing facilities and new facilities shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the SPP OATT. The Formula Rate and the charges produced thereunder shall be effective for service on and after January 1, 2009. The Formula Rate shall be applicable on and after January 1 of each calendar year for service from January 1 – December 31 of each calendar year (the "Rate Year"), subject to the review, challenge and true-up procedures of this Appendix 1.

## Section 2 Annual Updates

a. No later than 5 p.m. CPT on October 1 of each year, SPS, or Xcel Energy Services Inc. ("XES") or another representative of Xcel Energy on SPS's behalf, shall determine and post its Annual Update to be effective during the next Rate Year. The Annual Update shall consist of the following:

(i) a data-populated version of the Formula Rate template setting forth the projected ATRR for the next Rate Year ("Projected ATRR") plus any applicable True-up Adjustment, as defined in Section 3.a., produced by operation of the Formula Rate;

(ii) a recalculation of the projected Base Plan Upgrade ("***BPU***") ATRR for the next Rate Year plus any applicable BPU True-up adjustment;

(iii) with respect to any True-up Adjustment or BPU True-up Adjustment calculated pursuant to Section 3, a calculation of applicable interest on any net over or under recovery based on the interest rates specified in the Commission's regulation at 18 C.F.R § 35.19a. The interest rate to be applied to the over or under recovery amounts shall be determined using the average rate for the twenty-one (21) months preceding October of the current year. The interest payable shall then be calculated by multiplying the average interest rate (monthly) by the over or under recovery amount by 24 months, the period during which the over or under recovery exists.

(iv) a recalculation of the Zonal ATRR, NITS Rate, PTP Rates, BPU ATRR, Meter Charge, Radial Line Charge, and the Schedule 1 Rates for the next Rate Year;

(v) supporting documentation, including, but not limited to, fully functioning Excel® files (or such other native format files), required to support, demonstrate and explain information upon which the Annual Update is based;

(vi) disclosure of the following changes to the extent any has taken effect since January 1, 2009, or since the prior October 1, and affects the Formula Rate or calculation of the Annual Update or the allocation of costs or revenues to SPS's transmission customers: changes in (a) FERC's Uniform System of Accounts ("USoA"), (b) FERC Form No. 1 reporting requirements as applicable, (c) any FERC ratemaking orders applicable to the SPS

Formula Rate, (d) the accounting policies, practices or procedures of SPS, (e) the SPP and/or the Xcel OATTs as they relate to SPS, or (f) classification or reclassification of facilities from transmission to radial or from radial to transmission (inclusive of changes to the net book value of such facilities as a result of depreciation) (changes in items (a) through (f) collectively referred to as "***Material Changes***");

(vii) disclosure and documentation of the impact of any changes in the classification of "Transmission Facilities" as defined in Attachment AI of the SPP OATT that took effect since January 1, 2009, or in the most recent proceeding year, that impact the Formula Rate or Radial Line Charge(s) to any transmission customer(s).

(viii) a copy of that actuarial report(s) estimating SPS's Post-Employment Benefits Other Than Pensions expenses for the next Rate Year pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Post-Employement Benefits Other than Pensions ("***PBOP***"); and

(ix) information regarding wholesale gains on SPS's sale or transfer of a transmission asset.

b. SPS shall contemporaneously post and notify its transmission customers, other parties to FERC Docket No. ER08-313 as of the date the settlement is filed with the Commission and affected state regulatory commissions (collectively, "Interested Parties") of the availability of the Annual Update on the publicly-accessible portions of the SPS page of the SPP OASIS[1] and the Transmission page of the Xcel Energy Inc. Web Site[2] (collectively, the "Web Sites"). The posting shall include both a Portable Document Format and fully functioning Excel® file (or such other native format file) of all materials contained in the Annual Update.

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1 Currently http://www.oatioasis.com/SPS/index.html

2 http://www.xcelenergy.com/Texas/Company/Transmission/Pages/Open_Access_Transmission Tariff.aspx

c. If October 1 falls on a weekend or a holiday recognized by FERC, the Annual Update shall be posted by 5:00 p.m. CPT on the next business day.

d. Each year, no later than October 20, or the next business day if October 20 is not a business day, SPS shall convene a meeting among SPS and Interested Parties and their respective representatives ("Customer Meeting") to explain the Annual Update for the next Rate Year. This Customer Meeting shall (i) allow enough time for SPS to present details about its Annual Update; (ii) provide Interested Parties and their respective representatives the chance to seek information and clarifications from SPS about the Annual Update; and (iii) allow for participation via teleconference. Interested Parties shall be provided written notice at least fourteen (14) calendar days prior to the Customer Meeting. Written notice may be provided by email to the representative(s) of the Interested Party on record with SPS.

e. SPS shall modify the Annual Update to reflect any changes that it and the Interested Parties have agreed upon as of November 15, or the next business day if November 15 is not a business day, and on such date, provide SPS's Zonal ATRR and each Base Plan Upgrade's Revenue Requirement and description to the SPP for the purpose of SPP preparing any necessary tariff filing.[3] SPS shall also cause the revised Annual Update to be posted on the Web Sites no later than December 1. Contemporaneous with the posting of the revised Annual Update, SPS shall file the revised Annual Update with the Commission ("Annual Informational Filing"). If December 1 falls on a weekend or a holiday recognized by FERC, the Annual Informational Filing shall be posted no later than 4:00 p.m. CPT on the next business day. The Annual Informational Filing and posting will include both Portable Document Format and fully functioning Excel® file (or such other native format file) of all materials contained in the revised Annual Update. As soon as available, such posting shall also include the docket number assigned by the FERC to the Annual Informational Filing. The Annual Informational Filing shall not require Commission action.[4]

3 In the event that the SPP is no longer required to make a tariff filing to reflect SPS's Zonal ATRR in the SPP OATT, and to the extent consistent with applicable Commission precedent, the November 15 deadline may be delayed or extended, as appropriate, until such later deadline established by the SPP that will facilitate timely billing of the new Zonal ATRR in the subsequent Rate Year.

4 The transmittal letter accompanying the Annual Informational Filing shall inform the Commission that the Annual Informational Filing is not intended to be subject to the Commission's notice requirements, that it is not intended for the Commission to take action accepting the Annual Informational Filing, and shall inform the Commission regarding the procedures contained in these Implementation Procedures for review and challenge of the Annual Informational Filing. If the Commission issues a notice of or an order accepting the Annual Informational Filing, SPS or XES shall advise the Commission of the challenge process in these Implementation Procedures and shall work with the settling parties in Docket No. ER08-313-000, et al., to seek rescission of such action. No Commission action on the Annual Informational Filing shall affect any rights under the Formula Rate or these Implementation Procedures.

f. The Annual Update for the new Rate Year shall:

(i) be based upon SPS's most recent budget and other information for the new Rate Year, that reasonably projects costs properly recorded (or to be recorded) on the books and records of SPS consistent with the Commission's USoA, FERC's orders establishing generally applicable transmission ratemaking policies, FERC accounting policies and practices, SPP's policies, and the SPP and Xcel Energy OATTs; effective January 1, 2015, PBOP charges will be based on the PBOP expense amount reported in SPS's most recent annual actuarial valuation report as of the date of SPS's Annual Update; and

(ii) compute the Projected ATRR using a rate base reflecting the following:

(1) an average of 13 monthly balances shall be applied to (i) gross plant balance for all plant functions, (ii) accumulated depreciation and amortization balance for all plant functions, (iii) the gross plant balance associated with the generator step-ups, (iv) capital structure balances (that is, long-term debt, preferred stock, and common equity), and (v) Construction Work in Progress ("CWIP") balance (if/when CWIP recovery is approved by the Commission);

(2) an average of the beginning of year and end of year balances shall be applied to (i) accumulated deferred income tax balances, (ii) unamortized balance of abandoned incentive plant (if/when abandoned incentive plant recovery is approved by the Commission), (iii) unamortized balance of extraordinary property loss (if/when recovery is approved by the Commission), (iv) land held for future use plant balance, (v) materials and supplies, and (vi) prepayments;

(3) Cash Working Capital shall be calculated (the value will be set to zero until an alternative recovery mechanism is approved by the Commission);

(4) the most recent end of the year actual plant balances shall be used in the calculation of the Radial Line Charges and the Meter Charges;

(5) for each Base Plan Upgrade project, the revenue requirement credit shall be based on the projected investment amount, the projected in-service date and the projected Fixed Charge Rate ("*FCR*").

**Section 3 True-up Adjustment**

The True-up Adjustment component of the Zonal ATRR for each Rate Year, beginning with 2011, shall be determined as follows:

a. Beginning with 2010, no later than 5 p.m. CPT on June 15 of each year, SPS or XES or another representative of Xcel Energy on SPS's behalf, shall calculate and post the ATRR for the previous Rate Year based on its actual costs as reflected in its FERC Form No. 1 and its books and records for that Rate Year ("Actual ATRR"). The Actual ATRR shall be compared with the Projected ATRR for the same year ("True-up Year") to determine any excess or shortfall in the projected Zonal ATRR that was used for billing purposes in the True-up Year. In addition, actual divisor loads

shall be compared to projected divisor loads and the difference multiplied by the zonal rate actually billed to determine any excess or shortfall in collection due to volume. The sum of the excess or shortfall due to the actual versus projected Zonal ATRR and the excess or shortfall due to volume shall constitute the ("True-up Adjustment"). The True-up Adjustment shall have the following support:

(i) a data-populated version of the Formula Rate template setting forth the Actual ATRR for the True-up Year;

(ii) a determination of the difference between the Projected ATRR and the Actual ATRR for such True-up Year, as set forth in Section 3.a. herein, shall be provided in Worksheet A included in the data populated version of the Formula Rate as described in item (i);

(iii) a determination of the difference between the Projected BPU ATRR and the Actual BPU ATRR for such True-up Year shall be provided in Worksheet A that is included in the data populated version of the formula;

(iv) supporting documentation required hereunder, including, but not limited to, fully functioning Excel® files (or such other native format files), which demonstrate or explain information not otherwise set out in SPS's FERC Form No. 1;

(v) disclosure of any Material Changes on the calculation of the True-up Adjustment to the extent that such Material Changes have taken effect since January 1, 2009, or since the prior October 1, and those Material Changes affect the Formula Rate or calculation of the True-up Adjustment or the allocation of costs or revenues to SPS's transmission customers; and

(vi) an example True-up Adjustment of the 2009 net revenue requirement (using illustrative numbers) has been provided as Exhibit A attached hereto.

a. By no later than June 15, SPS shall contemporaneously post the True-up Adjustment on the Web Sites and SPS shall file a letter with the Commission ("True-up Filing") announcing the availability of the True-up Adjustment on the Web

Sites (i.e., it will not file the entirety of the True-up Adjustment). If June 15 falls on a weekend or a holiday recognized by FERC, the True-up Filing shall be filed and posted no later than 4:00 p.m. CPT on the next business day. The True-up Adjustment posting shall include both a Portable Document Format and fully functioning Excel® file (or such other native format file) of all materials contained in the True-up Adjustment. SPS shall notify the Interested Parties of the availability of the True-up Filing and posting. The True-up Filing shall not require Commission action.

b. Each year, no later than July 15, SPS shall convene a meeting among SPS and other Interested Parties and their respective representatives ("True-up Customer Meeting"). This True-up Customer Meeting shall (i) allow enough time for SPS to present details about its True-up Adjustment; (ii) provide Interested Parties and their respective representatives the chance to seek information and clarifications from SPS about the True-up Adjustment; and (iii) allow for participation via teleconference. SPS shall post and Interested Parties shall be provided written notice at least fourteen (14) calendar days prior to the True-up Customer Meeting. Written notice may be provided by email to the representative(s) of the Interested Party on record with SPS.

c. The True-up Adjustment shall:

(i) be based on costs that are prudently incurred and properly recorded on the books and records of SPS, including SPS's FERC Form No. 1 data, as applicable, for the most recently completed calendar year consistent with the USoA, FERC's orders establishing generally applicable transmission ratemaking policies, and, to the extent specified in the Formula Rate, SPS's books and records kept in conformance with the FERC USoA, FERC accounting policies and practices, SPP's policies, and the SPP and Xcel Energy OATTs;

(ii) compute the Actual ATRR using the same methodology for calculating rate base and capital structure balances as specified for the Annual Update in Section 2(f)(ii) above;

(iii) compute the Actual BPU ATRR using the actual Base Plan Upgrade project investment amount(s), the actual in-service date(s), and the actual FCR; and

(iv) include a side-by-side comparison of the actual ATRR formula rate components as compared with the projected ATRR formula rate components for the True-up Year ("Variance Analyses").

d. Summary of Formula Rate Process including True-up Adjustment:

(i) Monthly charges shall be based on the Zonal ATRR that uses projected data for each Rate Year. For example, those charges for service from January 1, 2009 through December 31, 2009 shall be based on projected 2009 plant-in-service costs. Beginning January 1, 2012, the monthly charges shall be based on the Zonal ATRR using projected data that includes projected data for the BPU ATRR.

(ii) The Zonal ATRR based on projected 2009 data shall be trued-up in June 2010 to a Zonal ATRR based on actual data. Beginning with the 2012 Rate Year, the Zonal ATRR and the BPU ATRR based on projected data shall be trued-up in June 2013 to a Zonal ATRR and BPU ATRR based on actual data.

(iii) Differences between the Zonal ATRR and the BPU ATRR calculated using projected and actual data for a given True-up Year that result from the True-up Adjustment process shall be rolled forward to the following projected Rate Year, including interest. For example, the True-up Adjustment for the 2012 Formula Rates would be calculated in June 2013 and included in the rate formula effective January 2014.

(iv) The sequence outlined in subsections (i), (ii) and (iii), above, shall repeat each subsequent Rate Year and is summarized below:

| Month | Year | Action |
|---|---|---|
| Oct. | 2009 | Annual Update - SPS populates the formula with Year 2010 projected data. Formula template amounts for 2010 actual data are left blank at this time. |
| June | 2010 | True-up Adjustment - SPS populates the Year 2009 projected data formula with Year 2009 actual data and calculates the 2009 True-up Adjustment (before interest). |
| Oct. | 2010 | Annual Update - SPS calculates the interest to include in the 2009 True-up Adjustment. |
| Oct. | 2010 | Annual Update - SPS populates the formula with Year 2011 projected data and includes the 2009 True-up Adjustment amount into the Zonal ATRR for 2011. Formula template amounts for 2011 actual data are left blank at this time. |
| June | 2011 | True-up Adjustment - SPS populates the Year 2010 projected data formula with Year 2010 actual data and calculates the 2010 True-up Adjustment (before interest). |
| Oct. | 2011 | Annual Update - SPS calculates the interest to include in the 2010 True-up Adjustment. |
| Oct. | 2011 | Annual Update - SPS populates the formula with Year 2012 projected data and inputs the 2010 True-up Adjustment amount into the Zonal ATRR for 2012. Formula template amounts for 2012 actual data are left blank at this time. |

| | | |
|---|---|---|
| June | 2012 | True-up Adjustment - SPS populates the formula with 2011 actual data and calculates the 2011 True-up Adjustment (before interest). |
| Oct. | 2012 | Annual Update - SPS calculates the interest to include in the 2011 True-up Adjustment. |
| Oct. | 2012 | Annual Update – SPS populates the formula with Year 2013 projected data including projected data for the BPU ATRR and inputs the 2011 True-up Adjustment amount into the Zonal ATRR for Year 2013. Formula template amounts for 2013 actual data are left blank at this time. |
| June | 2013 | True-up Adjustment – SPS populates the formula with 2012 actual data including the actual BPU ATRR and calculates the 2012 Zonal ATRR and BPU ATRR True-up adjustments (before interest). |
| Oct. | 2013 | Annual Update – SPS calculates the interest to include in the 2012 True-up Adjustment. |
| Oct. | 2013 | Annual Update – SPS populates the formula with Year 2014 projected data including projected data for the BPU ATRR and inputs the 2012 Zonal ATRR and the 2012 BPU ATRR True-up Adjustment amounts into the Zonal ATRR and BPU ATRR for 2014. Formula template amounts for 2014 actual data are left blank at this time. |
| June | (Year) | True-up Adjustment - SPS populates the formula with (Year - 1) actual data and calculates the (Year – 1)True-up Adjustment (before interest). |
| Oct | (Year) | Annual Update – SPS calculates the interest to include in the (Year – 1) True-up Adjustment. |
| | | Annual Update - SPS populates the formula with |

(Year +1) projected data and (Year –1) True-up Adjustment.

e. The True-up Adjustment is subject to challenge and review in accordance with the procedures set forth in this Appendix 1, and all other rights that any entity may have under the Federal Power Act ("FPA") or the Commission's regulations.

## Section 4 Annual Review Procedures

Each Annual Update and True-up Adjustment shall be subject to the following review procedures ("Annual Review Procedures"):

a. Beginning June 15, but no later than November 30 of each year, any Interested Party and any entity that has standing to challenge SPS formula rates under the FPA may serve reasonable information requests in writing on SPS concerning the True-up Adjustment and/or the Annual Update for the next calendar year ("Information Requests"). The deadline may be extended by mutual consent.

b. Information Requests submitted according to Section 4.a., above, shall be limited to what is appropriate to determine whether the Formula Rate (inclusive of any corrections) has been applied accurately, appropriately, and in accordance with its terms. Permissible Information Requests include, but are not limited to, Information Requests regarding Material Changes and Information Requests related to whether costs have been prudently incurred and whether costs have been properly recorded, on the books and records of SPS, including SPS's FERC Form No. 1, as applicable, consistent with the USoA, FERC's orders establishing generally applicable transmission ratemaking policies, FERC accounting policies and practices, SPP's policies, and the SPP and Xcel Energy OATTs. Such Information Requests

shall not solicit information concerning costs or allocations where those specific costs or allocations have been addressed by any final FERC order or by any final settlement approved by the appropriate authority, court or agency, except to determine if the costs or allocations have been accurately and appropriately implemented in accordance with the terms of the order and/or settlement or to determine if different circumstances might affect such prior actions. Interested Parties should make good faith efforts to submit consolidated sets of Information Requests that limit the number and overlap of questions to the maximum extent practicable.

c. SPS shall make a good faith effort to respond to Information Requests pertaining to the Annual Update or True-up Adjustment within fourteen (14) calendar days after receipt of such Information Requests. Information requests received after 4 p.m. CPT shall be considered received the next business day.

**Section 5** **Resolution of Issues and Challenges to Annual Update and/or True-Up Adjustments**

a. No later than December 5 of each year, any Interested Party may notify SPS in writing of any specific challenge(s) to any component of the most recently posted True-up Adjustment and/or Annual Update ("Preliminary Challenge"). Within five (5) business days of receiving notice of such challenge(s), SPS shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) on the Web Sites. SPS and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through negotiations, and shall allow any Interested Party to participate in such negotiations. Any modification to the True-up Adjustment or the Annual Update that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the Annual Update and True-up Adjustment for the next Rate Year and incorporated into the Company's Annual Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the Formula Rate, such changes shall be filed with the Commission and such changes to the Formula Rate shall have an effective date of January 1 of the Rate Year under review subject to Commission approval.

b. SPS shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which SPS agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the Annual Update or True-up Adjustment will result. If SPS disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.

c. All information and correspondence produced pursuant to these Implementation Procedures may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the FPA, or in any proceeding before the U.S. Court of Appeals to review a FERC decision related to the Formula Rate. SPS may, however, designate any response to an Information Request as confidential if the information conveyed is not publicly available. Interested Parties' representatives shall treat such response as non-public information provided in confidence. Interested Parties may use responses designated as confidential in connection with any informal dispute resolution process commenced pursuant to Section 5.a. herein, any Formal Challenge brought pursuant to Section 5.e. herein, or in conjunction with a protest to a proposed change to the formula rate initiated by SPS through a separate FPA Section 205 filing; provided, however, when so used, such response shall initially be filed under seal (unless the claim of confidentiality is waived by SPS), subject to a later determination by the presiding authority that the material is, in whole or in part, not entitled to confidential treatment.

d. If SPS and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of SPS's response to the issue(s), senior management representatives of SPS and the Interested Parties shall meet to try to resolve the issue(s).

e. If these senior management representatives are not able to resolve the issue(s) within sixty (60) calendar days, any Interested Party that has not resolved any Preliminary Challenge to a True-up Adjustment may file with FERC a Formal Challenge to a True-up Adjustment pursuant to these Implementation Procedures ("Formal Challenge").

(i) Failure to notify SPS of an issue shall not bar pursuit of such issue in the filing of a Formal Challenge.

(ii) Failure to notify SPS of an issue shall not bar pursuit of such issue in a subsequent Annual Update or True-up Adjustment review.

(ii) Failure to file a Formal Challenge regarding an issue(s) as to a given Annual Update or True-up Adjustment shall not bar pursuit of such issue(s) or the filing of a Formal Challenge as to such issue(s) as relates to a subsequent Annual Update or True-up Adjustment review.

f. In any proceeding ordered by the FERC in response to a Formal Challenge raised under these Implementation Procedures, SPS shall bear the burden of demonstrating the justness and reasonableness of the charges resulting from its application of the Formula Rate, and of proving that it properly applied the Formula Rate, properly calculated the challenged Annual Update or True-up Adjustment pursuant to the Formula Rate, and that adoption of any Material Change is just and reasonable. Nothing herein is intended to alter the burden applied by FERC with respect to prudence challenges.

g. Any changes to the data inputs resulting from Preliminary Challenges or Formal Challenges that are not agreed to or resolved by a final Commission Order on or before November 15 shall be incorporated into the Formula Rate and True-up Adjustment for the next Rate Year that begins after the negotiations have become final.

h. It is recognized that resolution of Preliminary Challenges and/or Formal Challenges related to Material Changes may necessitate pro forma adjustments to the Formula Rate calculations, changes to the Formula Rate, or changes to the input data to restore the intent of the formula as of the effective date of the settlement or as the Formula Rate may be

subsequently modified by FERC or through settlement, and to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential. It is further recognized that the impact of any such pro forma adjustment or changes to the Formula Rate calculation, the Formula Rate, or input data, may be applicable to the entire Rate Year at issue in a Preliminary Challenge or Formal Challenge. If such pro forma adjustment occurs mid-year, it shall be effective mid-year, however, the charges produced by the Formula Rate shall not be adjusted mid-year but rather the impact on the charges from the pro forma adjustment shall be reflected in the True-up Adjustment. If such a change in the Formula Rate is agreed to by the settling parties in Docket No. ER08-313-000 et al. or required by FERC, SPS shall file such Formula Rate change under FPA Section 205, with requests for waiver of applicable notice requirements, to permit the change to become effective for the Annual Update or True-up Adjustment for the Rate Year under review, which requests for waiver of the applicable notice requirements shall not be opposed by any settling party in Docket No. ER08-313-000, et al.

i. Except as provided in Section 5.h, no party shall, in conjunction with the Annual Update or True-up Adjustment, seek to modify the Formula Rate (i.e., all modifications to the Formula Rate shall require an FPA filing).

**Section 6** **Challenges to the Formula**

a. Nothing in these Annual Formula Rate Implementation Procedures shall be deemed to limit in any way the right of any party to file a request for prospective relief under FPA Sections 205, 206 or 306 and FERC's regulations to change the Formula Rate. Any party may challenge the continuing reasonableness of the Formula Rate or the charges produced thereby.

b. Neither failure to notify SPS of an issue nor failure to file a Formal Challenge nor failure to exercise any rights under FPA Sections 205, 206, and 306 and FERC's regulations in any given year shall be construed as a bar to raising any issue in any proceeding initiated at FERC.

**Section 7** **Corrections to FERC Form No. 1, Annual Update, or True-up Adjustment**

a. Notwithstanding any other provision of these Implementation Procedures, (i) if SPS identifies, determines or concludes that corrections to any prior year's FERC Form No. 1 or Annual Update or True-up Adjustment pursuant to the Formula Rate are required to correct an error, or (ii) at any time an Interested Party presents information or raises a concern to SPS that indicates that an error exists or a correction is required to any prior year's FERC Form No. 1 or Annual Update or True-up Adjustment, SPS shall investigate the alleged error(s) and within 30 days shall inform Interested Parties of the results of the investigation by posting such results on its Web Sites as set forth in Section 2.b. The results of the investigation shall include an explanation of the nature of the alleged error(s) and the extent to which SPS agrees or disagrees that such error(s) require corrections to the FERC Form No. 1, Annual Update or True-up Adjustment.

b. If a correction to an Annual Update or True-up Adjustment results from the error, no mid-year adjustment will result, but an adjustment will be made in a future period as follows.

SPS shall promptly correct such error(s) identified in Section 7.a., and shall notify Interested Parties of such correction(s) by posting an appropriate amended Annual Update or True-up Adjustment on the Web Sites as set forth in Section 2.b. If a correction to the Annual Update or True-up Adjustment is identified before November 15 (i.e., before the commencement of the next Rate Year), the modified charges produced by the Formula Rate shall be reflected in the next Rate Year. Otherwise, the correction shall be reflected in the next True-up Adjustment, and credited in the following Rate Year.

c. In any Rate Year in which an out-of-period correction is reflected, SPS shall also include worksheets to describe such adjustments, including interest on the total correction for the entire period in which the error existed through and

including the Rate Year in which the correction is reflected in the Annual Update. The applicable interest rate shall be the FERC-published interest rates.

d. In the event SPS corrects or fails to correct an Annual Update or True-up Adjustment pursuant to this Section 7, Interested Parties shall have the same rights to review and submit challenges to the correction(s) or SPS's failure to make a correction as those parties otherwise would have had pursuant to these Annual Formula Rate Implementation Procedures, without abridgement or restriction, if the Form No. 1, Annual Update, or True-up Adjustment had been correctly stated in the first instance; provided, however, the scope of review of the Section 7 correction, the formula line item reflecting the Section 7 correction, and the worksheets calculating the Section 7 correction is limited to the aspects of the Formula Rate, Annual Update and/or True-up Adjustment affected by the out-of-period correction(s).

**Section 8** **Changes to Formula Rate Initiated by SPS**

a. Any changes to the Formula Rate initiated by SPS, including any changes necessitated by Material Changes, may only be implemented as a result of a filing with FERC under Section 205 or 206 of the FPA.

b. However, in the event that FERC mandates any changes in the format for the FERC Form No. 1 or the USoA, SPS may make a filing with FERC under FPA Section 205 that updates the FERC Form No. 1 and USoA references in its Formula Rate to reflect any such changes prior to or coincident with the Annual Update or True-up Adjustment where these changes are reflected in the Formula Rate. Such filing may not be used to raise issues unrelated to the proposed changes. If such a change in the Formula Rate is required pursuant to this Section 8.b., the FPA Section 205 filing may include a request for waiver of applicable notice requirements, to permit the change to become effective for the Annual Update or True-up Adjustment for the applicable Rate Year, which requests for waiver of notice requirements shall not be opposed by any settling party in Docket No. ER08-313-000, et al.

## Section 9 Changes to the Stated Inputs in the Formula Rate

a. The following Formula Rate inputs shall be stated values to be used in the Formula Rate (both for the Annual Update and True-up Adjustment) until changed by a filing pursuant to Section 205 of the FPA or by a proceeding under Section 206 of the FPA: (a) the rate of return on common equity ("*ROE*"); and (b) depreciation rates or amortization periods. With respect to the PBOP charges, the amount shall be based on an Actuarial Study and is net of any amounts received from the Federal government for the prescription drug subsidy ("Medicare D Subsidy"). The amount SPS will contribute to its external PBOP trust will be at a minimum equal to its actual PBOP expense.

Effective on and after October 20, 2014: with respect to a filing under FPA Section 205 to change the transmission formula ROE established in the comprehensive Settlement Agreement in Docket No. EL05-19-000 et al. ("*Settlement Agreement*"), SPS will not submit a filing prior to October 31, 2019 seeking to increase the fixed settlement ROE of 10.5 percent (which includes the SPP RTO membership adder), and will not request an effective date earlier than January 1, 2020; with respect to a filing under FPA Section 206 to the change the fixed settlement ROE of 10.5 percent, no Settling Party to the Settlement Agreement will file or support an FPA Section 206 filing to reduce the fixed settlement ROE prior to October 31, 2019, and no Settling Party will request a refund effective date earlier than January 1, 2020 ("*Limited ROE Moratorium*").

b. For extraordinary property losses, the unamortized balance shall be included in rate base and shall be amortized for Formula Rate purposes only after FERC has authorized the amount of the loss and the amortization of the loss for ratemaking purposes.

c. For abandoned plant, the unamortized balance shall be included in rate base and shall be amortized for Formula Rate purposes only after FERC has authorized the amount of any abandoned plant and the amortization of the balance for ratemaking purposes.

EXHIBIT A

**EXAMPLE OF 2009 TRUE-UP ADJUSTMENT:**

Projected 2009 net ATRR was $90,000,000, projected load was 4,500,000 kw and the resulting zonal rate was $20.00 per kw-yr.

Actual 2009 net ATRR calculated based on FERC Form No. 1 data available in May, 2010 is $88,000,000, actual 12 CP load is 4,512,820 kw for a resulting zonal rate of $19.50 per kw-yr.

**2009 TRUE-UP ADJUSTMENT CALCULATION:**

There is an over recovery of the net revenue requirement equal to $2,000,000 ($90,000,000 – $88,000,000 = $2,000,000).

There is also a $256,400 over recovery in revenue collection due to volume ((4,500,000kw – 4,512,820kw) X $20 per kw-yr = $256,400).

In this example, the total True-up Adjustment amount would be a net over recovery of $2,256,400 ($2,000,000 + $256,400 = $2,256,400), which would be applied as a reduction to the 2011 projected net ATRR beginning in January 2011.

This same amount can also be calculated by taking the difference between the 2009 projected zonal rate and the zonal rate calculated based on actual data times the actual load (($20.00 – $19.50) per kw-yr X 4,512,820 kw = $2,256,400). (Allow for rounding.)

**EXAMPLE OF 2012 TRUE-UP ADJUSTMENT:**

Projected 2012 Zonal ATRR = $118M  Actual 2012 Zonal ATRR = $120M
Projected 2012 BPU ATRR = $10M  Actual 2012 BPU ATRR = $9M
Projected Load = 5,400,000 kW  Actual Load = 5,200,000 kW
Projected Zonal Rate = $20.00 per kW-yr. (($118M - $10M) / 5,400,000 kW)
Actual Zonal Rate = $21.35 per kW-yr. (($120M - $9M) / 5,200,000 kW)

**2012 TRUE-UP ADJUSTMENT CALCULATION:**
Zonal ATRR under recovery of $2M. ($120M - $118M)

Zonal ATRR under recovery of $1M from the BPU ARR. ($9M - $10M. The projected BPU ATRR revenue credit reducing the Zonal ATRR was $1M higher than the actual BPU ATRR.)

Zonal ATRR under recovery of $4M due to the volume variance, projected load as compared to actual load. ((5,200,000 kW – 5,400,000 kw) x $20.00 per kW = $4M.)

In this example, the total Zonal ATRR True-up would be a net under recovery of $7M. [5] ($2M + $1M + $4M)

[5] The BPU ATRR amount is revenue credited to the Zonal ATRR. Because the projected BPU ARR was $1M higher than the actual BPU ATRR, the projected Zonal ATRR was $1M lower than it should have been. In the next annual update, the projected BPU revenue credit will be reduced by $1M from the BPU ATRR true-up. This results in a smaller BPU revenue credit and a larger projected Zonal ATRR.

This same amount can also be calculated by taking the difference between the 2012 actual zonal rate and the projected zonal rate times the actual load. (($21.35 per kW - $20.00 per kW) x 5,200,000 kW = $7M.) (Allow for rounding.)

# Addendum 6 to Attachment H

**Rate Formula Template**
**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**

**Table of Contents**


| Worksheet Name | Description |
|---|---|
| | Derivation of PTP |
| Page 1 | Rates |
| | Derivation of Projected |
| Page 2 | Net ATRR |
| | Allocator |
| Page 3 | Calculations |
| Page 4 | Notes & Comments |
| | Account 456 Supporting |
| A | Schedule |
| | Account 454 Supporting |
| B | Schedule |
| C | True-Up Worksheet |
| | True-Up Page 2 - Derivation |
| D | of True-Up for Net ATRR |
| | Schedule - System |
| F | Scheduling etc |
| | Billing Units |
| G | Divisor |
| G1 | Historic Year Actual Billing Units for Computing Divisor True Up |
| | SPP Transmission Cost |
| H | Allocation Revenue Offsets |
| | Upgrade Fixed Charge |
| I | Rate |
| | Transmission Upgrade Project |
| J1 | #1 Calculations |
| | Transmission Upgrade Project |
| J2 | #2 Calculations |
| | SPP RTO Incentive |
| K | Adder |
| L | Transmission Plant Used for Other Purposes (for internal use only) |


| **Decision Variables** | Choice: 1 = GP; 0 = NP |
|---|---|
| Switch for use of General Plant vs Net Plant Allocator for Debt Service | 0 |

Switch for use of Incentive Plant (column K) in Worksheets J1 and J2 to feed page 1, Line 8, Transmission Revenue Offset

Choice: 1 = No Incentive Plant; 0 = Incentive Plant

1

| | |
|---|---|
| **Forecast Year:** | 0 |
| | Choice: 1 = Incentive Adder Granted by FERC; 0 Adder not Granted by FERC |
| **ROE Transmission Investment Incentive Adder (basis points):** | 0 |
| | Choice: 1 = RTO Incentive Adder Granted by FERC; 0 RTO Incentive Adder not Granted by FERC |
| **RTO Incentive Adder** | 1 |

**Rate Formula Template**
**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**



Formula Rate - Cash Flow
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
For the 12 months ending 12/31/0

| Line No. | Act | Description | Reference/ Note | Total | Allocator | (3) x (4) **Allocated to Transmission** |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| | | **A. Zonal Net Annual Transmission Revenue Requirement (ATRR)** | | | | |
| 1 | | **Gross Annual Transmission Revenue Requirement** | Page 2, Line 25, Col 5 | | | #DIV/0! |
| | | **Revenue Credits** | | | | |
| 2 | 456 | Less: Revenue from SPP for and Other Short-term Point-to-Point Service | Note A, 'Worksheet A | $ - | GT 0.000 PP 0 | $ - |
| 3 | 454 | Less: Transmission Related Rents | Note B, 'Worksheet B | $ - | GT 0.000 PP 0 | $ - |
| 4 | | Less: Revenues from service provided by the ISO at a discount | Worksheet B | $ - | GT 0.000 PP 0 | $ - |
| 5 | | **TOTAL TRANSMISSION REVENUE CREDITS** | Sum Lines 2 to 4 | | | $ - |
| | | **True-Up Adjustment** | | | | |
| 6a | | Prior Year Actual Net ATRR | Worksheet C | $ - | | |
| 6b | | Prior Year Projected Net ATRR | Worksheet C | $ - | | |
| 6c | | Prior Year ATRR True-Up | Worksheet C | | | $ - |
| 6d | | Prior Year Divisor True-Up | Note C, Worksheet C | | | $ - |
| 6e | | Interest on Prior Year True-Up | Worksheet C | | | $ - |
| 6f | | **Total True-Up Amount** | Sum Lines 6c to 6e | | | $ - |
| 7 | | **ZONAL NET TRANSMISSION REVENUE REQUIREMENT WITH TRUE-UP** | Line 1 - Line 5 + | | | #DIV/0! |

| | | | |
|---|---|---|---|
| | **ADJUSTMENT** | Line 6f | |
| | **Transmission Project Revenue Offset Under Schedule 11** | | |
| 8 | Total Schedule 11 Revenue Offset | Worksheets J1 & J2 | #DIV/0! |
| 9 | **ZONAL NET ATRR FOR SPP OPEN ACCESS TRANSMISSION TARIFF - Attachment H** | Line 7 minus Line 8 | #DIV/0! |
| | **B. Point-to-Point Transmission Service Rates** | | |
| | **DIVISOR (MW)** | | |
| 10 | Projected 12 CP for requirements (RQ) service | Note G1, Worksheet G | 0.000 MW |
| 11 | Plus 12 CP of firm bundled sales over one year not in line 11 | Note G2, Worksheet G | 0.000 MW |
| 12 | Plus 12 CP of Network Load not in line 11 | Note G3, Worksheet G | 0.000 MW |
| 13 | Less 12 CP of firm P-T-P over one year | Note G4, Worksheet G | 0.000 MW |
| 14 | Plus Contract Demand of firm P-T-P over one year | Worksheet G | 0.000 MW |
| 15 | Less Contract Demand from Grandfathered Interzonal transactions over one year | Note G5, Worksheet G | 0.000 MW |
| 16 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount | Worksheet G | 0.000 MW |
| 17 | Total Demand | Sum Lines 10 to 16 | 0.000 MW |
| | **Rates for Point-to-Point Service** | | |
| 18 | Point-to-Point Firm & Non-Firm ($/MW/Year) | Line 9 / Line 17 | $ - |
| 19 | Point-to-Point Firm & Non-Firm ($/MW/Month) | Line 18 / 12 months | $ - |
| 20 | Point-to-Point Firm & Non-Firm ($/MW/Week) | Line 18 / 52 weeks | $ - |
| 21 | Point-to-Point Firm ($/MW/Day) On Peak | Line 20 / 5 days | $ - |
| 22 | Point-to-Point Firm ($/MW/Day) Off Peak | Line 20 / 7 days | $ - |
| 23 | Non-firm Point-to-Point ($/MW/Day) On Peak | Line 20 / 5 days | $ - |

| | | | |
|---|---|---|---|
| 24 | Non-firm Point-to-Point ($/MW/Day) Off Peak | Line 20 / 7 days | $ - |
| 25 | Non-firm Point-to-Point ($/MW/Hour) On Peak | Line 23 / 16 hours | $ - |
| 26 | Non-firm Point-to-Point ($/MW/Hour) Off Peak | Line 24 / 24 hours | $ - |
| | FERC Annual Charge ($/MWh) | | |
| 27 | Short Term | Note D | $ - |
| 28 | Long Term | | $ - |

**C. Scheduling, System Control and Dispatch Service Annual Revenue Requirement**

| | | | |
|---|---|---|---|
| 29 | Scheduling, System Control and Dispatch Service Costs | Note F, Worksheet F | $ - |
| 30 | **Divisor (MW)** | Line 17 | - |
| | **Rates for Ancillary Service 1: Scheduling, System Control and Dispatch Service** | | |
| 31 | AS1 ($ / MW-Year) | Line 29 / Line 30 | #DIV/0! |
| 32 | AS1 ($ / MW-Month) | Line 31 / 12 | #DIV/0! |

**Rate Formula Template**
**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**



Formula Rate - Cash Flow
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
For the 12 months ending 12/31/0

| Line No. | Acct | Description | Reference/Note | Total | Allocator | **Allocated to Transmission** |
|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) |
| | | **Gross Annual Transmission Revenue Requirement (ATRR)** | | | | **(3) x (4)** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | **Operating & Maintenance (O&M)** | | | | | | |
| 1 | 560 - 574 | Transmission | | $ - | T E | 0.00 000 | $ - | |
| 2 | 565 | Less: Transmission of Electricity by Others | Note W, Worksheet H | $ - | | 1.00 000 | $ - | |
| 2a | 561 | Less: Load Dispatching | Worksheet F | $ - | | 1.0 000 0 | $ - | |
| | | **TOTAL O&M** | | $ - | | | $ - | |
| | | **Administrative & General (A&G)** | | | | | | |
| 3 | 920 - 932 | A&G | | $ - | W /S | 0.00 000 | $ - | |
| 4 | | Less FERC Annual Fees in Acct 928 | | $ - | W /S | 0.00 000 | $ - | |
| 5 | 923 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad | Note I | $ - | W /S | 0.00 000 | $ - | |
| 5a | | 'Plus Transmission Related Reg. Comm. Exp. | Note I | $ - | T E | 0.00 000 | $ - | |
| 6 | | Common | | $ - | C E | 0.00 000 | $ - | |
| 7 | | Transmission Lease Payments | | $ - | | 1.00 000 | $ - | |
| 8 | | **TOTAL O&M + A&G** | Sum Lines 2, 3,5a,6,7 minus Lines 4 & 5 | $ - | | | $ - | |
| | | **Debt Service** | | | | | | |
| 9 | 427 | Debt Service | | $ - | N P | #DI V/0! | #DIV/0! | |
| 10 | 428 | Amortization of premium or discount | | $ - | N P | #DI V/0! | #DIV/0! | |
| 12 | | **TOTAL DEBT SERVICE** | Sum Lines 9 & 10 | $ - | | | #DIV/0! | |
| | | **Taxes Other Than Income Taxes** | Note U | | | | | |
| | | Labor Related | | | | | | |
| 13 | 926 | Payroll | | $ - | W /S | 0.00 000 | $ - | |
| 14 | 185 | Highway and vehicle | | $ - | W /S | 0.00 000 | $ - | |
| 15 | | Plant Related | | | | | | |
| 1 | | Property | | $ | G | 0.00 | $ | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 6 | 505 | | | - | P | 000 | - | |
| 1 | | | | $ | | 0.00 | $ | |
| 7 | | Gross Receipts | | - | | 000 | - | |
| 1 | | | | $ | G | 0.00 | $ | |
| 8 | | Other | | - | P | 000 | - | |
| 1 | | | | $ | G | 0.00 | $ | |
| 9 | 408 | Payments in lieu of taxes | | - | P | 000 | - | |
| 2 | | | | $ | | | $ | |
| 0 | | **TOTAL TAXES** | Sum Lines 13 to 19 | - | | | - | |
| 2 1 | | **SUBTOTAL** | Sum Lines 8, 12, & 20 | | | | #DIV/0! | |
| 2 | | | | $ | G | 0.00 | $ | |
| 2 | | **MARGIN REQUIREMENT** | Note M | - | P | 000 | - | |
| 2 3 | | **RTO Incentive Adder (Order Nos. 679 & 679-A)** | Note K, Worksheet K | #DIV/0! | | 1.00 000 | #DIV/0! | |
| 2 4 | | **Additional Margin on Incentive Plant Transmission Upgrade Projects** | Note J, Worksheet J | #DIV/0! | | 1.00 000 | #DIV/0! | |
| 2 5 | | **GROSS REVENUE REQUIREMENT w/o INCENTIVE PLANT** | Sum Lines 21 & 22 | | | | #DIV/0! | |
| 2 6 | | **GROSS REVENUE REQUIREMENT w INCENTIVE PLANT** | Sum Lines 25, 23 & 24 | | | | #DIV/0! | |

**Rate Formula Template**

Return to TOC

**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**



Formula Rate - Cash Flow
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
For the 12 months ending 12/31/0

| Line No. | (1) Description | (2) Reference/Note | (3) Total | | (4) Allocator | (5) **Allocated to Transmission** **(3) x (4)** |
|---|---|---|---|---|---|---|
| | **SUPPORTING CALCULATIONS AND NOTES** | | | | | |
| | **GROSS PLANT IN SERVICE** | | | | | |
| 1 | Production | 310-316, 320-325, 330-336, 340-346 | $ - | N/A | 0.00000 | $ - |
| 2 | Transmission | 350-359 | $ - | GTP | 0.00000 | $ - |
| 3 | Distribution | 360-373 | $ - | N/A | 0.00000 | $ - |
| 4 | General & Intangible | 301-303, 389-399 | $ - | W/S | 0.00000 | $ - |
| 5 | Common | | $ - | CE | 0.00000 | $ - |
| 6 | TOTAL GROSS PLANT | Sum Lines 1 to 5 | $ - | | | $ - |
| 7 | | Line 6 col (5) / Line 6 col (3) | | | **Gross Plant Allocator (GP) =** | **0.00000** |
| | **ACCUMULATED DEPRECIATION** | All plant deprec. Goes into same FERC acct. | | | | |
| 8 | Production | 108 | $ - | N/A | | $ - |
| 9 | Transmission | 108 | $ - | N/A | | #DIV/0! |
| 10 | Distribution | 108 | $ - | N/A | | $ - |
| 11 | General & Intangible | 108 | $ | N | | $ |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | | | - | / | | - |
| | | | | A | | |
| | | | | N | | |
| 1 | | | $ | / | | $ |
| 2 | Common | 108 | - | A | | - |
| 1 | | Sum Lines 8 to | $ | | | |
| 3 | Sub-Total | 12 | - | | | #DIV/0! |

**NET PLANT**

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | N | | |
| 1 | | Line 1 minus | $ | / | | $ |
| 4 | Production | Line 8 | - | A | 0.00000 | - |
| | | | | N | | |
| 1 | | Line 2 minus | $ | T | | |
| 5 | Transmission | Line 9 | - | P | #DIV/0! | #DIV/0! |
| | | | | N | | |
| 1 | | Line 3 minus | $ | / | | $ |
| 6 | Distribution | Line 10 | - | A | 0.00000 | - |
| | | | | W | | |
| 1 | | Line 4 minus | $ | / | | $ |
| 7 | General & Intangible | Line 11 | - | S | 0.00000 | - |
| 1 | | Line 5 minus | $ | C | | $ |
| 8 | Common | Line 12 | - | E | 0.00000 | - |
| 1 | | Sum Lines 14 | $ | | | |
| 9 | Sub-Total | to 18 | - | | | #DIV/0! |
| | | | | | **Net Plant Allocator (NP) =** | **#DIV/0!** |

| | | | | | |
|---|---|---|---|---|---|
| | **TRANSMISSION PLANT INCLUDED IN ISO RATES** | | **Gross Plant** | **Net Plant** | |
| 2 | | | $ | $ | |
| 0 | Total transmission plant | Line 2 | - | - | |
| 2 | Less transmission plant | | $ | $ | |
| 1 | excluded from ISO rates | Note L | - | - | |
| 2 | Less transmission plant included in OATT Ancillary | | $ | $ | |
| 2 | Services | Note O | - | - | |
| 2 | Transmission plant | Line 20 minus | $ | $ | |
| 3 | included in ISO rates | Lines 21 & 22 | - | - | |
| | | | | **Gross Transmission** | |
| 2 | Percentage of gross | | | **Plant Allocator** | |
| 4 | transmission plant included in ISO Rates | Col (3) - 'Line 23 / Line 20 | | **(GTP) =** | **0.00000** |
| | Percentage of net | | | **Net Transmission** | |
| 2 | transmission plant included | Col (4) - Line | | **Plant Allocator** | |
| 5 | in ISO Rates | 23 / Line 20 | | **(NTP) =** | **#DIV/0!** |

| | | | |
|---|---|---|---|
| | **TRANSMISSION EXPENSES** | | |
| 2 | Total transmission | Page 2, Line 1, | $ |
| 6 | expenses | col (3) | - |

| | | | | | |
|---|---|---|---|---|---|
| 27 | Less transmission expenses included in OATT Ancillary Services | Note N | | | $ - |
| 28 | Included transmission expenses | Line 26 minus Line 27 | | | $ - |
| 29 | Percentage of transmission expenses after adjustment | Line 28 / Line 26 | | | 0.00000 |
| 30 | Percentage of transmission plant included in ISO Rates | Line 24. col 5 | | Gross Transmission Plant Allocator | 0.00000 |
| 31 | Percentage of transmission expenses included in ISO Rates | Line 29 x Line 30 | | **Transmission Expense Allocator (TE) =** | **0.00000** |
| | **WAGES & SALARIES** | Note P | | | |
| 32 | Production | | $ - | 0.00000 | $ - |
| 33 | Transmission | | $ - | GTP 0.00000 | $ - |
| 34 | Distribution | | $ - | 0.00000 | $ - |
| 35 | Other | | $ - | 0.00000 | $ - |
| 36 | Total | Sum Lines 32 to 35 | $ - | | $ - |
| 37 | | Line 36 - col (5) / col (3) | | **Wages & Salaries Allocator (W/S) =** | **0.00000** |
| | **COMMON PLANT** | Note Q | | | |
| 38 | Electric | Line 6 col (3) | | | $ - |
| 39 | Gas | | | | $ - |
| 40 | Water | | | | $ - |
| 41 | Total | Sum Lines 38 to 40 | | | $ - |
| 42 | % Electric | Line 38 / Line 41 | | | 0% |
| | | Line 37 x Line 41 | | **Common Plant Allocator (CE) =** | **0.00000** |
| | **REVENUE CREDITS** | | | | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | | Load |
| 43 | a. Bundled Non-RQ Sales for Resale | Note R | | | 0.00 |
| 44 | b. Bundled Sales for Resale included in Divisor | | | | 0.00 |

| | | | |
|---|---|---|---|
| | on page 1 | | |
| 4 | | Line 47 minus | |
| 5 | Total | Line 48 | 0.00 |

**Rate Formula Template**

Return to TOC

**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**



**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
For the 12 months ending 12/31/0
Formula Rate - Cash Flow

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data are to FERC account numbers

| Note Letter | | | | | |
|---|---|---|---|---|---|
| New | | | | | |
| A | The revenues credited on page 1 line 2 include a) amounts received directly from the SPP for Point-to-Point transmission service where the demand is not included in the divisor; b) amounts from customers taking service under grandfathered agreements where the demand is not included in the rate divisor; and c) imputed revenues related to short-term reservations of LES's merchant function. Revenue associated with Federal Regulatory Commission annual charges, gross receipts taxes, ancillary services and facilities excluded from the Transmission Cost of Service are not incuded as revenue credits. Revenue from transmission customers whose coincident peak loads are included in the divisor of the load-ratio share calculation are not included as revenue credits. See Worksheet A for details. | | | | |
| B | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. See Worksheet B for details. | | | | |
| C | Calculation of Prior Year Divisor True-Up | | | | |
| | Historic Year Actual Divisor | Pg C, line 1 | - | | kW |
| | Projected Year Divisor | Pg C, line 2 | - | | kW |
| | Difference between Historic & Projected Year Divisors | | - | | kW |
| | Prior Year Projected Annual Cost ($ per kw per year) | | | $0.00 | |
| | Projected Year Divisor True-Up (Line 3 x Line 4) | | | $0.00 | |
| D | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any. | | | | |
| F | System control and load dispatch costs. | | | | |
| G1 | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of ISO coincident monthly peaks. RQ service is service that the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). | | | | |

| | |
|---|---|
| G2 | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of ISO coincident monthly peaks. |
| G3 | LF as defined above at time of ISO coincident monthly peaks. |
| G4 | LF as defined above at time of ISO coincident monthly peaks. |
| G5 | Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1. |
| I | Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting. |
| K | The FERC, in Order Nos. 679 and 679-A, offers a 50-basis point incentive adder for transmission owners joining an RTO as long as the return on equity for the transmission owner is within a zone of reasonableness. In order to be comparable with transmission owners in RTOs (including SPP), LES has included this 50-basis-point incentive adder in its revenue requirements. |
| L | Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until RUS 12 balances are adjusted to reflect application of seven-factor test). |
| M | The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement as a percent of interest expense yields a TIER (times interest earned ratio), and the Margin Requirement as a percent of debt service is the DSR (debt service ratio), either of which may be referred to as a Margin Ratio (MR). Some utilities have MRs required by bond covenants and/or MRs that include expenses additional to interest or debt service (for example, an MR equal to a percentage of the sum of DS+O&M). The ISO will review such party's filings to assure that the MRs are consistent with those applicable to native load or required by bond covenants and utility must provide workpapers showing derivation of margin. |
| N | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561. |

| | |
|---|---|
| O | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| P | If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 37 equal to the gross plant allocator (GP) at page 3, line 7. |
| Q | Enter dollar amounts. |
| R | Line 45 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor. |
| U | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| V | Additional revenue requirement for facilities receiving incentives. See worksheets I, J, and K |
| W | FERC 565 on page 2 includes STEP BPF, STEP HWBW, CWIP, Balanced Portfolio Projects, Balanced Portfolio Transfers, and Priority Projects associated with the Southwest Power Pool. These costs are excluded from the ATRR because they are not funded by transmission rates. |

## Rate Formula Template

Return to TOC

**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
**Worksheet A - Revenue Credits, Account 456**

**Detail of 456 - Transmission Wheeling Fees**

| Line No. | FERC Account | Description | Transmission | Other | Total |
|---|---|---|---|---|---|
| 1 | | Scheduling Fees | | - | - |
| 2 | | Reactive | | - | - |
| 3 | | Regulation | | - | - |
| 4 | | Distribution Line | | - | - |
| 5 | | Distribution Subs | | - | - |
| 6 | | Transformers | | - | - |
| 7 | | Losses | | - | - |
| 8 | | Distribution Wheeling Fees (Direct) | | - | - |
| 9 | | Transmission Revenue for Trans Included in Divisor | $ - | | $ - |
| 10 | | Total Transmission Revenue - All Transactions | $ - | | $ - |
| 11 | 456 | | $ - | - | $ - |
| 12 | | Add: Short-term LES Merchant PTP * | | | $ - |
| 13 | | Revenue Credits | | | $ - |

* See Worksheet G - Billing Units Divisor (line 40) for details

**Rate Formula Template**

Return to TOC

**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
**Worksheet B - Revenue Credits - Rents, Account 454**

**Detail of 454 - Rent**

| Line No. | FERC Account | Description | Total | Other | Transmission Revenue Credit |
|---|---|---|---|---|---|
| | 454.16, 454.17, | | $ | $ | $ |
| 1 | 454.19 | Rent | - | - | - |
| | | Allocated portion of general | $ | $ | $ |
| 2 | 454.12, 454.13 | rent (1) | - | - | - |
| | All Other Sub | | $ | $ | $ |
| 3 | Accts | Other | - | - | - |
| | | | $ | $ | $ |
| 4 | 454 | Rent Revenue Credits | - | - | - |

| | |
|---|---|
| Revenues from service provided by the ISO at a discount | $ - |

(1) Split based on Wages and Salaries. Allocator derived on page 3, line 37

**Rate Formula Template**
**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
**Worksheet C - True-Up Calculations**

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| Line No. | (1) Description | (2) Reference/Note | (3) Total | |
|---|---|---|---|---|
| | **TRUE-UP CALCULATIONS** | | | |
| | **Calculation of Historic Year Divisor True-Up (1)** | | | |
| 1 | Historic Year Actual Divisor | Worksheet G1 | - | kW |
| 2 | Historic Year Projected Dvisor | Worksheet G1 | - | kW |
| 3 | Difference between Historic & Projected Year Divisors | line 1 minus line 2 | - | kW |
| 4 | Historic Year Projected Annual Cost | | $ - | $/kW -year |
| 5 | **Projected Year Divisor True-Up** | line 3 x line 4 | $ - | |
| | **Calculation of Historic Year Net ATRR True-Up (2)** | | | |
| 6 | Historic Year Actual Net ATRR (i.e., Actual Transmission Cost) | See worksheet D | $ - | |
| 7 | Historic Year Projected Net ATRR | See worksheet D | $ - | |
| 8 | **Prior Year ATRR True-Up** | line 6 minus line 7 | $ - | |
| 9 | **Total Net ATRR True-Up** | line 5 + line 8 | $ - | |

| | **Interest on Historic Year True-Up** | **APR** | **QPR** |
|---|---|---|---|
| 10 | If Historic Actual < Projected, Overcollection | 0.00% | 0.000% |
| 11 | If Historic Actual > Projected, Undercollection | 0.00% | 0.000% |

| | | Quarter | Levelized True-Up | Interest Charge |
|---|---|---|---|---|
| 1 | | | $ | $ |
| 2 | 1 | | - | - |
| 1 | | | $ | $ |
| 3 | 2 | | - | - |
| 1 | | | $ | $ |
| 4 | 3 | | - | - |
| 1 | | | $ | $ |
| 5 | 4 | | - | - |
| 1 | | | | **$** |
| 6 | | **Total** | | **-** |

Notes

(1) Historic Year Divisor True-Up is computed to account for the difference in volume between projected and actual experience.

(2) Historic Year Actual and Projected Net ATRR accounts for SPP Transmission Project Revenue Offsets

**Computation of ATRR Adjustment**

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**Page 2 Worksheet**
Formula Rate - Cash Flow
**For Rates Effective January 1, 2013**
**LINCOLN ELECTRIC SYSTEM**
For the 12 Months Ended 12/31/2011
**Worksheet D - Net ATRR True-Up Calculations**

| Line No | Description | (1) Reference/Note (1) | (2) | (3) Projected Total | (4) Actual Total | (5) Delta (4) - (3) | (6) Allocator | (7) Projected **Allocated to Transmission (3) x (6)** | (8) Actual **Allocated to Transmission (4) x (6)** |
|---|---|---|---|---|---|---|---|---|---|
| | **Gross Annual Transmission Revenue Requirement (ATRR)** | | | | | | | | |
| | **O&M** | | | | | | | | |
| 1 | Transmission | | | $ - | $ - | $ - | TE 0.000 | $ - | $ - |
| 2 | Less Account 565 | | | $ - | $ - | $ - | 1.000 | $ - | $ - |
| 3 | **A&G** | | | $ - | $ - | $ - | W/S 0.000 | $ - | $ - |
| 4 | Less FERC Annual Fees | | | $ - | $ - | $ - | W/S 0.000 | $ - | $ - |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad | Note I | | $ - | $ - | $ - | W/S 0.000 | $ - | $ - |
| 5a | Plus Transmission Related Reg. Comm. Exp. | Note I | | $ - | $ - | $ - | TE 0.000 | $ - | $ - |
| 6 | Common | | | $ - | $ - | $ - | CE 0.000 | $ - | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 00 | | | |
| | | | | | | | 1.0 | | | |
| | Transmission | | $ | $ | $ | | 00 | $ | $ | |
| 7 | Lease Payments | | - | - | - | | 00 | - | - | |
| | | Sum lines 1, 3, 5a, 6, 7 less | | | $ | | | $ | $ | |
| 8 | **TOTAL O&M** | 2, 4, 5 | 0 | 0 | - | | | - | - | |
| | **DEBT SERVICE** | | | | ` | | | | | |
| | | | | | | | 0.0 | | | |
| | | | $ | $ | $ | N | 00 | $ | $ | |
| 9 | Debt Service | | - | - | - | P | 00 | - | - | |
| | Amortization of | | | | | | 0.0 | | | |
| 1 | premium or | | $ | $ | $ | N | 00 | $ | $ | |
| 0 | discount | | - | - | - | P | 00 | - | - | |
| | | Sum | | | | | | | | |
| 1 | **TOTAL DEBT** | lines 9 | $ | $ | | | | $ | $ | |
| 1 | **SERVICE** | & 10 | - | - | | | | - | - | |
| | **TAXES OTHER THAN INCOME TAXES** | Note K | | | | | | | | |
| | LABOR RELATED | | | | | | | | | |
| | | | | | | | W 0.0 | | | |
| 1 | | | $ | $ | $ | / | 00 | $ | $ | |
| 2 | Payroll | | - | - | - | S | 00 | - | - | |
| | | | | | | W | 0.0 | | | |
| 1 | Highway and | | $ | $ | $ | / | 00 | $ | $ | |
| 3 | vehicle | | - | - | - | S | 00 | - | - | |
| 1 | | | | | $ | | | $ | $ | |
| 4 | PLANT RELATED | | | | - | | | - | - | |
| | | | | | | | 0.0 | | | |
| 1 | | | $ | $ | $ | G | 00 | $ | $ | |
| 5 | Property | | - | - | - | P | 00 | - | - | |
| | | | | | | | 0.0 | | | |
| 1 | Gross | | $ | $ | $ | | 00 | $ | $ | |
| 6 | Receipts | | - | - | - | | 00 | - | - | |
| | | | | | | | 0.0 | | | |
| 1 | | | $ | $ | $ | G | 00 | $ | $ | |
| 7 | Other | | - | - | - | P | 00 | - | - | |
| | | | | | | | 0.0 | | | |
| 1 | Payments in | | $ | $ | $ | G | 00 | $ | $ | |
| 8 | lieu of taxes | | - | - | - | P | 00 | - | - | |
| | | Sum lines 12 | | | | | | | | |
| 1 | **TOTAL OTHER** | through | | | | | | $ | $ | |
| 9 | **TAXES** | 18 | 0 | 0 | | | | - | - | |

Note this is the "Available for Debt Service" and Debt Service from the OR, unaudited, page 9.

| **Project** | **Actual** | **Delta** |
|---|---|---|

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | **ted** | | |
| 21 | **SUBTOTAL** | Sum lines 8, 11, 19 | | | | | | $ - | $ - | **Avail. For D.S. minus D.S.** | $ - | $ - | $ - |
| | | | | | | | | | | | $ - | $ - | $ - |
| 22 | **MARGIN REQUIREMENT** | Note M | $ - | $ - | $ - | GP | 0.000000 | $ - | $ - | | $ - | $ - | $ - |
| 23 | **RTO Incentive Adder (Order Nos. 679 & 679-A)** | Note K, Worksheet K | $ - | $ - | $ - | | 1.00 | $ - | $ - | | | | |
| 25 | **Additional Margin on Incentive Plant** Transmission Upgrade Projects | Note J, Worksheet J1 + Worksheet J2 | $ - | $ - | $ - | | 1.00 | $ - | $ - | | | | |
| 26 | **GROSS REVENUE REQUIREMENT w/o INCENTIVE PLANT** | | | | | | | $ - | $ - | | | | |
| 27 | **GROSS REVENUE REQUIREMENT w INCENTIVE PLANT** | | | | | | | $ - | $ - | | | | |
| 29 | **Transmission Project Revenue Offset Under Schedule 11** Total Schedule 11 Revenue Offset | | **Projected** $ - | **Actual** $ - | **Delta** $ - | | 1.00 | $ - | $ - | | | | |

| | | | | |
|---|---|---|---|---|
| 3 0 | **NET ATRR FOLLOWING TRANSMISSION REVENUE OFFSETS w/o INCENTIVE PLANT** | Line 26 minus Line 29 | $ - | $ - |
| 3 1 | **NET ATRR FOLLOWING TRANSMISSION REVENUE OFFSETS w INCENTIVE PLANT** | Line 27 minus Line 29 | $ - | $ - |

| | |
|---|---|
| Note | (1) All references made here are to Worksheets and Notes in the Historical Year Template |

**Rate Formula Template**

Return to TOC

**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
For the 12 months ending 12/31/0
**Worksheet F**
**Scheduling, System Control and Dispatch Service**

| Line No. | FERC Account | Description | Amount |
|---|---|---|---|
| | | **Determine Scheduling, System Control & Dispatch Cost** | |
| 1 | 561 | Load Dispatching | $ - |
| 2 | 556 | System Control & Load Dispatch | $ - |
| 3 | | **Total ATRR for AS#1** | **$ -** |

## Transmission Rate Calculation

**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**

Return to TOC

### Worksheet G - Billing Units Divisor

| | | | Projected Network Load | | | | Projected LTPTP Reservations | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Month | Hour & Date for Network | LES Load | Less: Load in other SPP Zones | Plus: Network WS Load | Total Network Load | Contract Demand of firm P-T-P over one year | Firm bundled sales over one year | Firm P-T-P over one year | Contract Demand from Grandfathered Interzonal transactions over one year | Contract Demands from service over one year provided by ISO at a discount |
| 1 | Jan | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 2 | Feb | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 3 | Mar | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 4 | Apr | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 5 | May | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 6 | June | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 7 | Jul | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 8 | Aug | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 9 | Sept | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 10 | Oct | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 11 | Nov | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 12 | Dec | | - | | | 0.00 | 0 | 0.0 | 0.00 | 0.0 | 0.0 |
| 13 | Total | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1 | 12 CP Average | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0. | 0.00 | 0.00 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | | | | | | | 0 | | |
| | | | | | | | | 0 | | |
| 1 | **Total Billing** | | | | | | | **0.0** | | |
| 5 | **Units** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0.00** | **0** | **0.00** | **0.00** |

Projected Wholesale NW Load - MW

| | | Total WS Load | | | Total |
|---|---|---|---|---|---|
| 16 | Jan | 0.00 | | | 0.00 |
| 17 | Feb | 0.00 | | | 0.00 |
| 18 | Mar | 0.00 | | | 0.00 |
| 19 | Apr | 0.00 | | | 0.00 |
| 20 | May | 0.00 | | | 0.00 |
| 21 | June | 0.00 | | | 0.00 |
| 22 | July | 0.00 | | | 0.00 |
| 23 | Aug | 0.00 | | | 0.00 |
| 24 | Sept | 0.00 | | | 0.00 |
| 25 | Oct | 0.00 | | | 0.00 |
| 26 | Nov | 0.00 | | | 0.00 |
| 27 | Dec | 0.00 | | | 0.00 |
| 28 | Total MW | 0.00 | 0.00 | 0.00 | 0.00 |

(5) Detail of LES Marketing Transactions. See lines 29 - 41 below

Projected LES Marketing Long-Term Transactions

| | OASIS # | | | | | Total |
|---|---|---|---|---|---|---|
| 29 | Jan | 0.00 | | | | 0.00 |
| 30 | Feb | 0.00 | | | | 0.00 |
| 31 | Mar | 0.00 | | | | 0.00 |
| 32 | Apr | 0.00 | | | | 0.00 |
| 33 | May | 0.00 | | | | 0.00 |
| 34 | June | 0.00 | | | | 0.00 |
| 35 | July | 0.00 | | | | 0.00 |
| 36 | Aug | 0.00 | | | | 0.00 |
| 37 | Sept | 0.00 | | | | 0.00 |
| 38 | Oct | 0.00 | | | | 0.00 |
| 39 | Nov | 0.00 | | | | 0.00 |
| 40 | Dec | 0.00 | | | | 0.00 |
| 41 | Total | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Projected LES Marketing Short-Term Transactions

| | Hourly | Daily | Weekly | Monthly |
|---|---|---|---|---|
| PTP-Firm | 0.00 | 0.00 | 0.00 | 0.00 |
| PTP Non-Firm | 0.00 | 0.00 | 0.00 | 0.00 |
| PTP-Firm | 0.00 | 0.00 | 0.00 | 0.00 |
| PTP Non-Firm | 0.00 | 0.00 | 0.00 | 0.00 |
| PTP-Firm | 0.00 | 0.00 | 0.00 | 0.00 |
| PTP Non-Firm | 0.00 | 0.00 | 0.00 | 0.00 |
| Total All Short-Term Transactions* | | | | 0.00 |

* Sum transferred to Worksheet A, Line 12

**Transmission Rate Calculation**

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**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 2013**
**Worksheet G1 - Historic Year Actual Billing Units for Computing Divisor True Up**

| 2011 Actual Network Load | Actual LTPTP Reservations | 2011 Projected Network Load | Projected LTPTP Reservations |
|---|---|---|---|

| Line No. | Month | Hour & Date for Network | LES Load | Less: Load in other SPP Zones | Plus: Network WSL Load | Total Network Load | Contract Demand of firm P-T-P over one year | Firm bundled sales over one year | Firm P-T-P over one year | Contract Demand from Grandfathered Interzonal transactions over one year | Contract Demands from service over one year provided by ISO at a discount |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jan | | - | | | - | - | - | - | - | - |
| 2 | Feb | | - | | | - | - | - | - | - | - |

| Line No. | Month | Hour & Date for Network | LES Load | Less: Load in other SPP Zones | Plus: Network WSL Load | Total Network Load | Contract Demand of firm P-T-P over one year | Firm bundled sales over one year | Firm P-T-P over one year | Contract Demand from Grandfathered Interzonal transactions over one year | Contract Demands from service over one year provided by ISO at a discount |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jan | | - | | | - | - | - | - | - | - |
| 2 | Feb | | - | | | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Mar | - | | | - | - | | - | - | - | - | 3 | Mar | - | | | - | - | - | - | - | - |
| 4 | Apr | - | | | - | - | | - | - | - | - | 4 | Apr | - | | | - | - | - | - | - | - |
| 5 | May | - | | | - | - | | - | - | - | - | 5 | May | - | | | - | - | - | - | - | - |
| 6 | June | - | | | - | - | | - | - | - | - | 6 | June | - | | | - | - | - | - | - | - |
| 7 | Jul | - | | | - | - | | - | - | - | - | 7 | Jul | - | | | - | - | - | - | - | - |
| 8 | Aug | - | | | - | - | | - | - | - | - | 8 | Aug | - | | | - | - | - | - | - | - |
| 9 | Sept | - | | | - | - | | - | - | - | - | 9 | Sept | - | | | - | - | - | - | - | - |
| 10 | Oct | - | | | - | - | | - | - | - | - | 10 | Oct | - | | | - | - | - | - | - | - |
| 11 | Nov | - | | | - | - | | - | - | - | - | 11 | Nov | - | | | - | - | - | - | - | - |
| 12 | Dec | - | | | - | - | | - | - | - | - | 12 | Dec | - | | | - | - | - | - | - | - |
| 13 | Total | - | - | - | - | - | | - | - | - | - | 13 | Total | - | - | - | - | - | | - | - | - |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 14 | **12 CP Average** | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** | 14 | **12 CP Average** | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** |
| 15 | **Total Billing Units** | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** | 15 | **Total Billing Units** | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** |
| 16 | **Total** | | | | | | | | | | **-** | 16 | **Total** | | | | | | | | | | **-** |

**Rate Formula Template**

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**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**

For the 12 months ending 12/31/2013

**Worksheet H**
**Account 565 Transmission by Others**

| Line No. | FERC Account | Description | Notes | | (1) |
|---|---|---|---|---|---|
| 1 | **565** | **Account Total** | | $ | - |
| 2 | | Less: Transmission by Others | | $ | - |
| 3 | | Less SPP Administrative Costs | | $ | - |
| 4 | | Portion of 565 included in transmission rates | Line 1 minus Line 2&3 | $ | - |

**Rate Formula Template**

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**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
**Worksheet I - Transmission Upgrade Project Fixed Charge Rate**

**Calculate Fixed Charge Rate (FCR) for Transmission Upgrade Projects**

| Line No. | Description | Notes | Amount |
|---|---|---|---|
| 1 | LES Forecast Zonal Revenue Requirement (w/o incentive plant) | Page 2, Line 25 | #DIV/0! |
| 2 | Less: Revenue Credits | Page 1, Line 5 | $ - |
| 3 | Less: Depreciation Expense | LES Financial Services | $ - |
| 4 | Revenue Requirement w/o Depr | Line 1 minus Line 2 & Line 3 | #DIV/0! |
| 5 | Net Plant | Page 3, Line 23, Col 4 | $0 |
| 6 | Net Rev Req w/o Depreciation | Line 4 above | #DIV/0! |
| 7 | **Fixed Charge Rate - Upgrade Project** | Line 6 / Line 5 | **#DIV/0!** |

# Rate Formula Template

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## Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates
## For Rates Effective January 1, 0
## LINCOLN ELECTRIC SYSTEM
## Worksheet J1 - LES Transission Upgrade (TU) Project #1

Facilities receiving incentives accepted by FERC in Docket No.

| Line No. | **Project Description:** | | | | |
|---|---|---|---|---|---|
| 1 | Investment | $0 | Current Year | | 0 |
| 2 | Service Year (yyyy) | 0 | Incentive ROE increase (Basis Points) | 0 | #DIV/0! |
| 3 | Service Month (1-12) | 0 | FCR w/o incentives, less depreciation | | #DIV/0! |
| 4 | Useful life (Yrs) | 1 | FCR w/ incentives approved for these facilities, less dep | | #DIV/0! |
| 5 | CIAC (Yes or No) | | Annual Depreciation Expense | | $0 |

| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | TU Rev Req w/o Incentives | TU Rev Req w/ Incentives | Additional ATRR for Incentives on TU Projects |
|---|---|---|---|---|---|---|---|---|
| 6 | 0 | 1 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | 1 | 2 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | 2 | 3 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | 3 | 4 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 10 | 4 | 5 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | 5 | 6 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 12 | 6 | 7 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 13 | 7 | 8 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 14 | 8 | 9 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 15 | 9 | 10 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 16 | 10 | 11 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 17 | 11 | 12 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 18 | 12 | 13 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 19 | 13 | 14 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 20 | 14 | 15 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 21 | 15 | 16 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 22 | 16 | 17 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 23 | 17 | 18 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 24 | 18 | 19 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 25 | 19 | 20 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 26 | 20 | 21 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 27 | 21 | 22 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 28 | 22 | 23 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 29 | 23 | 24 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 30 | 24 | 25 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 31 | 25 | 26 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 32 | 26 | 27 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 33 | 27 | 28 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 34 | 28 | 29 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 35 | 29 | 30 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 36 | 30 | 31 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 37 | 31 | 32 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 38 | 32 | 33 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 39 | 33 | 34 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 40 | 34 | 35 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 41 | 35 | 36 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 42 | 36 | 37 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 43 | 37 | 38 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 44 | 38 | 39 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 45 | 39 | 40 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 46 | 40 | 41 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

## Rate Formula Template

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**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
**Worksheet J2 - LES Transmission Upgrade (TU) Project #2**

Facilities receiving incentives accepted by FERC in Docket No.

| Line No. | | | | | |
|---|---|---|---|---|---|
| | **Project Description:** | | | | |
| 1 | Investment Service Year (yyyy) | $0 | Current Year | | 0 |
| 2 | Service Month (1-12) | 0 | Incentive ROE increase (Basis Points) | 0 | #DIV/0! |
| 3 | Useful life (Yrs) | 0 | FCR w/o incentives, less depreciation | | #DIV/0! |
| 4 | CIAC (Yes or No) | 1 | FCR w/ incentives approved for these facilities, less dep | | #DIV/0! |
| 5 | | | Annual Depreciation Expense | | $0 |

| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | TU Rev Req w/o Incentives | TU Rev Req w/ Incentives | Additional ATRR for Incentives on TU Projects |
|---|---|---|---|---|---|---|---|---|
| 6 | 0 | 1 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | 1 | 2 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | 2 | 3 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | 3 | 4 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 10 | 4 | 5 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | 5 | 6 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 12 | 6 | 7 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 13 | 7 | 8 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 14 | 8 | 9 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 15 | 9 | 10 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 16 | 10 | 11 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 17 | 11 | 12 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 18 | 12 | 13 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 19 | 13 | 14 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 20 | 14 | 15 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 21 | 15 | 16 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 22 | 16 | 17 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 23 | 17 | 18 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 24 | 18 | 19 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 25 | 19 | 20 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 26 | 20 | 21 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 27 | 21 | 22 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 28 | 22 | 23 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 29 | 23 | 24 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 30 | 24 | 25 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 31 | 25 | 26 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 32 | 26 | 27 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 33 | 27 | 28 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 34 | 28 | 29 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 35 | 29 | 30 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 36 | 30 | 31 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 37 | 31 | 32 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 38 | 32 | 33 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 39 | 33 | 34 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 40 | 34 | 35 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 41 | 35 | 36 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 42 | 36 | 37 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 43 | 37 | 38 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 44 | 38 | 39 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 45 | 39 | 40 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| 46 | 40 | 41 | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $0 | $0 | $0 | #DIV/0! | #DIV/0! | #DIV/0! |

**Rate Formula Template**

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**Using 0 Projected and Financial Operating Data for Southwest Power Pool Rates**
**For Rates Effective January 1, 0**
**LINCOLN ELECTRIC SYSTEM**
**Worksheet K - SPP RTO Incentive Adder**

| Line No. | Description | Amount | Equity % |
|---|---|---|---|
| | **Calculate Premium for Joining an RTO** | | |
| | (Plant based on 2013 data) | | |
| 1 | Transmission Plant | $0 | |
| 2 | Allocated Share of General | $0 | |
| 3 | Total Plant | $0 | |
| 4 | X Equity Ratio | #DIV/0! | |
| 5 | X 50 Basis Point Premium | 0.0050 | |
| | Premium $ | #DIV/0! | |
| | **Calculate Equity %** | | |
| | (Based on 2011 Balance Sheet) | | |
| 6 | Long-term Debt | $0 | #DIV/0! |
| 7 | Equity (Cash or Cash Equivalents) | $0 | #DIV/0! |
| 8 | Total | $0 | |

Formula Rate Implementation Protocols

## I. Annual True-Up and Annual Projection

1. The Formula Rate Template set forth in Attachment H, Addendum 6, of Southwest Power Pool's ("SPP") Open Access Transmission Tariff ("OATT") and these Formula Rate Implementation Protocols comprise the filed rate by SPP for calculating Lincoln Electric System's ("LES") Zonal Annual Transmission Revenue Requirement ("ATRR") for Transmission Service under the SPP OATT. LES shall follow the instructions specified in the Formula Rate Template to calculate annually its ATRR and the rates for its Network Integration Transmission Service and Point-to-Point transmission service, and the ATRR for Base Plan Upgrades and other network upgrades. These protocols shall apply to LES's calculation of its ATRR, including the calculation of the Annual True-Up ("Annual True-Up") and the projected net revenue requirement ("Annual Projection").

2. The Formula Rate shall be calculated annually with resulting rates applicable to service on and after January 1st through December 31st of each calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before June 1st, LES shall provide its Annual True-Up to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, LES shall request SPP to cause notice on the SPP exploder list titled "Formula Rate Posting Information Notification" or similar exploder list. Interested Parties may contact SPP to subscribe to the SPP exploder list. For purposes of these protocols, the term Interested Party includes, but is not limited to, customers under the SPP OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

4. On or before October 15th, LES shall provide its Annual Projection to SPP and cause such information to be posted on SPP's website and OASIS. Within ten (10) days of such posting, LES shall request SPP to cause notice on the exploder list titled "Formula Rate Posting Information Notification" or similar exploder list. Interested Parties can contact SPP to subscribe to the SPP exploder list.

5. LES shall submit to the Federal Energy Regulatory Commission ("FERC" or the "Commission") an Informational Filing as provided in Section V of these protocols.

6. If the date for posting the Annual True-Up or Annual Projection falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the Annual True-Up or Annual Projection will result in an equivalent extension of time for the submission of Information Requests discussed in Section II of the protocols.

7. A change to the Formula inputs related to revised depreciation rates or the fixed margin requirement may not be made absent an appropriate filing with FERC.

8. The Annual True-Up shall

   (i) Be based on actual data for the prior calendar year, and, to the extent specified in the Formula, upon the audited books and records of LES;

   (ii) Identify all material adjustments made to the data in determining formula inputs.

9. The Annual True-Up and Annual Projection shall:

   (i) Include a workable data-populated Formula Rate Template in native format with all formulas and links intact;

   (ii) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used;

   (iii) Provide sufficient information to enable Interested Parties to replicate the calculation;

   (iv) Identify any changes in the formula references;

   (v) With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

      (1) Identify any Accounting Changes, including:

         - The initial implementation of an accounting standard or policy;
         - The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction; and
         - Correction of errors and prior period adjustments that impact the calculation.

      (2) The implementation of new estimation methods or policies that change prior estimates. Identify items included in the calculation at an amount other than on a historical cost basis (e.g., fair value adjustments); identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs.

      (3) Provide, for each item identified pursuant to items I.9.v.1 - I.9.v.2 of these protocols, a narrative explanation of the individual impact of such changes on the calculation.

10. LES shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") after the Annual True-Up Publication Date but no sooner than seven (7)

days from the Publication Date and no later than July 15th. No less than twenty (20) days prior to such Annual True-Up Meeting, LES shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual True-Up Meeting and LES shall request SPP to provide notice of such meeting to the SPP email exploder list titled "Formula Rate Posting Information Notification" or similar exploder list.

11. The Annual True-Up Meeting will be hosted by LES in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. LES shall provide remote access for Interested Parties to participate in the meeting. The Annual True-Up Meeting shall (i) permit LES to explain and clarify its Annual True-Up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from LES about the Annual True-Up.

12. LES shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") after the Annual Projection Publication Date but no sooner than seven (7) days from the Publication Date and no later than November 30th. No less than twenty (20) days prior to such Annual Projected Rate Meeting, LES shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual Projected Rate Meeting and LES shall request SPP to provide notice of such meeting to the SPP email exploder list titled, "Formula Rate Posting Information Notification" or similar exploder list.

13. The Annual Projected Rate Meeting will be hosted by LES in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. LES shall provide remote access for Interested Parties to participate in the meeting. The Annual Projected Rate Meeting shall (i) permit LES to explain and clarify its Annual Projection and (ii) provide Interested Parties an opportunity to seek information and clarifications from LES about the Annual Projection.

14. Each year LES shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

## II. Information Exchange Procedures

Each Annual True-Up and Annual Projection shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have seventy-five (75) days following the Annual True-Up Meeting to serve reasonable information and document requests related to the Annual

True-Up; and sixty (60) days following the Annual Projection Publication Date to serve reasonable information and document requests on LES related to the Annual True-Up and Annual Projection ("Information Exchange Period"). If either of these dates falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(i) that LES has properly calculated its rate pursuant to the Formula Rate and the procedures in the Protocols;

(ii) that input data under the Formula Rate are properly recorded in any underlying workpapers;

(iii) the accuracy of data and the consistency with the Formula Rate of the actual Net Revenue Requirement (including any True-Up Adjustment) under review;

(iv) the extent of accounting changes that affect Formula Rate inputs;

(v) the prudence of actual costs and expenditures; and

(vi) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. LES shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

3. LES will cause to be posted on SPP's website and OASIS all information requests from Interested Parties and LES's response(s) to such requests; except, however, if responses to information and document requests include material deemed by LES to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by LES and the requesting party.

4. LES shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the results of the LES's Annual True-Up's or Annual Projection's incorporation into the SPP Tariff.

## III. Challenge Procedures

1. Interested Parties shall have until January 31st following the Publication Date to review the inputs, supporting explanations, allocations and calculations and to notify

LES in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or Annual Projection. The period of time from the Publication Date until January 31st shall be referred to as the Review Period. If January 31st falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual True-Up or Annual Projection as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual True-Up or Annual Projection. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual True-Up or Annual Projection, the Interested Party is barred from pursuing a Formal Challenge with respect to any issue for that Annual True-Up or Annual Projection but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or Annual Projection.

2. A party submitting an Informal Challenge to LES must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. LES shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. If LES disagrees with such challenge, LES will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31st, and LES must respond to all Informal Challenges by no later than February 28th.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section III.

4. Informal Challenges shall be limited to all issues that may be necessary to determine: (1) that LES has properly calculated its rate pursuant to the Formula Rate and the procedures in the Protocols; (2) that input data under the Formula Rate are properly recorded in any underlying workpapers; (3) the accuracy of data and the consistency with the Formula Rate of the actual Net Revenue Requirement (including any True-Up Adjustment) under review; (4) the extent of accounting changes that affect Formula Rate inputs; (5) the prudence of actual costs and expenditures; and (6) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

5. LES will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and LES's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by LES to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by LES and the requesting party.

6. Any changes or adjustments to the Annual True-Up or Annual Projection resulting from the Information Exchange and Informal Challenge processes that are agreed to by LES will be reported in the Informational Filing required pursuant to Section V of these protocols. Any such changes or adjustments agreed to by LES on or before November 30th will be reflected in the Annual Projection for the upcoming Rate Year. Any changes or adjustments agreed to by LES after November 30th will be reflected in the following year's Annual True-Up, as discussed in Section IV of these protocols.

7. An Interested Party shall have until March 31st (unless such date is extended with the written consent of LES to continue efforts to resolve the Informal Challenge) to make a Formal Challenge to the Annual True-up or Annual Projection posted in the previous calendar year.

8. Formal Challenges shall be filed against SPP pursuant to these protocols and shall satisfy all of the following requirements.

   (i) A Formal Challenge shall:

      (1) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

      (2) Explain how the action or inaction violates the filed rate formula or protocols;

      (3) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

         - proper calculation of the Annual True-up or Annual Projection pursuant to the Formula Rate and protocols;
         - whether the Formula Rate fails to include data properly recorded in accordance with these protocols;
         - whether there is an inaccuracy of data or inconsistency with the Formula Rate of the actual Net Revenue Requirement (including any True-Up Adjustment) under review;
         - the extent of accounting changes that affect Formula Rate inputs;
         - the prudence of actual costs and expenditures; and
         - any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

(4) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(5) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(6) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(7) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(8) State whether the filing party utilized the Informal Challenge procedures described in these protocols with regard to any issue.

(ii) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on LES. Service to LES must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on LES's Informational Filing required under Section V of these protocols.

9. A Formal Challenge shall be filed in the same docket as LES's Informational Filing discussed in Section V of these protocols. LES shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit any Informal Challenge during the applicable Review Period.

10. In any proceeding initiated by FERC concerning the Annual True-Up or Annual Projection or in response to a Formal Challenge, LES shall bear the burden of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

11. The implementation of any changes or adjustments resulting from any Formal Challenge made with FERC shall be subject to SPP Tariff Section 39.1.

12. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of LES to request SPP to file unilaterally, pursuant to section 205 of the Federal Power Act and the regulations thereunder, to change the Formula Rate or any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other

party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

13. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these protocols and the Annual True-Up and Annual Projection shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing before FERC.

## IV. Changes to Annual True-Up or Annual Projection

1. Except as provided in Section III.6 of these protocols, any changes to the data inputs, or as the result of any FERC proceeding to consider the Annual True-Up or Annual Projection, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Projection for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VI of these protocols.

2. In the event that LES identifies an error in the Annual True-Up, or is required by applicable law to correct an error, LES shall correct such error in good faith and without regard to whether the correction increases or decreases LES's revenue requirements. Nothing in these protocols should or may be construed as preventing Interested Parties or FERC from protesting such correction as inappropriate.

## V. Informational Filings

1. By March 15$^{th}$ of each year, LES shall submit to FERC an informational filing ("Informational Filing") of its Annual Projection for the Rate Year, including its Annual True-Up. The Informational Filing will be for administrative and informational purposes only, and will not submit LES to the jurisdiction of the Commission under the Federal Power Act. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that LES has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during the Review Period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. LES shall request SPP to provide notice of the Informational Filing via an email exploder list and by posting the docket number assigned to LES's Informational Filing on SPP's website and OASIS.

2. Any challenges to the implementation of the Attachment H-LES Formula Rate must be made through the Challenge Procedures described in Section III of these protocols, and not in response to the Informational Filing.

## VI. Calculation of True-Up Adjustment for the Annual True-Up

The True-Up Adjustment for the Annual True-Up will be determined in the following manner:

1. The Projected Revenue Requirement for the previous year, not including any prior year True-Up Adjustment, shall be compared to the Actual Revenue Requirement calculated in accordance with LES's Formula Rate for the previous year using data for that same year, and, to the extent specified in the Formula, upon the audited books and records of LES, to determine any over or under recovery plus interest ("True-Up Adjustment"). The True-Up Adjustment and related calculations shall be posted as part of LES's Annual True-Up to SPP's website and OASIS no later than June 1st (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day).

    (i) Interest on any over recovery of the net revenue requirement or any over recovery due to volume changes shall be determined based on the Commission's regulation at 18 C.F.R. § 35.19a. Interest on any under recovery of the net revenue requirement or any under recovery due to volume changes shall be calculated on the basis of LES's actual short-term debt costs capped at the applicable FERC refund interest rate as provided in 18 C.F.R. § 35.19a. In either case, the interest payable shall be calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the revenue requirement or volume changes exists. The interest rate to be applied to the over or under recovery amounts will be determined using the average rate for the nineteen (19) months preceding August of the current year. The interest amount will be included in the projected costs made available October 15.

2. The Net ATRR for transmission services for the following year shall be the sum of the projected revenue requirement for the following year minus Total Transmission Revenue Credits, plus or minus the True-up Adjustment from the previous year, if any, including interest.

# Addendum 7 to Attachment H

12/31/2XXX

**Formula Rate Template**
**For the 12 months ended 12/31/2XXX**

**Nebraska Public Power District**

| (A) Line No. | (B) | (C) Reference Worksheet/ Note | (D) | (E) | (F) Allocated Amount |
|---|---|---|---|---|---|
| **A.** | **NETWORK SERVICE** | | | | |
| 1 | GROSS REVENUE REQUIREMENT | Page 2, line 28, col. (F) | | | $ - |
| | REVENUE CREDITS | (Note A) | Total | Allocator | |
| 2 | Account No. 454 | Line 3, Page 3 of 4 | $ - | 1.0000 | - |
| 3 | Account No. 456 | Line 8, Page 3 of 4 | $ - | 1.0000 | - |
| 4 | TOTAL REVENUE CREDITS | (sum Line 2 thru Line 3) | | | $ - |
| 5 | Prior Year True-up | Worksheet K | | | $ - |
| 6 | NET REVENUE REQUIREMENT - BEFORE ADJUSTMENTS FOR UPGRADES | (Line 1 minus Line 4 plus Line 5) | | | $ - |
| 7 | Less: Base Plan Upgrades (w/o incentives) | Worksheet I | | | $ - |
| 8 | Less: Economic Upgrades (w/o incentives) | Worksheet I | | | - |
| 9 | Less: Requested Upgrades (w/o incentives) | Worksheet I | | | - |
| 10 | TOTAL ADJUSTMENTS FOR UPGRADES | (Line 7 thru Line 9) | | | $ - |
| 11 | **SPP ZONAL REVENUE REQUIREMENT** | (Line 6 minus Line 10) | | | **$ -** |
| **B.** | **POINT-TO-POINT SERVICE** | | | | |
| 12 | Rate Divisor: Average of 12 coincident system peaks for NPPD | Worksheet G (Note B) | | - | MW |

| | | | |
|---|---|---|---|
| | Zone | | |
| 13 | Annual Point-to-Point Rate in $/MW - Year | (Line 11 / Line 12) | $ - |
| 14 | Monthly Point-to-Point Rate $/MW - Month | (Line 13 /12) | $ - |
| 15 | Weekly Point-to Point Rate in $/MW - Weekly | (Line 13 /52) | $ - |
| 16 | Daily On-Peak Point-to-Point Rate in $/MW - Day | (Line 13 /260) | $ - |
| 17 | Daily Off-Peak Point-to-Point Rate in $/MW - Day | (Line 13 /365) | $ - |
| 18 | Hourly On-Peak Point-to-Point Rate in $/MW - Hourly | (Line 13 /4160) | $ - |
| 19 | Hourly Off-Peak Point-to-Point Rate in $/MW - Hourly | (Line 13 /8760) | $ - |
| 20 | Meter Reading Charge | (Note C) | |

**C. SPP REGIONAL SERVICE**

| | | | |
|---|---|---|---|
| 21 | **BASE PLAN UPGRADES ATRR FOR SPP COLLECTION UNDER SCHEDULE 11** | Worksheet I, Line 42 | **$ -** |
| 22 | ATRR for Economic & Requested Upgrades | Worksheet I, Line 43 & Line 44 | - |
| 23 | Total | (Line 21 plus Line 22) | $ - |

**Formula Rate Template**
**For the 12 months ended 12/31/2XXX**

**Nebraska Public Power District**

| (A) Line No. | (B) | (C) Reference Worksheet/Note | (D) NPPD Total | (E) Allocator | (F) Transmission (Col D times Col E) |
|---|---|---|---|---|---|
| | **O&M** | | | | |
| 1 | Transmission | Worksheet A, 16.D | $ - | DA | $ - |
| 2 | Less: Account 561 (Load Dispatching) | Worksheet A, 2.D | - | DA | - |
| 3 | Less: Account 565 (Transmission By Others) | Worksheet A, 5.D | - | DA | - |
| 4 | A&G | Worksheet B, 11.D | - | DA | - |
| 5 | Less: FERC Annual Fees | | 0 | | 0 |
| 6 | Less: EPRI & Reg. Comm. Exp. & Non-safety Ad | (Note D) | 0 | DA | 0 |
| 7 | Plus: Transmission Related Reg.Comm. Expense | (Note D) | 0 | | 0 |
| 8 | Common | | 0 | | 0 |
| 9 | Transmission Lease Payments | | 0 | | 0 |
| 10 | TOTAL O&M | (sum Lines 1, 4, 7, 8, 9 less 2, 3, 5, 6) | $ - | | $ - |
| | **DEBT SERVICE** | | | | |
| 11 | | | $ | | $ |
| 11 | Debt Service | Worksheet C, 9.C | - | | - |
| 12 | Amortization of premium or discount | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 13 | TOTAL DEBT SERVICE | (sum Line 11 thru Line 12) | | | $ - | |
| | **TAXES OTHER THAN INCOME TAXES** | (Note E) | | | | |
| | LABOR RELATED | | | | | |
| 14 | Payroll | | | | | |
| 15 | Highway and vehicle | | | | | |
| 16 | PLANT RELATED | | | | | |
| 17 | Property | Worksheet D, 2.D | $ - | | DA | $ - |
| 18 | Gross Receipts | | | 0 | | 0 |
| 19 | Other | | | 0 | | 0 |
| 20 | Payments in lieu of taxes | Worksheet D, 1.D | - | | | 0 |
| 21 | TOTAL OTHER TAXES | (sum Line 14 thru Line 20) | $ - | | | $ - |
| 22 | SUBTOTAL | (sum Lines 10, 13, 21) | | | | $ - |
| 23 | Construction from Revenue | (Note F) | $ - | | DA | 0 |
| 24 | SUBTOTAL - REV. REQTS BEFORE FERC INCENTIVE | (sum Lines 22, 23) | | | | $ - |
| 25 | FERC Incentive / RTO (50 basis points equivalent) | Worksheet H | | | | - |
| 26 | SUBTOTAL - REV. REQUIREMENTS | Line 24 plus Line 25 | | | | $ - |
| 27 | Factor to remove stepdown transformation | Worksheet J (Note G) | | | | 0.0% |
| 28 | REVENUE REQUIREMENTS | Line 26 multiplied by Line 27 | | | | $ - |

**Formula Rate Template**
**For the 12 months ended 12/31/2XXX**

**Nebraska Public Power District**

| (A) Line No. | (B) | (C) | (D) |
|---|---|---|---|
| | **SUPPORTING CALCULATIONS AND NOTES** | | |
| | **REVENUE CREDITS** | | **Amount** |
| | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | (Note H) | |
| 1 | 454 Total | Worksheet E, 1.D | $ - |
| 2 | Less: Rent related to All Other | Worksheet E, 1.F | - |
| 3 | Rent for Transmission Facilities | | $ - |
| | ACCOUNT 456 (OTHER ELECTRIC REVENUES) | | |
| 4 | Total 456 Revenue | Worksheet F, 1.D | $ - |
| 5 | Less: Revenue related to All Other | Worksheet F, 1.F | |

| | | | |
|---|---|---|---|
| | | | - |
| | | | $ |
| 6 | Other Electric Revenues - Transmission | Worksheet F, 1.E | - |
| 7 | Less: Transmission chgs for all transm transactions incl in Divisor on pg 1 | Worksheet F, 15.E | - |
| | | | $ |
| 8 | Total - Included as Revenue Credit on pg 1 | | - |

**Formula Rate Template**
**For the 12 months ended 12/31/2XXX**

**Nebraska Public Power District**

| Note Letter | |
|---|---|
| A | The revenue credits shall include a) amounts received directly from SPP for PTP transmission services, b) direct assignment charges for transmission facilities, the cost of which has been included in revenue requirements, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from revenue requirements are not included as revenue credits. Revenues from Transmission Customers whose coincident peak loads are included in the rate divisor are not included as revenue credits. |
| B | Network transmission for firm wholesale and retail service sinking on NPPD's transmission system, plus long-term point-to-point capacity reservations that are not under the SPP OATT. |
| C | Meter reading charge not calculated but to be included in the service agreement for network and point-to-point transactions where applicable. |
| D | Line 6 - Includes payments made to EPRI that constitute annual membership dues (Account 930.2), all Regulatory Commission Expenses (Account 928), and amounts posted to an A & G account for non-safety related advertising (Account 930.1). Line 7 - Regulatory Commission Expenses (Account 928) directly related to transmission service, RTO filings, or transmission siting. |
| E | Labor related taxes (e.g. FICA, unemployment taxes) are included, along with base salary, in appropriate FERC O&M or A&G account when charged. Applicable highway and vehicle related taxes are also included in the appropriate FERC O&M or A&G account when charged. Plant related taxes such as property, gross receipts, and other assessments are charged directly in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Formula Rate Template, since they are recovered elsewhere. |
| F | Construction from Revenue replaces the Margin Requirement and is the margin the utility uses in calculating rates applicable to its native load sales. |
| G | Removes dollar amount of transmission plant related to stepdown transformation facilities that are excluded from transmission facilities under the SPP OATT. |
| H | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. |

**Formula Rate Template**
**For the 12 months ended 12/31/2XXX**

**Nebraska Public Power District - Schedule 1 Revenue Requirements**

| Line No. | | Reference Worksheet/Note | Annual Revenue Requirement |
|---|---|---|---|

**A. Schedule 1 ARR**

| | | | |
|---|---|---|---|
| 1 | Total Load Dispatch & Scheduling (Account 561) | Page 2, Line 2, Col (F) | $ - |
| 2 | Less: Load Dispatch - Scheduling, System Control and Dispatch Service (FERC 561.4) | | - |
| 3 | Less: Load Dispatch - Transmission Service Studies (FERC 561.6) | | - |
| 4 | Less: Load Dispatch - Generation Interconnection Studies (FERC 561.7) | | - |
| 5 | Less: Load Dispatch - Reliability, Planning & Standards Development Services (FERC 561.8) | | - |
| 6 | Subtotal | (Line 1 - (Line 2 thru Line 5)) | $ - |
| 7 | Less: Revenue Credit for transmission service not included in the divisor | | - |
| 8 | Prior Year True-up | Worksheet K | - |
| 9 | **Net Schedule 1 Revenue Requirement for Zone** | | **$ -** |

**B. Schedule 1 Rate Calculations**

| | | | | |
|---|---|---|---|---|
| 10 | Rate Divisor: Average of 12 coincident system peaks for NPPD Zone | Worksheet G (Note B) | - | MW |
| 11 | Annual Point-to-Point Rate in $/MW - Year | (Line 9 / Line 10) | $ - | |
| 12 | Monthly Point-to-Point Rate in $/MW - Month | (Line 11 / 12) | $ - | |
| 13 | Weekly Point-to-Point Rate in $/MW - Weekly | (Line 11 / 52) | $ - | |
| 14 | Daily Point-to-Point Rate in $/MW - Day | (Line 11 / 260) | $ - | |
| 15 | Hourly Point-to-Point Rate in $/MW - Hour | (Line 11 / 4,160) | $ - | |

## Nebraska Public Power District
## Worksheet A - Transmission O&M Expenses

| (A) Line No. | (B) Account No. | (C) Description | (D) Total | (E) Transmission (115kV and greater) | (F) Subtransmission (less than 115 kV) |
|---|---|---|---|---|---|
| | | Operation Expense | | | |
| 1 | 560 | Operation Supervision & Eng-Trans | $ - | $ - | $ - |
| 2 | 561 | Load Dispatching-Transmission | - | - | - |
| 3 | 562 | Station Expenses - Transmission | - | - | - |
| 4 | 563 | Overhead Line Expenses - Transmission | - | - | - |
| 5 | 565 | Transmission By Others | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 6 | 566 | Misc Transmission Expenses | - | - | - |
| 7 | | Total Transmission Operation Exp | $ - | $ - | $ - |
| | | Maintenance Expense | | | |
| 8 | 569 | Maintenance of Structures | $ - | $ - | $ - |
| 9 | 569.1 | Maintenance of Computer Hardware | - | - | - |
| 10 | 569.2 | Maintenance of Computer Software | - | - | - |
| 11 | 569.3 | Maintenance of Communication Equipment | - | - | - |
| 12 | 570 | Maintenance Supr & Eng-Trans | - | - | - |
| 13 | 571 | Maintenance of Overhead Lines - Transmission | - | - | - |
| 14 | 573 | Maintenance of Misc Transmission Plant | - | - | - |
| 15 | | Total Transmission Maintenance Exp | $ - | $ - | $ - |
| 16 | | Total Transmission O&M | $ - | $ - | $ - |

## Nebraska Public Power District
## Worksheet B - Administrative & General (A&G) Expenses

| (A) Line No. | (B) Account No. | (C) Description | (D) Total | (E) Transmission | (F) All Other |
|---|---|---|---|---|---|
| 1 | 920 | A&G Salaries | $ - | $ - | $ - |
| 2 | 921 | Office Supplies & Exp | - | - | - |
| 3 | 922 | A&G Expense Transferred | - | - | - |
| 4 | 923 | Outside Services Employed | - | - | - |
| 5 | 924 | Property Insurance | - | - | - |
| 6 | 925 | Injuries & Damages | - | - | - |
| 7 | 926 | Employee Pension/Benefits | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 8 | 930 | Misc General | - | - | - |
| 9 | 931 | Rents | - | - | - |
| 10 | 935 | Maintenance of General Plant | - | - | - |
| 11 | | Total | $ - | $ - | $ - |

NOTE: Administrative & General (A & G) expenses are derived and dependent upon the specific department or functional area incurring the cost (e.g. Finance & Accounting, Human Resources, etc.). Costs incurred by each of these A & G departments are posted to "cost collectors". Costs are broken down into the FERC accounts listed above based on type (e.g. Salaries - FERC 920; Outside Services - FERC 923, etc.). Cost drivers are determined for each A & G department and/or cost (e.g. Human Resources - # of employees; Property Insurance - Utility Plant in Service) and an allocation basis is assigned. Several allocation bases are used to allocate A & G costs. The most common allocation basis used is a three-factor formula that uses a combination of O & M expenses, # of employees, and Utility Plant in Service. FERC Account 922 includes A&G costs transferred to capital projects. Transmission's applicable share of these credits is based on the cash flow of Transmission projects.

## Nebraska Public Power District
## Worksheet C - Debt Service

| (A) Line No. | (B) Description | (C) Total | (D) Transmission | (E) All Other | (F) Description/Allocation Basis |
|---|---|---|---|---|---|
| 1 | Principal Payments on Long Term Debt | $ - | $ - | $ - | See Note A below |
| 2 | Principal Payments on Short Term Debt | - | - | - | See Note B below |
| 3 | Interest on Long Term Debt | - | - | - | See Note A below |
| 4 | Other Interest Expense | - | - | - | See Note B below |
| 5 | Other Debt Service Adjustments | - | - | - | Includes other debt service adjustments associated with prior debt issues, |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | capitalized leases and other misc debt issues. Transmission's share of other debt service adjustments is through direct assignment. |
| 6 | Capitalized Interest | - | - | - | Long-term debt interest expense posted for GAAP purposes, but backed out in current year for rate making purposes as amounts are not paid in current year but built into future debt service payments. See Note A for further details. |
| 7 | Subtotal Debt Service | $ - | $ - | $ - | |
| 8 | Less: Interest Income & Other Revenues | - | - | - | Interest income is derived from investments in the revenue and debt service funds. Transmission's share of interest income is the allocable share of how each of these funds are ultimately used (revenue fund used to pay expenses; debt service funds used to pay debt). |
| 9 | Total Debt Service (Net) | $ - | $ - | $ - | |

Note A: Annual principal and interest payments for long-term debt are based on debt service schedules. Transmission's share of debt is based on the amount applicable to transmission projects. Transmission's share of general plant projects funded with long-term debt is determined on a project-by-project basis.

Note B: Annual principal payments on short-term debt and other interest expense are derived using a comprehensive write-off schedule for all projects funded with short-term debt. Transmission's share of debt is based on the amount specifically used to fund transmission projects. Transmission's share of general plant projects funded with short-term debt is determined on a project-by-project basis.

## Nebraska Public Power District
## Worksheet D - Taxes Other Than Income Taxes

| (A) Line No. | (B) Account No. | (C) Description | (D) Total | (E) Transmission | (F) All Other | (G) Allocation Basis |
|---|---|---|---|---|---|---|
| | | | $ | $ | $ | |
| 1 | 408 | In Lieu of Taxes | - | - | - | |
| 2 | 408 | Property Taxes | - | - | - | Only taxes other than income taxes applicable to transmission are property taxes related to transmission facilities in South Dakota and Iowa |
| 3 | | Total - Taxes Other Than Income Taxes | $ - | $ - | $ - | |

## Nebraska Public Power District
## Worksheet E - Rent from Electric Property

| (A) Line No. | (B) Account No. | (C) Description | (D) Total | (E) Transmission | (F) All Other | (G) Allocation Basis |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | 454 | Rent from Electric Property | $ - | $ - | $ - | Direct assignment of specific Transmission customers |

## Nebraska Public Power District
## Worksheet F - Other Electric Revenues

| (A) Line No. | (B) Account No. | (C) Description | (D) Total | (E) Transmission | (F) All Other |
|---|---|---|---|---|---|
| | | | $ | $ | $ |
| 1 | 456 | Other Electric Revenues | - | - | - |
| 2 | | Less: | | | |
| 3 | | TO's LSE Direct Assignment Revenue Credits | | 0 | |
| 4 | | TO's LSE Sponsored (Requested or Economic) Upgrade Revenue Credits | | 0 | |
| 5 | | TO's LSE Network Upgrades for Generation Interconnection - Credits | | 0 | |
| 6 | | TO's Point-to-Point Revenue for GFA's Associated with Load Included in the Divisor | | 0 | |
| 7 | | Network Service Revenue (Schedule 9) Associated with Load Included in the Divisor | | 0 | |
| 8 | | TO's Revenue Associated with Transmission Plant Excluded From SPP Tariff | | 0 | |
| 9 | | Wholesale Distribution Charges | | 0 | |
| 10 | | TO's LSE Revenue from Ancillary Services Provided | | 0 | |
| 11 | | Base Plan Revenue Received | | 0 | |
| 12 | | SPP Point-to-Point Revenues and Associated Ancillary Services (Schedule 1) Already Distributed to Customers in the Zone | | 0 | |
| 13 | | Ancillary Revenues (Schedule 1) | | 0 | |
| 14 | | Other | | 0 | |
| 15 | | Total Revenues Adjusted from Acct. 456 (Line 3 thru Line 14) | | $ - | |
| 16 | | Amount included as Revenue Credit to ATRR (Line 1 minus Line 15) | | $ - | |

**Worksheet G - Network Load**

Based on NPPD Monthly Transmission System Firm

Peak Demands for 12-Months Actual Loads (August 2XXX - July 2XXX)

| Line No. | SPP Load Responsibility | Peak Day Peak Hour / Average 12-month | 1/XX/2XXX XX:00 | 2/XX/2XXX XX:00 | 3/XX/2XXX XX:00 | 4/XX/2XXX XX:00 | 5/XX/2XXX XX:00 | 6/XX/2XXX XX:00 | 7/XX/2XXX XX:00 | 8/XX/2XXX XX:00 | 9/XX/2XXX XX:00 | 10/XX/2XXX XX:00 | 11/XX/2XXX XX:00 | 12/XX/2XXX XX:00 | 12 Month Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | NPPD | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 2 | MEAN | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 3 | MEAN_ACJ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 4 | Neligh | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 5 | Tri-State | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 6 | Tri-State RMR | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 7 | OPPD | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 8 | Rushmore | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 9 | South Sioux City | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 10 | Superior | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 11 | Big Rivers | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 12 | WAPA | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 13 | Beatrice | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 14 | Scribner | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 15 | Valentine | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 16 | Loup Basin | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 17 | GFA PTP Capacity Reservations | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 18 | Total | 0 | - | - | - | - | - | - | - | - | - | - | - | - | - |

NOTE: SPP Load Responsibility will be updated without submitting revisions to the Formula Rate Template.

**Worksheet H - 50 Basis Point Incentive Margin Calculation for NPPD**

| Line No. | Return *with* Margin | IPL | | | | Mid-American | | | | OPPD | | | | NSP | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | w/ Margin of 50 | | | | w/ Margin of 50 | | | | w/ Margin of 50 | | | | w/ Margin of 50 | |
| | | $ | % | Cost | Weighted | $ | % | Cost | Weighted | $ | % | Cost | Weighted | $ | % | Cost | Weighted |
| 1 | LTD | $ 807,670,817 | 4.19% | 6.76% | 0.0283 | $1,019,573,069 | 4.25% | 7.26% | 0.0308 | $ 692,943,244 | 3.20% | 5.70% | 0.0182 | $ 1,706,821,604 | 4.20% | 6.20% | 0.0260 |
| 2 | Preferred | 150,000,000 | 7.83% | 7.63% | 0.0059 | 48,714,222 | 2.68% | 5.97% | 0.0016 | | 0.00% | | 0.0000 | - | 0.00% | 0.00% | 0.0000 |
| 3 | Common Stock | 969,560,516 | 5.08% | 12.81% | 0.0065 | 1,225,340,842 | 5.10% | 13.72% | 0.0070 | 1,152,635,102 | 6.28% | 12.80% | 0.0080 | 2,136,565,851 | 5.68% | 12.80% | 0.0073 |
| 4 | Total | $1,927,031,933 | 10.00% | | 0.0407 | $2,293,628,133 | 10.00% | | 0.0394 | $1,845,578,346 | 10.00% | | 0.0262 | $3,843,387,455 | 10.00% | | 0.0333 |
| 5 | Transmission Rate Base | $ 192,191,965 | | | | $ 197,163,706 | | | | $ 160,576,972 | | | | $ 620,045,541 | | | |
| 6 | Transmission Return | | | | $ 19,038,067 | | | | $ 21,068,108 | | | | $ 16,293,762 | | | | $ 61,466,341 |

| | Return *without* Margin | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Cost | Weighted | | | Cost | Weighted | | | Cost | Weighted | | | Cost | Weighted |
| 7 | LTD | | | 6.76% | 0.0283 | | | 7.26% | 0.0308 | | | 5.70% | 0.0182 | | | 6.20% | 0.0260 |
| 8 | Preferred | | | 7.63% | 0.0059 | | | 5.97% | 0.0016 | | | | 0.0000 | | | 0.00% | 0.0000 |
| 9 | Common Stock | | | 12.81% | 0.0065 | | | 13.72% | 0.0070 | | | 12.80% | 0.0080 | | | 12.80% | 0.0073 |

| | | 8% | 10% | 80% | 80% |
|---|---|---|---|---|---|
| 10 | Total | 0.0966 | 0.1042 | 0.0986 | 0.0963 |
| 11 | Transmission Return w/o margin | $18,565,744 | $20,544,458 | $15,832,889 | $59,710,386 |
| 12 | Transmission Margin Return | $472,323 | $523,650 | $529,904 | $1,755,955 |
| 13 | Convert to 50 Basis Points | $472,323 | $523,650 | $529,904 | $1,755,955 |
| | **Calculate Return as a % of Revenue Requirements** | | | | |
| 14 | Revenue Requirement w/ return | $63,918,980 | $56,748,463 | $30,810,041 | $165,787,119 |
| 15 | Less: Return included in above | (472,323) | (523,650) | (529,904) | (1,755,955) |
| 16 | Less: Income Taxes Included Above | (8,800,712) | (10,659,024) | - | (27,690,850) |
| 17 | Revenue Requirement w/o Return | $54,645,945 | $45,565,789 | $30,280,937 | $136,340,314 |
| 18 | 50 Basis Points as a % of Total RR w/o Return | 0.86% | 1.15% | 1.75% | 1.29% |
| | **Calculate Total Effect of 50 Basis Points** | | | | |
| 19 | Total 50 basis points Return all Participants | $3,281,832 | | | |
| 20 | Total RR w/o Return | 266,832,985 | | | |
| 21 | Return % Average all Participants | 1.2299190% | | | |
| | **Calculate NPPD's Equivalent Incentive** | | | | |
| 22 | NPPD Revenue | $ | | | |

| | | | |
|---|---|---|---|
| 2 | Requirements w/o 50 basis point incentive (pg.2, line 24) | - | |
| | Margin % | | (Ro |
| 2 | Return all | 1.23 | und |
| 3 | Participants | % | ed) |
| | 50 Basis | | |
| 2 | Point | $ | |
| 4 | Incentive | - | |

**Nebraska Public Power District**
**Worksheet I - ATRR Calculation for Base Plan, Economic, and Requested Upgrades**

| | | | |
|---|---|---|---|
| | New Plant | | |
| 1 | Carrying Charge | | |
| | **Fixed Charge Rate (FCR) if not** | | |
| 2 | **a CIAC** | | |
| | | Formula Line | |
| | Net Transmission Revenue | Page 1 of 4, | $ |
| 3 | Requirement | Line 6 | - |
| | Net Transmission | Worksheet L, Line 15, Col | $ |
| 4 | Plant | (G) | - |
| | Base Fixed Charge Rate | Line 3 / Line | |
| 5 | (FCR) | 4 | 0.00% |
| | 100 basis point as | 2 x Worksheet H, Line 23 - | |
| 6 | % of Revenue | NPPD Equivalent Incentive | 2.46% |
| | FCR with 100 basis points | Line 5 * (1 + | |
| 7 | incentive | Line 6) | 0.00% |
| | FCR value of 100 | Line 7 - Line | |
| 8 | basis points | 5 | 0.00% |

| | | Details | | Project A |
|---|---|---|---|---|
| | Enter Type of | | | |
| 9 | Project | Schedule 12 | (Yes or No) | Base Plan |
| 1 | Useful life of the | | | |
| 0 | project | Life | | |
| 1 | Input the allowed | Increased ROE | | |
| 1 | increase in ROE | (Basis Points) | | |
| 1 | | | | |
| 2 | Line 5 | Base FCR | | 0.0000% |
| | Line 12 plus line 8 | | | |
| 1 | times (line | FCR for This | | |
| 3 | 11/100) | Project | | 0.0000% |
| | Project subaccount of Plant in Service Account 101 or | | | |
| 1 | 106 if not yet | | | $ |
| 4 | classified | Investment | | - |
| | | Annual | | |
| 1 | Line 14 divided by | Depreciation | | |
| 5 | line 10 | Exp | | - |
| | Month in which project is placed | | | |
| 1 | in service (e.g. | Month In Service or Month for | | |
| 6 | Jan=1) | CWIP | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 7 | | | **Invest Yr** | **Beginning** | **Depreciation** | **Ending** | **Revenue** | **Actual Revenue** | **True-Up Adj. (Before** | **True-Up Adj. (Incl.** |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Requirements | Rec'd | Interest) | Interest) |
| 1 | | | $ | $ | $ | $ | | | |
| 18 | WO Incentive | 2XXX | - | - | - | - | | | |
| 19 | W Incentive | 2XXX | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | Details | | Project B |
|---|---|---|---|---|
| 20 | Enter Type of Project | Schedule 12 | (Yes or No) | Economic |
| 21 | Useful life of the project | Life | | |
| 22 | Input the allowed increase in ROE | Increased ROE (Basis Points) | | |
| 23 | | | | |
| 24 | Line 5 | Base FCR | | 0.0000% |
| 25 | Line 23 plus line 8 times (line 22/100) | FCR for This Project | | 0.0000% |
| 26 | Project subaccount of Plant in Service Account 101 or 106 if not yet classified | Investment | | $ - |
| 27 | Line 25 divided by line 21 | Annual Depreciation Exp | | - |
| 28 | Month in which project is placed in service (e.g. Jan=1) | Month In Service or Month for CWIP | | |

| | | Invest Yr | Beginning | Depreciation | Ending | Revenue Requirements | Actual Revenue Rec'd | True-Up Adj. (Before Interest) | True-Up Adj. (Incl. Interest) |
|---|---|---|---|---|---|---|---|---|---|
| 29 | | | $ | $ | $ | $ | | | |
| 30 | WO Incentive | 2XXX | - | - | - | - | | | |
| 31 | W Incentive | 2XXX | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | Details | | Project C |
|---|---|---|---|---|
| 32 | Enter Type of Project | Schedule 12 | (Yes or No) | Requested |
| 33 | Useful life of the project | Life | | |
| 34 | Input the allowed increase in ROE | Increased ROE (Basis Points) | | |
| 35 | | | | |
| 36 | Line 5 | Base FCR | | 0.0000% |
| 37 | Line 34 plus line 8 times (line 33/100) | FCR for This Project | | 0.0000% |
| 38 | Project subaccount of Plant in Service Account 101 or 106 if not yet classified | Investment | | $ - |
| 39 | Line 36 divided by line 32 | Annual Depreciation Exp | | - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 3 8 | Month in which project is placed in service (e.g. Jan=1) | Month In Service or Month for CWIP | | | | | | | | |
| 3 9 | | | Invest Yr | Beginning | Depreciation | Ending | Revenue Requirements | Actual Revenue Rec'd | True-Up Adj. (Before Interest) | True-Up Adj. (Incl. Interest) |
| 4 0 | | WO Incentive | 2XXX | $ - | $ - | $ - | $ - | | | |
| 4 1 | | W Incentive | 2XXX | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Summary | ARR w/o Incentive (Revenue Credit) | ARR w/ Incentive (Before True-Up) | Prior Year True-Up Adj. (Worksheet K) | ARR w/Incentive (Incl. True-Up) |
|---|---|---|---|---|---|
| 4 | Base Plan | $ | $ | $ | $ |
| 2 | Upgrade | - | - | - | - |
| 4 | Economic | | | | |
| 3 | Upgrade | - | - | - | - |
| 4 | Requested | | | | |
| 4 | Upgrade | - | - | - | - |
| 4 5 | Totals | $ - | $ - | $ - | $ - |

4 6 Note: The actual revenue received and true-up adjustment amounts are $0 for the projected year's revenue requirements. The total true-up adjustment for all projects is included in Lines 42-45.

**Nebraska Public Power District**
**Worksheet J - Factor to Remove Stepdown Transformation**

| Line # | FERC Plant Code | Transmission Assets - 12/31/2XXX | Gross Plant |
|---|---|---|---|
| 1 | 350T | Trans-Land & Land Rights | $ - |
| 2 | 351T | Trans-[Reserved] | - |
| 3 | 352T | Trans-Structures & Improvement | - |
| 4 | 353T | Trans-Station Equipment | - |
| 5 | 354T | Trans-Towers & Fixtures | - |
| 6 | 355T | Trans-Poles & Fixtures | - |
| 7 | 356T | Trans-Overhd Conductor/Devices | - |
| 8 | 357T | Trans-Underground Conduit | - |
| 9 | | Total - Transmission Assets (Line 1 thru Line 8) | $ - |
| 10 | | Non-qualifying 345 kV Substation Assets | $ - |
| 11 | | Non-qualifying 230 kV Substation Assets | - |
| 12 | | Non-qualifying 115 kV Substation Assets | - |
| 13 | | Total - Non-qualifying Substation Assets (Line 10 thru Line 12) | $ - |
| 14 | | Total - Qualifying Transmission Assets (Line 9 minus Line13) | $ - |
| 15 | | % of Qualifying Transmission Assets (Line 14 divided by Line 9) | 0.0% |

**Nebraska Public Power District Worksheet K - Prior Year True-up**

**Timeline**

| Step | Month | Year | Action |
|---|---|---|---|
| 1 | Aug | Year 0 | NPPD populates the formula rate using projected costs for Year 1 |
| 2 | Aug | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Aug | Year 1 | NPPD populates the formula rate using projected costs for Year 2 |
| 5 | Aug | Year 1 | Post results of Step 4 |
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | May | Year 2 | NPPD populates the formula rate using actual costs and divisor billing units for Year 1 |
| 8 | May | Year 2 | Calculate the difference between the Actual Revenue Requirements per the formula rate calculated in Step 7 and Actual Revenues (Note A) |
| 9 | May | Year 2 | Post results from Step 7 and Step 8 |
| 10 | Aug | Year 2 | NPPD populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |
| 11 | Aug | Year 2 | Post results of Step 10 |

**Reconciliation details**

| | | Zonal ATRR | BPU | EU | RU | Schedule 1 | Total |
|---|---|---|---|---|---|---|---|
| 12 | Actual Revenue Requirements from Step 7 | $ - | $ - | $ - | $ - | $ - | $ - |
| 13 | Actual Revenues (Note A) | - | - | - | - | - | - |
| 14 | True-up Amount (before interest) | $ - | $ - | $ - | $ - | $ - | $ - |

**Interest Calculation (Note D)**

| | | | |
|---|---|---|---|
| | **Short term Interest Rate** | | |
| 15 | Other Interest Exp.(Acct. 431) | | $ - |
| 16 | Notes Payable (Acct. 231) Sum of the Daily amounts (Note B) | | - |
| 17 | No. of Days (enter 1-365) | | - |
| 18 | Annual Short-term Int Rate | (line 15 / line 16 * line 17) | |
| 19 | Interest Rate per 18 C.F.R. 35.19a | | |
| 20 | **Applicable Interest Rate for True-Up (minimum of lines 18 and 19)** | | **0.000%** |

| | | Zonal ATRR | BPU | EU | RU | Schedule 1 | Total |
|---|---|---|---|---|---|---|---|
| 21 | True-Up Amount (line 14) | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 22 | | Interest on True-up Amount ([Applicable Interest Rate / 12 months]*24 months] | - | - | - | - | - | - | | | |
| 23 | | **True-up Adjustment (Note C)** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | | |

Notes:

A For Zonal ATRR and Schedule 1, NPPD to calculate Actual Revenues by applying the Year 1 rates from Step 3 to the actual loads included in the divisor for Year 1 in Step 7. For Base Plan Upgrades (BPU), Economic Upgrades (EU), and Requested Upgrades (RU), the Actual Revenues are those NPPD receives during Year 1.

B Sum of the daily short-term borrowings is supplied from the Finance Department.

C The amounts shown are for a full 12 month year, if the year is a partial year, divide the resultant True-Up amount by 12 and multiply by the months in the partial year.

D Rate to be based on Jan-March actual data for current year.

**Nebraska Public Power District**
**Worksheet L - Net Transmission Plant (Excluding Stepdown Transformation)**

| (A) | (B) | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|
| **Line #** | **Month** | **Year** | **Net Book - Beg of Period** | **Net Additions/ Retirements** | **Depreciation** | **Balance - Net Trans Plant - End of Month** |
| 1 | Beginning Balance | | | | | $ - |
| 2 | January | | $ - | $ - | $ - | - |
| 3 | February | | - | - | - | - |
| 4 | March | | - | - | - | - |
| 5 | April | | - | - | - | - |
| 6 | May | | - | - | - | - |
| 7 | June | | - | - | - | - |
| 8 | July | | - | - | - | - |
| 9 | August | | - | - | - | - |
| 10 | September | | - | - | - | - |
| 11 | October | | - | - | - | - |
| 12 | November | | - | - | - | - |
| 13 | December | | - | - | - | - |
| 14 | Totals | | | $ - | $ - | |
| 15 | | | | | Avg Net Book (Sum of Line 1 thru Line 13 divided by 13) | $ - |

# Formula Rate Implementation Protocols

## Section I Annual Update and Annual True-Up

1. The Formula Rate Template set forth in Attachment H, Addendum 7 of Southwest Power Pool's ("SPP") Open Access Transmission Tariff ("OATT") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate by SPP for calculating Nebraska Public Power District's ("NPPD") Zonal Annual Transmission Revenue Requirement ("ATRR") for Transmission Service under the SPP OATT. NPPD must follow the instructions specified in the Formula Rate Template to calculate annually the rates for Network Integration Transmission Service ("NITS"), the rates for Schedule 1 Service, the rates for Point-to-Point services over facilities in SPP Zone 17 and the ATRR for Base Plan Upgrades and other network upgrades. These protocols shall apply to NPPD's calculation of its ATRR, including the calculation of the Annual True-Up ("Annual True-Up") and the projected net Zonal ATRR ("Annual Update").

2. The Formula Rate shall be recalculated annually with resulting rates applicable to service on and after January 1 of each calendar year through December 31 of the same calendar year ("Rate Year"). The resulting rates implemented each January 1 will be subject to review and true-up as further provided in the Protocols.

3. On or before August 1st, NPPD shall provide its Annual Update to SPP and cause such information to be posted on SPP's website and OASIS. The date of such posting is referred to herein as the "Annual Update Publication Date." On the same day, NPPD shall provide notice of such posting to all parties on an SPP email exploder list. Interested Parties ("Interested Parties") can contact SPP to subscribe to the SPP exploder list. For purposes of these protocols, the term Interested Party includes, but is not limited to customers under the SPP OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

4. On or before May 1st, NPPD shall provide its Annual True-Up to SPP and cause such information to be posted on SPP's website and OASIS. The date of such posting is referred to herein as the "Annual True-Up Publication Date." On the same day, NPPD shall provide notice of such posting to all parties on an SPP email exploder list. Interested Parties can contact SPP to subscribe to the SPP exploder list.

5. NPPD shall request SPP to submit to FERC an Informational Filing as provided in Section V of these protocols.

6. If the date for posting the Annual True-Up or Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day.

7. A change to the Formula Rate fixed inputs related to return on equity, incentive adders to return on equity, or revised depreciation rates may not be made absent an appropriate filing with FERC.

8. The Annual True-Up shall

   (a) Be based on actual data as recorded in the books and records of NPPD consistent with FERC accounting policies and practices.

   (b) Identify all material adjustments made to such actual data in determining formula inputs.

9. The Annual True-Up and Annual Update shall

   (a) Include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact;

   (b) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used;

   (c) Provide sufficient information to enable Interested Parties to replicate the calculation;

   (d) With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

      (i) Identify any Accounting Changes, including

         - the initial implementation of an accounting standard or policy;
         - the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
         - correction of errors and prior period adjustments that impact the calculation;
         - the implementation of new estimation methods or policies; and
         - changes to income tax elections;

      (ii) Identify items included in the calculation at an amount other than on a historic cost basis (e.g., fair value adjustments);

      (iii) Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs;

(iv) Provide, for each item identified pursuant to items I.9.d.i - I.9.d.iii of these protocols, a narrative explanation of the individual impact of such changes on the calculation; and

(v) Include for the applicable Rate Year the following information related to affiliate cost allocation;

- a detailed description of the methodologies used to allocate and directly assign costs between NPPD and its affiliates, if any, by service category or function for the applicable Rate Year, including any changes to such cost allocation methodologies from the prior year and the reasons and justifications for those changes; and

- the magnitude of any such costs that have been allocated or directly assigned between NPPD and each affiliate by service category or function for the applicable period.

10. NPPD shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") no sooner than ten (10) days from the Annual True-Up Publication Date and no later than June 1st. No less than twenty (20) days prior to such Annual True-Up Meeting, NPPD shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual True-Up Meeting and NPPD shall provide notice of such meeting to the SPP email exploder list. The Annual True-Up Meeting will be hosted by NPPD in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. NPPD shall provide remote access for Interested Parties to participate in the meeting. The Annual True-Up Meeting shall (i) permit NPPD to explain and clarify its Annual True-Up, and (ii) provide Interested Parties an opportunity to seek information and clarification from NPPD about the Annual True-Up.

11. NPPD shall hold an open meeting among Interested Parties ("Annual Update Meeting") no sooner than ten (10) days from the Annual Update Publication Date and no later than August 31st. No less than twenty (20) days prior to such Annual Update Meeting, NPPD shall provide notice on SPP's website and OASIS of the time, date, and location of the Annual Update Meeting and NPPD shall provide notice of such meeting to an SPP email exploder list. The Annual Update Meeting will be hosted by NPPD in the forum of its choice which may include video conferencing, webinar, internet conferencing, phone conferencing, in person, or other similar options. NPPD shall provide remote access for Interested Parties to participate in the meeting. The Annual Update Meeting shall (i) permit NPPD to explain and clarify its Annual Update and (ii) provide Interested Parties an opportunity to seek information and clarification from NPPD about the Annual Update and Annual True-Up.

12. Each year NPPD shall endeavor to coordinate with other Transmission Owners in SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

**Section II Information Exchange Procedures**

1. Each Annual True-Up and Annual Update shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

   (a) Interested Parties shall have until seventy-five (75) days following the Annual True-Up Publication Date to serve reasonable information and document requests related to the Annual True-Up; and sixty (60) days from the Annual Update Publication Date to serve reasonable information and document requests related to the Annual Update and the Annual True-Up ("Information Exchange Period"). If either of these dates falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

      (i) the extent, effect or impact of an Accounting Change;

      (ii) whether the Annual True-Up or Annual Update fails to include data properly recorded in accordance with these protocols;

      (iii) the proper application of the Formula Rate and procedures in these protocols;

      (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual True-Up or Annual Update;

      (v) the prudence of actual costs and expenditures, including the prudence of NPPD's procurement methods and cost control methodologies;

      (vi) the effect of any change to the underlying FERC Uniform System of Accounts; or

      (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

(b) NPPD shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

(c) NPPD will cause to be posted on SPP's website and OASIS all information requests from Interested Parties and NPPD's response(s) to such requests; except, however, if responses to information and document requests include material deemed by NPPD to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by NPPD and the requesting party.

(d) NPPD shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing NPPD's Annual True-Up or Annual Update.

2. No later than December 20th of each year, NPPD, upon final approval of NPPD's Board of Directors, will provide SPP for posting on SPP's website and OASIS NPPD's Annual Update for SPP to include in the Zonal ATRR and resulting rates to become effective January 1st of the following calendar year.

## Section III Challenge Procedures

1. Interested Parties shall have until the later of thirty (30) days after NPPD's last response to information requests or November 21st (unless such period is extended with the written consent of NPPD or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify NPPD in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up and/or Annual Update. The period of time from the Publication Dates until the date Informal Challenges are due shall be referred to as the Review Period. If the date for submitting Informal Challenges falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual True-Up and/or Annual Update as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual True-Up and/or Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual True-Up and/or Annual Update, the Interested Party is barred from

pursuing a Formal Challenge with respect to any issue for that Annual True-Up and/or Annual Update but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or Annual Update.

2. A party submitting an Informal Challenge to NPPD must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. NPPD shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. NPPD, and where applicable, SPP, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If NPPD disagrees with such challenge, NPPD will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section III.

4. Informal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or Annual Update fails to include data properly recorded in accordance with these protocols; (3) the proper application of the Formula Rate and procedures in these protocols; (4) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual True-Up and Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying FERC Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula. Any Interested Party seeking to challenge the prudence of actual costs or expenditures shall first raise the matter with NPPD in accordance with this Section III before pursuing a Formal Challenge.

5. NPPD will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and NPPD's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by NPPD to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by NPPD and the requesting party.

6. Any changes or adjustments to the Annual True-Up or Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by NPPD will be reported in the Informational Filing required pursuant to Section V of these protocols. Any such changes or adjustments agreed to by NPPD on or before November 30$^{th}$ will be reflected in the Annual Update for the upcoming Rate Year. Any changes or adjustments agreed to by NPPD after

November 30th will be reflected in the Annual True-Up for the year represented in the Annual Update, as discussed in Section IV of these protocols.

7. Interested Parties shall have until March 31st (unless such date is extended with the written consent of NPPD to continue efforts to resolve the Informal Challenge) to file any Formal Challenges to the Annual True-Up or Annual Update posted in the previous calendar year.

8. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

   (a) A Formal Challenge shall:

      (i) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or protocols;

      (ii) Explain how the action or inaction violates the filed Formula Rate or protocols;

      (iii) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

         - The extent or effect of an Accounting Change;

         - Whether the Annual True-Up or Annual Update fails to include data properly recorded in accordance with these protocols;

         - The proper application of the Formula Rate and procedures in these protocols;

         - The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual True-Up or Annual Update;

         - The prudence of actual costs and expenditures;

         - The effect of any change to the underlying FERC Uniform System of Accounts; or

         - Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

(iv) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(v) State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(vii) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(viii) State whether the filing party utilized the Informal Challenge procedures described in these protocols with regard to any issue.

(b) Any person filing a Formal Challenge must serve a copy of the Formal Challenge on NPPD. Service to NPPD must be simultaneous with any filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on NPPD's Informational Filing required under Section V of these protocols.

9. All Formal Challenges shall be served on NPPD on the date of such filing as specified in Section III.8.b above. A Formal Challenge shall be filed in the same docket as NPPD's Informational Filing discussed in Section V of these protocols. NPPD shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit any Informal Challenge during the applicable Review Period.

10. In any proceeding initiated by FERC concerning the Annual True-Up or Annual Update or in response to a Formal Challenge, NPPD shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

11. The implementation of any changes or adjustments resulting from any Formal Challenge made with FERC will be subject to: (1) approval by NPPD's Board of Directors; and (2) SPP Tariff Section 39.1.

12. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of NPPD to request SPP to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

13. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these protocols, and the Annual True-Up and Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

14. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the FERC Uniform System of Accounts, shall first raise the matter with NPPD in accordance with this Section III before pursuing a Formal Challenge.

**Section IV Changes to Annual True-Up or Annual Update**

1. Except as provided in Section III.6 of these protocols, any changes to the data inputs, including but not limited to changes as the result of any FERC proceeding to consider the Annual True-Up or Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

   Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VI of these protocols.

2. In the event that NPPD identifies an error in the Annual True-Up, or is required by applicable law to correct an error, NPPD shall correct such error in good faith and without regard to whether the correction increases or decreases NPPD’s revenue requirements, in a manner consistent with SPP Tariff Section 7.1. Nothing in these protocols should or may be construed as preventing Interested Parties or the FERC from protesting such correction as inappropriate.

## Section V Informational Filings

1. By January 15th of each year, NPPD shall request SPP to submit to FERC an informational filing ("Informational Filing") of its Annual Update for the Rate Year, including its Annual True-Up. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that NPPD has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, NPPD shall provide notice of the Informational Filing via an SPP email exploder list and by posting the docket number assigned to NPPD's Informational Filing on SPP's website and OASIS.

2. Any challenges to the implementation of the Attachment H - NPPD Formula Rate must be made through the Challenge Procedures described in Section III of these protocols and not in response to the Informational Filing.

## Section VI Calculation of True-Up Adjustment for the Annual True-Up

The True-Up Adjustment for the Annual True-Up will be determined in the following manner:

1. The projected ATRR included in the Annual Update for the previous year shall be compared to the actual revenue recovered during such period, calculated in accordance with Worksheet K of NPPD's Formula Rate Template. Actual costs incurred during the applicable calendar year will be compared to actual revenues, from the books and records of NPPD consistent with FERC accounting policies and practices, to determine any over- or under- recovery plus interest ("True-Up Adjustment"). The True-Up Adjustment and related calculations shall be posted as part of NPPD's Annual True-Up to SPP's website and OASIS no later than May 1st (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day).

    (a) Interest on any over-recovery or any under-recovery of ATRR shall be determined using the interest rate equal to NPPD's actual short-term debt costs, calculated as NPPD's actual weighted average annual short-term interest rate, capped at the applicable FERC refund interest rate. The interest amount will be included in the Annual Update made available on August 1st. For purposes of the foregoing, short-term debt interest expense annual rate

shall be calculated in accordance with Worksheet K to the Formula Rate Template.

2. The Net ATRR for transmission services for the following year shall be the sum of the projected revenue requirement for the following year and a True-Up Adjustment for the previous year, including interest as explained above.

# Addendum 8 to Attachment H

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Calculate Net Annual Transmission Revenue Requirements (ATRR) and Rates for SPP Tariff**

| Line No. | Acct | Description | Notes | Total Transmission |
|---|---|---|---|---|
| | **A. Zonal Net ATRR** | | | |
| 1 | | Gross ATRR | | |
| | | Revenue Credits | | |
| 2 | 456 | Less: Rev from SPP for Point-to-Point | Note A, Worksheet A | |
| 3 | 456 | Less: Other Short-term Point-to-Point Revenue | Note A, Worksheet A | |
| 4 | 454 | Less: Transmission Related Rents | Note B, Worksheet B | |
| 5 | | Total Transmission Revenue Credits | | |
| 6 | | OPPD Zonal Revenue Requirement | | |
| 7 | | Less: Base Plan Upgrades Revenues | Note C, Worksheet C, C1 + C2 | |
| 8 | | **Zonal Net ATRR for SPP Open Access Transmission Tariff (OATT) Attachment H** | Note G, Worksheet G | |
| | **B. Point-to-Point Transmission Service Rates** | | | |
| | | **Divisor** | | |
| 9 | | Network - Average of 12 Coincident Peaks | Note D, Worksheet D | |
| 10 | | Long-Term PTP Reservations | Note D, Worksheet D | |
| 11 | | Total Demand | | |
| | | **Rates for SPP OATT Attachment T** | | |
| 12 | | Point-to-Point Firm & Non-Firm ($/Kilowatt (kW) /Year) | Line 8 / Line 11 / 1000 | |

| | | |
|---|---|---|
| 13 | Point-to-Point Firm & Non-Firm ($/kW/Month) | Line 12 / 12 months |
| 14 | Point-to-Point Firm & Non-Firm ($/kW/Week) | Line 12 / 52 weeks |
| 15 | Point-to-Point Firm ($/kW/Day) On Peak | Line 14 / 5 days |
| 16 | Point-to-Point Firm ($/kW/Day) Off Peak | Line 14/ 7 days |
| 17 | Non-firm Point-to-Point ($/kW/Day) On Peak | Line 14 / 5 days |
| 17a | Non-firm Point-to-Point ($/kW/Day) Off Peak | Line 14 / 7 days |
| 18 | Non-firm Point-to-Point ($/kW/Hour) On Peak | Line 17 / 16 |
| 18a | Non-firm Point-to-Point ($/kW/Hour) Off Peak | Line 17a / 24 |

| | | | |
|---|---|---|---|
| | **C. Base Plan Uprade ATRR** | Note C | |
| 19 | Base Plan Upgrade ATRR without Incentives | Worksheets C, C1, C2, etc. | |
| 20 | Additonal ATRR for Incentives on Base Plan Upgrades | | |
| 21 | **Base Plan Upgrade ATRR for SPP OATT Schedule 11** | | |
| | **D. Scheduling, System Control, and Dispatch Annual Revenue Requirements** | | |
| 22 | **OPPD Scheduling, System Control & Dispatch Costs for SPP Schedule 1** | Note E, Worksheet E | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Calculate Gross ATRR**

| Line No. | Account | Description | Notes | Total OPPD | Adjustments | Adjust OPPD | Transmission Allocation Basis | Transmission Allocation % | Transmission |
|---|---|---|---|---|---|---|---|---|---|
| | | **Operating & Maintenance (O&M)** | | | | | | | |
| | | Direct O&M | | | | | | | |
| 23 | 500-557 | Production | | | | | n/a | | |
| 24 | 580-598 | Distribution | | | | | n/a | | |
| 25 | 901-917 | Customer | | | | | n/a | | |
| 26 | | Subtotal | | | | | | | |
| 27 | 560-574 | Transmission | | | | | All Transmission | 100% | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 28 | 565 | Less: Transmission of Electricity by Others | Note K, Worksheet K | | | |
| 29 | 561 | Less: Load Dispatch (Acct 561) | Note N, Worksheet E | | | |
| 30 | | Subtotal | | | | |
| | | Administrative & General (A&G) | | | | |
| 31 | 920-932 | A&G | | | Wages & Salaries | |
| 32 | | Less: Federal Energy Regulatory Commission Assessment Fees in 928 | | | Wages & Salaries | |
| 33 | | Less: Gen Advertising (930.02) | Note H, Worksheet H | | Wages & Salaries | |
| 34 | | Less: Misc General Exp (930.03) | Note H, Worksheet H | | Wages & Salaries | |
| 35 | | Total A&G | | | | |
| 36 | | Total O&M and A&G | | | | |
| | | **Depreciation & Amortization Expense** | Note F, Worksheet F | | | |
| 37 | 310-346 | Production | | | Direct to Production | |
| 38 | 352-359 | Transmission | | | Direct to Transmission | |
| 39 | 360-373 | Distribution | | | Direct to Dist | |
| 40 | 389-397 & 301-313 | General & Intangible | | | Wages & Salaries | |
| 41 | | Total Depreciation & Amortization | | | | |
| 42 | 408.1-409.1 | **Payments in Lieu of Taxes** | Note Q | | Direct to Distribution | |
| 43 | 427-432 | **Interest Expense** | Note P | | Net Plant | |
| 44 | | **Margin Requirement** | Note L | | Net Plant | |
| 45 | | **Regional Transmisison Organization Incentive (RTO)** | Note J, Worksheet J | | Direct to Transmission | |
| 46 | | Required Revenues w/o Add Margin on Incentive Plant | | | | |
| 47 | | **Additional Margin on Incentive Plant** | | | | |
| 48 | | Base Plan Upgrades | Note I, Worksheets C, C1, C2 | | Direct to Transmission | |

| | | | | | |
|---|---|---|---|---|---|
| 49 | Non-Base Plan Upgrades | Note I, Worksheets I & I1 | | Direct to Transmission | |
| 50 | **Gross ATRR** | | | | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Calculate Allocators**

| Line No. | Description | Notes | % Allocator |
|---|---|---|---|
| | **Wages & Salaries** | Note O | |
| 51 | Production | | |
| 52 | Transmission | | |
| 53 | Distribution | | |
| 54 | Customer/Other | | |
| 55 | Subtotal | | |
| 56 | A&G | | |
| 57 | Total | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Plant in Service** | Note M | Booked Total OPPD | SPP AI Adjustments | Assign Intangible | Plant Adjusted for SPP AI Definition | Transmission | Transmission Allocation % |
| | Plant in Service | | | | | | | |
| 58 | Transmission | Gross Transmission Plant Allocation | | | | | | |
| 59 | All Other | | | | | | | |
| 60 | Subtotal | | | | | | | |
| 61 | General & Intangible | Allocated on Gross Transmission Plant % | | | | | | |

| | | | |
|---|---|---|---|
| 62 | Electric & Intangible Plant * | | |
| | Accumulated Depreciation | | |
| 63 | Transmission | | |
| 64 | All Other | | |
| 65 | Subtotal | | |
| 66 | General & Intangible | Allocated to trans based on Gross Transmission Plant % | |
| 67 | Electric & Intangible Plant | | |
| | Net Plant | | |
| 68 | Transmission | Line 55 - Line 60 | |
| 69 | All Other | Line 56 - Line 61 | |
| 70 | Subtotal | | |
| 71 | General & Intangible | Line 58 - Line Line 63 | |
| 72 | Electric & Intangible Plant | Net Plant Allocator | |

| * Reconcile to OPPD 2007 Annual Report | | |
|---|---|---|
| | | Plant |
| 73 | Electric & Intangible Plant * | Line 59 |
| 74 | Expirmental & Plt for future use - 103,105 | |
| 75 | Completed Construction not Classified-106 | |
| 76 | Construction Work in Progress - 107 | |
| 77 | Electric Plant - Annual Report | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**

**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

| Note | **Notes** |
|---|---|

A The revenues credited include a) amounts received directly from the SPP for Point-to-Point transmission service where the demand is not included in the divisor, b) amounts from customers taking service under grandfathered agreements where the demand is not included in the rate divisor and c) imputed revenues related to short-term reservations of OPPD's merchant function. Revenue associated with Federal Energy Regulatory Commission annual charges, gross receipts taxes, ancillary services and facilities excluded from the Transmission Cost of Service are not included as revenue credits. Revenues from transmission customers whose coincident peak loads are included in the divisor of the load-ratio share calculation are not included as revenue credits. See Worksheet A for details.

B Includes income related only to transmission facilities. See Worksheet B for details.

C Base Plan Upgrades are calculated by applying the Base Plan Upgrade Fixed Charge Rate to the SPP-approved Base Plan Upgrade Plant. See Worksheet C, C1 and C2, etc. for details.

D Network Service coincident peaks is the utility's maximum monthly megawatt load for Requirements Service at the time of zonal coincident monthly peaks. Requirements Service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning) and includes OPPD's retail load and total requirements wholesale load. Long-term Point-to-Point includes long-term (greater than one year in duration) firm Point-to-Point transactions, including grandfathered reservations on OPPD's system and OPPD's marketing function long-term reservations. See Worksheet D for details.

E System control and load dispatch costs.

F Adjusts depreciation and amortization expense to reflect SPP Attachment AI plant adjustments. See Worksheet F for details.

G Revenue will be collected from both SPP load and grandfathered load. See Worksheet G for details.

H Includes all regulatory commission expenses that can be allocated to transmission (excluding Federal Energy Regulatory Commission Assessment Fees and Annual Charges - if applicable). Includes all safety-related advertising A&G expenses and General Plant accounts, and may be functionalized based on other methods rather than on wages and salaries. Full documentation must be provided. See Worksheet H for details.

I Additional revenue requirement for facilities receiving incentives. See Worksheet C1, C2 and I1 for details.

J The Federal Energy Regulatory Commission, in its Order No. 679 and No. 679-A, offers a 50-basis-point incentive adder for transmission owners joining an RTO as long as the return on equity for the transmission owner is within a zone of reasonableness. In order to be comparable with transmission owners in RTOs (including SPP), OPPD has included this 50-basis-point incentive adder in its revenue requirements.

K Removes cost of transmission service provided by others including OPPD account 565, department number 495, plus Western Area Power Administration transmission costs. Amount remaining is for facilities/maintenance costs on transmission. See Worksheet K for details.

L The Margin Requirement is the margin OPPD uses in calculating rates applicable to its native load customers. The Margin Requirement, in conjunction with depreciation and amortization expense, must cover OPPD principal payments, the minimum level of debt service coverage (ratio of net receipts to debt service) and an adequate return on equity to provide internally generated funds for OPPD's regular construction and working capital needs. Equity is also one of the factors contributing to OPPD's financial standing. OPPD sets its Margin Requirement based on a variety of financial ratios including Debt Service Coverage Ratio, Fixed Charge Ratio and earnings.

M Adjustments reflect the definition of transmission facilities under Attachment AI of the SPP tariff. Plant does not include Accounts 103, 105, 106 or 107, Experimental, Plant Held for Future Use, Completed Construction Not Classified and Construction Work in Progress, respectively, which are classified subsequent to the closing of the books for the year. OPPD does not have Common Plant.

N Removes transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.

O Wages and salaries expensed.

P Includes all interest expense.

Q Includes Payments in Lieu of Taxes and Iowa taxes.

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet A - Revenue Credits, Account 456**

**Detail of 456 - Transmission Wheeling Fees**

| | | | | | | Transmission Related Revenue | | | |
|---|---|---|---|---|---|---|---|---|---|
| Line No. | FERC Account | Description | Transmission | Other | Total | Revenue associated with billing units included in the Denominator | Revenue associated with BPU Charges | Transmission Revenue Credit | Total Transmission Revenue |
| 1 | | Scheduling Fees | | | | | | | |
| 2 | | Reactive | | | | | | | |
| 3 | | Regulation | | | | | | | |
| 4 | | Distribution Line | | | | | | | |
| 5 | | Distribution Subs | | | | | | | |
| 6 | | Transformers | | | | | | | |
| 7 | | Losses | | | | | | | |
| 8 | | Distribution Wheeling Fees (Direct) | | | | | | | |
| 9 | | MAPP F & SPP Revenue | | | | | | | |
| 10 | | Point-to-Point Firm (PTP) | | | | | | | |
| 11 | | Point-to-Point Non-Firm (NF PTP) | | | | | | | |
| 12 | 456 | | | | | | | | |

| | | |
|---|---|---|
| 13 | Add: Short-term OPPD Merchant PTP * | |
| 14 | **Revenue Credits** | |

* See Worksheet D (line 42) for details

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet B - Revenue Credits Rents, Account 454**

**Detail of 454 - Rent**

| Line No. | FERC Account | Description | Total | Other | Transmission Revenue Credit |
|---|---|---|---|---|---|
| 1 | 45416, 45417, 45419 | Rent | | | |
| 2 | 45412, 45413 | Allocated portion of general rent (1) | | | |
| 3 | All Other Sub Accts | Other | | | |
| 4 | 454 | **Rent Revenue Credits** | | | |

(1) Split based on Wages and Salaries. Allocator shown on page 3

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet C - BPU Fixed Charge Rate**

**Calculate Fixed Charge Rate (FCR) for Base Plan Upgrade Projects**

| Line No. | Description | Amount | Notes |
|---|---|---|---|

| | | | |
|---|---|---|---|
| 1 | OPPD Zonal Revenue Requirement (w/o incentive plant) | | Page 2, Line 46 |
| 2 | Less: Revenue Credits | | Page 1, Line 5 |
| 3 | Less: Depreciation Expense | | Page 2, Line 41 |
| 4 | Revenue Requirement w/o Depr | | |
| 5 | Net Plant | | Page 3, Line 72 |
| 6 | Net Rev Req w/o Depreciation | | Line 4 above |
| 7 | **BPU FCR** | | |

**Formula-based Rate Template**

**Omaha Public Power District (OPPD)**

**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet C1 - OPPD Base Plan Upgrade #1**

Facilities receiving incentives accepted by FERC in Docket No.

| Line No. | | | | | |
|---|---|---|---|---|---|
| | **Project Description:** | | | | |
| 1 | Investment | | Current Year | | |
| 2 | Service Year (yyyy) | | Incentive ROE increase (Basis Points) | | |
| 3 | Service Month (1-12) | | FCR w/o incentives, less depreciation | | |
| 4 | Useful life | | FCR w/ incentives approved for these facilities, less dep | | |
| 5 | CIAC (Yes or No) | | Annual Depreciation Expense | | |

| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | BPU Rev Req w/o Incentives | BPU Rev Req w/ incentives | Additonal ATRR for Incentives on Base Plan Upgrades |
|---|---|---|---|---|---|---|---|---|
| 6 | 0 | 1 | | | | | | |
| 7 | 1 | 2 | | | | | | |
| 8 | 2 | 3 | | | | | | |

| | | |
|---|---|---|
| 9 | 3 | 4 |
| 10 | 4 | 5 |
| 11 | 5 | 6 |
| 12 | 6 | 7 |
| 13 | 7 | 8 |
| 14 | 8 | 9 |
| 15 | 9 | 10 |
| 16 | 10 | 11 |
| 17 | 11 | 12 |
| 18 | 12 | 13 |
| 19 | 13 | 14 |
| 20 | 14 | 15 |
| 21 | 15 | 16 |
| 22 | 16 | 17 |
| 23 | 17 | 18 |
| 24 | 18 | 19 |
| 25 | 19 | 20 |
| 26 | 20 | 21 |
| 27 | 21 | 22 |
| 28 | 22 | 23 |
| 29 | 23 | 24 |
| 30 | 24 | 25 |
| 31 | 25 | 26 |
| 32 | 26 | 27 |
| 33 | 27 | 28 |
| 34 | 28 | 29 |
| 35 | 29 | 30 |
| 36 | 30 | 31 |
| 37 | 31 | 32 |
| 38 | 32 | 33 |
| 39 | 33 | 34 |
| 40 | 34 | 35 |
| 41 | 35 | 36 |
| 42 | 36 | 37 |
| 43 | 37 | 38 |

| | | |
|---|---|---|
| 44 | 38 | 39 |
| 45 | 39 | 40 |
| 46 | 40 | 41 |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet C2 - OPPD Base Plan Upgrade #2**

Facilities receiving incentives accepted by FERC in Docket No.

| Line No. | | | | | |
|---|---|---|---|---|---|
| | **Project Description:** | | | | |
| 1 | Investment | | Current Year | | |
| 2 | Service Year (yyyy) | | Incentive ROE increase (Basis Points) | | |
| 3 | Service Month (1-12) | | FCR w/o incentives, less depreciation | | |
| 4 | Useful life | | FCR w/ incentives approved for these facilities, less dep | | |
| 5 | CIAC (Yes or No) | | Annual Depreciation Expense | | |

| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | BPU Rev Req w/o Incentives | BPU Rev Req w/ incentives | Additonal ATRR for Incentives on Base Plan Upgrades |
|---|---|---|---|---|---|---|---|---|
| 6 | 0 | 1 | | | | | | |
| 7 | 1 | 2 | | | | | | |
| 8 | 2 | 3 | | | | | | |
| 9 | 3 | 4 | | | | | | |
| 10 | 4 | 5 | | | | | | |
| 11 | 5 | 6 | | | | | | |
| 12 | 6 | 7 | | | | | | |
| 13 | 7 | 8 | | | | | | |
| 14 | 8 | 9 | | | | | | |
| 15 | 9 | 10 | | | | | | |

| | | |
|---|---|---|
| 16 | 10 | 11 |
| 17 | 11 | 12 |
| 18 | 12 | 13 |
| 19 | 13 | 14 |
| 20 | 14 | 15 |
| 21 | 15 | 16 |
| 22 | 16 | 17 |
| 23 | 17 | 18 |
| 24 | 18 | 19 |
| 25 | 19 | 20 |
| 26 | 20 | 21 |
| 27 | 21 | 22 |
| 28 | 22 | 23 |
| 29 | 23 | 24 |
| 30 | 24 | 25 |
| 31 | 25 | 26 |
| 32 | 26 | 27 |
| 33 | 27 | 28 |
| 34 | 28 | 29 |
| 35 | 29 | 30 |
| 36 | 30 | 31 |
| 37 | 31 | 32 |
| 38 | 32 | 33 |
| 39 | 33 | 34 |
| 40 | 34 | 35 |
| 41 | 35 | 36 |
| 42 | 36 | 37 |
| 43 | 37 | 38 |
| 44 | 38 | 39 |
| 45 | 39 | 40 |
| 46 | 40 | 41 |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet D - Billing Units Divisor**

| Line No. | Month | Hour & Date for Network | Network Load: OPPD Load | Network Load: Less: Load in other SPP Zone (6) | Network Load: Plus: Network WS Load Less WAPA (4) | Network Load: Total Network Load | LTPTP Reservations - Grandfathered: Misc WAPA Deliveries in OPPD's CA (1) | LTPTP Reservations - Grandfathered: NPPD (2) | LTPTP Reservations - Grandfathered: LES (3) | LTPTP Reservations - Grandfathered: OPPD (5) | LTPTP Reservations - Grandfathered: Total LTPTP | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Jan | | | | | | | | | | | |
| 2 | Feb | | | | | | | | | | | |
| 3 | Mar | | | | | | | | | | | |
| 4 | Apr | | | | | | | | | | | |
| 5 | May | | | | | | | | | | | |
| 6 | June | | | | | | | | | | | |
| 7 | Jul | | | | | | | | | | | |
| 8 | Aug | | | | | | | | | | | |
| 9 | Sept | | | | | | | | | | | |
| 10 | Oct | | | | | | | | | | | |
| 11 | Nov | | | | | | | | | | | |
| 12 | Dec | | | | | | | | | | | |
| 13 | Total | | | | | | | | | | | |
| 14 | 12 CP Average | | | | | | | | | | | |
| 15 | Avg of LTPTP Res | | | | | | | | | | | |
| 16 | **Total Billing Units to Page 1** | | | | | | | | | | | |

(1) Auburn, Fremont, Falls City, Nebraska City Utilities, Peru, Syracuse, Tecumseh,

UNO

(2) Nehawka, Plattsmouth, Verden & OASIS numbers 1296314, 1296321

(3) OASIS numbers 575883, 71115703

(4) Calculate Wholesale Network Load w/o WAPA. See Lines 17 - 29 below.

Calculate Wholesale NW Load - MW

| | | Total WS Load | Less: Syracuse - WAPA | Less: Tecumseh - WAPA | Total |
|---|---|---|---|---|---|
| 17 | Jan | | | | |
| 18 | Feb | | | | |
| 19 | Mar | | | | |
| 20 | Apr | | | | |
| 21 | May | | | | |
| 22 | June | | | | |
| 23 | July | | | | |
| 24 | Aug | | | | |
| 25 | Sept | | | | |
| 26 | Oct | | | | |
| 27 | Nov | | | | |
| 28 | Dec | | | | |
| 29 | Total MW | | | | |

(5) Detail of OPPD Marketing Transactions. See lines 30 - 42 below

OPPD Marketing Long-Term Transactions

| | OASIS # | 882824 | 1259288 | 71081671 & 899323 | 71248077 & 902662 | Total |
|---|---|---|---|---|---|---|
| 30 | Jan | | | | | |
| 31 | Feb | | | | | |
| 32 | Mar | | | | | |
| 33 | Apr | | | | | |
| 34 | May | | | | | |
| 35 | June | | | | | |
| 36 | July | | | | | |
| 37 | Aug | | | | | |
| 38 | Sept | | | | | |
| 39 | Oct | | | | | |

OPPD Marketing Short-Term Transactions

| | Hourly | Daily | Weekly | Monthly |
|---|---|---|---|---|
| PTP-Firm | | | | |
| PTP Non-Firm | | | | |
| PTP-Firm | | | | |
| PTP Non-Firm | | | | |
| PTP-Firm | | | | |
| PTP Non-Firm | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 40 | Nov | | | | | | |
| 41 | Dec | | | | | Total All Short-Term Transactions | |
| 42 | Total | - | - | - | - | - | |

(6) Steinauer, Wahoo and North Bend Network Load in NPPD's Zone

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet E - ARR for Ancillary Service #1 - Scheduling System Control & Dispatch**

| Line No. | FERC Account | Description | Amount |
|---|---|---|---|
| | | **Determine Scheduling, System Control & Dispatch Cost** | |
| 1 | 561 | Load Dispatching | |
| 2 | 556 | System Control & Load Dispatch | |
| 3 | | **Total ATRR for AS#1** | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet F - OPPD Depreciation Expense Adjustment Detail**

| Line No. | Function | As Booked | Intangible Plant Depreciation Exp | SPP AI - Lines & Subs | SPP AI - Generator Leads & Step-Ups | Total Depr Exp Adjustment | Adjusted Depreciation Expense |
|---|---|---|---|---|---|---|---|
| 1 | Production | | | | | | |

| | | |
|---|---|---|
| 2 | Transmission | |
| 3 | Distribution | |
| 4 | General | |
| 5 | Intangible | |
| 6 | Total | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**

**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet G - OPPD Revenue Summary**
**Based on Proposed Rates & Historic Billing Units**

| Line No. | Description | SPP Rates | GFA Rates | BPU Rates | Total System |
|---|---|---|---|---|---|
| 1 | Billing Units (Avg MW) | | | | |
| 2 | Rates | | | | |
| 3 | Total Revenue | | | | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet H - OPPD Account 930 Details**
Descriptions are from OPPD's Accounting Manual

| Line No. | Account No. | Description | Amount |
|---|---|---|---|
| 1 | 930.01 | Corporate Notices & Fees | |

| | | | |
|---|---|---|---|
| 2 | 930.02 | Industry Association/Corporate Communications | |
| 3 | 930.03 | Miscellaneous General Expenses | |
| 4 | | Total Account 930 | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet I - Fixed Charge Rate w/o Incentive for Non-Base Plan Upgrade**

| Line No. | Description | Transmission Amount | % Debt Equity | Notes |
|---|---|---|---|---|
| | **Calculate Fixed Charge Rate (FCR) without Incentive Return** | | | |
| 1 | Required Revenue w/o Incentive Return | | | Page 2, Line 45 |
| 2 | Less: Revenue Credits | | | Page 1, Line 5 |
| 3 | Less: Depreciation Expense | | | Page 2, Line 41 |
| 4 | Revenue Requirement w/o Depr | | | |
| 5 | Net Plant | | | Page 3, Line 69 |
| 6 | Net Rev Req w/o Depreciation | | | Line 4 above |
| 7 | FCR w/o Incentive | | | |
| | **Calculate Equity %** | | | |
| 8 | Long-term Debt * | | | OPPD Financials |
| 9 | Equity | | | OPPD Financials |
| 10 | Total | | | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet I1 - OPPD Incentive Plant #1 for Non-Base Plan Upgrades**

Facilities receiving incentives accepted by FERC in Docket No.

| Line No. | **Project Description:** | | | Amounts |
|---|---|---|---|---|
| 1 | Investment | | Current Year | |
| 2 | Service Year (yyyy) | | Incentive ROE increase (Basis Points) | |
| 3 | Service Month (1-12) | | FCR w/o incentives, less depreciation | |
| 4 | Useful life | | FCR w/ incentives approved for these facilities, less dep | |
| 5 | CIAC (Yes or No) | | Annual Depreciation Expense | |
| 6 | | | | |

| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | BPU Rev Req w/o Incentives | BPU Rev Req w/ incentives | Additional Revenue Requirement |
|---|---|---|---|---|---|---|---|---|
| 7 | 0 | 1 | | | | | | |
| 8 | 1 | 2 | | | | | | |
| 9 | 2 | 3 | | | | | | |
| 10 | 3 | 4 | | | | | | |
| 11 | 4 | 5 | | | | | | |
| 12 | 5 | 6 | | | | | | |
| 13 | 6 | 7 | | | | | | |
| 14 | 7 | 8 | | | | | | |
| 15 | 8 | 9 | | | | | | |
| 16 | 9 | 10 | | | | | | |
| 17 | 10 | 11 | | | | | | |
| 18 | 11 | 12 | | | | | | |
| 19 | 12 | 13 | | | | | | |
| 20 | 13 | 14 | | | | | | |
| 21 | 14 | 15 | | | | | | |
| 22 | 15 | 16 | | | | | | |
| 23 | 16 | 17 | | | | | | |
| 24 | 17 | 18 | | | | | | |
| 25 | 18 | 19 | | | | | | |
| 26 | 19 | 20 | | | | | | |
| 27 | 20 | 21 | | | | | | |
| 28 | 21 | 22 | | | | | | |
| 29 | 22 | 23 | | | | | | |
| 30 | 23 | 24 | | | | | | |

| | | |
|---|---|---|
| 31 | 24 | 25 |
| 32 | 25 | 26 |
| 33 | 26 | 27 |
| 34 | 27 | 28 |
| 35 | 28 | 29 |
| 36 | 29 | 30 |
| 37 | 30 | 31 |
| 38 | 31 | 32 |
| 39 | 32 | 33 |
| 40 | 33 | 34 |
| 41 | 34 | 35 |
| 42 | 35 | 36 |
| 43 | 36 | 37 |
| 44 | 37 | 38 |
| 45 | 38 | 39 |
| 46 | 39 | 40 |
| 47 | 40 | 41 |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective**
_____

**Worksheet J - SPP RTO Incentive Adder**

| Line No. | Description | Amount | Equity % |
|---|---|---|---|
| | **Calculate Premium for Joining an RTO** | | |
| | (Plant based on 2006 data) | | |
| 1 | Transmission Plt | | |
| 2 | Allocated Share of General | | |
| 3 | Total Plant | | |
| 4 | X Equity Ratio | | |
| 5 | X 50 Basis Point Premium | 0.0050 | |
| | Premium $$ | | |

**Calculate Equity %**

(Based on 2007 Balance Sheet)

| | | |
|---|---|---|
| 6 | Long-term Debt | |
| 7 | Equity | |
| 8 | Total | |

**Formula-based Rate Template**
**Omaha Public Power District (OPPD)**
**Using _____ Actual Financial & Operating Data for Southwest Power Pool (SPP) Rates Effective _____**

**Worksheet K - Account 565 Transmission by Others**

| Line No. | Account No. | Description | | Amount |
|---|---|---|---|---|
| 1 | 565 | Account Total | | |
| | | Less: Transmission by Others | | |
| 2 | | Trans service in MAPP, MISO, SPP, WAPA | | |
| 3 | | Other | | |
| 4 | | Total Transmission by Others | | |
| 5 | | Portion of Account 565 Included in Transmission Rates | | |

# Addendum 9 to Attachment H



Rate Formula Template
Utilizing FERC Form 1 Data

Enter whether Actuals or Projected Data
For the 12 months ended

**ITC-Great Plains, LLC.**

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | | | Allocated Amount |
| 1 | GROSS REVENUE REQUIREMENT | (line 78) | | 12 months | $ - |
| 2 | REVENUE CREDITS | | Total | | |
| 3 | Account No. 454 and 456 | (Notes G and M) (Line 99) | - | | - |
| 4 | Account No. 456.1 | (Line 102) | - | | - |
| 5 | Net Revenue Requirement | [line 1 - (lines 3 & 4)] | | | - |
| 6 | Under(Over)True-up Adjustment w interest | (Attach 1, line 69) | | | - |
| 7 | Incentives | (Attach 1, line 24) | | | - |
| 8 | Total Revenue Requirement | | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data

Enter whether Actuals or Projected Data
For the 12 months ended

**ITC-Great Plains, LLC.**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. Note N | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE | (Note J) | | | | |
| 9 | Production | (Wksht 2) | - | NA | 0.00000 | - |
| 10 | Transmission (Note L) | (Wksht 1) | - | T | 1.00000 | - |
| 11 | Distribution | (Wksht 2) | - | NA | 0.00000 | - |
| 12 | General & Intangible | (Wksht 2) | - | W/S | 0.00000 | - |
| 13 | Line deliberately left blank | | | | | |
| 14 | TOTAL GROSS PLANT (sum lines 9-13) | | - | GP= | 0.000% | - |
| | ACCUMULATED DEPRECIATION and AMORTIZATION | (Note J) | | | | |
| 15 | Production | (Wksht 2) | - | NA | 0.00000 | - |
| 16 | Transmission (Note L) | (Wksht 1) | - | T | 1.00000 | - |
| 17 | Distribution | (Wksht 2) | - | NA | 0.00000 | - |
| 18 | General & Intangible | (Wksht 2) | - | W/S | 0.00000 | - |
| 19 | Line deliberately left blank | | | | | |
| 20 | TOTAL ACCUM. DEPR & AMORT (sum lines 15-19) | | - | | | - |
| | NET PLANT IN SERVICE | | | | | |
| 21 | Production | (line 9- line 15) | - | | | - |
| 22 | Transmission | (line 10- line 16) | - | | | - |
| 23 | Distribution | (line 11- line 17) | - | | | - |
| 24 | General & Intangible | (line 12- line 18) | - | | | - |
| 25 | Line deliberately left blank | | | | | |
| 26 | TOTAL NET PLANT (sum lines 21-25) | | - | NP= | 0.000% | - |
| | ADJUSTMENTS TO RATE BASE (Note A) | | | | | |
| 27 | Account No. 281 (enter negative) | (Wksht 5) | - | NA | 0.00000 | - |
| 28 | Account No. 282 (enter negative) | (Wksht 5) | - | NP | 0.00000 | - |
| 29 | Account No. 283 (enter negative) | (Wksht 5) | - | NP | 0.00000 | - |
| 30 | Account No. 190 | (Wksht 5) | - | NP | 0.00000 | - |
| 31 | Account No. 255 (enter negative) | (Wksht 5) | - | NP | 0.00000 | - |
| 32 | Transmission CWIP | (Wksht 1) | - | T | 1.00000 | - |
| 33 | Unamortized Regulatory Asset - Start Up & Development | (Wksht 2) (Note U) | - | T | 1.00000 | - |
| 34 | Unamortized Regulatory Asset - Project | (Attach 1) (Notes L and U) | - | T | 1.00000 | - |
| 35 | Unamortized Abandoned Plant | (Attach 1) (Notes L and U) | 0 | T | 1.00000 | 0 |
| 36 | TOTAL ADJUSTMENTS (sum lines 27-35) | | - | | | - |
| 37 | LAND HELD FOR FUTURE USE (Note G) | (Wksht 5) | - | T | 1.00000 | - |
| | WORKING CAPITAL (Note C) | | | | | |
| 38 | CWC | (1/8 * line 53) | - | | (1/8 * line 53) | - |
| 39 | Materials & Supplies (NOTE B) | (Wksht 5) | - | T | 1.00000 | - |
| 39a | Customer Funded Reserves (enter negative) | Note P | 0 | | | 0 |
| 40 | Prepayments (Account 165) (Note O) | (Wksht 5) | - | GP | 0.00000 | - |
| 41 | TOTAL WORKING CAPITAL (sum lines 38-40) | | - | | | - |
| 42 | RATE BASE (sum lines 26, 36, 37, & 41) | | - | | | - |

Rate Formula Template
Utilizing FERC Form 1 Data

Enter whether Actuals or Projected Data
For the 12 months ended

**ITC-Great Plains, LLC.**

| | (1) | (2) | (3) | | (4) | (5) |
|---|---|---|---|---|---|---|
| | | **Form No. 1 Page, Line, Col.** | **Company Total** | **Allocator** | | **Transmission** (Col 3 times Col 4) |
| | O&M Note N | | | | | |
| 43 | Transmission Less Amortization in Lines 43 a & b (Note K) | 321.112.b less 43a & b; Note S | - | T | 1.00000 | - |
| 43a | Amortization of Regulatory Asset - Start Up & Development | FERC Order (Note U) | - | T | 1.00000 | - |
| 43b | Amortization of Regulatory Asset - Project | (Wksht 1) (Note U) | - | T | 1.00000 | - |
| 44 | Less Account 565 | 321.96.b | - | T | 1.00000 | - |
| 45 | A&G | 323.197.b | - | W/S | 0.00000 | - |
| 46 | Less FERC Annual Fees | (Wksht 6, line 3) | - | W/S | 0.00000 | - |
| 47 | Less EPRI & Reg. Comm. Exp. & Other (Note D & Wksht 6) | (Wksht 6, lines 1,2,9) | - | W/S | 0.00000 | - |
| 48 | Less PBOP expenses in Year | (Wksht 6) | - | W/S | 0.00000 | - |
| 49 | Plus Transmission Related Reg. Comm. Exp. (Note D & Wksht 6) | (Wksht 6, line 5) | - | W/S | 0.00000 | - |
| 50 | Plus PBOP expense allowed amount | (Wksht 6) | - | W/S | 0.00000 | - |
| 51 | Line deliberately left blank | | | | | |
| 52 | Line deliberately left blank | | | | | |
| 53 | TOTAL O&M (sum lines 43, 43a, 43b, 45, & 49 to 52 less lines 44, & 46 to 48) | | - | | | - |
| | DEPRECIATION EXPENSE Note N | (Note J) | | | | |
| 54 | Transmission (Note L) | 336.7.f | - | T | 1.00000 | - |
| 55 | General and Intangible | 336.1.f & 336.10.f | - | W/S | 0.00000 | - |
| 56 | Line deliberately left blank | | | | | |
| 57 | Amortization of Abandoned Plant | (Attach 1) (Notes L and U) | 0 | T | 1.00000 | 0 |
| 58 | TOTAL DEPRECIATION (Sum lines 54-57) | | - | | | - |
| | TAXES OTHER THAN INCOME TAXES (Note E) | Note N | | | | |
| 59 | LABOR RELATED | | | | | |
| 60 | Payroll | 263.i | - | W/S | 0.00000 | - |
| 61 | Highway and vehicle | 263.i | - | W/S | 0.00000 | - |
| 62 | PLANT RELATED | | | | | |
| 63 | Property | 263.i | - | GP | 0.00000 | - |
| 64 | Gross Receipts | 263.i | - | DA | 1.00000 | - |
| 65 | Other | 263.i | - | GP | 0.00000 | - |
| 66 | Line deliberately left blank | | | | | |
| 67 | TOTAL OTHER TAXES (sum lines 60-66) | | - | | | - |
| | INCOME TAXES | (Note F) | | | | |
| 68 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | |
| 69 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.00% | | | |
| 70 | where WCLTD=(line 95) and R= (line 98) | | | | | |
| 71 | and FIT, SIT & p are as given in footnote F. | | | | | |
| 72 | 1 / (1 - T) = (T from line 68) | | 0.0000 | | | |
| 73 | Amortized Investment Tax Credit (266.8f) (enter negative) | | 0 | | | |
| 73a | (Excess)/Deficient Deferred Income Taxes (Note V) | | | | | |
| 74 | Income Tax Calculation = line 69 * line 77 | | 0 | Calculated | | - |
| 75 | ITC adjustment (line 72 * line 73) | | 0 | NP | 0.00000 | - |
| 75a | (Excess)/Deficient Deferred Income Tax Adjustment | (line 72 * line 73a) | 0 | NP | 0.00000 | - |
| 76 | Total Income Taxes | (line 74 plus line 75 plus line 75a) | 0 | | | - |
| | RETURN | | | | | |
| 77 | [ Rate Base (line 42) * Rate of Return (line 98)] | | 0 | Calculated | | - |
| 78 | REV. REQUIREMENT (sum lines 53, 58, 67, 76, 77) | | 0 | | | - |

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | Enter whether Actuals or Projected Data For the 12 months ended

**ITC-Great Plains, LLC.**

79 SUPPORTING CALCULATIONS and NOTES

WAGES & SALARY ALLOCATOR (W&S)

| | | Form 1 Reference | $ | Transmission | | W&S Allocator ($ / Allocation) |
|---|---|---|---|---|---|---|
| 81 | Production | 354.20.b | 0 | | | |
| 82 | Transmission | 354.21.b | 0 | 0 | | |
| 83 | Distribution | 354.23.b | 0 | | | |
| 84 | Other | 354.22, 24, & 25.b | 0 | | | |
| 85 | Total (sum lines 81-84) [WS equals 1 if there are no wages & salaries] | | 0 | 0 | = | 0.00000 |
| 85a | | | | | | =W/S |

86 Line deliberately Left
87 Line deliberately Left
88 Line deliberately Left
89 Line deliberately Left
90 Line deliberately Left
91 Line deliberately Left

RETURN (R)

| | | | | | | $ |
|---|---|---|---|---|---|---|
| 92 | | Long Term Interest | (Wrksht 3, line 33) | | | - |
| 93 | | Preferred Dividends (118.29.c) (positive number) | | | | - |
| 94 | | Common Stock | (Wksht 3) | | | 0 |

| | | | $ | % | Cost | | Weighted |
|---|---|---|---|---|---|---|---|
| 95 | Long Term Debt (Note T) | (Wksht 3) | | | 0.0000 | WCLTD= | |
| 96 | Preferred Stock | (Wksht 3) | | | 0.0000 | | |
| 97 | Common Stock (line 94) (Note I) | (line 94) | | | 0.1141 | | |
| 98 | Total (sum lines 95 - 97) | | 0 | | | R= | |

REVENUE CREDITS

| | | | | | |
|---|---|---|---|---|---|
| | | | | 0 | |
| 99 | ACCOUNT 454 and 456 (RENT and OTHER ELEC REVENUE) | Notes G and M | (Wksht 6, line 30) | Input to line 3 | - |
| | ACCOUNT 456.1 (REVENUES FROM TRANSMISSION FOR OTHERS) | | (330.x.n); Note S | | |
| 100 | a. Transmission charges for all transmission transactions | | | | |
| 101 | b. Transmission charges for all transmission transactions under this formula that are not revenue credited | | | | |
| 102 | Total of (a)-(b) | | | Input to line 4 | - |

Note: Line 100 includes Sch 1 revenue, if any, and line 101 does not include Sch 1 revenue except as provided for in Note S. All revenues will be credited that reflect facilities or expenses included in the formula, if the underlying charges are not developed in the formula and shown on Attachment 1.

**SUPPORTING CALCULATIONS AND NOTES**
Rate Formula Template

Utilizing FERC Form 1 Data

Enter whether Actuals or Projected Data

For the 12 months ended

**ITC-Great Plains, LLC.**

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

| Note Letter | |
|---|---|
| A | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.<br>Deferred taxes exclude deferred taxes on true-up, regulatory assets, goodwill, facilities, or premium on asset acquisitions unless the underlying amount is included in rate base. |
| B | Identified in Form 1 as being only transmission related. |
| C | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission<br>Prepayments are the electric related prepayments booked to Account No. 165. |
| D | EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, advertising except safety related and education and outreach related advertising included in Account 930.1. Line 47 - Regulatory Commission Expenses directly related to transmission service, ISO/RTO filings, or transmission siting itemized at 351.h.<br>All EEI lobbying expenses and EPRI industry association dues shall be excluded from the costs recoverable under the Formula Rate.<br>EEI or EPRI research, development and demonstration<br>expenses associated with projects in which transmission customers can voluntarily participate shall be recovered under the Formula Rate<br>only up to a maximum annual aggregate amount of $100,000. |
| E | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.<br>Taxes related to income are excluded. Gross receipts taxes that are retail related are not included in transmission revenue requirement. |
| F | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (line 110).<br>For each Rate Year (including both Annual Projections and True-Up Adjustments) the statutory income tax rates utilized in the Formula<br>Rate shall reflect the weighted average rates actually in<br>effect during the Rate Year. For example, if the statutory tax rate is 10% from January 1 through June 30, and 5% from July 1 through<br>December 31, such rates would be weighted 181/365 and 184/365, respectively. |

| Inputs Required: | | | |
|---|---|---|---|
| | FIT = | 0.00% | |
| | SIT= | 0.00% | (State Income Tax Rate or Composite SIT from Wksht 6) |
| | p = | 0.00% | (percent of federal income tax deductible for state purposes) |

| | |
|---|---|
| G | Transmission related. |
| H | Note Deliberately left blank |
| I | ROE is fixed and no change in ROE may be made absent a filing with FERC.<br>Equity ratio shall be capped so as not to exceed sixty percent (60%), calculated on the basis of a 13 month average. Long term debt<br>percentage will be adjusted so that the capitalization ratio shall always equal 100. |
| J | Excludes amounts related to Asset Retirement Obligations. Depreciation rates are shown on Wksht 4 and do not change absent a filing with FERC. |
| K | The amortization for all regulatory assets will be booked to Account 566 |
| L | All transmission plant, transmission accumulated depreciation, CWIP, Unamortized Regulatory Asset--Project, Unamortized Abandoned Plant, transmission depreciation expense, Amortization of Regulatory Asset-Project, and Amortization of abandoned plant must be broken out by project on Attachment 1 and the applicable Wkshts.<br>Accordingly, the "T" allocator is equal to 1.00000. |
| M | Rent credits and credits for Other revenues exclude credits for facilities or expenses whose costs are not included in the formula rate. |
| N | ITC shall not seek rate recovery of payments to other Transmission Owners or their affiliates, other than payments for services rendered or assets acquired at net book value, without approval to recover those payments pursuant to a Section 205 filing. |
| O | Prepaid Pension Expense costs shall be excluded from rate base whether recorded in Account 165--Prepayments or in another account. |
| P | ITC will make a Section 205 filing for authority to create any Customer-Funded Reserve, and include a credit to rate base for any such Customer-Funded Reserves. |
| Q | Deferred income taxes directly related to transmission plant will be identified by project in Line 9a of Attachment 1. The balance of the ADIT will be allocated in distributed charges in Line 21 of Attachment 1. |
| R | The cost of projects for plant excluded from rate base, e.g., direct assignment facilities under SPP OATT Attachment AI, generator interconnections and generator step-up substations, will be shown as separate projects on Attachment 1 and thus excluded from rate base and revenue requirement of other projects. |
| S | Any revenues associated with costs in Accounts 561-561.8 will either offset the expenses or be revenue credited. pursuant to FERC Docket ER09-548 Settlement Terms, Section II. C. 1 |
| T | The Formula Rate shall include the annual amortization of gains and losses resulting from interest rate hedging; provided that the net cost (or cost reduction due to net gains) shall be limited in True-Up calculations so as not to exceed 6 basis points in the weighted average cost of capital. To determine the includable hedging costs or gains, ITC will multiply the total 3-component capitalization (LTD, PS and CS) by 0.0006, and compare the result to the hedging cost or gain amount amortized in the year. |
| U | The Formula Rate shall not recover any charges associated with a Regulatory Asset or Abandoned Plant until a filing is made under FPA Section 205 seeking to recover such charges and recovery has been authorized by the Commission. |
| V | Includes the amortization of any excess/deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority. The excess and deficient deferred income tax adjustment (page 3, line 75a) will reduce or increase income tax expense by the amount of the excess or deficiency (page 3, line 73a) multiplied by (1/1-T). |

ITC Great Plains, LLC
Cost Year
Trued Up Year
Attachment 1
Revenue Requirement by Project

| | | | (a) Project #1 | (b) Project #2 | (c) Project #3 | (d) Project #4 | (e) Project #5 | (f) Project #6 | (g) Project #7 | (h) Project #8 | (i) Project #9 | (j) Project #10 | (k) Project #11 | (h) Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Project Designation | Source | | | | | | | | | | | | |
| 2 | Project Name | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 3 | Attach H? (Yes or No) | Note R | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 4 | Transmission Gross Plant in Service | (Wksht 1, line 45) | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | Transmission Accumulated Depreciation | (Wksht 1, line 90) | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | Transmission Net Plant | (line 4 less line 5) | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | CWIP | (Wksht 1, line 105) | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | Regulatory Asset - Project | (Wksht 1, line 120) | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Unamortized Abandoned Plant | (Wksht 1, line 136) | - | - | - | - | - | - | - | - | - | - | - | - |
| 9a | Accumulated Deferred Income Taxes | Note Q & (Wksht 1, line 152) | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | Net Plant & CWIP | (sum lines 6 - 9a) | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | Return | (Attach H, line 98 * line 10) | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | Taxes | (Attach H, line 69 * line 11) | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | Depreciation | Total = (Attach H, line 54) | | | | | | | | | | | | - |
| 14 | Amortization of Regulatory Asset - Project | (Wksht 1, line 121) | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | Line deliberately left blank | | | | | | | | | | | | | |
| 16 | Amortization Abandoned Plant | (Wksht 1, line 137) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Direct Charges | (sum lines 11 - 16) | - | - | - | - | - | - | - | - | - | - | - | - |
| 18 | Net Revenue Requirement | (Attach H, line 5) | | | | | | | | | | | | - |
| 19 | Gross Plant including Investment for CIACs | (Wksht 1, line 15) | - | - | - | - | - | - | - | - | - | - | - | - |
| 20 | Relative % of Gross Plant and CIAC | (Column line 19 / Total line 19) | | | | | | | | | | | | |
| 21 | Distributed Charges | (Total is line 18 less line 17, Total * line 20) | - | - | - | - | - | - | - | - | - | - | - | - |
| 22 | Revenue Requirement before Incentives | (line 17 + line 21) | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | ROE Incentive Adder | (in Basis Points per FERC order for project) | | - | - | - | - | - | - | - | - | - | - | |
| 24 | Incentive | (line 10 * line 23 * Attach H % Equity line 97 * Attach H line 72) | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | Revenue Requirement with Incentives | (line 22 + line 24) | - | - | - | - | - | - | - | - | - | - | - | - |

Note: lines 8, 9, 14 & 16 cannot change absent FERC order

True-up Instructions

The True-up Adjustment is the difference between the Net Revenue Requirement for that year and the actual Revenues for the Prior Year

| | | | | Project #1 | Project #2 | Project #3 | Project #4 | Project #5 | Project #6 | Project #7 | Project #8 | Project #9 | Project #10 | Project #11 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26 | Project Designation | Source | | | | | | | | | | | | | |
| 27 | Project Name | (Attach 1, line 2) | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| 28 | Attach H? (Yes or No) | (Attach 1, line 3) | | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A | |
| | True-Up Calculation for Actuals Year only | | 0 | | | | | | | | | | | | |
| 29 | Revenue Requirement before incentives H | (line 22) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 30 | Rev Reqmnt before incentives--non base formula rate | (line 22) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 31 | Subtotal | (line 29 + line 30) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 32 | Revenue Requirement--incentives H | (line 24) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 33 | Revenue Requirement--incentives non-base | (line 24) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 34 | Total | (sum lines 31 to 33) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | Actual Revenues--base formula rate H | 330.n (Note 1) | | | | | | | | | | | | | - |
| 36 | Actual Revenues--non base formula | 330.n (Note 1) | | - | - | - | - | - | - | | | | | | - |
| 37 | Subtotal | (line 35 + line 36) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 38 | Actual Revenues--Incentives H | 330.n (Note 1) | | | | | | | | | | | | | - |
| 39 | Actual Revenues--Incentives non-base | 330.n (Note 1) | | | | | | | | | | | | | - |
| 40 | Total | (sum lines 37 to 39) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 41 | Under(Over) True-Up Adj before Incentives H | (line 29 - line 35) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 42 | Under(Over) True-Up Adj--non base formula rate | (line 30 - line 36) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 43 | Subtotal | (line 41 + line 42) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 44 | Under(Over) True-Up Adj incentives H | (line 32 - line 38) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 45 | Under(Over) True-Up incentives non-base | (line 33 - line 39) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 46 | Total | (sum lines 43 to 45) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 47 | Interest Rate Base Under(Over) | (Wksht 7) | | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% | |
| 48 | Months | Note 2 | | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | 24 | |
| 49 | Interest True-Up before incentives H | (line 47 * line 41 * line 48) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 50 | Interest True-Up non base formula rate | (line 47 * line 42 * line 48) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 51 | Subtotal | (line 49 + line 50) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 52 | Interest True-Up Incentives H | (line 47 * line 44 * line 48) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 53 | Interest True-Up Incentives non-base | (line 47 * line 45 * line 48) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 54 | Total | (sum lines 51 to 53) | | - | - | - | - | - | - | - | - | - | - | - | - |
| 55 | Under(Over) with Interest base H | (line 41 + line 49) | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 56 | Under(Over) with Interest non-base | (line 42 + line 50) | - | - | - | - | - | - | - | - | - | - | - | - |
| 57 | Subtotal | (line 55 + line 56) | - | - | - | - | - | - | - | - | - | - | - | - |
| 58 | Under(Over) with Interest incentives H | (line 44 + line 52) | - | - | - | - | - | - | - | - | - | - | - | - |
| 59 | Under(Over) with Interest incentives non-base | (line 45 + line 53) | - | - | - | - | - | - | - | - | - | - | - | - |
| 60 | Total | (sum lines 57 to 59) | - | - | - | - | - | - | - | - | - | - | - | - |
| | Projected Charge Calculation for Projected Only | | | | | | | | | | | | | |
| 61 | Projected Net Revenue Requirement--Attach H | Projected Attach H | | | | | | | | | | | | - |
| 62 | Projected Net Revenue Requirement--non-Attach H | Projected Attach H | | | | | | | | | | | | - |
| 63 | Subtotal | (line 61 + line 62) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 64 | Projected Incentive--Attach H | Projected Attach H | | | | | | | | | | | | - |
| 65 | Projected Incentive--non-Attach H | Projected Attach H | | | | | | | | | | | | - |
| 66 | Subtotal | (line 64 + line 65) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 67 | True-Up Adjustment--Attach H | (line 55 + line 58) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 68 | True-Up Adjustment--non-Attach H | (line 56 + line 59) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 69 | Subtotal | (line 67 + line 68) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 70 | Total Charges Attach H Projected | (sum lines 61, 64 & 67) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 71 | Total Charges Non-Attach H Projected | (sum lines 62, 65 & 68) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 72 | Total Charges | (line 70 + line 71) (Note 3 & 4) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |

(1) Actual Transmission Revenues as reported on Form 1, page 330 corresponding to Actual Net Revenue Requirement for services recovered through formula rate (projects shown here on Attachment 1). Actual Revenues do not include revenues treated as revenue credits in the formula, revenue from incentives (except for incentive true-up), and true-ups under the formula, but do include adjustments including out-of-period adjustments.
Actual Revenues shall be adjusted to add back Unpaid Obligations that otherwise reduce reported revenues.

(2) The number of months is equal to the sum of:
1/2 of the number of months during the period the over or under collection occurred, plus
The number of months between the last month in which the over or under collection occurred and the first month of the refund or surcharge for the over or under collection, plus
1/2 the number of months during the period the over or under collection is refunded or surcharged.

(3) Note deliberately left blank.

(4) SPP is required to design their charges such that the projected and trued-up revenue requirement for each project contained herein is recovered for each year in each year.

ITC Great Plains, LLC
Cost Year
Trued Up Year
Worksheet 1
13 Month Balances

| | | | | Source | (a) Proj #1 N/A | (b) Proj #2 N/A | (c) Proj #3 N/A | (d) Proj #4 N/A | (e) Proj #5 N/A | (f) Proj #6 N/A | (g) Proj #7 N/A | (h) Proj #8 N/A | (i) Proj #9 N/A | (j) Proj #10 N/A | (k) Proj #11 N/A | (l) Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Plant in Service--Transmission before Contributions in Aid of Construction (CIAC) | | | | | | | | | | | | | | | |
| 2 | Dec | 2008 | p207.58 | | | | | | | | | | | | | - |
| 3 | Jan | 2009 | Company records | | | | | | | | | | | | | - |
| 4 | Feb | 2009 | Company records | | | | | | | | | | | | | - |
| 5 | Mar | 2009 | Company records | | | | | | | | | | | | | - |
| 6 | Apr | 2009 | Company records | | | | | | | | | | | | | - |
| 7 | May | 2009 | Company records | | | | | | | | | | | | | - |
| 8 | Jun | 2009 | Company records | | | | | | | | | | | | | - |
| 9 | Jul | 2009 | Company records | | | | | | | | | | | | | - |
| 10 | Aug | 2009 | Company records | | | | | | | | | | | | | - |
| 11 | Sep | 2009 | Company records | | | | | | | | | | | | | - |
| 12 | Oct | 2009 | Company records | | | | | | | | | | | | | - |
| 13 | Nov | 2009 | Company records | | | | | | | | | | | | | - |
| 14 | Dec | 2009 | p207.58 | | | | | | | | | | | | | - |
| 15 | Avg | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | Plant in Service--Transmission CIAC | | | | | | | | | | | | | | | |
| 17 | Dec | 2008 | p207.58 | | | | | | | | | | | | | - |
| 18 | Jan | 2009 | Company records | | | | | | | | | | | | | - |
| 19 | Feb | 2009 | Company records | | | | | | | | | | | | | - |
| 20 | Mar | 2009 | Company records | | | | | | | | | | | | | - |
| 21 | Apr | 2009 | Company records | | | | | | | | | | | | | - |
| 22 | May | 2009 | Company records | | | | | | | | | | | | | - |
| 23 | Jun | 2009 | Company records | | | | | | | | | | | | | - |
| 24 | Jul | 2009 | Company records | | | | | | | | | | | | | - |
| 25 | Aug | 2009 | Company records | | | | | | | | | | | | | - |
| 26 | Sep | 2009 | Company records | | | | | | | | | | | | | - |
| 27 | Oct | 2009 | Company records | | | | | | | | | | | | | - |
| 28 | Nov | 2009 | Company records | | | | | | | | | | | | | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | Dec | 2009 | p207.58 | | | | | | | | | | | | - |
| 30 | Avg | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 31 | Plant in Service--Transmission with CIAC | | | | | | | | | | | | | | |
| 32 | Dec | 2008 | p207.58 | - | - | - | - | - | - | - | - | - | - | - | - |
| 33 | Jan | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 34 | Feb | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | Mar | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 36 | Apr | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 37 | May | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 38 | Jun | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 39 | Jul | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 40 | Aug | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 41 | Sep | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 42 | Oct | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 43 | Nov | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - | - |
| 44 | Dec | 2009 | p207.58 | - | - | - | - | - | - | - | - | - | - | - | - |
| 45 | Avg | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 46 | Depreciation Reserve--Transmission before CIAC | | | | | | | | | | | | | | |
| 47 | Dec | 2008 | p219.25c | | | | | | | | | | | | - |
| 48 | Jan | 2009 | Company records | | | | | | | | | | | | - |
| 49 | Feb | 2009 | Company records | | | | | | | | | | | | - |
| 50 | Mar | 2009 | Company records | | | | | | | | | | | | - |
| 51 | Apr | 2009 | Company records | | | | | | | | | | | | - |
| 52 | May | 2009 | Company records | | | | | | | | | | | | - |
| 53 | Jun | 2009 | Company records | | | | | | | | | | | | - |
| 54 | Jul | 2009 | Company records | | | | | | | | | | | | - |
| 55 | Aug | 2009 | Company records | | | | | | | | | | | | - |
| 56 | Sep | 2009 | Company records | | | | | | | | | | | | - |
| 57 | Oct | 2009 | Company records | | | | | | | | | | | | - |
| 58 | Nov | 2009 | Company records | | | | | | | | | | | | - |
| 59 | Dec | 2009 | p219.25c | | | | | | | | | | | | - |
| 60 | Avg | | | - | - | - | - | - | - | - | - | - | - | - | - |
| 61 | Depreciation Reserve--Transmission CIAC | | | | | | | | | | | | | | |
| 62 | Dec | 2008 | p219.25c | | | | | | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | - |
| 63 | Jan | 2009 | Company records | | | | | | | | | | - |
| 64 | Feb | 2009 | Company records | | | | | | | | | | - |
| 65 | Mar | 2009 | Company records | | | | | | | | | | - |
| 66 | Apr | 2009 | Company records | | | | | | | | | | - |
| 67 | May | 2009 | Company records | | | | | | | | | | - |
| 68 | Jun | 2009 | Company records | | | | | | | | | | - |
| 69 | Jul | 2009 | Company records | | | | | | | | | | - |
| 70 | Aug | 2009 | Company records | | | | | | | | | | - |
| 71 | Sep | 2009 | Company records | | | | | | | | | | - |
| 72 | Oct | 2009 | Company records | | | | | | | | | | - |
| 73 | Nov | 2009 | Company records | | | | | | | | | | - |
| 74 | Dec | 2009 | p219.25c | | | | | | | | | | - |
| 75 | Avg | | | - | - | - | - | - | - | - | - | - | - | - |
| 76 | Depreciation Reserve with CIAC | | | | | | | | | | | | |
| 77 | Dec | 2008 | p219.25c | - | - | - | - | - | - | - | - | - | - | - |
| 78 | Jan | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 79 | Feb | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 80 | Mar | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 81 | Apr | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 82 | May | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 83 | Jun | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 84 | Jul | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 85 | Aug | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 86 | Sep | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 87 | Oct | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 88 | Nov | 2009 | Company records | - | - | - | - | - | - | - | - | - | - | - |
| 89 | Dec | 2009 | p219.25c | - | - | - | - | - | - | - | - | - | - | - |
| 90 | Avg | | | - | - | - | - | - | - | - | - | - | - | - |
| 91 | CWIP Transmission | | | | | | | | | | | | | |
| 92 | Dec | 2008 | p216.b | | | | | | | | | | | - |
| 93 | Jan | 2009 | Company records | | | | | | | | | | | - |
| 94 | Feb | 2009 | Company records | | | | | | | | | | | - |
| 95 | Mar | 2009 | Company records | | | | | | | | | | | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 96 | Apr | 2009 | Company records | | | | | | | | | | | - |
| 97 | May | 2009 | Company records | | | | | | | | | | | - |
| 98 | Jun | 2009 | Company records | | | | | | | | | | | - |
| 99 | Jul | 2009 | Company records | | | | | | | | | | | - |
| 100 | Aug | 2009 | Company records | | | | | | | | | | | - |
| 101 | Sep | 2009 | Company records | | | | | | | | | | | - |
| 102 | Oct | 2009 | Company records | | | | | | | | | | | - |
| 103 | Nov | 2009 | Company records | | | | | | | | | | | - |
| 104 | Dec | 2009 | p216.b | | | | | | | | | | | - |
| 105 | Avg | | | - | - | - | - | - | - | - | - | - | - | - |
| 106 | Project Specific Regulatory Asset | | | | | | | | | | | | | |
| 107 | Dec | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 108 | Jan | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 109 | Feb | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 110 | Mar | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 111 | Apr | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 112 | May | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 113 | Jun | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 114 | Jul | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 115 | Aug | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 116 | Sep | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 117 | Oct | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 118 | Nov | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 119 | Dec | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 120 | Avg | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 121 | Amortization | | FERC Order | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 122 | Unamortized Abandoned Plant | | | | | | | | | | | | | |
| 123 | Dec | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 124 | Jan | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 125 | Feb | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 126 | Mar | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 127 | Apr | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 128 | May | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 129 | Jun | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 130 | Jul | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 131 | Aug | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 132 | Sep | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 133 | Oct | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 134 | Nov | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 135 | Dec | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 136 | Avg | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 137 | Amortization | | FERC Order | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 138 | Accumulated deferred income taxes directly related to transmission plant (enter negative) | | | | | | | | | | | | | |
| 139 | Dec | | | | | | | | | | | | | 0 |
| 140 | Jan | | | | | | | | | | | | | 0 |
| 141 | Feb | | | | | | | | | | | | | 0 |
| 142 | Mar | | | | | | | | | | | | | 0 |
| 143 | Apr | | | | | | | | | | | | | 0 |
| 144 | May | | | | | | | | | | | | | 0 |
| 145 | Jun | | | | | | | | | | | | | 0 |
| 146 | Jul | | | | | | | | | | | | | 0 |
| 147 | Aug | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 148 | Sep | | | | | | | | | | | | 0 |
| 149 | Oct | | | | | | | | | | | | 0 |
| 150 | Nov | | | | | | | | | | | | 0 |
| 151 | Dec | | | | | | | | | | | | 0 |
| 152 | Avg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

ITC Great Plains, LLC
Cost Year
Trued Up Year
Worksheet 2
13 Month Balances

| | | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|---|---|
| | | | Regulatory Asset Start Up & Development FERC Order | Intangible p207.5.g | General p207.58.g | Subtotal Intangible & General | Column deliberately left blank | Production p207.46.g | Distribution p207.75.g |
| | Plant in Service | | | | | | | | |
| 1 | Dec | 2008 | 0 | | | 0 | | | |
| 2 | Jan | 2009 | 0 | | | 0 | | | |
| 3 | Feb | 2009 | 0 | | | 0 | | | |
| 4 | Mar | 2009 | 0 | | | 0 | | | |
| 5 | Apr | 2009 | 0 | | | 0 | | | |
| 6 | May | 2009 | 0 | | | 0 | | | |
| 7 | Jun | 2009 | 0 | | | 0 | | | |
| 8 | Jul | 2009 | 0 | | | 0 | | | |
| 9 | Aug | 2009 | 0 | | | 0 | | | |
| 10 | Sep | 2009 | 0 | | | 0 | | | |
| 11 | Oct | 2009 | 0 | | | 0 | | | |
| 12 | Nov | 2009 | 0 | | | 0 | | | |
| 13 | Dec | 2009 | 0 | | | 0 | | | |
| 14 | Avg | | 0 | 0 | 0 | 0 | | 0 | 0 |

| | | | | Intangible p200.21.c | General p219.28 | Subtotal Intangible & General | Column deliberately left blank | Production p219.20 thru 219.24 | Distribution p219.26 |
|---|---|---|---|---|---|---|---|---|---|
| | Depreciation Reserve | | | | | | | | |
| 15 | Dec | 2008 | | | | 0 | | | |
| 16 | Jan | 2009 | | | | 0 | | | |
| 17 | Feb | 2009 | | | | 0 | | | |
| 18 | Mar | 2009 | | | | 0 | | | |
| 19 | Apr | 2009 | | | | 0 | | | |
| 20 | May | 2009 | | | | 0 | | | |
| 21 | Jun | 2009 | | | | 0 | | | |
| 22 | Jul | 2009 | | | | 0 | | | |
| 23 | Aug | 2009 | | | | 0 | | | |
| 24 | Sep | 2009 | | | | 0 | | | |
| 25 | Oct | 2009 | | | | 0 | | | |
| 26 | Nov | 2009 | | | | 0 | | | |
| 27 | Dec | 2009 | | | | 0 | | | |
| 28 | Avg | | | 0 | 0 | 0 | | 0 | 0 |

ITC Great Plains, LLC
Cost Year
Trued Up Year
Worksheet 3
Capital Structure

| | | | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|---|---|
| | | | Proprietary Capital p112.16c | Preferred Stock p112.3c | Acct 216.1 p112.12.c | Comp Inc 219 p112.15.c | Common Stock [(a)-(b)-(c)-(d)] | Long Term Debt 112.18c-112.21c |
| 1 | Dec | 2008 | 0 | | | | 0 | |
| 2 | Jan | 2009 | | | | | 0 | |
| 3 | Feb | 2009 | | | | | 0 | |
| 4 | Mar | 2009 | | | | | 0 | |
| 5 | Apr | 2009 | | | | | 0 | |
| 6 | May | 2009 | | | | | 0 | |
| 7 | Jun | 2009 | | | | | 0 | |
| 8 | Jul | 2009 | | | | | 0 | |
| 9 | Aug | 2009 | | | | | 0 | |
| 10 | Sep | 2009 | | | | | 0 | |
| 11 | Oct | 2009 | | | | | 0 | |
| 12 | Nov | 2009 | | | | | 0 | |
| 13 | Dec | 2009 | | | | | 0 | |
| 14 | Avg | | 0 | 0 | 0 | 0 | 0 | 0 |
| 15 | Interest Expense for interest rate computation: | | | | | | | |
| 16 | | | | | | | | |
| 17 | Long Term Interest (117, sum of 62.c through 67.c) | | | | | | | |
| 18 | | | | | | | | |
| 19 | Net cost (gain) of hedging included in line 17 | | | | | | | |
| 20 | | | | | | | | |
| 21 | Capitalization | | | | (Attach H, line 98) | | | 0 |
| 22 | Hedging factor (six basis points) | | | | | | | 0.0006 |
| 23 | Computed amount of gain or loss | | | | (Line 21 * Line 22) | | | 0 |
| 24 | | | | | | | | |
| 25 | Maximum allowable cost { MIN[Line ABS(Line 19) or Line 23] if Line 19 is net cost; zero if no net gain/cost} | | | | | | | 0 |
| 26 | Maximum allowable (gain) {-MIN[Line ABS(Line 19) or Line 23] if Line 19 is net gain; zero if no net gain/loss} | | | | | | | 0 |
| 27 | | | | | | | | |
| 28 | | | | | | | | |
| 29 | Allowable amount (Line 25 if net loss, or Line 26 if net gain, zero if no net gain/loss) | | | | | | | 0 |
| 30 | | | | | | | | |
| 31 | Less: net cost(gain) of hedging | | | | (Line 19) | | | 0 |
| 32 | Plus: allowable amount | | | | (Line 29) | | | 0 |
| 33 | Interest Expense in formula (Input to Attach H, Line 92) | | | | (Line 17 - Line 31 + Line 32) | | | 0 |
| 34 | | | | | | | | |

ITC Great Plains, LLC
Cost Year
Trued Up Year
Worksheet 4
Depreciation Rates

| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | General & Intangible | Column deliberately left blank | Proj #1 Elm Creek ElmCreek | Proj #2 FlatRidge CIAC | Proj #3 N/A | Proj #4 N/A | Proj #5 N/A | Proj #6 N/A | Proj #7 N/A | Proj #8 N/A | Proj #9 N/A | Proj #10 N/A | Proj #11 N/A |
| | Depreciation & Amortization Rates | | | | | | | | | | | | | |
| 1 | 350.1 | | | 1.67% | 1.67% | | | | | | | | | |
| 2 | 352 | | | 1.75% | 1.75% | | | | | | | | | |
| 3 | 353 | | | 2.29% | 2.29% | | | | | | | | | |
| 4 | 354 | | | 1.87% | 1.87% | | | | | | | | | |
| 5 | 355 | | | 1.87% | 1.87% | | | | | | | | | |
| 6 | 356 | | | 1.85% | 1.85% | | | | | | | | | |
| 7 | 357 | | | 1.91% | 1.91% | | | | | | | | | |
| 8 | 358 | | | 1.82% | 1.82% | | | | | | | | | |
| 9 | 301 | | | | | | | | | | | | | |
| 10 | 302 | | | | | | | | | | | | | |
| 11 | 303 | 2.00% | | | | | | | | | | | | |
| 12 | 389 | 1.67% | | | | | | | | | | | | |
| 13 | 390 | 2.20% | | | | | | | | | | | | |
| 14 | 391.1 | 5.00% | | | | | | | | | | | | |
| 15 | 391.2 | 20.00% | | | | | | | | | | | | |
| 16 | 392 | 18.00% | | | | | | | | | | | | |
| 17 | 393 | 10.00% | | | | | | | | | | | | |
| 18 | 394 | 10.00% | | | | | | | | | | | | |
| 19 | 395 | 20.00% | | | | | | | | | | | | |
| 20 | 396 | 9.00% | | | | | | | | | | | | |
| 21 | 397 | 10.00% | | | | | | | | | | | | |
| 22 | 398 | 20.00% | | | | | | | | | | | | |
| 23 | 399 | 20.00% | | | | | | | | | | | | |

ITC Great Plains, LLC
Cost Year
Trued Up Year
Worksheet 5
Other Rate Base Items

| | | Source | (a) Beginning of Year | (b) End of Year | (c) Average Balance |
|---|---|---|---|---|---|
| 1 | Acct No. 281 (enter negative) | 273.8.k | | | 0 |
| 2 | Acct No. 282 (enter negative) | 275.2.k | | | 0 |
| 3 | Acct No. 283 (enter negative) | 277.9.k | | | 0 |
| 4 | Acct No. 190 | 234.8.c | | | 0 |
| 5 | Acct No. 255 (enter negative) | 267.8.h | | | 0 |
| 6 | Prepayments (Account 165) | 111.57.c | | | 0 |
| 7 | Materials & Supplies | 227.4 | | | 0 |
| 8 | Stores Expense Undistributed | 227.16 | | | 0 |
| 9 | Wage & Salary Allocator | Attach H | 0% | 0% | 0% |
| 10 | Transmission Related Stores Exp Undistributed | | 0 | 0 | 0 |
| 11 | Total | (line 7 + line 10) | 0 | 0 | 0 |
| | Land Held for Future Use | | | | |
| 12 | Total | p214 | 0 | 0 | 0 |
| 13 | Non-Transmission Related | | 0 | 0 | 0 |
| 14 | Transmission Related | (line 12 - line 13) | 0 | 0 | 0 |

Note: For Accumulated Deferred Income Taxes, see Note A.

ITC Great Plains, LLC
Cost Year
Trued Up Year
Worksheet 6
Expenses

| | | | Total |
|---|---|---|---|
| 1 | EPRI Dues and Note D EEI & EPRI R&D in excess of $100K | p352-353 | |
| | Regulatory Expense Related to Transmission | | |
| 2 | Acct 928 Total | p323.189.b | |
| 3 | FERC Annual Assessment included above | | 0 |
| 4 | Non-transmission related | | |
| 5 | Transmission related | | 0 |
| | Safety Related Advertising Cost Support | | |
| 6 | Acct 930.1 General Advertising expense | p323.191.b | |
| 7 | Safety related | | |
| 8 | Education and Outreach related | | |
| 9 | Non-safety or Non-Education & Outreach related | | 0 |

Income Tax Rates

| | | State Income Tax | Weight | Composite |
|---|---|---|---|---|
| 10 | | | | |
| 11 | State 1 | | 1 | 0 |
| 12 | State 2 | | | 0 |
| 13 | State 3 | | | 0 |
| 14 | State 4 | | | 0 |
| 15 | Weighted Average | | | 0 |

| | | |
|---|---|---|
| 16 | Calculation of PBOP Expenses | |
| 17 | Total PBOP expenses | 2,666,000 |
| 18 | Amount relating to retired personnel | 0 |
| 19 | Amount allocated on Labor | 2,666,000 |
| 20 | Total labor dollars | 31,136,000 |
| 21 | Cost per labor dollar | 0.09 |
| 22 | ITC-Great Plains labor(labor not capitalized) current year | |
| 23 | ITC-Great Plains PBOP expense allowed amount | 0 |
| 24 | ITC-Great Plains PBOP Expense in Account 926 for current years | |

Lines 17 - 21 cannot change absent approval or acceptance by FERC in a separate proceeding.

| | | | | Amount |
|---|---|---|---|---|
| 25 | ACCOUNT 454 and 456 (RENT and OTHER ELECTRIC REVENUES) | | | |
| 26 | Account 454 Rent from electric property (details below) | p 300.19b | | |
| | a | | | |
| | b | | | |
| | c | | | |
| 27 | Account 456 Other electric revenues (details below) | p 300.21b | | |
| | a | | | |
| | b | | | |
| | c | | | |
| 28 | Subtotal (show transaction data if different Form 1 total) | | | 0 |
| 29 | Revenues for facilities or expenses not included in the formula (show detail) | | | |
| | a | | | |
| | b | | | |
| | c | | | |
| 30 | Rent credit and Other revenue credits | (line 28 - line 29) | | 0 |

ITC Great Plains, LLC
Cost Year
Trued Up
Year
Worksheet 7
True-Up

| | (a) Year | (b) Month | (c) ITC GP Short-term Borrowing Rate Note 1 | (d) ITC GP Short-term Borrowing Rate adjusted for months with zero balance Note 2 | (e) Note Reference | (f) ITC GP Short-term Borrowing Rate adjusted for months with zero balance Monthly Rate | (g) FERC Refund Rate Note 3 | (h) ITC GP Short-term Borrowing Rate adjusted for months with zero balance |
|---|---|---|---|---|---|---|---|---|
| 1 | | Jul | | | | - | | - |
| 2 | | Jun | | | | - | | - |
| 3 | | May | | | | - | | - |
| 4 | | Apr | | | | - | | - |
| 5 | | Mar | | | | - | | - |
| 6 | | Feb | | | | - | | - |
| 7 | | Jan | | | | - | | - |
| 8 | | Dec | | | | - | | - |
| 9 | | Nov | | | | - | | - |
| 10 | | Oct | | | | - | | - |
| 11 | | Sep | | | | - | | - |
| 12 | | Aug | | | | - | | - |
| 13 | | Jul | | | | - | | - |
| 14 | | Jun | | | | - | | - |
| 15 | | May | | | | - | | - |
| 16 | | Apr | | | | - | | - |
| 17 | | Mar | | | | - | | - |
| 18 | | Feb | | | | - | | - |
| 19 | | Jan | | | | - | | - |
| 20 | Total | | | | | | - | - |
| 21 | Count | | | | | | - | - |
| 22 | Average monthly rate | | | | | | - | - |

Note 1: Weighted-average interest rate of ITC Great Plains' borrowings under short-term credit agreements (including revolving credit agreements) at month-end.

Note 2: Interest rate for months with zero short term borrowings at month-end will be based on data for most recent prior month.

Note 3: FERC refund interest rate 18 CFR 35.19a [http://www.ferc.gov/legal/acct-matts/interest-rates.asp]

ITC Great Plains, LLC
Cost Year xx/xx/20x1
Correction in Year 20x4
Worksheet 7
True-Up
Note 4

| | (a) Year | (b) Month | (c) ITC GP Short-term Borrowing Rate Note 1 | (d) ITC GP Short-term Borrowing Rate adjusted for months with zero balance Note 2 | (e) Note Reference | (f) ITC GP Short-term Borrowing Rate adjusted for months with zero balance Monthly Rate | (g) FERC Refund Rate Note 3 | (h) ITC GP Short-term Borrowing Rate adjusted for months with zero balance |
|---|---|---|---|---|---|---|---|---|
| 1 | | Jul | | | | 0 | | 0 |
| 2 | | Jun | | | | 0 | | 0 |
| 3 | | May | | | | 0 | | 0 |
| 4 | | Apr | | | | 0 | | 0 |
| 5 | | Mar | | | | 0 | | 0 |
| 6 | | Feb | | | | 0 | | 0 |
| 7 | | Jan | | | | 0 | | 0 |
| 8 | | Dec | | | | 0 | | 0 |
| 9 | | Nov | | | | 0 | | 0 |
| 10 | | Oct | | | | 0 | | 0 |
| 11 | | Sep | | | | 0 | | 0 |
| 12 | | Aug | | | | 0 | | 0 |
| 13 | | Jul | | | | 0 | | 0 |
| 14 | | Jun | | | | 0 | | 0 |
| 15 | | May | | | | 0 | | 0 |
| 16 | | Apr | | | | 0 | | 0 |
| 17 | | Mar | | | | 0 | | 0 |
| 18 | | Feb | | | | 0 | | 0 |
| 19 | | Jan | | | | 0 | | 0 |
| 20 | | Dec | | | | 0 | | 0 |
| 21 | | Nov | | | | 0 | | 0 |
| 22 | | Oct | | | | 0 | | 0 |
| 23 | | Sep | | | | 0 | | 0 |
| 24 | | Aug | | | | 0 | | 0 |
| 25 | | Jul | | | | 0 | | 0 |
| 26 | | Jun | | | | 0 | | 0 |
| 27 | | May | | | | 0 | | 0 |
| 28 | | Apr | | | | 0 | | 0 |
| 29 | | Mar | | | | 0 | | 0 |
| 30 | | Feb | | | | 0 | | 0 |
| 31 | | Jan | | | | 0 | | 0 |
| 32 | Total | | | | | | - | - |
| 33 | Count | | | | | | - | - |
| 34 | Average monthly rate | | | | | | - | - |

Note 1: Weighted-average interest rate of ITC Great Plains' borrowings under short-term credit agreements (including revolving credit agreements) at month-end.

Note 2: Interest rate for months with zero short term borrowings at month-end will be based on data for most recent prior month.

Note 3: FERC refund interest rate 18 CFR 35.19a [http://www.ferc.gov/legal/acct-matts/interest-rates.asp]

Note 4: Template for interest rate for corrections based on corrections to cost year 1, with effect of corrections included in charges to customers in year 4; subsequent correction years would be computed similar.

COMPANY NAME

ADIT Balance Lead Sheet

Enter Rate Period (i.e., 2019 actuals)

| | Rate Base Adjustment for FAS 109 Regulatory Assets/(Liabilities) | | | | Totals | References |
|---|---|---|---|---|---|---|
| | 190 | 281 | 282 | 283 | | |
| Total Deferred Tax Balance | | | | | - | Year-end balance from FERC Form No. 1 will be populated. See footnotes below for FERC Form No. 1 page references |
| Income taxes related to AFUDC Equity regulatory asset | | | | | - | |
| Income taxes related to Excess/Deficient deferred income tax regulatory assets and liabilities | - | - | - | - | - | See Footnote A. Amounts also reported in 'ASC 740 and Other Items' in FERC Form No. 1 Footnotes. |
| Income taxes related to formula rate true-up | | | | | - | FERC Form No. 1 Footnotes |
| Income taxes related to CIAC | | | | | - | |
| *Add Adjustments as needed per Company* | | | | | - | |
| December 31 Balance for Ratemaking | - | - | - | - | - | Balances as adjusted included in formula |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | rate tariff used to calculate 'Adjustments to Rate Base' | |
| | **(Excess)/Deficient Amortization Entry** | | | | **Totals** | **References** |
| | **190** | **281** | **282** | **283** | | |
| Account 410.1 | - | - | - | - | - | See Footnote B |
| Account 411.1 | - | - | - | - | - | See Footnote C |
| (Excess)/Deficient Amortization | - | - | - | - | - | To Attachment H - Page 3, Line 73a |

Footnotes for other items that require explanation.

**Rate Base Adjustment for FAS 109 Regulatory Assets/(Liabilities) Table Instructions**

The purpose of the table 'Rate Base Adjustment for FAS 109 Regulatory Assets/(Liabilities)' on this worksheet is to show any adjustments for ratemaking for the applicable rate year.

In order to tie to inputs used in formula rate tariff, note that this table may include more information than the Excess/Deficient ADIT information required by FERC in Order No. 864.

These deferred tax account balances can also be found in the FERC Form No. 1 references or the footnotes therein.
Account No. 190 - FERC Form No. 1 Page 234, line 8, column c
Account No. 281 - FERC Form No. 1 Page 273, line 8, column k
Account No. 282 - FERC Form No. 1 Page 275, line 2, column k
Account No. 283 - FERC Form No. 1 Page 277, line 9, column k

Footnote A - Rate base adjustments can be found on the "ADIT Balance Worksheet" tab within the ending balance line for the above-referenced rate year.

Both the protected and unprotected portions for each amortization method/period need to be added together for each separate account (i.e., 190, 281, 282 and 283) to calculate the rate

base adjustment for that account.
The following table shows the columns associated with each account.

| Account | Columns |
|---|---|
| 190 | A & B |
| 281 | C & D |
| 282 | E, F & G |
| 283 | H & I |

**(Excess)/Deficient Amortization Entry Table Instructions**

The purpose of the '(Excess)/Deficient Amortization Entry' table of this worksheet is to show the (excess)/deficient amortization entries to Accounts 410.1 and 411.1 by deferred tax account.
The total (excess)/deficient amortization is the input for the formula rate template on Page 3, Line 73a of Attachment H.

Footnote B - The (Excess)/Deficient Amortization booked to Account 410.1 can be found on the "ADIT Balance Worksheet" tab within the "Amortization of Excess/Deficient ADIT" line in the section for the above-referenced rate year.
Both the protected and unprotected portions for each amortization method/period need to be added together for each separate account (i.e., 190, 281, 282 and 283) to calculate the total amortization for that account. If the total calculated amortization for an account is positive, then the (Excess)/Deficient Amortization is booked to Account 410.1.
Please see Footnote A above for the columns associated with each account.

Footnote C - The (Excess)/Deficient Amortization booked to Account 411.1 can be found on the "ADIT Balance Worksheet" tab within the "Amortization of Excess/Deficient ADIT" line in the section for the above-referenced rate year.

Both the protected and unprotected portions for each amortization method/period need to be added together for each separate account (i.e., 190, 281, 282 and 283) to calculate the total amortization for that account. If the total calculated amortization for an account is negative, then the (Excess)/Deficient Amortization is booked to Account 411.1.
Please see Footnote A above for the columns associated with each account.

COMPANY NAME ADIT Balance Worksheet

| Line No. | | A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **FERC Account** | **190** | **190** | **281** | **281** | **282** | **282** | **282** | **283** | **283** | **Total 190/281/282/283** | **Total 182.3** | **Total 254** |
| 2 | **ADIT Type** | **Protected** | **Unprotected** | **Protected** | **Unprotected** | **Protected** | **Unprotected** | **Unprotected** | **Unprotected** | **Unprotected** | | | |
| 3 | **Amortization Methodology/Period** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | **Various (See Footnotes)** | | | |
| 4 | **Balance as of 12/31/2016** | | | | | | | | | | **-** | | |
| 5 | | | | | | | | | | | | | |
| 6 | Tax Rate for Income | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | Tax Gross-Up Income Tax Gross-Up | | | | | | | | | | - | | - | - |
| 8 | | | | | | | | | | | | | | | |
| 9 | | **Balance as of 12/31/2016** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | | **-** | **-** |
| 10 | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | |
| 12 | | **Balance as of 01/01/2017** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | | **-** | **-** |
| 13 | 2017 Actuals | Tax Rate Change Remeasurement - Excess | | | | | | | | | | - | | | |
| 14 | 2017 Actuals | Tax Rate Change Remeasurement - Deficient | | | | | | | | | | - | | | |
| 15 | 2017 Actual | Amortization of Excess/Deficient ADIT | | | | | | | | | | - | | | |

| | | |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | Actuals 2018 Actuals 2018 Actuals | Remeasurement - Excess Tax Rate Change Remeasurement - Deficient Amortization of Excess/Deficient ADIT | | | | | | | | | | | - | | | | | |
| 28 | | | | | | | | | | | | | - | | | | | |
| 29 | | | | | | | | | | | | | | | | | | |
| 30 | | **Balance as of 12/31/2018** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31 | | | | | | | | | | | | | | | | | | |
| 32 | | Tax Rate for Income Tax Gross-Up | | | | | | | | | | | | | | | | |
| 33 | | Income Tax Gross-Up | | | | | | | | | | | - | | - | - | | |
| 34 | | | | | | | | | | | | | | | | | | |
| 35 | | **Balance as of** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 44 | | | | | | | | | | | | | | |
| 45 | | Tax Rate for Income Tax Gross-Up | | | | | | | | | | | | |
| 46 | | Income Tax Gross-Up | | | | | | | | | - | | - | - |
| 47 | | | | | | | | | | | | | | |
| 48 | | **Balance as of 12/31/2019** | - | - | - | - | - | - | - | - | - | - | - | - |
| 49 | | | | | | | | | | | | | | |
| 50 | | | | | | | | | | | | | | |
| 51 | | **Balance as of 01/01/2020** | - | - | - | - | - | - | - | - | - | - | - | - |
| 52 | 2020 Actuals | Tax Rate Change Remeasurement - Excess | | | | | | | | | - | | | |
| 53 | 2020 Actuals | Tax Rate Change Remeasurement - Deficient | | | | | | | | | - | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 54 | 2020 Actuals | Amortization of Excess/(Deficient) ADIT | | | | | | | | | | | - | | |
| 55 | | | | | | | | | | | | | | | |
| 56 | | **Balance as of 12/31/2020** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 57 | | | | | | | | | | | | | | | |
| 58 | | Tax Rate for Income Tax Gross-Up | | | | | | | | | | | | | |
| 59 | | Income Tax Gross-Up | | | | | | | | | | | - | - | - |
| 60 | | | | | | | | | | | | | | | |
| 61 | | **Balance as of 12/31/2020** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 62 | | | | | | | | | | | | | | | |
| 63 | Footnotes for other items that require explanation. | | | | | | | | | | | | | | |

64

The first populated version of the ADIT Balance Worksheet to be included in the
65 tariff will be populated starting with balances as of 12/31/16. Subsequent versions
66 will at a minimum show the prior year and current year balances.

The Tax Rate Change Remeasurement lines
in this worksheet are populated with
67 amounts from the respective tax
68 remeasurement tabs.

This ADIT Worksheet lists the amortization method associated with federal protected
69 excess/deficient deferred income taxes resulting from changes to income tax laws, income
70 tax rates and other actions taken by the federal taxing authority.

The company amortizes protected federal excess/deficient deferred
71 income taxes following amortization methods required under the
normalization provisions of the Internal Revenue code.
Beginning with the 2023 rate year, the company will utilize the Alternative Method
72 as defined in Internal Revenue Service, Revenue Procedure 2020-39, Section 2.08,
73 to amortize excess taxes from the Tax Cut and Jobs Act (“TCJA”).

This ADIT Worksheet lists the amortization period for unprotected excess/deficient deferred income taxes resulting
74 from changes to income tax laws, income tax rates (including changes in apportionments) and other actions taken
by a taxing authority that are not federal protected
excess/deficient
75 deferred income taxes.
The amortization

method used is detailed below.

*Where applicable add footnotes to explain amortization methods, periods, etc.*

**COMPANY NAME**

**Remeasurement Calculation for Tax Rate Change**

| Line | Temporary Differences Description | *P or U* Protected / Unprotected | Temp Diff Amount | Old Rate | ADIT at Old Rate | New Rate | ADIT at New Rate | Calculated Excess / Deficient | Other Adjustment(s) | Excess / Deficient | Protected | Unprotected |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) (Col. 3 * Col. 4) | (6) | (7) (Col. 3 * Col. 6) | (8) (Col. 7 - Col. 5) | (9) | (10) (Col. 8 + Col.9) | (11) | (12) |
| 1 | Account 190 | | | | | | | | | | | |
| 2 | Fed - NOL - Protected | | | | - | | - | - | | - | - | - |
| 3 | Fed - NOL - Unprotected | | | | - | | - | - | | - | - | - |
| 4 | Fed - Benefit of State Income Tax | | | | - | | - | - | | - | - | - |
| 5 | Fed - Other | | | | - | | - | - | | - | - | - |
| 6 | State Net of Fed Offset - Other | | | | - | | - | - | | - | - | - |
| 7 | *Add Categories* | | | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | *as needed per Company* | | | - | | - | - | | - | - | - |
| 8 | Subtotal 190 | | | - | | - | - | - | - | - | - |
| 9 | | | | | | | | | | | |
| 10 | Account 281 | | | | | | | | | | |
| 11 | Federal - Plant Related - Protected | | | - | | - | - | | - | - | - |
| 12 | Federal - Plant Related - Unprotected | | | - | | - | - | | - | - | - |
| 13 | State Net of Fed Offset - Plant Related | | | - | | - | - | | - | - | - |
| 14 | *Add Categories as needed per Company* | | | - | | - | - | | - | - | - |
| 15 | Subtotal 281 | | | - | | - | - | - | - | - | - |
| 16 | | | | | | | | | | | |
| 17 | Account 282 | | | | | | | | | | |
| 18 | Federal - Plant Related - Protected | | | - | | - | - | | - | - | - |
| 19 | Federal - Plant Related - Unprotected | | | - | | - | - | | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20 | State Net of Fed Offset - Plant Related | | - | | - | - | | - | - | - |
| 21 | *Add Categories as needed per Company* | | - | | - | - | | - | - | - |
| 22 | | | | | | | | | | |
| 22 | Subtotal 282 | | - | | - | - | - | - | - | - |
| 22 | | | | | | | | | | |
| 23 | | | | | | | | | | |
| 24 | | | | | | | | | | |
| 24 | Account 283 | | | | | | | | | |
| 25 | Fed - Regulatory Deferral | | - | | - | - | | - | - | - |
| 26 | State Net of Fed Offset - Regulatory Deferral | | - | | - | - | | - | - | - |
| 27 | Fed - Other | | - | | - | - | | - | - | - |
| 28 | State Net of Fed Offset - Other | | - | | - | - | | - | - | - |
| 29 | Fed - Startup costs and debt | | - | | - | - | | - | - | - |
| 30 | State - Startup costs and debt | | - | | - | - | | - | - | - |
| 31 | *Add Categories as needed per Company* | | - | | - | - | | - | - | - |
| 32 | | | | | | | | | | |
| 32 | Subtotal 283 | | - | | - | - | - | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 33 | | | | | | | | | |
| 34 | Total | - | - | - | - | - | | - | - |
| 35 | | | | | | - | OK | | |

Footnotes for other items that require explanation.

Each subsequent tax rate change will add remeasurement tabs as needed

Remeasurement tabs may be removed once the period containing the tax rate change is no longer shown on the ADIT Balance Worksheet

*Where applicable add footnotes to explain remeasurement*

**COMPANY NAME**

**Remeasurement Calculation for Tax Rate Change**

*P or*

| Line | Temporary Differences Description | *U* Protected / Unprotected | Temp Diff Amount | Old Rate | ADIT at Old Rate | New Rate | ADIT at New Rate | Calculated Excess / Deficient | Other Adjustment(s) | Excess / Deficient | Protected | Unprotected |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) |
| | | | | | (Col. 3 * Col. 4) | | (Col. 3 * Col. 6) | (Col. 7 - Col. 5) | | (Col. 8 + Col.9) | | |
| 1 | Account 190 | | | | | | | | | | | |
| 2 | Fed - NOL - Protected | | | | - | | - | - | | - | - | - |
| 3 | Fed - NOL - Unprotected | | | | - | | - | - | | - | - | - |
| 4 | Fed - Benefit of State Income Tax | | | | - | | - | - | | - | - | - |
| 5 | Fed - Other | | | | - | | - | - | | - | - | - |
| 6 | State Net of Fed Offset - Other | | | | - | | - | - | | - | - | - |
| 7 | *Add Categories as needed per Company* | | | | - | | - | - | | - | - | - |
| 8 | Subtotal 190 | | | | - | | - | - | - | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | |
| 10 | Account 281 | | | | | | | | |
| 11 | Federal - Plant Related - Protected | | - | | - | | - | | - | - |
| 12 | Federal - Plant Related - Unprotected | | - | | - | | - | | - | - |
| 13 | State Net of Fed Offset - Plant Related | | - | | - | | - | | - | - |
| 14 | *Add Categories as needed per Company* | | - | | - | | - | | - | - |
| 15 | Subtotal 281 | | - | | - | | - | | - | - |
| 16 | | | | | | | | | | |
| 17 | Account 282 | | | | | | | | |
| 18 | Federal - Plant Related - Protected | | - | | - | | - | | - | - |
| 19 | Federal - Plant Related - Unprotected | | - | | - | | - | | - | - |
| 20 | State Net of Fed Offset - Plant Related | | - | | - | | - | | - | - |
| 21 | *Add Categories* | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | *as needed per Company* | | | - | | - | - | | - | - | - |
| 2 | | | | | | | | | | | |
| 2 | Subtotal 282 | | | - | | - | - | - | - | - | - |
| 2 | | | | | | | | | | | |
| 3 | | | | | | | | | | | |
| 2 | | | | | | | | | | | |
| 4 | Account 283 | | | | | | | | | | |
| 2 | Fed - Regulatory | | | | | | | | | | |
| 5 | Deferral | | | - | | - | - | | - | - | - |
| | State Net of Fed Offset - | | | | | | | | | | |
| 2 | Regulatory | | | | | | | | | | |
| 6 | Deferral | | | - | | - | - | | - | - | - |
| 2 | | | | | | | | | | | |
| 7 | Fed - Other | | | - | | - | - | | - | - | - |
| 2 | State Net of Fed | | | | | | | | | | |
| 8 | Offset - Other | | | - | | - | - | | - | - | - |
| 2 | Fed - Startup | | | | | | | | | | |
| 9 | costs and debt | | | - | | - | - | | - | - | - |
| 3 | State - Startup | | | | | | | | | | |
| 0 | costs and debt | | | - | | - | - | | - | - | - |
| | *Add Categories* | | | | | | | | | | |
| 3 | *as needed per* | | | | | | | | | | |
| 1 | *Company* | | | - | | - | - | | - | - | |
| 3 | | | | | | | | | | | |
| 2 | Subtotal 283 | | | - | | - | - | - | - | - | - |
| 3 | | | | | | | | | | | |
| 3 | | | | | | | | | | | |
| 3 | | | | | | | | | | | |
| 4 | Total | | | - | | - | - | - | - | - | - |

| | | | |
|---|---|---|---|
| 35 | | - | OK |
| 36 | Footnotes for other items that require explanation. | | |
| 37 | | | |
| 38 | Each subsequent tax rate change will add remeasurement tabs as needed<br>Remeasurement tabs may be removed once the period containing the tax rate change is no longer shown on the ADIT Balance Worksheet | | |
| 40 | | | |
| 41 | *Where applicable add footnotes to explain remeasurement* | | |
| 42 | | | |

# ITC Great Plains
# Formula Rate Implementation Protocols

October 23, 2009

## Section 1 Annual Projection

a. The formula rate template ("Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of ITC Great Plains for transmission service under the Southwest Power Pool ("SPP") Open Access Transmission Tariff ("OATT"). ITC Great Plains must follow the instructions specified in the Formula Rate to calculate annually its total projected Annual Transmission Revenue Requirements ("Projected Total ATRR") and its projected ATRR by individual project ("Projected Individual ATRR"). Cost recovery for each project shall be consistent with SPP's cost recovery assignments.

b. The Formula Rate and the Annual Projection (as defined in Section 1.c, below) produced by application of the Formula Rate shall initially be effective for service on and after August 18, 2009. Charges under the Formula Rate shall be recalculated each year. The Projected Total ATRR and Projected Individual ATRRs calculated under Attachment H-ITC Great Plains shall be applicable for service on and after each January 1 of a given calendar year through December 31 of such calendar year (the "Rate Year"), subject to review, challenge, true-up and refunds or surcharges with interest, as provided herein.

c. On or before September 1, 2009, and on or before September 1 of each succeeding Rate Year ("Posting Date"), ITC Great Plains shall recalculate both its Projected Total ATRR and its Projected Individual ATRRs, producing the updated charges for the upcoming Rate Year (the "Annual Projection") and shall cause an electronic version of the Annual Projection to be posted at a publicly accessible location on SPP's internet website.

    (i) If the Posting Date falls on a weekend or a holiday recognized by the FERC, then the Posting Date shall be the next business day.[1]

d. The Annual Projection shall be based upon FERC Form 1 reporting requirements as applicable to ITC Great Plains, FERC's orders establishing general transmission ratemaking policies applicable to ITC Great Plains, FERC's Uniform System of Accounts ("USoA"), the books and records of ITC Great Plains consistent with the USoA, ITC Great Plains' accounting policies and practices, and the SPP OATT provisions affecting the charges under the Formula Rate.

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[1] Unless specified as a business day, "day" means "calendar day."

e. As part of the Annual Projection, ITC Great Plains shall include the following:

(i) ITC Great Plains' Projected Total ATRR, including information in workpapers regarding projected costs of plant in forecasted rate base, expected construction schedule and in-service dates. All inputs shall be provided in sufficient detail to identify the components of ITC Great Plains' Projected Total ATRR.

(ii) A recalculation of Projected Individual ATRRs.

(iii) A data-populated Template including fully functioning spreadsheet files, or as applicable, other native format data, showing all calculations in the Annual Projection, as well as all supporting calculations and workpapers that demonstrate and explain such information.

f. By October 1 of each year, ITC Great Plains shall hold a public meeting ("Customer Meeting") to explain the Annual Projection for the next calendar year and answer questions concerning the Annual Projection and the proposed True-Up Adjustment posted pursuant to Section II.a., below. ITC Great Plains will provide the opportunity for remote participation at Customer Meetings.

(i) To ensure that Interested Parties (as defined in Section 1.g., below) receive sufficient advance notice of Customer Meetings, ITC Great Plains shall schedule each Customer Meeting at least thirty (30) days in advance and cause such notice to be posted at a publicly accessible location on SPP's internet website, and provide Interested Parties notice of the Customer Meeting via e-mail to the most recent e-mail address provided by the Interested Party to ITC Great Plains.

g. Any intervenor in FERC Docket No. ER09-548, any transmission customer or eligible customer under SPP's OATT, state regulatory commissions, state consumer advocates, and FERC staff ("Interested Parties") may submit questions to ITC Great Plains regarding the Annual Projection until October 15, and ITC Great Plains shall use best efforts to post written responses within 15 days of receipt, but no later than November 1.

h. ITC Great Plains shall modify the Annual Projection to reflect any changes that it and the Interested Parties agree upon and shall cause the revised Annual Projection to be posted at a publicly accessible location on SPP's internet website. Changes posted prior to November 15[2] shall be reflected in the charges for the Rate Year beginning on the following January 1. Changes posted after November 15 will be reflected in the True-Up Adjustment for the Rate Year.

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[2] In the event that the SPP is no longer required to make a tariff filing to reflect ITC's Projected ATRR in the SPP OATT, and to the extent consistent with applicable Commission precedent, the November 15 deadline may be delayed or extended until December 1.

## Section 2 True-Up Adjustment

a. On or before June 1, 2010, and on or before June 1 of each succeeding Rate Year ("Publication Date"), ITC Great Plains shall calculate the Actual Annual Transmission Revenue Requirement ("Actual Total ATRR") and the Actual ATRR by individual project for the preceding calendar year pursuant to the Formula Rate ("Actual Individual ATRRs") (Attachment H-ITC Great Plains, Appendix A) and cause them to be posted at a publicly accessible location on SPP's internet website, and shall submit the True-Up Adjustment to the Federal Energy Regulatory Commission ("FERC" or "Commission") in an informational filing.

(i) If the Publication Date falls on a weekend or a holiday recognized by the FERC, then the Publication Date shall be the next business day.

(ii) The informational filing with the Commission is not intended to be subject to the Commission's notice requirements, but any such lack of notice does not limit the Commission's authority to initiate a proceeding on its own motion.

b. The True-Up Adjustment for the Rate Year:

(i) shall be calculated for the individual project revenue requirements and shall equal the respective Actual Individual ATRRs less the Projected Individual ATRRs for each project. In the event SPP does not bill the Projected Individual ATRR charges, the True-Up Adjustment shall be calculated as Actual Individual ATRRs less the Actual Revenues (equal to the charges actually billed by SPP for transmission service during the Rate Year). In no case shall the True-Up be calculated such that ITC recovers (i) more than its Actual Individual ATRRs; or (ii) any Unpaid Obligations. Unpaid Obligations shall be defined as any ITC charges that were billed by SPP (whether zonal or SPP-wide) but which SPP did not actually collect. ITC commits to use commercially reasonable efforts to obtain from SPP, and make available to Interveners in FERC Docket No. ER09-548, data concerning both amounts that are billed and those collected with respect to the ITC charges in order to ensure that no adjustment for Unpaid Obligations is included.

(ii) shall include a data-populated Template (*i.e.*, a working spreadsheet) showing all calculations in the Actual Total ATRR and in the Actual Individual ATRRs as well as all supporting calculations and workpapers that demonstrate and explain information not otherwise set out in ITC Great Plains' FERC Form 1.[3]

(iii) shall be based upon ITC Great Plains' FERC Form 1 for the most recent calendar year, FERC Form 1 reporting requirements as applicable to ITC Great Plains, FERC's orders establishing general transmission ratemaking policies applicable to ITC Great Plains, FERC's USoA, the books and records of ITC Great Plains consistent with the USoA, ITC Great Plains' accounting policies and practices, and the SPP OATT provisions affecting the charges under the Formula Rate.

(iv) shall provide supporting documentation for all data (and all adjustments thereto or allocations thereof) not otherwise available in the FERC Form 1 that are used in the Formula Rate;[4]

(v) shall include disclosure of and an explanation of changes in ITC Great Plains' accounting policies and practices with respect to capitalization policy, changes in the application of the FERC USoA that result in the recording of transactions in a different account, and changes in the FERC USoA and Form 1 reflected in the current True-Up Adjustment calculation of Actual Total ATRR and Actual Individual ATRRs from those in effect for the previous year's True-Up Adjustment calculation, to the extent such changes, individually or in the aggregate affect the charges calculated under the Formula Rate ("Material Accounting Changes"). To the extent there are Material Accounting Changes, ITC Great Plains shall disclose those in its FERC Form 1 and/or Form 3-Q, available at the FERC website (www.ferc.gov);

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[3] If the referenced form is superseded, the successor form(s) shall be utilized and supplemented in order to provide equivalent information for the Formula Rate template with the same level of detail as in the superseded form.

[4] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate True-Up Adjustment will either be taken directly from the FERC Form 1 or reconcilable to the FERC Form 1 by the application of clearly identified and supported information. Where the reconciliation in the True-Up Adjustment is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

(vi) shall include disclosure of known changes in (1) FERC's USoA; (2) FERC Form No. 1 reporting requirements; (3) FERC's orders establishing general transmission ratemaking policies applicable to ITC Great Plains; or (4) SPP OATT provisions affecting the charges under the Formula Rate that have occurred since the later of the effective date or the posting of the most recent such disclosure, to the extent that items (1) through (4) above have an effect on the charges under the Formula Rate or calculation of the Annual Projection or True-Up Adjustment, as applicable;

(vii) shall be subject to review and challenge in accordance with the procedures set forth in Sections 3 and 4 of these Protocols; and

(viii) shall be subject to review and challenge with respect to the prudence of any costs and expenditures included for recovery in the True-Up Adjustment; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof in such prudence challenges.

c. If any changes to the data inputs, including but not limited to revisions or restatements of ITC Great Plains' Form 1 or changes resulting from any FERC proceeding to consider a True Up Adjustment, would affect the charges collected under the Formula Rate for any Rate Year, such corrections and any resulting adjustment(s) to the past Actual Total ATRR and past Actual Individual ATRRs shall be identified and reflected in the True-Up Adjustment for the next effective Rate Year, with interest as provided herein. ITC shall promptly notify the Interested Parties of such changes and file a correction to the True-Up Adjustment with FERC as an amended informational filing and provide a copy to the SPP for prompt posting at a publicly accessible location on the SPP internet website. Such corrections shall be reflected, with Interest as calculated pursuant to section 2.d, below, in the next True-Up and Annual Projection. Review of corrections to any True-Up Adjustment reflected in an Annual Projection will be conducted during the process surrounding the Annual Projection and True-Up Adjustment in which the corrections are reflected.

d. Interest on any over-recovery of the net revenue requirement shall be determined based on the interest rates set forth in the Commission's regulations at 18 C.F.R. § 35.19a. Interest on any under-recovery of the net revenue requirement for the current True-Up Adjustment shall be determined using the interest rate equal to the lower of the FERC interest rate or the rate on any ITC Great Plains revolving credit facility. In either case, the interest payable shall be calculated using the average of the interest rates used to calculate the time value of money for the twenty-four (24) months during which the over- or under-recovery in the net revenue requirement exists. The interest rate to be applied to the over- or under- recovery in the net revenue requirement will be determined using the average of the interest rates for the nineteen (19) months preceding August of the current year.

(i) Interest on any over- or under-recovery due to corrections for preceding True-Up Adjustment Rate Years shall be calculated monthly on such over- or under-recovery from July 1 of the corrected Rate Year through June 30 of the Rate Year in which such over- or under-recovery is reflected ("Correction Period"), as illustrated in Attachment 1 to these Protocols. The applicable interest rates for an over-recovery shall be as computed on Worksheet 8 to the Formula Rate. The applicable interest rates for an under-recovery shall be as computed on Worksheet 8 to the Formula Rate.

e. The Formula Rate shall not recover any charges associated with a Regulatory Asset or Abandoned Plant until ITC has made an FPA Section 205 filing seeking to recover such charges and has been authorized by the Commission to do so.

**Section 3 Annual Review Procedures**

Each True-Up Adjustment shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have the longer of 135 days after each annual Publication Date or until October 15 to serve reasonable information requests on ITC Great Plains ("Review Period"). Such information requests shall be limited to what is necessary to determine if ITC Great Plains has properly calculated the Annual Projection and the True-Up Adjustment and its components (including any corrections pursuant to Section 2.c) according to the procedures in these Protocols, whether the costs included in the True-Up Adjustment are properly recorded (including whether the costs are appropriately recovered by ITC Great Plains and whether the costs were put in correct accounts and in the correct amounts), prudently incurred, and otherwise consistent with ITC Great Plains' accounting policies and practices consistent with the USoA, whether the Formula Rate has been applied according to its terms including the procedures in these Protocols, and whether there has been a change in the application of the Formula Rate due to a change in (1) FERC's USoA; (2) FERC Form No. 1 reporting requirements; (3) FERC's orders establishing general transmission ratemaking policies applicable to ITC Great Plains; or (4) SPP OATT provisions affecting the charges under the Formula Rate, to the extent that items (1) through (4) above have an effect on the Formula Rate or calculation of the Annual Projection or True-Up Adjustment, as applicable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation method have been determined by FERC with respect to this Formula Rate (or resolved by a settlement with respect to this Formula Rate accepted by FERC) or in the context of True-Up Adjustments for other years, except that such information requests shall be permitted if they seek to determine (i) whether a prior year's approach on a given matter was the same or different from the current year's approach, (ii) whether there have been changed circumstances, or (iii) in connection with corrections pursuant to Section 2.c.

b. ITC Great Plains shall make a good faith effort to respond to information requests (the scope of which is defined in subsection a, above) within fifteen (15) days of receipt of such requests, but no later than November 1. Information requests received after 4 p.m. CPT shall be considered received the next business day.

c. If ITC Great Plains and any Interested Party are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, ITC Great Plains or the Interested Party may petition FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of information, as appropriate, in accordance with the Annual Review Procedures and consistent with FERC's discovery rules.

d. Interested Parties shall have until the latest of thirty (30) days after the production of all information, including the production of information as a result of the resolution of a discovery dispute under Section 3.c, thirty (30) days after resolution of a dispute that does not result in the production of additional information, or November 30 to notify ITC Great Plains in writing of any specific challenges, including challenges to the application of the Formula Rate or any specific challenges based on Material Accounting Changes or changes in (1) FERC's USoA; (2) FERC Form No. 1 reporting requirements; (3) FERC's orders establishing general transmission ratemaking policies applicable to ITC Great Plains; or (4) SPP OATT provisions affecting the charges under the Formula Rate, to the extent that items (1) through (4) above have an effect on charges under the Formula Rate or calculation of the Annual Projection or True-Up Adjustment, as applicable ("Preliminary Challenge"). The time period for Interested Parties to raise Preliminary Challenges is the "Preliminary Challenge Period."

e. ITC Great Plains may not propose any changes to the Formula Rate by means of the Annual Projection or True-Up Adjustment. Any modifications to the Formula Rate will require a FERC order.

**Section 4 Resolution of Challenges**

a. ITC Great Plains shall provide a written response to any Preliminary Challenge submitted to it within fifteen (15) business days of receipt. Its written response shall notify the Interested Party of the extent to which ITC Great Plains agrees or disagrees with the position raised by the Interested Party, and what, if any, modifications to the True-Up Adjustments will result. If ITC Great Plains disagrees with the Preliminary Challenge, it shall provide supporting documentation with its response.

b. If ITC Great Plains and any Interested Party(ies) have not fully resolved to all Interested Party's(ies') satisfaction any Preliminary Challenge, an Interested Party shall have the right to file a challenge with the FERC, pursuant to Section 206 or 306 of the Federal Power Act ("Formal Challenge"). Any Formal Challenge must be filed

with FERC by the later of (i) thirty (30) days after receipt of ITC Great Plains' response to a Preliminary Challenge, or (ii) January 19, and shall be served on ITC Great Plains by electronic service on the date of such filing; however, there shall be no need to make a Formal Challenge or to await conclusion of the Preliminary Challenge Period if the FERC already has initiated a proceeding to consider the True-Up Adjustment.

c. Failure to notify ITC Great Plains of a Preliminary Challenge shall not bar pursuit of the issue (i) in a Formal Challenge, and/or (ii) in a subsequent True-Up Adjustment review.

d. If ITC Great Plains and any Interested Party(ies) agree upon a resolution to a Preliminary Challenge, such resolution shall be reflected in the Annual Projection as provided in Section 1.h, if resolution is reached by November 8. Otherwise, any resolution to a Preliminary Challenge, or a Formal Challenge, if applicable, shall be reflected in the first True-Up Adjustment following resolution of the challenge, with interest as provided herein.

e. Any response by ITC Great Plains to a Formal Challenge must be submitted to the FERC within the time period specified by a FERC notice in response to the Formal Challenge, or, if no such notice is issued, within thirty (30) days of the date of the filing of the Formal Challenge, unless such time period is extended by the mutual agreement of ITC Great Plains and the Interested Party filing a Formal Challenge or by FERC, and shall be served on the filing Party(ies) by electronic service on the date of such filing.

f. In any proceeding concerning a given year's True-Up Adjustment (including corrections) or Material Accounting Change(s), ITC Great Plains shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has reasonably and accurately calculated the True-Up Adjustment and/or reasonably adopted and applied the Material Accounting Change.

g. Failure to file a Formal Challenge regarding an issue raised in a Preliminary Challenge shall not bar pursuit of such issue(s) or the filing of a Formal Challenge as to such issue(s) as relates to a subsequent True-Up Adjustment review.

h. All information and correspondence produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the Federal Power Act, or in any proceeding before a U.S. Court of Appeals to review a FERC decision concerning the Formula Rate.

i. Nothing herein shall be deemed to limit in any way the right of ITC Great Plains to file unilaterally, pursuant to FPA Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, ROE), or

to replace the Formula Rate with a stated rate, or the right of any other party or FERC acting *sua sponte* to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder.

j. These Protocols in no way limit the rights of ITC Great Plains or any party or FERC acting *sua sponte* to initiate a proceeding at FERC at any time with respect to the Formula Rate or any Annual Projection or True-Up Adjustment consistent with the party's full rights under the Federal Power Act, including Sections 205, 206 and 306, and FERC's regulations.

k. Neither failure to notify ITC Great Plains of a Preliminary Challenge, nor failure to file a Formal Challenge, nor failure to exercise any rights under FPA Sections 205, 206, and 306 and FERC's regulations in any given year shall be construed as a bar to raising any issue in any proceeding initiated at FERC; however, neither ITC Great Plains nor any Interested Party shall be precluded from raising any such failure or the reason for such failure as a factor(s) to be considered by the Commission in resolving such issue.

l. In response to a FERC order on a challenge under FPA Section 306, ITC may be required to correct past errors resulting in a charge being collected other than that authorized under the Formula Rate.

**Section 5 Construction Work in Progress**

a. Accounting. For transmission projects where ITC Great Plains has been authorized by the Commission to include 100 percent of Construction Work in Progress ("CWIP") in transmission rate base ("incentive transmission project"), ITC Great Plains shall use the following accounting procedures to ensure that it does not recover an Allowance for Funds Used During Construction ("AFUDC") for such project.

(i) ITC Great Plains shall assign each authorized incentive transmission project a unique Funding Project Number ("FPN") for internal cost tracking purposes.

(ii) ITC Great Plains shall record actual construction costs to each FPN through work orders that are coded to correspond to the FPN for each incentive transmission project. Such work orders shall be segregated from work orders for non-incentive transmission projects for which the Commission has not authorized ITC Great Plains to include any portion of CWIP in rate base. The fixed asset accounting system requires certain basic information to establish a work order, such as whether the work order is eligible for AFUDC.

(iii) For each incentive transmission project ITC Great Plains shall prepare monthly work order summaries of costs incurred under the associated FPN. These summaries shall show monthly additions to CWIP and plant in

service and shall correspond to amounts recorded in ITC Great Plains' FERC Form 1. ITC Great Plains shall use these summaries as data inputs into the Annual Update calculated pursuant to Section 1. ITC Great Plains shall make such work order summaries available upon request under the Annual Review Procedures of Section 3.

(iv) When an incentive transmission project, or portion thereof, is placed into service, Accounting shall cause the fixed asset accounting system to transfer the accumulated charges from account 107 - CWIP to account 106 – Completed Construction Not Classified. The result of this transfer is that ITC Great Plains deducts from the total CWIP the accumulated charges for work orders under the FPN for that project, or portion thereof. The purpose of this control process is to ensure that expenditures are not double counted as both CWIP and as plant in service.

(v) For non-incentive transmission projects, ITC Great Plains shall record AFUDC to be applied to CWIP, exclusive of the portion of such CWIP for a non-incentive project that is included in rate base pursuant to Commission authorization, and capitalized when the project is placed into service.

b. Annual Reporting. For transmission projects where ITC Great Plains has been authorized by the Commission to include any portion of CWIP in transmission rate base, ITC Great Plains shall post the following information concerning each such projects at a publicly accessible location on SPP's internet website at the time of ITC Great Plains' Annual Update that shall include the following information concerning each such projects:

(i) the actual amount of CWIP recorded for each project through the most recently reported quarter end;

(ii) the resulting effect on the CWIP revenue requirement for the most recently completed year;

(iii) a statement of the current status of each project; and

(iv) the estimated in-service date for each project.

**ITC Great Plains**
**Formula Rate Implementation Protocols**

## Attachment 1

### Example of Calculation of Interest on Over- or Under-Recovery due to Corrections in Previous Years (Protocols, Section 2.e(i))

i) If the rate year 1 is completed, and the revenue requirement is initially identified in year 2, but then subsequently corrected in time to incorporate the corrected true-up in year 3, then interest would be computed for the 24 month period from mid-year of the cost year until mid-year of the true-up year.

ii) However, if the correction was identified after the true-up adjustment was incorporated in charges to customers in year 3, but in time to incorporate a true-up adjustment in year 4, then the amount of the adjustment would be computed for a 36 month period.

iii) For example, if the initial under-recovery principal amount was $1000 in year 1, and the interest rate on under-recoveries was 3% per year and the interest rate on over-recoveries was 5%, then ordinarily the amount to be recovered from ratepayers in year 3 would be $1060.

iv) However, if there were a correction, such that the under-recovery principal amount was $2100 in year 1, (rather than the $1,000 under recovery in (iii) above), and the corrected amount was not incorporated into charges until year 4, then ratepayers would be charged $1060 in year 3, and charged [($2100 - $1000) x .03 x 3) ] + ($2100 - $1000) = $1199 in year 4.

v) However, if there were a correction such that the principal amount was an $1100 over-recovery in year 1 (rather than the $1,000 under recovery in (iii) above), and the corrected amount was not incorporated into charges until year 4, ratepayers would be charged $1060 in year 3, then ratepayers would be credited as follows:

[($1100 + $1000) x .05 x 3)] + ($1100 + $1000) = $2415 in year 4.

# Addendum 10 to Attachment H – Part 1A

**Evergy Metro Inc.(EMe)**

**Rate Formula Template**

**Table of Contents**

**Overview**

The formula is calculated in two steps. The first step is to fill out Tabs A-1 thru A-11, and the Actual Gross Rev Req tab with data from the previous year's Form 1. This data input results in the calculation of the actual annual transmission revenue requirement (Actual ATRR) for the previous year, as shown in the Actual Net Rev Req tab. The results of this calculation are presented to the customers for review no later than June 1 each year.

The TU (True-up) tab uses the Actual ATRR from the Actual Net Rev Req tab and compares it to the Projected ATRR (without the True-up for a prior year) that customers were billed for the same period. Interest is added to the difference and the adjusted true-up then is included in the Projected Net Rev Req tab.

The projected O&M and plant balances are calculated in Tabs P-1 thru P-5. These sheets feed into the Projected Gross Rev Req tab and ultimately into the Projected Net Rev Req tab. The RTO Projects Smry tab retrieves project specific data from other tabs to calculate the amount of revenue requirements associated with those projects which are contained in the total Projected Gross Revenue Requirement amount. The Spon Projects Smry tab does the same process for Sponsored projects. The total revenue requirements for these two groups of upgrades and revenue credits are subtracted from the EMe total revenue requirement to obtain the Zonal ATRR (line 20, before true-up). This calculation is shown on the Projected Net Rev Req tab. This tab also calculates the point-to-point zonal rates. SPP rates are set on the trued up Base Plan Net Revenue Requirements, Balanced Portfolio Net Revenue Requirements, and ITP/Priority Projects Net Revenue Requirements as well as the trued up Zonal Net Revenue Requirements. The specific charges are defined under the SPP Open Access Transmission Tariff.

Cells highlighted in yellow are data input cells. Some cells may reference the results from other calculations in the formula. Such cell references may change from year to year, requiring manual adjustment of the reference or the direct entry of the proper value.

| Filed Page | Tab | Description |
|---|---|---|

| | | |
|---|---|---|
| **2** | Summary | Summary of projected revenue requirements,  point to point rates, and Schedule 1 rates. |
| **3** | Actual Net Rev Req | Actual net revenue requirements for most recent calendar year |
| **4-8** | Actual Gross Rev Req | Actual gross revenue requirements for most recent calendar year |
| **9** | Actual Sch 1 Rev Req | Actual revenue requirements for Schedule 1 |
| **10** | A-1 (Act. Rev. Credits) | Actual revenue credits |
| **11** | A-2 (Act. Divisor) | Actual transmission system load |
| **12-13** | A-3 (Act  ADIT) | Actual Accumulated Deferred Income Taxes (ADIT) |
| ***14-17*** | *A3-2 (Act ADIT wkst)* | *Deficient/Excess Deferred Income Taxes* |
| ***18-20*** | A-4 (Act. Excluded Assets) | Assets excluded from transmission rate base |
| ***21-22*** | A-5 (Act. Depreciation Rate) | Depreciation rates for each account |
| ***23*** | A-6 (Act. Taxes Other) | Actual taxes other than income taxes |
| ***24-29*** | A-7 (Act. RTO Directed Projects) | Actual RTO-directed projects: Base Plan, Balanced Portfolio, and ITP/Priority Projects |
| ***30*** | A-8 (Act. Sponsored Projects) | Actual sponsor-funded projects |
| ***31-37*** | A-9 (Act. Incentive Plant) | Actual incentive returns |
| ***38*** | A-10 (Act. A&G) | Actual Administrative and General Expenses |
| **39-40** | A-11 (Act. 13-Mo & BOY and EOY Aver.) | Actual 13-Month averages and BOY-EOY averages for rate base items |

| | | |
|---|---|---|
| ***41-42*** | TU (True-up) | True-up adjustment and interest calculation |
| ***43-51*** | RTO Project Smry | Actual and projected RTO-directed projects |
| ***52-54*** | Spon Project Smry | Actual and projected sponsor-funded projects |
| ***55*** | Projected Net Rev Req | Projected net revenue requirements for next calendar year |
| ***56-60*** | Projected Gross Rev Req | Projected gross revenue requirements for next calendar year |
| ***61*** | Projected Schedule 1 Rev Req | Projected revenue requirements for Schedule 1 |
| ***62-65*** | P-1 (Proj Trans Plant) | Projected transmission plant for next calendar year and incentive returns |
| ***66*** | P-2 (Proj. Exp. & Rev. Credits) | Projected expenses and revenue credits for next calendar year |
| ***67*** | P-3 (Proj. Trans. Network Load) | Projected transmission system load |
| ***68-71*** | P-4 (Proj. RTO Projects) | Projected RTO-directed projects:  Base Plan, Balanced Portfolio, ITP/Priority Projects |
| ***72*** | P-5 (Proj. Sponsored. Projects) | Projected sponsor-funded projects |

Rate Formula Template

Utilizing FERC Form 1 Data

Projected Revenue Requirements

For the 12 months ended - December 31, 20XX

Evergy Metro Inc.

(EMe)

| Line No. | (1) | (2) | (3) | (4) | (5) Amount | |
|---|---|---|---|---|---|---|
| **A.** | **Net Revenue Requirement Including True-Up** | | | | | |
| 1 | Base Plan Net Revenue Requirements | (Projected Net Rev Req, ln 28) | $ - | | | |
| 2 | Balanced Portfolio Net Revenue Requirement | (Projected Net Rev Req, ln 29) | - | | | |
| 3 | ITP/Priority Projects-1 Net Revenue Requirement | (Projected Net Rev Req, ln 30) | - | | | |
| 4 | ITP/Priority Projects-2 Net Revenue Requirement | (Projected Net Rev Req, ln 31) | - | | | |
| 5 | Total | (sum line 1 thru line 4) | | | $ - | |
| 6 | Zonal Net Revenue Requirement | (Projected Net Rev Req, ln 33) | | | | $ - |
| **B.** | **Point-to-Point Service** | | | | | |
| 7 | EMe 12-CP. Peak Demand | (Wksht. P-3, line 15) | | | | - MW |
| 8 | Annual Point-to-Point Rate in $/MW - Year | ( Line 6 / line 7) | | | $ - | |
| 9 | Monthly Point-to-Point Rate in $/WM - Month | ( Line 8 / 12 months) | | | $ - | |
| 10 | Weekly Point-to-Point Rate in $/MW - Weekly | ( Line 8 / 52 weeks) | | | $ - | |
| 11 | Daily On-Peak Point-to-Point Rate in $/MW - Day | ( Line 8 / 260 days) | | | $ - | |
| 12 | Daily Off-Peak Point-to-Point Rate in $/WM - Day | ( Line 8 / 365 days) | | | $ - | |
| 13 | Hourly On-Peak Point-to-Point Rate in $/MW - Hour | ( Line 11 / 16 hours) | | | $ - | |
| 14 | Hourly Off-Peak Point-to-Point Rate in $/WM - Hour | ( Line 12 / 24 hours) | | | $ - | |

| | | | | |
|---|---|---|---|---|
| **C.** | **Schedule 1 ARR** | | | |
| 15 | Net Schedule 1 Revenue Requirement for Zone | (Projected Sch 1 Rev Req, ln 9) | $ - | |
| **D** | **Schedule 1 Rate Calculations** | | | |
| 16 | EMe 12-CP. Peak Demand | (Wksht. P-3, line 15) | - | MW |
| 17 | Annual Point-to-Point Rate in $/MW - Year | (Line 15 / Line 16) | $ - | |
| 18 | Monthly Point-to-Point Rate in $/MW - Month | (Line 17 / 12) | $ - | |
| 19 | Weekly Point-to-Point Rate in $/MW - Week | (Line 17 / 52) | $ - | |
| 20 | Daily Point-to-Point Rate in $/MW - Day | (Line 17 / 365) | $ - | |
| 21 | Hourly Point-to-Point Rate in $/MW - Hour | (Line 17 / 8760) | $ - | |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Net Revenue Requirements
For the 12 months ended - December 31, 20XX

EVERGY METRO INC.
(EMe)



| Line No. | (1) | (2) Reference | (3) | (4) | (5) | (6) Amount |
|---|---|---|---|---|---|---|
| | **REVENUE REQUIREMENTS** | (incl. Approved Incentives, if any) | | | | |
| 1 | Total Transmission Facilities | (Act Gross Rev, p. 2, ln 27, col. 7) | | | | $ - |
| 2 | Base Plan Gross Revenue Requirements | (Wksht. A-7, ln 6) | $ - | | | |
| 3 | Balanced Portfolio Revenue Requirement | (Wksht. A-7, ln 10) | - | | | |
| 4 | ITP/Priority Projects-1 Revenue Requirement | (Wksht. A-7, ln 14) | - | | | |
| 5 | ITP/Priority Projects-2 Revenue Requirement | (Wksht. A-7, ln 18) | - | | | |
| 6 | Sponsored Gross Revenue Requirements | (Wksht. A-8, ln 4) | - | | | |
| 7 | Total | (sum line 2 thru line 6) | | $ - | | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | Zonal Gross Revenue Requirement | ( line 1 minus line 7) | | | $ | - |
| | **REVENUE CREDITS** | | | | | |
| 9 | Base Plan Gross Revenue Credit | (Wksht. A-1, p.2 line 13) | $ - | | | |
| 10 | Balanced Portfolio Revenue Credit | (Wksht. A-1, p.2 line 14) | - | | | |
| 11 | ITP/Priority Projects-1 Revenue Credit | (Wksht. A-1, p.2 line 15) | - | | | |
| 12 | ITP/Priority Projects-2 Revenue Credit | (Wksht. A-1, p.2 line 16) | - | | | |
| 13 | Total | (sum line 9 thru line 12) | | $ - | | |
| 14 | Zonal Gross Revenue Credit | (Wksht. A-1, p.1 line 39) | | | $ | - |
| | **NET REVENUE REQUIREMENT** | | | | | |
| 15 | Base Plan Net Revenue Requirements | ( line 2 minus line 9) | $ - | | | |
| 16 | Balanced Portfolio Net Revenue Req. | ( line 3 minus line 10) | - | | | |
| 17 | ITP/Priority Projects-1 Net Revenue Req. | ( line 4 minus line 11) | - | | | |
| 18 | ITP/Priority Projects-2 Net Revenue Req. | ( line 5 minus line 12) | - | | | |
| 19 | Total | (sum line 15 thru line 18) | | $ - | | |
| 20 | Zonal Net Revenue Requirement | ( line 8 minus line 14) | | | $ | - |
| 21 | Total Transmission Net Plant | (Act Gross Rev, p. 1, ln 16 less ln 17) | | | $ | - |
| 22 | Total Facilities Rev. Req. without Incentives | (Act Gross Rev, p. 2, ln 29 ) | | | $ | - |
| 23 | Actual Facilities Carrying Charge | ( line 22 / line 21) | | | | 0.0000% |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements

For the 12 months ended - December 31, 20XX

EVERGY METRO INC.. (EMe)

(EMe)



| Line No. | RATE BASE: | Form No. 1 Page, Line, Col. | EMe | EMe Total | | Allocator | | Transmission (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| | PLANT IN SERVICE | | | | | | | |
| 1 | Production | (Wksht. A-11, p.1, Line 1 & 2) | $ - | $ - | | | | |
| 2 | Transmission | (Wksht. A-11, p.1, Line 3) | - | - | | DA | 1.00000 | $ - |
| 3 | Less: Excluded Plant | (Wksht. A-4, p.1, Line 30 Note I & K) | | | | | | - |
| 4 | Distribution | (Wksht. A-11, p.1, Line 4) | - | - | | | | |
| 5 | General | (Wksht. A-11, p.1, Line 5) | - | - | | W/S | 0.00000 | - |
| 6 | Intangible & Other | (Wksht. A-11, p.1, Line 6) | - | - | | W/S | 0.00000 | - |
| 7 | TOTAL GROSS PLANT | (sum line 1, 2, 4, 5 & 6 less line 3) | $ - | $ - | | | | $ - |
| | ACCUMULATED DEPRECIATION | (Note Q) | | | | | | |
| 8 | Production | (Wksht. A-11, p.1, Line | $ | $ | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | 8 & 9) | - | - | | | |
| 9 | Transmission | (Wksht. A-11, p.1, Line 10) | - | - | DA | 1.00 000 | $ - |
| 10 | Less: Excluded Plant | (Wksht. A-4, p.1, Line 30 Note I & K) | | | | | - |
| 11 | Distribution | (Wksht. A-11, p.1, Line 11) | - | - | | | |
| 12 | General | (Wksht. A-11, p.1, Line 12) | - | - | W/S | 0.00 000 | - |
| 13 | Intangible & Other | (Wksht. A-11, p.1, Line 13) | - | - | W/S | 0.00 000 | - |
| 14 | TOTAL ACCUM. DEPRECIATION | (sum lines 8,9,11,12&13 less 10) | $ - | $ - | | | $ - |
| | NET PLANT IN SERVICE | | | | | | |
| 15 | Production | ( line 1- line 8) | $ - | $ - | | | |
| 16 | Transmission | ( line 2- line 9) | - | - | | | $ - |
| 17 | Less: Excluded Plant | ( line 3- line 10) | - | - | | | - |
| 18 | Distribution | ( line 4- line 11) | - | - | | | |
| 19 | General | ( line 5- line 12) | - | - | | | - |
| 20 | Intangible & Other | ( line 6- line 13) | - | - | | | - |
| 21 | TOTAL NET PLANT | (sum lines 15,16,18,19 & 20 less 17) | $ - | $ - | | | $ - |
| | ADJUSTMENTS TO RATE BASE | | | | | | |
| 22 | Accumulated Deferred Income Taxes | (Wksht. A-3, p.1, Line 9*b*) | $ - | $ - | DA | 1.00 000 | - |
| 23 | Reserve Funds (Non-Escrowed) | (Wksht. A-11, p.2, Line 23g) | - | - | DA | 1.00 000 | - |
| 24 | Unamortized Abandoned Transmission Plant | (Wksht. A-11, p.2, Line 25, Note S) | - | - | DA | 1.00 000 | - |
| 25 | CWIP for Incentive Transmission Projects | (Wksht. A-9, p.1, Line 24, Note T) | - | - | DA | 1.00 000 | - |
| 26 | CWIP Regulatory Liability for Transmission Projects | (Wksht. A-11, p.2, Line 28, Note T) | - | - | DA | 1.00 000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 27 | TOTAL ADJUSTMENTS | (sum lines 22 thru line 26) | $ - | $ - | | | $ - |
| 28 | LAND HELD FOR FUTURE USE | (Wksht. A-11, p.2, lines 31 Note B) | $ - | $ - | DA | 1.000 | $ - |
| | WORKING CAPITAL | | | | | | |
| 29 | CWC | calculated (Note C) | | | | | $ - |
| 30 | Materials & Supplies | (Wksht. A-11, p.1, Line 34 & 37) | $ - | $ - | TP | 0.000 | - |
| 31 | Stores Expense | (Wksht. A-11, p.2, Line 41) | - | - | W/S | 0.000 | - |
| 32 | Prepayments (Account 165) | (Wksht. A-11, p.2, Line 43) | - | - | W/S | 0.000 | - |
| 33 | TOTAL WORKING CAPITAL | (sum line 29 thru line 32) | $ - | $ - | | | $ - |
| 34 | Rate Base | (sum lines 21, 27 , 28 & 33) | | | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

EVERGY METRO INC.. (EMe)

(EMe)



| Lin | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | **Form No. 1** | **EMe** | **EMe Total** | | | **Transmission** |

| No. | | Page, Line, Col. | | | Allocator | | (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|
| | **O&M** | | | | | | |
| | | | $ | $ | | | |
| 1 | Transmission | 321.112.b | - | - | | | |
| 2 | Less Account 561 | 321.84.b thru 321.92.b 321.96.b | - | - | | | |
| 3 | Less Account 565 | (Note D) | - | - | | | |
| 3a | Less: Transmission Leases & Facility Charges | ( 321.Notes) | - | - | | | |
| 4 | Total Transmission O&M | ( line 1 less lines 2 thru 3a) (Note F) | $ - | $ - | TP | 0.00000 | $ - |
| 5 | A&G -Adjusted | (Wkshts. A-10, line 8) | - | - | W/S | 0.00000 | - |
| 5a | Less: Actual PBOP | (Wkshts. A-10, line 9) (Note R) | - | - | W/S | 0.00000 | - |
| 5b | Plus: PBOP (Projected 2010 see Note R) | (Wkshts. A-10, line 10) (Note R) | - | - | W/S | 0.00000 | - |
| 5c | Plus: Safety Advertising | (Wkshts. A-10, line 11) | - | - | W/S | 0.00000 | - |
| 5d | Plus: Advertising -Transmission | (Wkshts. A-10, line 16) | - | - | DA | 1.00000 | - |
| 5e | Plus: Research -Transmission | (Wkshts. A-10, line 21) | - | - | DA | 1.00000 | - |
| 5f | Plus: Regulatory Exp -Transmission | (Wkshts. A-10, line 26) | - | - | DA | 1.00000 | - |
| 5h | Plus: Corporate Visibility -Transmission | (Wkshts. A-10, line 32) | - | - | W/S | 0.00000 | - |
| 6 | Transmission Lease Payments & Facility Charges | (321.Notes) (Note E) | - | - | DA | 1.00000 | - |
| 7 | TOTAL O&M | (sum lines 4, 5, 5b thru 6 less 5a ) | $ - | $ - | | | $ - |
| | **DEPRECIATION EXPENSE** | (Note Q) | | | | | |
| 8 | Transmission | (336.7.f ) | $ | $ | TP | 0.00000 | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | - | - | | 000 | - |
| 9 | General | (336.10.b,c & d) | - | - | W/S | 0.00 000 | - |
| 1 0 | Intangible & Other | 336.1f | - | - | W/S | 0.00 000 | - |
| 1 1 | Amortization of Abandoned Transmission Plant | Acct. 407 (Note S) | - | - | DA | 1.00 000 | - |
| 1 2 | TOTAL DEPRECIATION | (sum line 8 thru line 11) | $ - | $ - | | | $ - |
| | **TAXES OTHER THAN INCOME TAXES** | (Note G) | | | | | |
| | LABOR RELATED | | | | | | |
| 1 3 | Payroll | (Wksht A-6, line 10) | $ - | $ - | W/S | 0.00 000 | $ - |
| 1 4 | Highway and vehicle | (Wksht A-6, line 10) | - | - | W/S | 0.00 000 | - |
| | PLANT RELATED | | | | | | |
| 1 5 | Property | (Wksht A-6, line 10, Note M) | - | - | GP | 0.00 000 | - |
| 1 6 | Gross Receipts | (Wksht A-6, line 10) | - | - | NA | | - |
| 1 7 | Other | (Wksht A-6, line 10) | - | - | GP | 0.00 000 | - |
| 1 8 | TOTAL OTHER TAXES | (sum line 13 thru line 17) | $ - | $ - | | | $ - |
| | **INCOME TAXES** | (Note H) | | | | | |
| 1 9 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | | | | 0.00% | | |
| 2 0 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | | | | 0.00% | | |
| 2 1 | GRCF = 1 / (1 - T) | (GRCF = 1 / (1-T from Line 19)) | | | - | | |
| 2 2 | Amortized Investment Tax Credit | (266.8f) (enter negative) | $ - | $ - | | | |
| *2 a* | ***(Excess)/Deficient Deferred Income Taxes*** | *(Wksht A3-2, Note U)* | *$ -* | *$ -* | | | |
| 2 | Income Tax Calculation | (Line 20*(Line 34 of | | | | | $ |

| | | | | | | |
|---|---|---|---|---|---|---|
| 3 | | Page 1)*( Line 21 of Page 4 ) + Line 26 of Page 4 ) | | | | - |
| 24 | ITC adjustment | ( line 21 X line 22) | - | NP = | 0.000 | - |
| *24a* | ***(Excess)/Deficient Deferred Income Tax Adjustment*** | *(Line 21 * line 22a)* | *$-* | *DA* | *1.000* | *-* |
| 25 | Total Income Taxes | ( line 23 plus line 24 *plus line 24a*) | | | | $ - |
| 26 | **RETURN** | ((Line 34 of Page 1)*( Line 21 of Page 4 ) + (Line 25 - Line 26) of Page 4 ) | | | | $ - |
| 27 | **GROSS REV. REQUIREMENT WITH INCENTIVES** | (sum line 7, 12, 18, 25 & 26) | $ - | | | $ - |
| 28 | LESS: Gross Revenue Requirements for Incentives | ( line 35 of page 4 ) | | | | - |
| 29 | **GROSS REV. REQUIREMENT** | ( line 27 less line 28) | $ - | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Actual Gross Rev Page 3 of 5

EVERGY METRO INC.. (EMe)

(EMe)

**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMe | (4) EMe Total | (5) Allocator | (6) | (7) Transmission (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|
| | **TRANSMISSION PLANT INCLUDED IN FORMULA** | | | | | | |
| | | | $ | $ | | | $ |
| 1 | Total transmission plant | (Line 7 of Page 3 ) | - | - | | | - |
| 2 | Less: Net Substation, 34kV, & Radial Lines to Distr. Plt. | (Wksht A-4, ln 28) (Note I) | - | - | | | - |
| 3 | Less: Total GSU in Transmission Plant | (Wksht. A-4, ln 7) (Note K) | - | - | | | - |
| | | | $ | $ | | | $ |
| 4 | Transmission plant included in rates | ( line 1 less lines 2 & 3) | - | - | | | - |
| 5 | Percentage of transmission plant included in rates | ( line 4 / line 1) | | | TP= | 0.00000 | |
| | **GROSS AND NET PLANT ALLOCATORS** GROSS PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | |
| | | | $ | $ | | | |
| 6 | Production | ( page 1, line 1 ) | - | - | NA | | |
| 7 | Transmission | ( page 1, line 2 ) | - | - | DA | 1.00000 | $ - |
| 8 | Less: Excluded Plant | ( page 1, line 3 ) | | | | | - |
| 9 | Distribution | ( page 1, line 4 ) | - | - | | | |
| 10 | General & Intangible | ( page 1, line 5 & 6 ) | - | - | W/S | 0.00000 | 0 |
| 11 | TOTAL GROSS PLANT | (sum Line 6, 7, 9 & 10 less Line 8) | $ - | $ - | GP = | 0.00000 | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | ACCUMULATED DEPRECIATION (ACTUAL HISTORICAL COST) (Note Q) | | | | | | |
| 1 | | | $ | $ | | | |
| 2 | Production | ( page 1, line 8 ) | - | - | NA | | |
| 3 | Transmission | ( page 1, line 9 ) | - | - | DA | 1.000000 | $ - |
| 4 | Less: Excluded Plant | ( page 1, line 10 ) | | - | | | - |
| 5 | Distribution | ( page 1, line 11 ) | - | - | | | |
| 6 | General & Intangible | ( page 1, line 12 & 13 ) | - | - | W/S | 0.000000 | 0 |
| 7 | TOTAL ACCUM. DEPRECIATION | (sum Line 12, 13, 15 & 16 less Line 14) | $ - | $ - | | | $ - |
| | NET PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | |
| 8 | Production | ( line 6 less 12) | $ - | $ - | | | |
| 9 | Transmission | ( line 7 less 13) | - | - | | | $ - |
| 20 | Less Excluded Plant | ( line 8 less 14) | - | - | | | - |
| 21 | Distribution | ( line 9 less 15) | - | - | | | |
| 22 | General & Intangible | ( line 10 less 16) | - | - | | | 0 |
| 23 | TOTAL NET PLANT | (sum Line 18, 19, 21 & 22 less Line 20) | $ - | $ - | NP = | 0.000000 | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

EVERGY METRO INC.. (EMe)

Actual Gross

(EMe)

**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMe | (4) EMe Total | (5) | (6) Allocator | (7) Transmission (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|
| | **WAGES & SALARY ALLOCATOR (W&S)** | | $ | $ | TP | Allocation | |
| 1 | Production | 354.20.b | $ - | $ - | | - | |
| 2 | Transmission | 354.21.b | 0 | - | 0.00000 | - | |
| 3 | Distribution | 354.23.b | 0 | - | | - | W&S Allocator ($ / Allocation) |
| 4 | Other | 354.24,25,26.b | 0 | - | | - | |
| 5 | Total | (sum line 1 thru line 4) | $ - | $ - | | 0 | |
| 5a | Wage & Salary Allocator Calculation | (Col 6, Line 5 divided by Col 4, Line 5) | | | | WS= | 0.00000 |
| | **RETURN (R)** | (Note N) | | | | | |
| 6 | Interest on Long-Term Debt | 256 & 257 notes | $ - | $ - | | | $ - |
| 7 | Amort. of Debt Disc. and Expense | 256 & 257 notes | - | - | | | - |
| 8 | Amortization of Loss on Reacquired Debt | 256 & 257 notes | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | - | | - | | | | - |
| 9 | Less: Amort. of Premium on Debt-Credit | 256 & 257 notes | - | | - | | | | - |
| 10 | Less: Amort. of Gain on Reacquired Debt-Credit | 256 & 257 notes | - | | - | | | | - |
| 11 | Long Term Interest | (sum line 6 to 8, less 9 & 10) | $ - | | $ - | | | | $ - |
| 12 | **Preferred Dividends** | 256 & 257 notes | $ - | | $ - | | | | $ - |
| | **Development of Common Stock:** | (Note N) | | | | | | | |
| 13 | Proprietary Capital | 256 & 257 notes | $ - | | $ - | | | | $ - |
| 14 | Less Preferred Stock | 256 & 257 notes | | 0 | - | | | | - |
| 15 | Less Noncontrolling Interest | 256 & 257 notes (Note O) | | 0 | - | | | | - |
| 16 | Less OCI Account 219 | 256 & 257 notes | - | | - | | | | - |
| 17 | Common Stock | ( line 13 Less 14, 15 & 16) | $ - | | $ - | | | | $ - |
| | | | $ | | $ | % | Cost (Note P) | | Weighted |
| 18 | Long Term Debt | 256 & 257 notes | $ - | | $ - | 0.00 % | - | WCLTD = | 0.000 0 |
| 19 | Preferred Stock | 256 & 257 notes | - | | - | 0.00 % | - | | 0.000 0 |
| 20 | Common Stock | 256 & 257 notes | - | | - | 0.00 % | 0.1110 | | 0.000 0 |
| 21 | Total | (sum line 18 thru line 20) | $ - | | $ - | 0.00 % | | R = | 0.000 000 |

**GROSS REV. REQUIREMENT FOR INCENTIVE PROJECTS**

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Plant Granted Incentive ROE Adder:** | | | | | |
| 2 | | | $ | $ | | |
| 2 | Total Incentive Plant | ( Wksht A-9, line 22) | - | - | | |
| 2 | | | | | | |
| 3 | Less: Total Accumulated Depreciation | ( Wksht A-9, line 22) | - | - | | |
| 2 | | | $ | $ | | |
| 4 | Net Incentive Plant | ( line 22 less line 23) | - | - | | |
| 2 | | ( Wksht A-9, p. 1, line | | | $ | |
| 5 | Incentive Return Including Taxes | 24) | | | - | |
| 2 | | ( line 25 *( page 2, line | | $ | | |
| 6 | Taxes Included in Incentive Return | 19) | | - | | |
| 2 | | | | | | |
| 7 | **Construction Work In Progress:** | | | | | |
| 2 | | ( Wksht A-9, p. 1, line | $ | $ | | |
| 8 | Total CWIP | 24 Note T) | - | - | | |
| 2 | | ( Wksht A-9, p. 1, line | | | $ | |
| 9 | Incentive Return Including Taxes | 24 ) | | | - | |
| 3 | | | | | | |
| 0 | **Abandoned Plant:** | | | | | |
| 3 | Unamortized Abandoned Transmission | ( line 24 of page 2) | $ | | | |
| 1 | Plant | (Note S) | - | | | |
| 3 | | ( line 21 X line 31 X ( | | $ | | |
| 2 | Tax-Adjusted Return on Abandoned Plant | 1 +EIT) | | - | | |
| 3 | | | | | | |
| 3 | Amortization Expense for Abandoned Plant | (Line 11 of page 2) | | - | | |
| 3 | | (sum line 32 thru line | | | $ | |
| 4 | Total Recovery for Abandoned Plant | 33) | | | - | |
| 3 | TOTAL GROSS REV. REQ. FOR | | | | | $ |
| 5 | INCENTIVE PROJ. | (sum line 25 , 29 & 34) | | | | - |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Actu
al
Gros
s

EVERGY METRO INC.. (EMe)

(EMe)

General Note: References to pages in this formula rate are indicated as: (page#, line#, col.#).

References to data from FERC Form 1 are indicated as: page#.line#.col

| Note Letter | |
|---|---|
| **A** | Reserved for future use. |
| **B** | Includes only Transmission plant. |
| **C** | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 7, col. 7.<br>Prepayments are the electric related prepayments booked to Account No. 165 and reported on FERC Form 1, p. 111, ln. 57.c. |
| **D** | Expenses recorded in Account 565, Transmission of Electricity by Others, are not recoverable through the formula rate. |
| **E** | Lease and joint facilities charges included on line 6, page 2 of 5, are those costs attributable to transmission facilities. |
| **F** | Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT. |
| **G** | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.<br>Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template. |
| **H** | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "percentage of federal income tax deductible for state income tax purposes". Furthermore, a utility that elected to utilize amortization of tax credits against taxable income rather than book tax credits to Account 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 2, line 21). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. KCMO Earnings Tax is not included in the calculation of the Composite State Income Tax Rate. |

Inputs Required: FIT = 0.00% Federal Income Tax Rate

| | | |
|---|---|---|
| SIT= | 0.00% | Composite State Income Tax Rate or Composite SIT |
| p = | 0.00% | Percentage of federal income tax deductible for state income tax purposes |

The Composite State Income Tax Rate reflects the effective rate for each tax jurisdiction, as well as the Composite Portion of FIT Deduction in State Returns:

| | Apportionment Factor | Rate | Effective Rate | % of FIT Deductible | Portion of Fed Tax Deductible = p |
|---|---|---|---|---|---|
| Missouri | 0.00% | 0.00% | 0.0000% | 0.00% | 0.00% |
| Kansas | 0.00% | 0.00% | 0.0000% | 0.00% | 0.00% |
| KS City | 0.00% | 0.00% | 0.0000% | 0.00% | 0.00% |
| Composite State Income Tax Rate | | | 0.0000% | | |
| Composite Portion of FIT Deduction for State Returns | | | | | 0.00% |

**I** Removes transmission plant determined by Commission order to be excluded from RTO transmission rate base under Docket No. EL08-89-000 (to the extent FERC Form 1 balances are not adjusted).

**J** Unless otherwise specified, OATT refers to the EMe and SPP OATTs.

**K** Removes generator step-up facilities determined by Commission order to be excluded from RTO transmission rate base under Docket No. EL08-89-000 (to the extent FERC Form 1 balances are not adjusted).

**L** Reserved for future use.

**M** If the transmission related component of property tax is specifically identified in Form 1, then a TP allocator shall be used. Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the Form 1.

**N** Beginning in 2009, included in page 256 notes of the FERC Form 1, the long term interest expense and preferred dividends and a 13-month average balance for long-term debt, preferred stock and common equity of Great Plains Energy will be provided. This information will be the reference for the capital structure and weighted cost of long term debt and preferred stock.

**O** The Noncontrolling Interest represents a third party's 50% investment in one of GPE's consolidated subsidiaries reported on the consolidated balance sheet's equity section separate from the parent's equity, as required by generally accepted accounting principles effective January 1, 2009.

**P** The approved ROE is 11.1%. No change in ROE may be made absent a filing with FERC. Any

incentive ROEs approved by the Commission are shown by project in Worksheet A-9.

**Q** The current depreciation rates used to calculate depreciation expense and accumulated depreciation balances are shown in worksheet A-5.

**R** The Post-Employment Benefits Other than Pensions (PBOP) expense projected for FY 2010 set forth below will be used in lieu of the actual PBOP in 2009 and subsequent years absent a filing with FERC that alters the amount.

| | |
|---|---|
| Post-Employment Benefits Other than Pensions | $8,598,615 |

**S** The Unamortized Abandoned Transmission Plant can only be included in rate base if authorized by the Commission.

**T** CWIP balances only included as authorized by the Commission. Regulatory liability offsets AFUDC accrual where CWIP is not included in state-regulated rate base.

***U*** *Includes the amortization of any excess/deficient income taxes resulting from changes to income tax rates (including changes in apportionment) and other actions take by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T).*

***V*** Reserved for future use.

**ALLOCATION FACTORS**

| Line No. | Allocators | Description | Location of Calculation or First Use of Allocator |
|---|---|---|---|
| 1 | **TP** | Percentage of transmission plant included in rate base. | Page 3, line 5, col 6 |
| 2 | **W/S** | Percentage of transmission labor included in rates | Page 4, line 5a, col 7 |
| 3 | **DA** | Direct assignment | First used on page 1, line 2, col 6 |
| 4 | **GP** | Ratio of allocated transmission, general, & intangible plant to total gross plant. | Page 3, line 11, col 6 |
| 5 | **NA** | Not applicable for the transmission formula rate. | First used on page 2, line 16, col 6 |

| | | | | |
|---|---|---|---|---|
| 6 | **NP** | Ratio of net transmission, general, & intangible plant to total net plant. | 6 | Page 3, line 23, col |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Schedule 1 Revenue Requirements
For the 12 months ended - December 31, 20XX



EVERGY METRO INC.
(EMe)

| Line No. | (1) | (2) Reference | (3) | (4) Amount |
|---|---|---|---|---|
| **A.** | **Schedule 1 ARR** | | | |
| 1 | Total Load Dispatch & Scheduling | (Act. Gross Rev Req, p.2,ln 2) | | $ - |
| 2 | Less: Scheduling, System Control and Dispatch Services (321.88.b) | | | - |
| 3 | Less: Transmission Service Studies | (321.90.b) | | - |
| 4 | Less: Reliability, Planning & Standards Dev. Services | (321.92.b) | | - |
| 5 | Total | (Line 1 Less Line 2 thru Line 4) | | $ - |
| 6 | Less: PTP Service Credit | (Wksht A-1, Page 1, Line 26) | | - |
| 7 | Net Schedule 1 Revenue Requirement for Zone | (Line 5 - Line 6) | | $ - |

**B. Schedule 1 Rate Calculations**

| | | | | |
|---|---|---|---|---|
| 8 | EMe 12-CP. Peak Demand | (Wksht A-2, Line 14) | - | MW |
| 9 | Annual Point-to-Point Rate in $/MW - Year | (Line 7 / Line 8) | $ - | |
| 10 | Monthly Point-to-Point Rate in $/MW - Month | (Line 9 / 12) | $ - | |
| 11 | Weekly Point-to-Point Rate in $/MW - Week | (Line 9 / 52) | $ - | |
| 12 | Daily Point-to-Point Rate in $/MW - Day | (Line 9 / 365) | $ - | |
| 13 | Hourly Point-to-Point Rate in $/MW - Hour | (Line 9 / 8760) | $ - | |



**Worksheet A-1 Revenue Credits**
**EMe -Detailed Revenue Credits -FY 20xx**

| | | | Total Company | Non-Transmission | Transmission |
|---|---|---|---|---|---|
| 1 | I. | **Rent from Electric Property, Account 454** | | | |
| 2 | | Account 4540001 - Other Rev -Rent Electric Property | $ - | $ - | $ - |
| 3 | | Transmission: | | | |
| 4 | | Farm Land Rental | - | | |
| 5 | | Rental From Cell Phone Attaches | - | | |
| 6 | | Equipment / Facilities Rental | - | | |
| 7 | | Rental Substation Property -Cell Towers | - | | |
| 8 | | Other Rental | - | | |
| 9 | | Total Transmission | $ - | | |
| 10 | | (Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and explanations in Section V, Notes below.) | | | |
| 11 | | | | | |
| 12 | II. | **Other Operating Revenues To Reduce Revenue Requirement** | | | $ - |
| 13 | | | | | |
| 14 | III. | **Revenues from Transmission of Electricity for Others, Account 456.1** | | | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | (Provide data sources and necessary explanations Section | | | | | |
| 15 | V, Notes below.) | | | | | |
| 16 | **Less:** | | | | | |
| | TO's LSE Direct Assignment Revenue | | | | | $ |
| 17 | Credits | | | | | - |
| | TO's LSE Sponsored Upgrade Revenue | | | | | |
| 18 | Credits | | | | | - |
| | TO's LSE Sch. 11 Rev. from Sponsored or Direct Assign | | | | | |
| 19 | Facilities - Network Credits | | | | | - |
| | TO's LSE Sch. 11 Rev. from Sponsored or Direct Assign | | | | | |
| 20 | Facilities - PtP Credits | | | | | - |
| | TO's LSE Network Upgrades for Generation | | | | | |
| 21 | Interconnection - Credits | | | | | - |
| | Point-To-Point Revenue for GFAs Associated | | | | | |
| 22 | with Load Included in the Divisor | | | | | - |
| | Network Service Revenue (Schedule 9) Associated With Load | | | | | |
| 23 | Included in the Divisor | | | | | - |
| | Revenue Associated with Transmission Plant | | | | | |
| 24 | Excluded From SPP Tariff | | | | | - |
| 25 | Wholesale Distribution Revenue | | | | | - |
| 26 | Schedule 1 Revenue | (Point-to-Point Subtotal: | $ | - | ) | - |
| 27 | Schedule 2 Revenue | | | | | - |
| 28 | Schedules 3-6 Revenue | | | | | - |
| | Zonal Network Revenue for TO's Facilities | | | | | |
| 29 | Under Schedule 11 -(Note 2) | | | | | - |
| | Region-wide Network Revenue for TO's | | | | | |
| 30 | Facilities Under Schedule 11 -(Note 2) | | | | | - |
| | Zonal Point-to-Point Revenue for TO's Facilities | | | | | |
| 31 | Under Schedule 11 -(Note 2) | | | | | - |
| | Region-wide Point-to-Point Revenue for TO's Facilities Under | | | | | |
| 32 | Schedule 11 - (Note 2) | | | | | - |
| 33 | Other | | | | | |
| 34 | Other | | | | | - |
| 35 | | | | | | |

| | | | |
|---|---|---|---|
| 36 | | **Total Adjustments** | $ - |
| 37 | | **Net 456.1 Account Activity** | $ - |
| 38 | | | |
| 39 | **IV.** | **Total Revenue Credits to Apply to Zonal Revenue Requirement** | $ - |
| 40 | | | |
| 41 | **V.** | **Notes** | |
| 42 | | (1) Data for this worksheet came from the FERC Form 1 and the Company's General Ledger. | |
| 43 | | (2) Includes any revenue from direct assignment to a customer of costs of a Base Plan, Balanced Portfolio, Priority or ITP project. | |
| 44 | | (3) | |
| 45 | | (4) | |

**A-1 Revenue Credits for Schedule 11 Revenue Requirements**

**EMe -Detailed Revenue Credits -FY 20xx**

| | | | | | |
|---|---|---|---|---|---|
| 1 | **Revenue Received for TO's Facilities Under Schedule 11** | (Sum Line 29 thru Line 32 on Page 1) | | | $ - |
| 2 | | | | | |
| 3 | **Allocation of Revenue to Facility Groups:** | (a) | (b) | (d) | (e) |
| 4 | | **Net Rev. Req with True-Up** | **Percentage** | | **Revenue** |

| | | | | Allocation | Allocation |
|---|---|---|---|---|---|
| 5 | | | (Note A) | | |
| 6 | | Base Plan | $ - | 0.0000 % | $ - |
| 7 | | Balanced Portfolio | - | 0.0000 % | - |
| 8 | | ITP/Priority Projects-1 | - | 0.0000 % | - |
| 9 | | ITP/Priority Projects-2 | - | 0.0000 % | - |
| 10 | | Total Schedule 11 Gross Revenue Requirement | $ - | 0.0000 % | $ - |
| 11 | | | | | |
| 12 | **Determine Net Revenue to Apply as Credit:** | | | | **Revenue Credit** |
| 13 | | Base Plan | (Line 6 col (a) less Line 6 col (e)) | | $ - |
| 14 | | Balanced Portfolio | (Line 7 col (a) less Line 7 col (e)) | | - |
| 15 | | ITP/Priority Projects-1 | (Line 8 col (a) less Line 8 col (e)) | | - |
| 16 | | ITP/Priority Projects-2 | (Line 9 col (a) less Line 9 col (e)) | | - |
| 17 | | Total Schedule 11 Gross Revenue Requirement | (Sum Line 13 thru Line 16 ) | | $ - |

**Note:** **A**. The Net Revenue Requirement with True-up from Projection for Actual Period, Schedule "Projected Net Rev Req".

**Worksheet A-2 -Divisor**

**EMe**

**Determination of Transmission Network Load (MW)**
**For the 12 months ended - December 31, 20XX**



**I. EMe**

**(source -FN1, page 400)**

| Line No. | Date | Hour Ending | EMe's Native System Peak Load | Adjustment | Adjusted EMeEMe's Native System Peak Load | Plus: 3rd Party Network Load (incl. gen.) | Reserve for Future Use | Plus: Grandfather Agreements | Reserve for Future Use | Reserve for Future Use | Less: Load Not Connected to the EMe's Transmission System | EMe's Transmission System Load (e-f+g+h+i+j-k) | Average Transmission Network Load for January thru August | Percentage of Aver. Jan - Aug Load |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
| 1 | | | - | - | - | - | - | - | | | | - | - | |
| 2 | | | - | - | - | - | - | - | | | | - | - | |
| 3 | | | - | - | - | - | - | - | | | | - | - | |
| 4 | | | - | - | - | - | - | - | | | | - | - | |
| 5 | | | - | - | - | - | - | - | | | | - | - | |
| 6 | | | - | - | - | - | - | - | | | | - | - | |
| 7 | | | - | - | - | - | - | - | | | | - | - | |
| 8 | | | - | - | - | - | - | - | | | | - | - | |
| 9 | | | - | - | - | - | - | - | | | | - | | 0.00 % |
| 10 | | | - | - | - | - | - | - | | | | - | | 0.00 % |
| 11 | | | - | - | - | - | - | - | | | | - | | 0.00 % |
| 12 | | | - | - | - | - | - | - | | | - | - | | 0.00 % |
| 13 | Total | | | n/a | | - | | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | | - | | - | - | - | - | - | - | - |
| 14 | 12-CP | | - | n/a | - | - | - | - | - | - | - | - | |

**Notes:**
Column
**(n) -** This column reflects the relationship of the actual load for each month (September, October, November and December) as a percentage of the average transmission network load for January through August. For example, the September percentage in column **(n)** is equal to the September load in column (**l**) divided by the 8-month average of column (**m**) shown on line 13.

**Worksheet A-3 - ADIT**



**Evergy Metro Inc.**
For the 12 months ended - December 31, 20XX

| Line No. | Summary | Total ADIT Allocated to Transmission (b + c + d) | Allocation of ADIT 100% NonTrans. Related (a) | 100% Trans. Related (b) | Plant Related ( c ) | Labor Related (d) |
|---|---|---|---|---|---|---|
| | | | $ | $ | $ | $ |
| 1 | **ADIT-255** | | - | - | - | - |
| 2 | **ADIT-282** | | - | - | - | - |
| 3 | **ADIT-283** | | - | - | - | - |
| 4 | **ADIT-190** | | - | - | - | - |
| | | | $ | $ | $ | $ |
| 5 | **Subtotal** | | - | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 6 | | **Wages & Salary Allocator** | | | | | | 0.000% | |
| 7 | | **Gross Plant Allocator** | | | | | 0.000% | | |
| 8 | | **Direct Assign Allocator** | | | | 100.00 0% | | | |
| | | | $ | $ | $ | $ | $ | | |
| 9 | | **ADIT *Subtotal*** | - | - | - | - | - | | |
| *9a* | | *EDIT Adjustment* | **-** | | | | | | |
| *9b* | | *ADIT Total* | ***$-*** | | | | | | |

| | | | | | **(A)** | **(B)** | **(C)** | **(D)** | **(E)** | ***(F)*** |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | **BOY Balance** | **EOY Balance** | **Average** | ***100%*** **NonTrans.** | ***100%*** **Trans.** | **Plant** | **Labor** | |
| | | **ADIT-Account 190 (Note 1)** | **Prior Year** | **Current Year** | **Balance** | **Related** | **Related** | **Related** | **Related** | ***Description*** |
| | 190200 | *Accumulated Deferred Income Tax Utility Oper Other* | | | | | | | | |
| 10 | | Reclass from 282 for Debit balances | $ - | $ - | $ - | | | $ - | | |
| 11 | | Emission credit sales | - | - | - | - | | | | |
| 12 | | Bond refunding amortization | - | - | - | - | | | | |
| 13 | | Retail Regulatory Assets/Liabilities | - | - | - | - | | | | |
| 14 | | KS & MO Additional Credit Amort | - | - | - | - | | | | |
| 15 | | Prior Years Depr Adj (Combustion Turbine) | - | - | - | - | | | | |
| 16 | | Bonus Pay Accrual | - | - | - | - | | | | |
| 17 | | FAS 106 Postretirement Benefits | - | - | - | - | | | | |
| 18 | | Customer Advances (Retail) | - | - | - | - | | | | |
| 19 | | Tax gross up on CIACs | - | - | - | - | | | | |
| 20 | | Partnership entries | - | - | - | - | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 21 | Tax Interest (FIN 48 & other contingencies) | - | - | - | - |
| 22 | Wolf Creek Decomm Co | - | - | - | - |
| 23 | AFDC Debt not in service | - | - | - | - |
| 24 | Tax Interest Capitalized in CWIP | - | - | - | - |
| 25 | Deferred Compensation - Non-current | - | - | - | - |
| 26 | MTM - Interest Rate Lock | - | - | - | - |
| 27 | FIN 48 Adjustments | - | - | - | - |
| 28 | Stock Compensation Accrual | - | - | - | - |
| 29 | Interest Rate Lock - through P&L | - | - | - | - |
| 30 | Vacation Accrual | - | - | - | - |
| 31 | Life insurance paid - severed Aquila employees | - | - | - | - |
| 32 | Bad Debt | - | - | - | - |
| 33 | Injuries and Damages | - | - | - | - |
| 34 | Deferred Compensation - (Current) | - | - | - | - |
| 35 | Interest Rate Lock - OCI Interest | - | - | - | - |
| 36 | *Reclass from 282 for Debit balances* | - | - | - | - |
| 37 | Cost of Removal (normalized) | - | - | - | - |
| 38 | AFUDC other than nuclear fuel | - | - | - | - |
| 39 | Capitalized computer hardware | - | - | - | - |
| 40 | Capitalized tax interest | - | - | - | - |
| 41 | CIAC | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | | | | | |
| 42 | | FAS106/Pensions | - | - | - | - | | | | | |
| 43 | | KEPCO interest refund | - | - | - | - | | | | | |
| 44 | | Repair retirements reversed | - | - | - | - | | | | | |
| 45 | | Vehicle tax depreciation capitalized | - | - | - | - | | | | | |
| 46 | | Other | - | - | - | - | | | | | |
| 47 | | Transmission CIAC | - | - | - | - | | | | | |
| 48 | | | | | - | | | | | | |
| 49 | 190400 | Deferred Taxes - OCI (Gas Hedge) | - | - | - | - | | | | | |
| 50 | 190500 | GBC Tax Credit Carry forward (Generation) | - | - | - | - | | | | | |
| 51 | 190601 | FASB 109 Adjustment | - | - | - | - | | | | | |
| 52 | 190602 | FASB 109 MO R&D Credit Deferred | - | - | - | - | | | | | |
| 53 | 190603 | FASB 109 Medicare Subsidies | - | - | - | - | | | | | |
| 54 | **Subtotal ( p.234.Notes)** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 55 | **Less FASB 109 Above if not separately removed** | | - | - | - | - | | | | | |
| 56 | **Total** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |

**Worksheet A-3 - ADIT**

**Evergy Metro Inc.**



**Allocation of ADIT**

For the 12 months ended - December 31, 20XX

| | | (A) | (B) 100% | (C) 100% | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|
| **BOY Balance** | **EOY Balance** | **Average** | **NonTrans.** | **Trans.** | **Plant** | **Labor** | |

| | | ADIT- Account 255 (Note 1) | Prior Year | Current Year | Balance | Related | Related | Related | Related | Description |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Accumulated Deferred Income Tax Other Property | | | | | | | | |
| 1 | 255520 | ITC - Wolf Creek ITC | $ - | $ - | $ - | $ - | | | | |
| 2 | 255634 | ITC - Electric | - | - | - | | | - | | |
| 3 | 255600 | ITC - Wolf Creek Sales | - | - | - | - | | | | |
| 4 | 255700 | ITC - Iatan 2 Advanced Coal Credit | - | - | - | - | | | | |
| 5 | | | | | - | | | | | |
| 6 | **Subtotal ( p.267.Notes)** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 7 | **Less FASB 109 Above if not separately removed** | | - | - | - | - | - | - | | |
| 8 | **Less FASB 106 Above if not separately removed** | | - | - | - | - | - | - | | |
| 9 | **Total** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |

| | | ADIT- Account 281 & 282 (Note 1) | BOY Balance Prior Year | EOY Balance Current Year | Average Balance | 100% NonTrans. Related | 100% Trans. Related | Plant Related | Labor Related | Description |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Accumulated Deferred Income Tax Other Property | | | | | | | | |
| 10 | 282611 | Total Plant | $ - | $ - | $ - | | | $ - | | |
| 11 | 282611 | Reclass Debit Balances to 190 | - | - | - | | | - | | |
| 12 | 282601 | FASB 109 | - | - | - | - | | | | |
| 13 | | | | | - | | | | | |
| 14 | **Subtotal ( p.275.Notes)** | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 15 | **Less FASB 109 Above if not** | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **separately removed** | - | - | - | - | | | | |
| 16 | **Less FASB 106 Above if not separately removed** | - | - | - | - | - | - | | |
| 17 | **Total** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |

| | | ADIT-Account 283 (Note 1) | BOY Balance Prior Year | EOY Balance Current Year | Average Balance | 100% NonTrans. Related | 100% Trans. Related | Plant Related | Labor Related | Description |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Accumulated Deferred Income Tax Other Utility | | | | | | | | |
| | 283300 | Deferred Tax Miscellaneous: | | | | | | | | |
| 17 | | Miscellaneous Accruals | $ - | $ - | $ - | | | | $ - | |
| 18 | | Bond Refinancing (Loss on Reacq Debt) | - | - | - | | | - | | |
| 19 | | Clearing Accounts | - | - | - | | | - | | |
| 20 | | Retail Regulatory Assets/Liabilities | - | - | - | | | - | | |
| 21 | | Employee pensions | - | - | - | | | - | | |
| 22 | | Prepaid Gross Receipts Tax | - | - | - | | | - | | |
| 23 | | Coal Premium Offset | - | - | - | | | - | | |
| 24 | | Interest on Decommissioning & Decontamination | - | - | - | | | - | | |
| 25 | | Section 174 Ded in CWIP (Iatan-Production) | - | - | - | | | - | | |
| 26 | | AFUDC Debt in CWIP | - | - | - | | | - | | |
| 27 | | Book Amort Mortgage Register Taxes | - | - | - | | | - | | |
| 28 | | Software Deduction in CWIP | - | - | - | | | - | | |
| 29 | | Nonutility Depreciation | - | - | - | | | - | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | | Nonutility Capitalized Interest | - | - | - | | | - | | | | | |
| 31 | | Nonutility Book Capitalized Software | - | - | - | | | - | | | | | |
| 32 | 28310 0 | Nuclear Fuel | - | - | - | | | - | | | | | |
| 33 | 28360 1 | FASB 109 Adjustment | - | - | - | | | - | | | | | |
| 34 | | | | | - | | | | | | | | |
| 35 | 28341 0/510 | FIN 48 Liability (after FERC Reclass) | - | - | - | | | - | | | | | |
| | | | $ | $ | $ | $ | $ | $ | $ | | | | |
| 36 | **Subtotal (p.277.Notes)** | | - | - | - | - | - | - | - | | | | |
| 37 | **Less FASB 109 Above if not separately removed** | | - | - | - | - | | | | | | | |
| 38 | **Less FASB 106 Above if not separately removed** | | | | | - | - | - | | | | | |
| | | | $ | $ | $ | $ | $ | $ | $ | | | | |
| 39 | **Total** | | - | - | - | - | - | - | - | | | | |

**NOTES:**

**1** ADIT items in each account will be in the same order as the prior year with any new line items, relative to the prior year, to be highlighted and added at the end of the list of items for each account. A line item maybe deleted when the amount for the line item has been zero through one complete rate cycle.

**2** ADIT impacts related to Contributions in Aid of Construction (CIAC) shall be designated as non-transmission related unless both of the following conditions apply: a) the facility for which the CIAC is paid is a Transmission Facility pursuant to Attachment AI of the SPP Open Access Transmission Tariff, and b) the FERC-approved tariffs or rate schedules under which the payment is made do not provide for full recovery by EMe of the ADIT impacts. More generally, ADIT items that are to be treated as 100% Non-Transmission should be so treated on the basis of the actual tax item, not based on the title used.

## Worksheet A3-2 - ADIT wkst

## Evergy Metro Inc. Accumulated Excess / Deficient Deferred Income Taxes ("EDIT") Actuals - For the 12 months ended 12/31/20XX



| | | | 12/31/xx | xxxx | xxxx | 12/31/xx | | 12/31/xx | xxxx | 12/31/xx | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | kj) |
| Line No. | | Item | BOY Balance Dr./(Cr.) (Note C) | Current Period Amortization | Current Period Other Activity Dr./(Cr.) (Note B) | EOY Balance Dr./(Cr.) (Note C) | Allocator | BOY Allocated Balance Dr./(Cr.) | Amortization Exp/(Ben) Allocated - Rate Base | EOY Allocated Balance Dr./(Cr.) | Amort Period or Method | Explanation (Note A) |
| | | 190 EDIT INCLUDED WITHIN ACCOUNTS 182 & 254 | | | | | | | | | | |
| 9 | 190200 | Accumulated Deferred Income Tax Utility Oper Other | | | | | | | | | | |
| 10 | | Reclass from 282 for Debit balances | | | | | | | | | | |
| 11 | | Emission credit sales | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 12 | | Bond refunding amortization | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 13 | | Retail Regulatory Assets/Liabilities | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 14 | | KS & MO Additional Credit Amort | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 15 | | Prior Years Depr Adj (Combustion Turbine) | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 16 | | Bonus Pay Accrual | - | - | | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 17 | | FAS 106 Postretirement Benefits | - | - | | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 18 | | Customer Advances (Retail) | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 19 | | Tax gross up on CIACs | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 20 | | Partnership entries | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 21 | | Tax Interest (FIN 48 & other contingencies) | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 22 | | Wolf Creek Decomm Co | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 23 | | AFDC Debt not in service | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 24 | | Tax Interest Capitalized in CWIP | - | - | | - | GP 4.254% | - | - | - | 10-yr | Plant |
| 25 | | Deferred Compensation - Non-current | - | - | | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 26 | | MTM - Interest Rate Lock | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 27 | | FIN 48 Adjustments | - | - | | - | GP 4.254% | - | - | - | 10-yr | Plant |
| 28 | | Stock Compensation Accrual | - | - | | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 29 | | Interest Rate Lock - through P&L | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 30 | | Vacation Accrual | - | - | | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 31 | | Life insurance paid - severed Aquila employees | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 32 | | Bad Debt | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 33 | | Injuries and Damages | - | - | | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 34 | | Deferred Compensation - (Current) | - | - | | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 35 | | Interest Rate Lock - OCI Interest | - | - | | - | GP 4.254% | - | - | - | 10-yr | Plant |
| 36 | | Reclass from 282 for Debit balances | | - | - | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 37 | | Cost of Removal (normalized) | - | - | - | - | NA 0.000% | - | - | - | ARAM | NonTrans |
| 38 | | AFUDC other than nuclear fuel | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| 39 | | Capitalized computer hardware | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| 40 | | Capitalized tax interest | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| 41 | | CIAC | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| 42 | | FAS106/Pensions | - | - | - | - | W/S 1.931% | - | - | - | ARAM | Labor |
| 43 | | KEPCO interest refund | - | - | - | - | NA 0.000% | - | - | - | ARAM | NonTrans |
| 44 | | Repair retirements reversed | - | - | - | - | NA 0.000% | - | - | - | ARAM | NonTrans |
| 45 | | Vehicle tax depreciation capitalized | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| 46 | | Other | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| 47 | | Transmission CIAC | - | - | - | - | DA 100.000% | - | - | - | 10-yr | Trans |
| 47a | | Deferred Liability -Lease 1 KC Place | - | - | - | - | W/S 1.931% | - | - | - | 10-yr | Labor |
| 47b | | Miscellaneous Accruals | - | - | - | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| 47c | | SO2 Allowance Write-down | - | - | - | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| | | Impairment Iatan 1 & 2 | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| | | Smart Grid Grant | - | - | - | - | GP 4.254% | - | - | - | ARAM | Plant |
| | | State NOL -Current | - | - | - | - | NA 0.000% | - | - | - | 10-yr | NonTrans |
| | | Contract Settlements | - | - | - | - | NA 0.000% | - | - | - | ARAM | NonTrans |
| | | Employee Pensions | - | - | - | - | W/S 1.931% | - | - | - | 10-yr | Labor |

*47d*

*47e*

*47f*

*47g*

*47h*

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 47i | Deferred Revenue -Solar Lease Rebates | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| | 47j | CT's Synthetic Lease | - | - | - | - | NA | 0.000% | - | - | - | ARAM | NonTrans |
| | 47k | Voluntary Employee Exit Program | - | - | - | - | W/S | 1.931% | - | - | - | 10-yr | Labor |
| | 47l | Accumulated Provision for Rate Refunds | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 47m | | Inventory Write-off | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 48 | | | | | | | | | | | | | |
| 49 | 190400 | Deferred Taxes - OCI (Gas Hedge) | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 50 | 190500 | GBC Tax Credit Carry forward (Generation) | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 51 | 190601 | FASB 109 Adjustment | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 52 | 190602 | FASB 109 MO R&D Credit Deferred | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 52a | 190602 | FASB 109 Misc Taxes Excess Deferreds | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 53 | 190603 | FASB 109 Medicare Subsidies | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 53 | 190603 | FASB 109 NOL Excess Deferreds | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 53a | 190300 | Federal NOL | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 53b | 190301 | State NOL | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 53c | 190300 | Federal NOL (Federal Rate Change) | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 53d | 190301 | State NOL (Federal Rate Change) | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 53d2 | 190301 | State NOL (MO Rate Change) | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 53e | 190350 | Ded Inc Tax Valuation Allowance | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| | | **Total 190 EDIT** | - | - | - | - | | | - | - | - | | |
| | | ***283 EDIT INCLUDED WITHIN ACCOUNTS 182 & 254*** | | | | | | | | | | | |
| | 283300 | Deferred Tax Miscellaneous: | | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 18 | | Miscellaneous Accruals | - | - | - | - | W/S | 1.931% | - | - | - | 10-yr | Labor |
| 19 | | Bond Refinancing (Loss on Reacq Debt) | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| 20 | | Clearing Accounts | - | - | - | - | W/S | 1.931% | - | - | - | 10-yr | Labor |
| 21 | | Retail Regulatory Assets/Liabilities | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 22 | | Employee pensions | - | - | - | - | W/S | 1.931% | - | - | - | 10-yr | Labor |
| 23 | | Prepaid Gross Receipts Tax | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 24 | | Coal Premium Offset | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 25 | | Interest on Decommissioning & Decontamination | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 26 | | Section 174 Ded in CWIP (Iatan-Production) | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 27 | | AFUDC Debt in CWIP | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| 28 | | Book Amort Mortgage Register Taxes | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| 29 | | Software Deduction in CWIP | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| 30 | | Nonutility Depreciation | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31 | | Nonutility Capitalized Interest | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 32 | | Nonutility Book Capitalized Software | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31a | | Jurisdictional Diff Iatan 1 and Common | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31b | | Stock Compensation Accrual | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31c | | Smart Grid Dem Grant Deferred | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31d | | Active Health and Welfare Benefits | - | - | - | - | W/S | 1.931% | - | - | - | 10-yr | Labor |
| 31e | | Section 174 Ded in CWIP (LaCygne Production) | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31f | | Tax Interest (FIN 48 & other contingencies) | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| 31g | | Deferred Inter-Co Gain | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31h | | Repair Expense in CWIP | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31i | | Performance Incentive on EEIA | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 31j | | Interest Rate Lock - OCI Interest | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 31k | Excess Deferreds - Tax Reform | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| | 31l | Excess Deferreds - MO Rate Change | - | - | - | - | NA | 0.000% | - | - | - | TBD | NonTrans |
| | 31m | MO Rate Change Sch 2018/2019 | - | - | - | - | W/S | 1.931% | - | - | - | 10-yr | Labor |
| | 31n | Interest Rate Lock - through P&L | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| | 32 | | - | - | - | - | | | | | | | |
| 33 | 283100 | Nuclear Fuel | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 34 | 283601 | FASB 109 Adjustment | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 35 | 283410/510 | FIN 48 Liability (after FERC Reclass) | - | - | - | - | GP | 4.254% | - | - | - | 10-yr | Plant |
| 36 | 283400 | Deferred Taxes - OCI (Gas Hedge) | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 35a | 283602 | FASB 109 Misc Taxes Excess Deferreds | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| 35b | 283603 | FASB 109 NOL Excess Deferreds | - | - | - | - | NA | 0.000% | - | - | - | 10-yr | NonTrans |
| | | **Total 283 EDIT** | - | - | - | - | | | - | - | - | | |
| 9a | 281000 | Total Plant | - | | | - | GP | 4.254% | - | | - | ARAM | Plant |
| | | Accumulated Deferred Income Tax Other Property | | | | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 10 | 282611 | Total Plant | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 10a | | Total Plant Protected | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 10b | | Total Plant Unprotected | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 10c | | Total Plant MO Rate Change | - | - | - | - | GP | 4.254% | - | - | - | TBD | Plant |
| 10d | | Total Plant Cutoff | - | - | - | - | GP | 4.254% | - | - | - | TBD | Plant |
| 10e | | Total Plant Montrose Retirement | - | - | - | - | GP | 4.254% | - | - | - | TBD | Plant |
| 11 | 282611 | Reclass Debit Balances to 190 | - | - | - | - | GP | 4.254% | - | - | - | ARAM | Plant |
| 12 | 282601 | FASB 109 | - | | | | NA | 0.000% | - | - | - | ARAM | NonTrans |
| | | **Total 281/282 EDIT** | - | - | - | - | | | - | - | - | | |
| | | **Total Excess/Deficient Deferred Income Taxes** | - | - | - | - | | | - | - | - | | |

| **EDIT Amortization :** | **Total** | **Allocator** | **Rate** | **Allocated** |
|---|---|---|---|---|
| **Total 190 EDIT** | - | See above | See above | - |
| **Total 283 EDIT** | - | W/S | 1.931% | - |
| **Total 281/282 EDIT** | - | GP | 4.254% | - |
| | - | | | - |

**Average Allocated EDIT Balance** -

Notes:

A *Each EDIT item is categorized into 1 of 5 categories. The selected category will will determine the Allocator applied to the EDIT balance.*

*1) NonTrans: The EDIT balance is 100% unrelated to the Transmission of electricity and the NA Allocator is applied.*

*2) Retail: The EDIT balance is 100% related to retail operations and the NA Allocator is applied.*

*3) Trans: The EDIT balance is 100% related to transmission operations and the DA Allocator is applied.*

*4) Plant: The EDIT balance is related to Property, Plant, & Equipment "PP&E" and the GP Allocator is applied.*

*5) Labor: The EDIT balance is labor related and the W/S Allocator is applied.*

*B Includes the impact of tax rate changes enacted during the period and adjustments to prior year activity. C EDIT balances exclude income tax gross-ups recorded to accounts 182.3 and 254*

**Worksheet A-4 - Excluded Assets**



**Evergy Metro Inc.**

**Assets Transferred from Transmission Rate Base**

At December 31, 20XX

| Line No. | | 13 -Month Average Balance | | |
|---|---|---|---|---|
| | | Asset | Reserve | Net |
| 1 | **I. GSU Values Transferred from Transmission** | | | |
| 2 | **GSU:** | | | |
| 3 | **EMe** | $ - | $ - | $ - |
| 4 | | - | - | - |
| 5 | Total GSUs in Transmission Plant | $ - | $ - | $ - |
| 6 | | | | |
| 7 | **II. Radial Lines, 34kV and Substation** | | | |

**Facilities Transferred**

**Radial Lines**

| | | | |
|---|---|---|---|
| **EMe** | $ - | $ - | $ - |
| | - | - | - |
| Total | $ - | $ - | $ - |

**Substation Facilities Transf to Distribution Plt.**

| | | | |
|---|---|---|---|
| **EMe** | $ - | $ - | $ - |
| | - | - | - |
| Total | $ - | $ - | $ - |

**34kV Lines**

| | | | |
|---|---|---|---|
| **EMe** | $ - | $ - | $ - |
| | - | - | - |
| Total | $ - | $ - | $ - |

**Less: Substation Facilities Transf to Trans. Plant**

| | | | |
|---|---|---|---|
| **EMe** | $ - | $ - | $ - |
| | - | - | - |
| Total | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| Net Substation, 34kV, & Radial Lines to Dist. Plt | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| **III. Net Transfer From Trans. (ln 7+ln 28)** | $ - | $ - | $ - |

**IV. 13 Month Average - Gross Plant**



| Line No. | | Gross Plant | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End. Balance Dec Y1 | - Jan Y2 | - Feb Y2 | - Mar Y2 | - April Y2 | - May Y2 | - June Y2 | - July Y2 | - Aug Y2 | - Sept Y2 | - Oct Y2 | - Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
| 31 | **GSU:** | | | | | | | | | | | | | | |
| 32 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 34 | **Total** | | | | | | | | | | | | | | $ - |
| 35 | **Radial Lines:** | | | | | | | | | | | | | | |
| 36 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 37 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 38 | **Total** | | | | | | | | | | | | | | $ - |
| 39 | **Substation Facilities - Transfer from Distribution Plant** | | | | | | | | | | | | | | |
| 40 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 41 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 42 | **Total** | | | | | | | | | | | | | | $ - |
| 43 | **34kV Lines** | | | | | | | | | | | | | | |
| 44 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 45 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 46 | **Total** | | | | | | | | | | | | | | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 47 | **Less: Substation Facilities Transfer to Transmission Plant** | | | | | | | | | | | | | | |
| 48 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 49 | | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 50 | **Total** | | | | | | | | | | | | | | $ - |
| 51 | **Total -Excluded Assets** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**V. 13 Month Average -Accumulated Depreciation**

| | | Accumulated Depreciation | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **End. Balance Dec Y1** | **- Jan Y2** | **- Feb Y2** | **- Mar Y2** | **- April Y2** | **- May Y2** | **- June Y2** | **- July Y2** | **- Aug Y2** | **- Sept Y2** | **- Oct Y2** | **- Nov Y2** | **End. Balance Dec Y2** | **13 Months Avg Balance** |
| 52 | **GSU:** | | | | | | | | | | | | | | |
| 53 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 54 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 55 | **Total** | | | | | | | | | | | | | | $ - |
| 56 | **Radial Lines:** | | | | | | | | | | | | | | |
| 57 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 58 | | | | | | | | | | | | | | | $ - |
| 59 | **Total** | | | | | | | | | | | | | | $ - |
| 60 | **Substation Facilities - Transfer from Distribution Plant** | | | | | | | | | | | | | | |
| 61 | **EMe** | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 62 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 63 | **Total** | | | | | | | | | | | | | | $ - |
| 64 | **34kV Lines** | | | | | | | | | | | | | | |
| 65 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 66 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 67 | **Total** | | | | | | | | | | | | | | $ - |
| 68 | **Less: Substation Facilities Transfer to Transmission Plant** | | | | | | | | | | | | | | |
| 69 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 70 | | | | | | | | | | | | | | | $ - |
| 71 | **Total** | | | | | | | | | | | | | | $ - |
| 72 | **Total -Excluded Assets** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**VI. 13 Month Average -Net Plant**



| | | **Net Plant** (Gross Plant less Accumulated Depreciation) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **End. Balance Dec Y1** | **Jan Y2** | **Feb Y2** | **Mar Y2** | **April Y2** | **May Y2** | **June Y2** | **July Y2** | **Aug Y2** | **Sept Y2** | **Oct Y2** | **Nov Y2** | **End. Balance Dec Y2** | **13 Months Avg Balance** |
| 73 | **GSU:** | | | | | | | | | | | | | | |
| 74 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 75 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 76 | **Total** | | | | | | | | | | | | | | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 77 | **Radial Lines:** | | | | | | | | | | | | | | |
| 78 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 79 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 80 | **Total** | | | | | | | | | | | | | | $ - |
| 81 | **Substation Facilities - Transfer from Distribution Plant** | | | | | | | | | | | | | | |
| 82 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 83 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 84 | **Total** | | | | | | | | | | | | | | $ - |
| 85 | **34kV Lines** | | | | | | | | | | | | | | |
| 86 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 87 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 88 | **Total** | | | | | | | | | | | | | | $ - |
| 89 | **Less: Substation Facilities Transfer to Transmission Plant** | | | | | | | | | | | | | | |
| 90 | **EMe** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 91 | | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 92 | **Total** | | | | | | | | | | | | | | $ - |
| 93 | **Total -Excluded Assets** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Worksheet A-5 - Weighted Depreciation Rates**

**EMe**
**Depreciation Rate Schedule 1**

Composite Depreciation Weighting for FY 2019 and Forward

| | | | Missouri | | Kansas | | FERC | | | EMe Composite | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| LN | A/C | Description | Allocation Factor | Rate | Allocation Factor | Rate | Allocation Factor | Rate | Allocation Basis | Total Allocation Factor | Composite Rate |
| | | | (a) | (b) | ( c ) | ( d) | (e) | (f) | (g) | (h) | (i) |
| 1 | 301 | Organization | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | 0.00% | PTD | 0.00% | **0.00%** |
| 2 | 302 | Franchises | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | 0.00% | 100 MO | 0.00% | **0.00%** |
| 3 | 303 01 | Misc Intangible - Substation (like A/C 353) | 0.0000% | 1.87% | 0.0000% | 1.84% | 0.0000% | 3.24% | D | 0.00% | **0.00%** |
| 4 | 303 02 | Misc Intangible - Cap Software 5 Year (Customer) | 0.0000% | 20.00% | 0.0000% | 20.00% | 0.0000% | 20.00% | C2 | 0.00% | **0.00%** |
| 5 | 303 02 | Misc Intangible - Cap Software 5 Year (Energy) | 0.0000% | 20.00% | 0.0000% | 20.00% | 0.0000% | 20.00% | E1 | 0.00% | **0.00%** |
| 6 | 303 05 | Misc Intangible - Cap Software 5 Year (Prod Demand) | 0.0000% | 20.00% | 0.0000% | 20.00% | 0.0000% | 20.00% | D | 0.00% | **0.00%** |
| 7 | 303 02 | Misc Intangible - Cap Software 5 Year (Sal/Wages) | 0.0000% | 20.00% | 0.0000% | 20.00% | 0.0000% | 20.00% | SW | 0.00% | **0.00%** |
| 8 | 303 03 | Misc Intangible - Cap Software 10 Year (Customer) | 0.0000% | 10.00% | 0.0000% | 10.00% | 0.0000% | 10.00% | C2 | 0.00% | **0.00%** |
| 9 | 303 03 | Misc Intangible - Cap Software 10 Year (Energy) | 0.0000% | 10.00% | 0.0000% | 10.00% | 0.0000% | 10.00% | E1 | 0.00% | **0.00%** |
| 10 | 303 04 | Misc Intangible - Commun Equip (like A/C 397) | 0.0000% | 2.86% | 0.0000% | 6.67% | 0.0000% | 3.65% | T&D | 0.00% | **0.00%** |
| 11 | 303 06 | Misc Intangible - Assec Eq (like A/C 345) | 0.0000% | 1.84% | 0.0000% | 1.89% | 0.0000% | 4.00% | D | 0.00% | **0.00%** |
| 12 | 303 07 | Misc Intangible - Steam Prod Structures (like A/C 312) | 0.0000% | 2.73% | 0.0000% | 4.21% | 0.0000% | 4.12% | S | 0.00% | **0.00%** |
| 13 | 303 | Misc Intangible - Trans. | 0.0000% | 2.64% | 0.0000% | 2.43% | 0.000% | 0.00 | D | 0.00% | **0.00%** |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 08 | Line (like A/C 355) | | | | | | % | | | |
| 14 | 303 10 | Misc Intangible – Iatan Hwy & Bridge | 0.0000% | 2.10% | 0.0000% | 4.15% | 0.0000 % | 3.44 % | D | 0.00% | **0.00%** |
| 15 | 303 11 | Misc Intan-LaCygne Road Overpass (like A/C 311) | 0.0000% | 1.65% | 0.0000% | 4.15% | 0.0000 % | 3.44 % | D | 0.00% | **0.00%** |
| 16 | 303 12 | Misc Intan-Montrose Highway (like A/C 311) | 0.0000% | 1.65% | 0.0000% | 4.15% | 0.0000 % | 3.44 % | D | 0.00% | **0.00%** |
| 17 | 303 15 | Misc Intangible – Cap Software 15 Year | 0.0000% | 6.67% | 0.0000% | 6.67% | 0.0000 % | 10.0 0% | C2 | 0.00% | **0.00%** |
| 18 | 350 | Land | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | N/A | 0.00% | **0.00%** |
| 19 | 350 | Land Rights | 0.0000% | 1.19% | 0.0000% | 0.00% | 0.0000 % | 1.19 % | PP | 0.00% | **0.00%** |
| 20 | 350 | Land Rights - Wolf Creek | 0.0000% | 1.19% | 0.0000% | 0.00% | 0.0000 % | 1.19 % | PP | 0.00% | **0.00%** |
| 21 | 350 | Wolf Creek Gross AFUDC - Land Rights | 0.0000% | 1.19% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | 100M O | 0.00% | **0.00%** |
| 22 | 352 | Structures and Improvements | 0.0000% | 1.98% | 0.0000% | 1.19% | 0.0000 % | 2.33 % | PP | 0.00% | **0.00%** |
| 23 | 352 | Wolf Creek - Structures and Improvement | 0.0000% | 1.98% | 0.0000% | 1.19% | 0.0000 % | 2.33 % | PP | 0.00% | **0.00%** |
| 24 | 352 | Wolf Creek Gross AFUDC - Structures & Improvement | 0.0000% | 1.98% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | 100M O | 0.00% | **0.00%** |
| 25 | 353 | Station Equipment | 0.0000% | 1.87% | 0.0000% | 1.84% | 0.0000 % | 3.24 % | PP | 0.00% | **0.00%** |
| 26 | 353 | Wolf Creek - Station Equipment | 0.0000% | 1.87% | 0.0000% | 1.84% | 0.0000 % | 3.24 % | PP | 0.00% | **0.00%** |
| 27 | 353 | Wolf Creek Gross AFUDC - Station Equipment | 0.0000% | 1.87% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | 100M O | 0.00% | **0.00%** |
| 28 | 353 | Station Equipment-Communication Eq (same as 397) | 0.0000% | 9.96% | 0.0000% | 1.82% | 0.0000 % | 3.65 % | PP | 0.00% | **0.00%** |
| 29 | 354 | Towers and Fixtures | 0.0000% | 0.88% | 0.0000% | .68% | 0.0000 % | 2.75 % | PP | 0.00% | **0.00%** |
| 30 | 355 | Poles and Fixtures | 0.0000% | 2.64% | 0.0000% | 2.43% | 0.0000 % | 3.89 % | PP | 0.00% | **0.00%** |
| 31 | 355 | Wolf Creek - Poles and Fixtures | 0.0000% | 2.64% | 0.0000% | 2.43% | 0.0000 % | 3.89 % | PP | 0.00% | **0.00%** |
| 32 | 355 | Wolf Creek Gross AFUDC - Poles and Fixtures | 0.0000% | 2.64% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | 100M O | 0.00% | **0.00%** |
| 33 | 356 | Overhead Conductors and | 0.0000% | 1.78% | 0.0000% | 1.38% | 0.0000 | 3.15 | PP | 0.00% | **0.00%** |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Devices | | | | | % | % | | | | |
| 34 | 356 | Wolf Creek - Overhead Conductors and Devices | 0.0000% | 1.78% | 0.0000% | 1.38% | 0.0000 % | 3.15 % | PP | 0.00% | **0.00%** |
| 35 | 356 | Wolf Creek Gross AFUDC - O/H Conductor & Devices | 0.0000% | 1.78% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | 100MO | 0.00% | **0.00%** |
| 36 | 357 | Underground Conduit | 0.0000% | 1.41% | 0.0000% | 0.88% | 0.0000 % | 2.10 % | PP | 0.00% | **0.00%** |
| 37 | 358 | Underground Conductors and Devices | 0.0000% | 0.68% | 0.0000% | 0.71% | 0.0000 % | 1.80 % | PP | 0.00% | **0.00%** |
| 38 | 389 | Land and Land Rights | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | PTD | 0.00% | **0.00%** |
| 39 | 390 | Structures and Improvements | 0.0000% | 2.75% | 0.0000% | 2.39% | 0.0000 % | 1.90 % | PTD | 0.00% | **0.00%** |
| 40 | 390 | Structures and Impr - Leasehold Impr (amort over lease) | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000 % | 0.00 % | PTD | 0.00% | **0.00%** |
| 41 | 391 | Office Furniture and Equipment | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000 % | 3.07 % | PTD | 0.00% | **0.00%** |
| 42 | 391 | Office Furniture and Equipment - WC Sub 706 | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000 % | 3.07 % | PTD | 0.00% | **0.00%** |
| 43 | 391 | Office Furniture and Equipment - Computers | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000 % | 3.07 % | PTD | 0.00% | **0.00%** |
| 44 | 392 | Transportation Equipment-Auto's | 0.0000% | 9.38% | 0.0000% | 10.57 % | 0.0000 % | 7.73 % | T&D | 0.00% | **0.00%** |
| 45 | 392 | Transportation Equipment - Light Trucks | 0.0000% | 11.73 % | 0.0000% | 10.26 % | 0.0000 % | 7.73 % | T&D | 0.00% | **0.00%** |
| 46 | 392 | Transportation Equipment - Heavy Trucks | 0.0000% | 9.94% | 0.0000% | 7.85% | 0.0000 % | 7.73 % | T&D | 0.00% | **0.00%** |
| 47 | 392 | Transportation Equipment - Tractors | 0.0000% | 5.68% | 0.0000% | 5.09% | 0.0000 % | 7.73 % | T&D | 0.00% | **0.00%** |
| 48 | 392 | Transportation Equipment - Trailers | 0.0000% | 1.36% | 0.0000% | 2.79% | 0.0000 % | 7.73 % | T&D | 0.00% | **0.00%** |
| 49 | 393 | Stores Equipment | 0.0000% | Gen | 0.0000% | Gen | 0.0000 | 3.17 | PTD | 0.00% | **0.00%** |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Plt Amortiz | | Plt Amortiz | % | % | | | | |
| 50 | 394 | Tools, Shop and Garage Equipment | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000% | 3.52% | | PTD | 0.00% | **0.00%** |
| 51 | 395 | Laboratory Equipment | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000% | 2.88% | | PTD | 0.00% | **0.00%** |
| 52 | 396 | Power Operated Equipment | 0.0000% | 7.94% | 0.0000% | 5.46% | 0.0000% | 5.33% | | T&D | 0.00% | **0.00%** |
| 53 | 397 | Communication Equipment | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000% | 3.65% | | T&D | 0.00% | **0.00%** |
| 54 | 397 | Wolf Creek - Communication Equipment | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000% | 3.65% | | T&D | 0.00% | **0.00%** |
| 55 | 397 | Wolf Creek Gross AFUDC - Communication Equip. | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000% | 0.00% | | 100MO | 0.00% | **0.00%** |
| 56 | 398 | Miscellaneous Equipment | 0.0000% | Gen Plt Amortiz | 0.0000% | Gen Plt Amortiz | 0.0000% | 5.59% | | PTD | 0.00% | **0.00%** |
| 57 | 399 | Other Tangible Property | 0.0000% | 0.00% | 0.0000% | | 0.0000% | 0.00% | | N/A | 0.00% | **0.00%** |

**Notes:**
**1**

EMe adopted a composite depreciation calculation in FY 2009 based on allocation methods of the predominant regulatory jurisdiction applied to the approved depreciation rates for each jurisdiction. Missouri is the predominant jurisdiction for EMe based upon size of load. Although the specific weighting values will change from year to year, the allocation methods (column g) and the stated jurisdictional depreciation rates (columns b, d, and f) documented in the above table will not change without an order from the Commission approving the new methods or depreciation rates. As the formula rate is updated each year, the above table will be populated with allocation factors reflecting the approved methods in order to calculate a composite depreciation rate for each line.

**2**

The Allocation Basis codes in the above table represent the weighting methods to apply to the approved jurisdictional depreciation rates to calculate composite depreciation expense on an account-specific basis for FERC Form No. 1. Following is the definition of each code:

**C2** The customer allocator is based on the number of customers receiving power in each regulatory jurisdiction.

**D** The demand allocator is based on the monthly coincident peak (CP) demands for each jurisdiction.

**E1** The energy allocator is based on the total annual kilowatt-hour usage of each jurisdiction's customers, adjusted for line losses.

**PP** The Gross PP allocator reflects the total gross production plant value allocated and specifically assigned to each jurisdiction as a percentage of EMe total gross production plant.

**PTD** The Gross PTD allocator reflects the total gross production, transmission, and distribution plant value allocated and specifically assigned to each jurisdiction as a percentage of EMe total gross production, transmission, and distribution plant.

**T&D** The Gross T&D allocator reflects the total gross transmission and gross distribution plant value allocated and specifically assigned to each jurisdiction as a percentage of EMe total gross transmission and gross distribution plant.

**S** The steam plant allocator is a blend of the demand allocator (D) and the energy allocator (E1), based on the percentage of gross production plant devoted to non-environmental and environmental functions, respectively.

**SW** The salary and wages allocator represents the weighting of salary and wages (excluding Administrative and General) for production, transmission, distribution, and customer accounts.



**Depreciation Rate**
**Schedule 2**

Composite Depreciation Weighting for FY 2008

| | | | Missouri | | | | Kansas | | | | FERC | | | EMe Composite | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| LN | A/C | Description | Allocation Factor | Allocation Basis | | Rate | Allocation Factor | | Allocation Basis | Rate | Allocation Factor | Allocation Basis | Rate | Total Allocation Factor | Total Rate |
| 1 | 301 | Organization | 54.2693 % | MPSC | | 0.00 % | 45.3469 % | | PTD | 0.00 % | 0.2954 % | PTD | 0.00 % | 99.91 % | **0.00 %** |
| 2 | 302 | Franchises | 100.0000% | MPSC | | 0.00 % | 0.0000 % | | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | **0.00 %** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 303 | Misc Intangible - Substation (like A/C 353) | 54.2693 % | MPSC | 2.24 % | 45.0305 % | D | 3.24 % | 0.6556 % | D | 3.24 % | 99.96 % | **2.70 %** |
| 4 | 303 | Misc Intangible - Cap Software 5 Year (Customer) | 54.2693 % | MPSC | 20.00 % | 46.3270 % | C2 | 20.00 % | 0.0000 % | C2 | 20.00 % | 100.60 % | **20.00 %** |
| 5 | 303 | Misc Intangible - Cap Software 5 Year (Energy) | 54.2693 % | MPSC | 20.00 % | 42.4456 % | E1 | 20.00 % | 0.7638 % | E1 | 20.00 % | 97.48 % | **20.00 %** |
| 6 | 303 | Misc Intangible - Cap Software 5 Year (Prod Demand) | 54.2693 % | MPSC | 20.00 % | 45.0305 % | D | 20.00 % | 0.6556 % | D | 20.00 % | 99.96 % | **20.00 %** |
| 7 | 303 | Misc Intangible - Cap Software 5 Year (Sal/Wages) | 54.2693 % | MPSC | 20.00 % | 44.9307 % | SW | 20.00 % | 0.5174 % | SW | 20.00 % | 99.72 % | **20.00 %** |
| 8 | 303 | Misc Intangible - Cap Software 5 Year (Transm Demand) | 54.2693 % | MPSC | 20.00 % | 45.0305 % | D | 20.00 % | 0.6556 % | D | 20.00 % | 99.96 % | **20.00 %** |
| 9 | 303 | Misc Intangible - Cap Software 10 Year (Customer) | 54.2693 % | MPSC | 10.00 % | 46.3270 % | C2 | 10.00 % | 0.0000 % | C2 | 10.00 % | 100.60 % | **10.00 %** |
| 10 | 303 | Misc Intangible - Cap Software 10 Year (Energy) | 54.2693 % | MPSC | 10.00 % | 42.4456 % | E1 | 10.00 % | 0.7638 % | E1 | 10.00 % | 97.48 % | **10.00 %** |
| 11 | 303 | Misc | 54.2693 | MPSC | 2.50 | 46.5061 | T&D | 3.65 | 0.1208 | T&D | 3.65 | 100.90 | **3.03** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Intangible - Commun Equip (like A/C 397) | % | | % | % | | % | % | | % | % | **%** |
| 12 | 303 | Misc Intangible - Assec Eq (like A/C 345) | 54.2693 % | MPSC | 4.12 % | 45.0305 % | D | 4.00 % | 0.6556 % | D | 4.00 % | 99.96 % | **4.07 %** |
| 13 | 303 | Misc Intangible - Steam Prod Structures (like A/C 312) | 54.2693 % | MPSC | 3.63 % | 45.0305 % | D | 4.12 % | 0.6556 % | S | 4.12 % | 99.96 % | **3.85 %** |
| 14 | 350 | Land | 53.6109 % | MPSC | 0.00 % | 45.0305 % | | 0.00 % | 0.6556 % | | 0.00 % | 99.30 % | **0.00 %** |
| 15 | 350 | Land Rights | 53.6109 % | MPSC | 1.19 % | 45.0305 % | D | 0.00 % | 0.6556 % | PP | 1.19 % | 99.30 % | **0.65 %** |
| 16 | 350 | Land Rights - MO Situs | 100.000 0% | MPSC | 1.19 % | 0.0000 % | | 0.00 % | 0.0000 % | | 1.19 % | 100.00 % | **1.19 %** |
| 17 | 350 | Land Rights - KS Situs | 0.0000 % | MPSC | 1.19 % | 100.000 0% | 100KS | 0.00 % | 0.0000 % | | 1.19 % | 100.00 % | **0.00 %** |
| 18 | 350 | Land Rights - Wolf Creek | 53.6109 % | MPSC | 1.19 % | 45.0305 % | D | 0.00 % | 0.6556 % | PP | 1.19 % | 99.30 % | **0.65 %** |
| 19 | 350 | Wolf Creek Gross AFUDC - Land Rights | 100.000 0% | MPSC | 1.19 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | **1.19 %** |
| 20 | 352 | Structures and Improvements | 53.6109 % | MPSC | 1.36 % | 45.0305 % | D | 2.33 % | 0.6556 % | PP | 2.33 % | 99.30 % | **1.81 %** |
| 21 | 352 | Wolf Creek - Structures and Improvement | 53.6109 % | MPSC | 1.36 % | 45.0305 % | D | 2.33 % | 0.6556 % | PP | 2.33 % | 99.30 % | **1.81 %** |
| 22 | 352 | Wolf Crk Gross AFUDC - Struct's & Improvement | 100.000 0% | MPSC | 1.36 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | **1.36 %** |
| 23 | 353 | Station | 53.6109 | MPSC | 2.24 | 45.0305 | D | 3.24 | 0.6556 | PP | 3.24 | 99.30 | **2.70** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Equipment | % | | % | % | | % | % | | % | % | **%** |
| 24 | 353 | Wolf Creek - Station Equipment | 53.6109 % | MPSC | 2.24 % | 45.0305 % | D | 3.24 % | 0.6556 % | PP | 3.24 % | 99.30 % | **2.70 %** |
| 25 | 353 | Wolf Creek Gross AFUDC - Station Equipment | 100.000 0% | MPSC | 2.24 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | **2.24 %** |
| 26 | 353 | Station Equipment-Communication Eq (same as 397) | 53.6109 % | MPSC | 2.50 % | 45.0305 % | D | 3.65 % | 0.6556 % | PP | 3.65 % | 99.30 % | **3.03 %** |
| 27 | 354 | Towers and Fixtures | 53.6109 % | MPSC | 2.00 % | 45.0305 % | D | 2.75 % | 0.6556 % | PP | 2.75 % | 99.30 % | **2.35 %** |
| 28 | 355 | Poles and Fixtures | 53.6109 % | MPSC | 3.59 % | 45.0305 % | D | 3.89 % | 0.6556 % | PP | 3.89 % | 99.30 % | **3.73 %** |
| 29 | 355 | Poles and Fixtures - MO Situs | 100.000 0% | MPSC | 3.59 % | 0.0000 % | | 3.89 % | 0.0000 % | | 3.89 % | 100.00 % | **3.59 %** |
| 30 | 355 | Poles and Fixtures - KS Situs | 0.0000 % | MPSC | 3.59 % | 100.000 0% | 100KS | 3.89 % | 0.0000 % | | 3.89 % | 100.00 % | **3.89 %** |
| 31 | 355 | Wolf Creek - Poles and Fixtures | 53.6109 % | MPSC | 3.59 % | 45.0305 % | D | 3.89 % | 0.6556 % | PP | 3.89 % | 99.30 % | **3.73 %** |
| 32 | 355 | Wolf Creek Gross AFUDC - Poles and Fixtures | 100.000 0% | MPSC | 3.59 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | **3.59 %** |
| 33 | 356 | Overhead Conductors and Devices | 53.6109 % | MPSC | 3.10 % | 45.0305 % | D | 3.15 % | 0.6556 % | PP | 3.15 % | 99.30 % | **3.12 %** |
| 34 | 356 | Overhead Conductors and Devices - MO Situs | 100.000 0% | MPSC | 3.10 % | 0.0000 % | | 3.15 % | 0.0000 % | | 3.15 % | 100.00 % | **3.10 %** |
| 35 | 356 | Overhead Conductors | 0.0000 % | MPSC | 3.10 % | 100.000 0% | 100KS | 3.15 % | 0.0000 % | | 3.15 % | 100.00 % | **3.15 %** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | and Devices - KS Situs | | | | | | | | | | | | |
| 36 | 356 | Wolf Creek - Overhead Conductors and Devices | 53.6109 % | MPSC | 3.10 % | 45.0305 % | D | 3.15 % | 0.6556 % | PP | 3.15 % | 99.30 % | **3.12 %** |
| 37 | 356 | Wolf Creek Gross AFUDC - O/H Conductor & Devices | 100.0000% | MPSC | 3.10 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | **3.10 %** |
| 38 | 357 | Underground Conduit | 53.6109 % | MPSC | 1.32 % | 45.0305 % | D | 2.10 % | 0.6556 % | PP | 2.10 % | 99.30 % | **1.68 %** |
| 39 | 358 | Underground Conductors and Devices | 53.6109 % | MPSC | 2.55 % | 45.0305 % | D | 1.80 % | 0.6556 % | PP | 1.80 % | 99.30 % | **2.20 %** |
| 40 | 389 | Land and Land Rights | 54.2693 % | MPSC | 0.00 % | 44.8604 % | PTD | 0.00 % | 0.4482 % | PTD | 0.00 % | 99.58 % | **0.00 %** |
| 41 | 390 | Structures and Improvements | 54.2693 % | MPSC | 2.54 % | 44.8604 % | PTD | 1.90 % | 0.4482 % | PTD | 1.90 % | 99.58 % | **2.25 %** |
| 42 | 390 | Structures and Impr - Leasehold Impr (amort over lease) | 54.2693 % | MPSC | 0.00 % | 44.8604 % | PTD | 0.00 % | 0.4482 % | PTD | 0.00 % | 99.58 % | **0.00 %** |
| 43 | 391 | Office Furniture and Equipment | 54.2693 % | MPSC | 5.40 % | 44.8604 % | PTD | 3.07 % | 0.4482 % | PTD | 3.07 % | 99.58 % | **4.34 %** |
| 44 | 391 | Office Furniture and Equipment - WC Sub 706 | 54.2693 % | MPSC | 5.40 % | 44.8604 % | PTD | 3.07 % | 0.4482 % | PTD | 3.07 % | 99.58 % | **4.34 %** |
| 45 | 391 | Office Furniture and Equipment - Computers | 54.2693 % | MPSC | 5.40 % | 44.8604 % | PTD | 3.07 % | 0.4482 % | PTD | 3.07 % | 99.58 % | **4.34 %** |
| 46 | 392 | Transportation Equipment | 54.2693 % | MPSC | 5.43 % | 46.5061 % | T&D | 7.73 % | 0.1208 % | T&D | 7.73 % | 100.90 % | **6.49 %** |
| 47 | 393 | Stores | 54.2693 | MPSC | 3.58 | 44.8604 | PTD | 3.17 | 0.4482 | PTD | 3.17 | 99.58 | **3.39** |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Equipment | % | | % | % | | % | % | | % | % | | **%** |
| 48 | 394 | Tools, Shop and Garage Equipment | 54.2693 % | MPSC | 2.61 % | 44.8604 % | PTD | 3.52 % | 0.4482 % | PTD | 3.52 % | 99.58 % | | **3.02 %** |
| 49 | 395 | Laboratory Equipment | 54.2693 % | MPSC | 3.37 % | 44.8604 % | PTD | 2.88 % | 0.4482 % | PTD | 2.88 % | 99.58 % | | **3.15 %** |
| 50 | 396 | Power Operated Equipment | 54.2693 % | MPSC | 5.55 % | 46.5061 % | T&D | 5.33 % | 0.1208 % | T&D | 5.33 % | 100.90 % | | **5.45 %** |
| 51 | 397 | Communication Equipment | 54.2693 % | MPSC | 2.50 % | 46.5061 % | T&D | 3.65 % | 0.1208 % | T&D | 3.65 % | 100.90 % | | **3.03 %** |
| 52 | 397 | Wolf Creek - Communication Equipment | 54.2693 % | MPSC | 2.50 % | 46.5061 % | T&D | 3.65 % | 0.1208 % | T&D | 3.65 % | 100.90 % | | **3.03 %** |
| 53 | 397 | Wolf Creek Gross AFUDC - Communication Equip. | 100.0000% | MPSC | 2.50 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | | **2.50 %** |
| 54 | 398 | Miscellaneous Equipment | 54.2693 % | MPSC | 3.16 % | 44.8604 % | PTD | 0.00 % | 0.4482 % | PTD | 5.59 % | 99.58 % | | **1.75 %** |
| 55 | 399 | Other Tangible Property | 100.0000% | MPSC | 0.00 % | 0.0000 % | | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | 0.00 % | |
| 56 | 399 | Other Tangible Property | 0.0000 % | MPSC | 0.00 % | 100.0000% | 100KS | 0.00 % | 0.0000 % | | 0.00 % | 100.00 % | 0.00 % | |

**Notes:**

**1** Listed in Schedule 2 are the allocation methods used to weight the depreciation rates for each jurisdiction to determine a composite depreciation rate for EMe as reflected in the FY 2008 Form 1. The methodology used in FY 2008 relied on allocation methods and values specific to Missouri and Kansas. The FERC allocations were determined consistently with the methods documented above in Schedule 1. Listed below is a description of the allocation for each jurisdiction:

**A** The 2008 allocation values for the Missouri jurisdiction were based on allocators calculated by the Missouri PSC (MPSC) staff in support of the Final Order in Missouri rate Case No. ER-2007-0291.

**B** The 2008 allocation values for the Kansas jurisdiction were based on the methods used by EMe to allocate related plant balances in Kansas rate case Docket No. 07-KCPE-905-RTS.

**C** The 2008 allocation values for the FERC jurisdiction were based on the applicable factors used by EMe to allocate related plant balances in Missouri rate Case No. ER-2007-0291. These account-specific methods are consistent with those documented in Schedule 1 above.

**2** The Allocation Basis codes in Schedule 2 have the same definitions as those in Schedule 1.

**Addendum 10 to Attachment H – Part 1B**

# Worksheet A-6 - Taxes Other Than Income Taxes

**EMe**



***Taxes Other than Income***

| Line No. | | Electric Acct 408.1, 409.1 ( I ) | Excluded | Adjusted | Payroll | Highway & Vehicle | Property | Gross Receipts, Uses & KC Earning Tax | Other | Other Misc | Total of Cost Distribution |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Ad Valorem: | | | - | | | | | | | - |
| 2 | Missouri | - | | - | | | - | | | | - |
| 3 | Kansas | - | | - | | | - | | | | - |
| 4 | Excise | | | - | | - | | | | | - |
| 5 | Franchise - Corporate | - | | - | | | | - | | | - |
| 6 | Payroll | - | | - | - | | | | | | - |
| 7 | Transaction | - | | - | | | | - | | | - |
| 8 | KC Earnings | - | | - | | | | - | | | - |
| 9 | Miscellaneous | | | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | | | | | - | - | | |
| 10 | Page 263, (i) | - | - | - | - | - | - | - | - | - | - |
| 11 | **(Reference to Act. Gross Rev Req Wksht)** | | | | (P. 2, ln 13) | (P.2, ln 14) | (P.2, ln 15) | (P.2, ln 16) | (P.2, ln 17) | (P.2, ln 17) | (P.2, ln 18) |
| 12 | | | | | | | | | | | |
| 13 | Federal | - | | | | | | | | | |
| 14 | State | | | | | | | | | | |
| 15 | Missouri | - | | | | | | | | | |
| 16 | Kansas | - | | | | | | | | | |
| 17 | | | | | | | | | | | |
| 18 | Page 263, ln 41, (i) | - | | | | | | | | | |

# Worksheet A-7 - Actual RTO Directed Transmission Projects

## Evergy Metro Inc.

For the 12 months ended -
December 31, 20XX

### Summary of Actual RTO Directed Transmission Projects



| Base Plan Project Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | 1 | $ - | 0.0000% | $ - | $ - | $ - |
| 2 | 2 | $ - | 0.0000% | $ - | $ - | $ - |
| 3 | 3 | $ - | 0.0000% | $ - | $ - | $ - |
| 4 | 4 | $ - | 0.0000% | $ - | $ - | $ - |
| 5 | 5 | $ - | 0.0000% | $ - | $ - | $ - |
| 6 | Total Base Plan Projects | $ - | | $ - | $ - | $ - |

| | Balanced Portfolio Project Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 7 | 1 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 8 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 9 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 10 | Total | | $ - | | $ - | $ - | $ - |

| | TIP/ Priority Project-1 Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 11 | 1 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 12 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 13 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 14 | Total | | $ - | | $ - | $ - | $ - |

| | ITP/ Priority Project-2 Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 15 | 1 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 16 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 17 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 18 | Total | $ - | | $ - | $ - | $ - | |

## Calculation of Net Plant for BPF Projects:

Page 2 of 6

Page 3 of 6

| | | | Project: SPP Proj. ID | | | Project: SPP Proj. ID | | | Project: SPP Proj. ID | | | Project: SPP Proj. ID | | | Project: SPP Proj. ID | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | | | |
| 3 | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 4 | Prior Yr | Dec | $ - | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 5 | Current Yr | Jan | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |
| 6 | Current Yr | Feb | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |
| 7 | Current Yr | Mar | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |
| 8 | Current Yr | Apr | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |
| 9 | Current Yr | May | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |
| 10 | Current Yr | Jun | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |
| 11 | Current Yr | Jul | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - | $ - | 0.000 0% | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | Current | Aug | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - |
| 2 | | | Yr | | | | | | | | | | | | | | | | | |
| 1 | | | Current | | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - |
| 3 | | | Yr | Sep | | | | | | | | | | | | | | | | |
| 1 | | | Current | | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - |
| 4 | | | Yr | Oct | | | | | | | | | | | | | | | | |
| 1 | | | Current | Nov | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - |
| 5 | | | Yr | | | | | | | | | | | | | | | | | |
| 1 | | | Current | | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - | | $ - | 0.000 0% | $ - |
| 6 | | | Yr | Dec | | | | | | | | | | | | | | | | |
| | | | | | | | Sum lines 5 - 16 | | | | Sum lines 5 - 16 | | | | Sum lines 5 - 16 | | | | Sum lines 5 - 16 | |
| 1 | | | | | | | | $ - | | | | $ - | | | | $ - | | | | $ - |
| 7 | | | | | | | | | | | | | | | | | | | | |
| 1 | | | | | | Prior Years Acc Dep: | - | | | Prior Years Acc Dep: | - | | | Prior Years Acc Dep: | - | | | Prior Years Acc Dep: | - | |
| 8 | | | **Total** | | | | | | | | | | | | | | | | | |
| 1 9 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | | Gross Plant | Accm. Deprec. | Net Plant | | Gross Plant | Accm. Deprec. | Net Plant | | Gross Plant | Accm. Deprec. | Net Plant |
| 2 0 | | | | | | | | | | | | | | | | | | | | |
| 2 1 | 2008 | $ - | $ - | $ - | 2008 | $ - | - | $ - | | $ - | - | $ - | | $ - | - | $ - | | $ - | - | $ - |
| 2 2 | 2009 | $ - | $ - | $ - | 2009 | | $ - | $ - | | | $ - | $ - | | | $ - | $ - | | | $ - | $ - |
| 2 3 | 2010 | $ - | $ - | $ - | 2010 | | $ - | $ - | | | $ - | $ - | | | $ - | $ - | | | $ - | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24 | 2011 | $ - | $ - | $ - | 01/01/2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | 2012 | $ - | $ - | $ - | 01/01/2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | 2013 | $ - | $ - | $ - | 01/01/2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | 2014 | $ - | $ - | $ - | 01/01/2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | 2015 | $ - | $ - | $ - | 01/01/2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | 2016 | $ - | $ - | $ - | 01/01/2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | 2017 | $ - | $ - | $ - | 01/01/2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | 2018 | $ - | $ - | $ - | 01/01/2018 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | 2019 | $ - | $ - | $ - | 01/01/2019 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | 2020 | $ - | $ - | $ - | 01/01/2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 3 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | 21 | - | - | - | 1 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 3 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | 22 | - | - | - | 2 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 3 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | 23 | - | - | - | 3 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 3 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | 24 | - | - | - | 4 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 3 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | 25 | - | - | - | 5 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 3 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | 26 | - | - | - | 6 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 4 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | 27 | - | - | - | 7 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 4 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | 28 | - | - | - | 8 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 4 | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | 29 | - | - | - | 9 | - | - | - | - | - | - | - | - | - | - |
| | | | | | 2 | | | | | | | | | | |
| | | | | | 0 | | | | | | | | | | |
| 4 | 20 | $ | $ | $ | 3 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | 30 | - | - | - | 0 | - | - | - | - | - | - | - | - | - | - |
| | 20 | $ | $ | $ | 2 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

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| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | | Prior Yr | Dec | | $ - | | | $ - | | | $ - | | |
| 5 | | | Current Yr | Jan | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 6 | | | Current Yr | Feb | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 7 | | | Current Yr | Mar | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 8 | | | Current Yr | Apr | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 9 | | | Current Yr | May | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 10 | | | Current Yr | Jun | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 11 | | | Current Yr | Jul | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 12 | | | Current Yr | Aug | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 13 | | | Current Yr | Sep | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 14 | | | Current Yr | Oct | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 15 | | | Current Yr | Nov | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 16 | | | Current Yr | Dec | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 17 | | | | | | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - |
| 18 | | **Total** | | | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| 21 | 2008 | $ - | $ - | $ - | 2008 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 22 | 2009 | $ - | $ - | $ - | 2009 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 23 | 2010 | $ - | $ - | $ - | 2010 | | $ - | $ - | | $ - | $ - | | $ - | $ - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24 | 2011 | $ - | $ - | $ - | 2011 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 25 | 2012 | $ - | $ - | $ - | 2012 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 26 | 2013 | $ - | $ - | $ - | 2013 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 27 | 2014 | $ - | $ - | $ - | 2014 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 28 | 2015 | $ - | $ - | $ - | 2015 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 29 | 2016 | $ - | $ - | $ - | 2016 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 30 | 2017 | $ - | $ - | $ - | 2017 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 31 | 2018 | $ - | $ - | $ - | 2018 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 32 | 2019 | $ - | $ - | $ - | 2019 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 33 | 2020 | $ - | $ - | $ - | 2020 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 34 | 2021 | $ - | $ - | $ - | 2021 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 35 | 2022 | $ - | $ - | $ - | 2022 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 36 | 2023 | $ - | $ - | $ - | 2023 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 37 | 2024 | $ - | $ - | $ - | 2024 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 38 | 2025 | $ - | $ - | $ - | 2025 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 39 | 2026 | $ - | $ - | $ - | 2026 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 40 | 2027 | $ - | $ - | $ - | 2027 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 41 | 2028 | $ - | $ - | $ - | 2028 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 42 | 2029 | $ - | $ - | $ - | 2029 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 43 | 2030 | $ - | $ - | $ - | 2030 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| | 2031 | $ | $ | $ | 2031 | | $ | $ | | $ | $ | | $ | $ |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 44 | | - | - | - | | | - | - | | - | - | | - | - |
| 45 | **Notes:** | | | | | | | | | | | | | |
| 46 | (A) | Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2) | | | | | | | | | | | | |
| 47 | (B) | This rate will reflect any future FERC approved depreciation rates. | | | | | | | | | | | | |
| 48 | (C) | Balance Portfolio Projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1. | | | | | | | | | | | | |
| 49 | (D) | Balance Portfolio Projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet. | | | | | | | | | | | | |
| 50 | (E) | Accumulated Depreciation will be brought forward from the prior year for each project. | | | | | | | | | | | | |

## Calculation of Net Plant for ITP / Priority Projects -1:



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | **Project:** | *1* | | **Project:** | *2* | | **Project:** | | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 4 | | | Prior Yr | Dec | | $ - | | | $ - | | | $ - | | |
| 5 | | | Current Yr | Jan | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 6 | | | Current Yr | Feb | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 7 | | | Current Yr | Mar | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 8 | | | Current Yr | Apr | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 9 | | | Current Yr | May | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 10 | | | Current Yr | Jun | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | | | Current Yr | Jul | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 12 | | | Current Yr | Aug | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 13 | | | Current Yr | Sep | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 14 | | | Current Yr | Oct | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 15 | | | Current Yr | Nov | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 16 | | | Current Yr | Dec | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 17 | | | | | | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - |
| 18 | | **Total** | | | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| 21 | 2008 | $ - | $ - | $ - | 2008 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 22 | 2009 | $ - | $ - | $ - | 2009 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 23 | 2010 | $ - | $ - | $ - | 2010 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 24 | 2011 | $ - | $ - | $ - | 2011 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 25 | 2012 | $ - | $ - | $ - | 2012 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 26 | 2013 | $ - | $ - | $ - | 2013 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 27 | 2014 | $ - | $ - | $ - | 2014 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 28 | 2015 | $ - | $ - | $ - | 2015 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 29 | 2016 | $ - | $ - | $ - | 2016 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 30 | 2017 | $ - | $ - | $ - | 2017 | | $ - | $ - | | $ - | $ - | | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | 2018 | $ - | $ - | $ - | 2018 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 32 | 2019 | $ - | $ - | $ - | 2019 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 33 | 2020 | $ - | $ - | $ - | 2020 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 34 | 2021 | $ - | $ - | $ - | 2021 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 35 | 2022 | $ - | $ - | $ - | 2022 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 36 | 2023 | $ - | $ - | $ - | 2023 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 37 | 2024 | $ - | $ - | $ - | 2024 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 38 | 2025 | $ - | $ - | $ - | 2025 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 39 | 2026 | $ - | $ - | $ - | 2026 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 40 | 2027 | $ - | $ - | $ - | 2027 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 41 | 2028 | $ - | $ - | $ - | 2028 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 42 | 2029 | $ - | $ - | $ - | 2029 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 43 | 2030 | $ - | $ - | $ - | 2030 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 44 | 2031 | $ - | $ - | $ - | 2031 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 45 | **Notes:** | | | | | | | | | | | | | |
| 46 | (A) | Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2) | | | | | | | | | | | | |
| 47 | (B) | This rate will reflect any future FERC approved depreciation rates. | | | | | | | | | | | | |
| 48 | (C) | ITP/Priority Project -1 that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1. | | | | | | | | | | | | |
| 49 | (D) | ITP/Priority Project -1 with incentives granted by FERC should be included in Sheet A-9 as well as this sheet. | | | | | | | | | | | | |
| 50 | (E) | Accumulated Depreciation will be brought forward from the prior year for each project. | | | | | | | | | | | | |

| **Calculation of Net Plant for ITP / Priority Projects -2** | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | Page 6 of 6 |
| 1 | | | | | | **Project:** | *1* | | **Project:** | *2* | | **Project:** | | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 4 | | | Prior Yr | Dec | | $ - | | | $ - | | | $ - | | |
| 5 | | | Current Yr | Jan | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 6 | | | Current Yr | Feb | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 7 | | | Current Yr | Mar | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 8 | | | Current Yr | Apr | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 9 | | | Current Yr | May | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 10 | | | Current Yr | Jun | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 11 | | | Current Yr | Jul | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 12 | | | Current Yr | Aug | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 13 | | | Current Yr | Sep | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 14 | | | Current Yr | Oct | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 15 | | | Current Yr | Nov | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 16 | | | Current Yr | Dec | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 17 | | | | | | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - |
| | | **Total** | | | | Prior | | | Prior | | | Prior | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | | | | | | Years Acc Dep: | - | | Years Acc Dep: | - | | Years Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| 21 | 2008 | $ - | $ - | $ - | 2008 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 22 | 2009 | $ - | $ - | $ - | 2009 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 23 | 2010 | $ - | $ - | $ - | 2010 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 24 | 2011 | $ - | $ - | $ - | 2011 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 25 | 2012 | $ - | $ - | $ - | 2012 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 26 | 2013 | $ - | $ - | $ - | 2013 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 27 | 2014 | $ - | $ - | $ - | 2014 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 28 | 2015 | $ - | $ - | $ - | 2015 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 29 | 2016 | $ - | $ - | $ - | 2016 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 30 | 2017 | $ - | $ - | $ - | 2017 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 31 | 2018 | $ - | $ - | $ - | 2018 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 32 | 2019 | $ - | $ - | $ - | 2019 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 33 | 2020 | $ - | $ - | $ - | 2020 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 34 | 2021 | $ - | $ - | $ - | 2021 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 35 | 2022 | $ - | $ - | $ - | 2022 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 36 | 2023 | $ - | $ - | $ - | 2023 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 37 | 2024 | $ - | $ - | $ - | 2024 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| | 2025 | $ | $ | $ | 2025 | | $ | $ | | $ | $ | | $ | $ |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 38 | | - | - | - | | | - | - | | - | - | | - | - |
| 39 | 2026 | $ - | $ - | $ - | 2026 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 40 | 2027 | $ - | $ - | $ - | 2027 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 41 | 2028 | $ - | $ - | $ - | 2028 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 42 | 2029 | $ - | $ - | $ - | 2029 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 43 | 2030 | $ - | $ - | $ - | 2030 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 44 | 2031 | $ - | $ - | $ - | 2031 | | $ - | $ - | | $ - | $ - | | $ - | $ - |
| 45 | **Notes:** | | | | | | | | | | | | | |
| 46 | (A) | Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2) | | | | | | | | | | | | |
| 47 | (B) | This rate will reflect any future FERC approved depreciation rates. | | | | | | | | | | | | |
| 48 | (C) | ITP/Priority Project -2 that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1. | | | | | | | | | | | | |
| 49 | (D) | ITP/Priority Project -1 with incentives granted by FERC should be included in Sheet A-9 as well as this sheet. | | | | | | | | | | | | |
| 50 | (E) | Accumulated Depreciation will be brought forward from the prior year for each project. | | | | | | | | | | | | |

**Worksheet A-8 - Actual Sponsored Upgrades**

**Evergy Metro Inc.**

For the 12 months ended -
December 31, 20XX

**Summary of Actual Sponsored Projects**



| | | (a) | (b) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| **Sponsored Project Description** | **In-Service** | **Net Plant** | **Actual Facility Carrying** | **Rev Reg** | **Actual Incentive Rev Reg (A-9** | **Total Actual Sponsored** |

| | | | | Charge | | Incentive Proj) | Rev Reg |
|---|---|---|---|---|---|---|---|
| | | | | | (a*b) | | (d + e) |
| 1 | 1 | | $ - | 0.0000% | $ - | $ - | $ - |
| 2 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 3 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 4 | Total | | $ - | | $ - | $ - | $ - |

| | **Calculation of Net Plant for Sponsored Upgrade:** | | | **Project:** SPP Proj. ID | | | **Project:** SPP Proj. ID *2* | | | **Project:** SPP Proj. ID | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 4 | | Prior Yr | Dec | $0 | | | $0 | | | $0 | | |
| 5 | | Current Yr | Jan | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 6 | | Current Yr | Feb | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 7 | | Current Yr | Mar | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 8 | | Current Yr | Apr | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 9 | | Current Yr | May | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 10 | | Current Yr | Jun | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 11 | | Current Yr | Jul | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 12 | | Current Yr | Aug | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 1 | | Current | Sep | $0 | 0.0000% | $ | $0 | 0.0000% | $ | $0 | 0.0000% | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | Yr | | | | | - | | | - | | | - | |
| 1 | | | Current | | | | | $ | | | $ | | | $ | |
| 4 | | | Yr | Oct | | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - | |
| 1 | | | Current | | | | | $ | | | $ | | | $ | |
| 5 | | | Yr | Nov | | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - | |
| 1 | | | Current | | | | | $ | | | $ | | | $ | |
| 6 | | | Yr | Dec | | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - | |
| 1 | | | | | | | | $ | | | $ | | | $ | |
| 7 | | | | | | | | - | | | - | | | - | |
| 1 | | | | | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | |
| 1 | | **Total** | | | | | | | | | | | | | |
| 9 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | |
| 2 | | | | | | | | | | | | | | | |
| 0 | | | | | | | | | | | | | | | |
| 2 | 200 | $ | $ | $ | | $ | | $ | $ | | $ | | | $ | |
| 1 | 8 | - | - | - | 2008 | - | - | - | - | - | - | $ | - | - | |
| 2 | 200 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 2 | 9 | - | - | - | 2009 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 3 | 0 | - | - | - | 2010 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 4 | 1 | - | - | - | 2011 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 5 | 2 | - | - | - | 2012 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 6 | 3 | - | - | - | 2013 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 7 | 4 | - | - | - | 2014 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 8 | 5 | - | - | - | 2015 | - | | - | - | | - | | - | | |
| 2 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 9 | 6 | - | - | - | 2016 | - | | - | - | | - | | - | | |
| 3 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 0 | 7 | - | - | - | 2017 | - | | - | - | | - | | - | | |
| 3 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 1 | 8 | - | - | - | 2018 | - | | - | - | | - | | - | | |
| 3 | 201 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 2 | 9 | - | - | - | 2019 | - | | - | - | | - | | - | | |
| 3 | 202 | $ | $ | $ | | $ | | $ | $ | | $ | | $ | | |
| 3 | 0 | - | - | - | 2020 | - | | - | - | | - | | - | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 4 | 1 | - | - | - | 2021 | - | - | - | - | - | - | |
| 3 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 5 | 2 | - | - | - | 2022 | - | - | - | - | - | - | |
| 3 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 6 | 3 | - | - | - | 2023 | - | - | - | - | - | - | |
| 3 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 7 | 4 | - | - | - | 2024 | - | - | - | - | - | - | |
| 3 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 8 | 5 | - | - | - | 2025 | - | - | - | - | - | - | |
| 3 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 9 | 6 | - | - | - | 2026 | - | - | - | - | - | - | |
| 4 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 0 | 7 | - | - | - | 2027 | - | - | - | - | - | - | |
| 4 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 1 | 8 | - | - | - | 2028 | - | - | - | - | - | - | |
| 4 | 202 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 2 | 9 | - | - | - | 2029 | - | - | - | - | - | - | |
| 4 | 203 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 3 | 0 | - | - | - | 2030 | - | - | - | - | - | - | |
| 4 | 203 | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 4 | 1 | - | - | - | 2031 | - | - | - | - | - | - | |

| | | |
|---|---|---|
| 4 | **Notes:** | |
| 4 | | Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service |
| 6 | **(A)** | (Actual Gross Rev Req, page 1, line 2) |
| 4 | | This rate will reflect any future FERC approved |
| 7 | **(B)** | depreciation rates. |
| 4 | **(C)** | Sponsored Upgrade Projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1. |
| 4 | | Sponsored Projects with incentives granted by FERC should be included in Sheet A-9 as |
| 9 | **(D)** | well as this sheet. |
| 5 | | Accumulated Depreciation will be brought forward from the |
| 0 | **(E)** | prior year for each project. |

**Worksheet A-9 - Actual Incentive Plant**

**EMe**

For the 12 months ended - December 31, 20XX

**Summary of Actual Incentive Projects**

| | Description - Zonal Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 2 | 2 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 3 | | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 4 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - Base Plan Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 1 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 6 | 2 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 7 | | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 8 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| Description - Sponsor Funded Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 9 | 1 | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 10 | 2 | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 11 | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 12 | Total | $ - | $ - | $ - | | | $ - | $ - |

| | Description of Balanced Portfolio Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 13 | 1 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 14 | 2 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 15 | | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 16 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - ITP/ Priority Project-1 | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 16 | 1 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 17 | 2 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 18 | | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 19 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - ITP/ Priority Project-2 | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 20 | 1 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 21 | 2 | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 22 | | | | $ - | $ - | $ - | 0.0000% | 0.0000 % | $ - | $ - |
| 23 | Total | | | $ - | $ - | $ - | | | $ - | $ - |
| 24 | Total for All Incentive Projects | | | $ - | $ - | $ - | | | $ - | $ - |

**Zonal Projects**

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | **Project: 1** | | ROE Adder: | 0.00% | | **Project: 2** | | ROE Adder: | 0.00% | | **Project: 3** | | ROE Adder: | 0.00% | | |
| | | | | | | Weighted | 0.00 | | | | Weighted | 0.00 | | | | Weighted | 0.00 | | |
| | | | | SPP Proj. ID | | ROE: | 0% | | | | ROE: | 0% | | | | ROE: | 0% | | |
| 2 | | | | | | Adder | 0.00 | | | | Adder | 0.00 | | | | Adder | 0.00 | | |
| 3 | | | | | | EIT: | % | | | | EIT: | % | | | | EIT: | % | | |
| 4 | | | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | |
| 5 | | Prior Yr | Dec | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | | | | |
| 6 | | Current Yr | Jan | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 7 | | Current Yr | Feb | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 8 | | Current Yr | Mar | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 9 | | Current Yr | Apr | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 10 | | Current Yr | May | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 11 | | Current Yr | Jun | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 12 | | Current Yr | Jul | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 13 | | Current Yr | Aug | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | |
| 14 | | Current | Sep | $ - | $ - | 0.00 | $ - | | $ - | $ - | 0.00 | $ - | | $ - | $ - | 0.00 | $ - | | |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 00% | - | |
| | | | | | Current | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | |
| 15 | | | | | Yr | Oct | - | - | 00% | - | | - | - | 00% | - | | - | - | 00% | - | |
| | | | | | Current | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | |
| 16 | | | | | Yr | Nov | - | - | 00% | - | | - | - | 00% | - | | - | - | 00% | - | |
| | | | | | Current | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | |
| 17 | | | | | Yr | Dec | - | - | 00% | - | | - | - | 00% | - | | - | - | 00% | - | |
| | | | | | | | | | Sum lines 6 - | $ | | | | Sum lines 6 - | $ | | | | Sum lines 6 - | $ | |
| 18 | | | | | | | | | 17 | - | | | | 17 | - | | | | 17 | - | |
| | | | | | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | |
| 19 | | | | **Total** | | | | | | | | | | | | | | | | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum Depr** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| | | $ | $ | $ | $ | $ | | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ |
| 22 | 2008 | - | - | - | - | - | 2008 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | $ | $ | | | | | | | | | | | | | | | | |
| 23 | 2009 | - | - | - | - | - | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |

| | | |
|---|---|---|
| 34 | 2020 | 2020 |
| 35 | 2021 | 2021 |
| 36 | 2022 | 2022 |
| 37 | 2023 | 2023 |
| 38 | 2024 | 2024 |
| 39 | 2025 | 2025 |
| 40 | 2026 | 2026 |
| 41 | 2027 | 2027 |
| 42 | 2028 | 2028 |
| 43 | 2029 | 2029 |
| 44 | 2030 | 2030 |
| 45 | | |

46 **(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the FERC.

**Base Plan Funded Projects**



| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | **Project: 1** | | ROE Adder: Weighted ROE Adder EIT: | 0.00% 0.000% | | **Project: 2** | | ROE Adder: Weighted ROE Adder EIT: | 0.00% 0.000% | | **Project: 3** | | ROE Adder: Weighted ROE Adder EIT: | 0.00% 0.000% | | |
| 2 | | | | | SPP Proj. ID | | | | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | | | | | | | | | |
| 4 | | | | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | | |
| 5 | | Prior Yr | Dec | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Current Yr | Jan | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 6 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Feb | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 7 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Mar | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 8 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Apr | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 9 | | | | | | | | | | | | | | | | | |
| | | Current Yr | May | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 10 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Jun | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 11 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Jul | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 12 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Aug | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 13 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Sep | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 14 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Oct | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 15 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Nov | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 16 | | | | | | | | | | | | | | | | | |
| | | Current Yr | Dec | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 17 | | | | | | | | | | | | | | | | | |
| | | | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - |
| 18 | | | | | | | | | | | | | | | | | |
| 19 | **Total** | | | | Prior | $ | | | | Prior | $ | | | | Prior | $ | |

| | | | | | | | | | Years Acc Dep: | - | | | | | Years Acc Dep: | - | | | | | Years Acc Dep: | - | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accum. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accum. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accum. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2008 | $ - | $ - | $ - | $ - | $ - | 2008 | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - |
| 23 | 2009 | $ - | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |
| 34 | 2020 | | | | | | 2020 | | | | | | | | | | | | | | | |
| 35 | 2021 | | | | | | 2021 | | | | | | | | | | | | | | | |
| 36 | 2022 | | | | | | 2022 | | | | | | | | | | | | | | | |
| 37 | 2023 | | | | | | 2023 | | | | | | | | | | | | | | | |
| 38 | 2024 | | | | | | 2024 | | | | | | | | | | | | | | | |
| 39 | 2025 | | | | | | 2025 | | | | | | | | | | | | | | | |
| 40 | 2026 | | | | | | 2026 | | | | | | | | | | | | | | | |
| 41 | 2027 | | | | | | 2027 | | | | | | | | | | | | | | | |
| 42 | 2028 | | | | | | 2028 | | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 43 | 2029 | | 2029 | | | | | | | | | | | | | | |
| 44 | 2030 | | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | | | |

46 **(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the FERC.

**Sponsor Funded Projects**



| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | **Project:** | **1** | ROE Adder: | 0.00% | | **Project:** | **2** | ROE Adder: | 0.00% | | **Project:** | **3** | ROE Adder: | 0.00% |
| 2 | | | | | SPP Proj. ID | | Weighted ROE: | 0.0000% | | | | Weighted ROE: | 0.0000% | | | | Weighted ROE: | 0.0000% |
| 3 | | | | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| 5 | | Prior Yr | Dec | $ - | $ - | | | | $0.00 | $ - | | | | $0.00 | $ - | | | |
| 6 | | Current Yr | Jan | $ - | $ - | 0.0000% | $ - | | $0.00 | $ - | 0.0000% | $ - | | $0.00 | $ - | 0.0000% | $ - | |
| 7 | | Current Yr | Feb | $ - | $ - | 0.0000% | $ - | | $0.00 | $ - | 0.0000% | $ - | | $0.00 | $ - | 0.0000% | $ - | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Current Yr | Mar | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 9 | Current Yr | Apr | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 10 | Current Yr | May | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 11 | Current Yr | Jun | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 12 | Current Yr | Jul | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 13 | Current Yr | Aug | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 14 | Current Yr | Sep | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 15 | Current Yr | Oct | $ - | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - | $0.00 | $ - | 0.00 00% | $ - |
| 16 | C | Nov | $ | $ | 0.00 | $ | $0.00 | $ | 0.00 | $ | $0 | $ | 0.00 | $ |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | ur re nt Yr C ur re nt | | - | - | | 00% | - | | 00 | - | | 00% | - | | .0 0 | - | | 00% | - | |
| 17 | | | | | | Yr | Dec | $ - | $ - | | 0.00 00% | $ - | | $0. 00 | $ - | | 0.00 00% | $ - | | $0 .0 0 | $ - | | 0.00 00% | $ - | |
| 18 | | | | | | | | | | | Sum lines 6 - 17 | $ - | | | | | Sum lines 6 - 17 | $ - | | | | | Sum lines 6 - 17 | $ - | |
| 19 | | | | **Total** | | | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2008 | $ - | $ - | $ - | $ - | $ - | 2008 | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - |
| 23 | 2009 | | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | 2020 | | 2020 | | | | | | | | | | | | | | |
| 35 | 2021 | | 2021 | | | | | | | | | | | | | | |
| 36 | 2022 | | 2022 | | | | | | | | | | | | | | |
| 37 | 2023 | | 2023 | | | | | | | | | | | | | | |
| 38 | 2024 | | 2024 | | | | | | | | | | | | | | |
| 39 | 2025 | | 2025 | | | | | | | | | | | | | | |
| 40 | 2026 | | 2026 | | | | | | | | | | | | | | |
| 41 | 2027 | | 2027 | | | | | | | | | | | | | | |
| 42 | 2028 | | 2028 | | | | | | | | | | | | | | |
| 43 | 2029 | | 2029 | | | | | | | | | | | | | | |
| 44 | 2030 | | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | | | |

46 **(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the FERC.

**Balanced Portfolio Project**

Page 5 of 7

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | **Project:** | **1** | ROE Adder: | 0.00% | | **Project:** | **2** | ROE Adder: | 0.00% | | **Project:** | **3** | ROE Adder: | 0.00% |
| 2 | | | | SPP Proj. ID | | Weighted ROE: | 0.000% | | | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% |
| 3 | | | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| 5 | Prior Yr | Dec | | $ - | $ - | | | $ - | $ - | | | | $ - | $ - | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | Current Yr | Jan | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 7 | | Current Yr | Feb | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 8 | | Current Yr | Mar | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 9 | | Current Yr | Apr | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 10 | | Current Yr | May | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 11 | | Current Yr | Jun | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 12 | | Current Yr | Jul | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 13 | | Current Yr | Aug | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 14 | | Current Yr | Sep | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 15 | | Current Yr | Oct | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 16 | | Current Yr | Nov | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 17 | | Current Yr | Dec | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - |
| 18 | | | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - |
| 19 | **Total** | | | | Prior | $ | | | | Prior | $ | | | | Prior | $ | |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Years Acc Dep: | - | | | | Years Acc Dep: | - | | | | Years Acc Dep: | - | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2008 | $ - | $ - | $ - | $ - | $ - | 2008 | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - |
| 23 | 2009 | | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |
| 34 | 2020 | | | | | | 2020 | | | | | | | | | | | | | | | |
| 35 | 2021 | | | | | | 2021 | | | | | | | | | | | | | | | |
| 36 | 2022 | | | | | | 2022 | | | | | | | | | | | | | | | |
| 37 | 2023 | | | | | | 2023 | | | | | | | | | | | | | | | |
| 38 | 2024 | | | | | | 2024 | | | | | | | | | | | | | | | |
| 39 | 2025 | | | | | | 2025 | | | | | | | | | | | | | | | |
| 40 | 2026 | | | | | | 2026 | | | | | | | | | | | | | | | |
| 41 | 2027 | | | | | | 2027 | | | | | | | | | | | | | | | |
| 42 | 2028 | | | | | | 2028 | | | | | | | | | | | | | | | |
| 43 | 2029 | | | | | | 2029 | | | | | | | | | | | | | | | |
| 44 | 2030 | | | | | | 2030 | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | | | | | | | | |

46 **(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for

specific incentive transmission projects if approved by the FERC.

**ITP / Priority Projects -1:**



| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | **Project:** | **1** | ROE Adder: | 0.00% | | **Project:** | **2** | ROE Adder: | 0.00% | | **Project:** | **3** | ROE Adder: | 0.00% |
| 2 | | | | | SPP Proj. ID | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% |
| 3 | | | | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% |
| 4 | | | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr. Rate / 12 | Depreciation Expense | |
| 5 | | Prior Yr | Dec | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | | | |
| 6 | | Current Yr | Jan | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 7 | | Current Yr | Feb | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 8 | | Current Yr | Mar | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 9 | | Current Yr | Apr | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 10 | | Current | May | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Yr | | | | | | | | | | | | | | | | |
| 11 | | | | | | Current Yr | Jun | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 12 | | | | | | Current Yr | Jul | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 13 | | | | | | Current Yr | Aug | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 14 | | | | | | Current Yr | Sep | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 15 | | | | | | Current Yr | Oct | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 16 | | | | | | Current Yr | Nov | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 17 | | | | | | Current Yr | Dec | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | |
| 18 | | | | | | | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | |
| 19 | | | | | | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2008 | $ - | $ - | $ - | $ - | | 2008 | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - |

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| | | - | - | | | |
|---|---|---|---|---|---|---|
| 23 | 2009 | | 2009 | | | |
| 24 | 2010 | | 2010 | | | |
| 25 | 2011 | | 2011 | | | |
| 26 | 2012 | | 2012 | | | |
| 27 | 2013 | | 2013 | | | |
| 28 | 2014 | | 2014 | | | |
| 29 | 2015 | | 2015 | | | |
| 30 | 2016 | | 2016 | | | |
| 31 | 2017 | | 2017 | | | |
| 32 | 2018 | | 2018 | | | |
| 33 | 2019 | | 2019 | | | |
| 34 | 2020 | | 2020 | | | |
| 35 | 2021 | | 2021 | | | |
| 36 | 2022 | | 2022 | | | |
| 37 | 2023 | | 2023 | | | |
| 38 | 2024 | | 2024 | | | |
| 39 | 2025 | | 2025 | | | |
| 40 | 2026 | | 2026 | | | |
| 41 | 2027 | | 2027 | | | |
| 42 | 2028 | | 2028 | | | |
| 43 | 2029 | | 2029 | | | |
| 44 | 2030 | | 2030 | | | |
| 45 | | | | | | |

46 **(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the FERC.

**ITP / Priority Projects -2:**



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Project: 1** | | ROE Adder: | 0.00% | **Project: 2** | | ROE Adder: | 0.00% | **Project: 3** | | ROE Adder: | 0.00% | |
| 1 | | | | | | | | | | | | | | |
| | | SPP Proj. ID | | Weighted | 0.00% | | | Weighted | 0.00% | | | Weighted | 0.00% | |
| 2 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | | | | ROE: Adder EIT: | 0.00% | | | | ROE: Adder EIT: | 0.00% | | | | ROE: Adder EIT: | 0.00% |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| 5 | | Prior Yr | Dec | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | | | |
| 6 | | Current Yr | Jan | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 7 | | Current Yr | Feb | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 8 | | Current Yr | Mar | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 9 | | Current Yr | Apr | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 10 | | Current Yr | May | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 11 | | Current Yr | Jun | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 12 | | Current Yr | Jul | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 13 | | Current Yr | Aug | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |
| 14 | | Current Yr | Sep | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | | $ - | $ - | 0.00% | $ - | |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | | | | | | Current Yr | Oct | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 16 | | | | | | Current Yr | Nov | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 17 | | | | | | Current Yr | Dec | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 18 | | | | | | | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | |
| 19 | | | | | | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Total Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2008 | $ - | $ - | $ - | $ - | $ - | 2008 | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - |
| 23 | 2009 | | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 34 | 2020 | 2020 | | | |
| 35 | 2021 | 2021 | | | |
| 36 | 2022 | 2022 | | | |
| 37 | 2023 | 2023 | | | |
| 38 | 2024 | 2024 | | | |
| 39 | 2025 | 2025 | | | |
| 40 | 2026 | 2026 | | | |
| 41 | 2027 | 2027 | | | |
| 42 | 2028 | 2028 | | | |
| 43 | 2029 | 2029 | | | |
| 44 | 2030 | 2030 | | | |

45

**(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for
46 specific incentive transmission projects if approved by the FERC.

**Addendum 10 to Attachment H – Part 2**

# Worksheet A-10 Administrative & General Expense



## Evergy Metro Inc.

For the 12 months ended - December 31, 20XX

| | Source | Description | Annual Expense | Allocation Method | Allocation Rate | Allocated |
|---|---|---|---|---|---|---|
| 1 | 323.197.b | Administrative & General Expense | $ - | W/S | 0.0000 % | $ - |
| 2 | 323.191.b | Less: General Advertising Costs | - | W/S | 0.000 0% | $ - |
| 3 | 323.189.b | Less: Regulatory Commission Expenses | - | W/S | 0.0000 % | $ - |
| 4 | 335 | Less: Corporate Visibility Expenses | | W/S | 0.000 0% | $ - |
| 5 | 335 | Less: Misc Nuclear Expenses ( included in Account 930.2) | | W/S | 0.0000 % | $ - |
| 6 | 353 | Less: Experimental & Gen. Research Exp. | | W/S | 0.000 0% | $ - |
| 7 | 335 | Less: Industry Association Dues | | W/S | 0.0000 % | $ - |
| 8 | | Subtotal | - | | | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 9 | | Less: Actual PBOP | | - | | W/S | 0.0000 % | $ - | |
| 10 | | Plus: PBOP (Projected 2010 to be used for FY2009 and following) | | - | | W/S | 0.000 0% | $ | - |
| 11 | 335 | Plus Safety Advertising | | - | | W/S | 0.0000 % | $ - | |
| 12 | 335 | Plus: General Advertising: | | | | | | | |
| 13 | | Transmission Facilities Siting | $ - | | | | | | |
| 14 | | Transmission Vegetation Management | $ - | | | | | | |
| 15 | | Transmission Reliability | $ - | | | | | | |
| 16 | | Total Advertising for Transmission | $ - | $ - | | DA | 100.0 0% | $ - | |
| 17 | 353 | Plus: Transmission Specific Research & Experimental | | | | | | | |
| 18 | | Project #1 | $ - | | | | | | |
| 19 | | Project #2 | $ - | | | | | | |
| 20 | | | $ - | | | | | | |
| 21 | | Total Research & Experimental Expenses | $ - | $ - | | DA | 100.0 0% | $ - | |
| 22 | 350 | Plus Transmission Related Reg. Comm. Exp. | | | | | | | |
| 23 | | Formula Rate | $ - | | | | | | |
| 24 | | Other-Specifically Assignable to Transmission | - | | | | | | |
| 25 | | | - | | | | | | |
| 26 | | Total Transmission | $ | | | DA | 100.0 | $ | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Regulatory Expense | - | - | | | 0% | - |
| 27 | 335 | Plus: Corporate Visibility Expenses: | | | | | | |
| 28 | | Regulatory | $ - | | | | | |
| 29 | | Reporting | $ - | | | | | |
| 30 | | Compliance | $ - | | | | | |
| 31 | | Shareholder Communications | $ - | | | | | |
| | | Total Corporate Visibility | $ - | $ - | | | | $ - |
| 32 | | Expenses | | | WS | 0.00% | | |
| 33 | | Total A&G Expense | | $ - | | | | $ - |

**Notes:**

None of the following expenses shall be recovered directly or indirectly through the formula rate:

**A.** Industry association dues (*e.g.*, EEI and EPRI).

**B.** The following charges to Account 930.2: nuclear power research expenses, miscellaneous general expenses related to Wolf Creek Nuclear Generating Station; Nuclear Energy Institute fees, assessments and other costs; and any other nuclear-related expenses.

**C.** Other experimental and general research expenditures (other than those related to transmission which shall be directly assigned to transmission).

**D.** Expenses to Maintain Corporate Visibility (except such costs related to regulatory, reporting, compliance, and shareholder communications).

**E.** Regulatory Commission expenses, other than FERC transmission-related dockets which shall be directly assigned to transmission. Transmission-related dockets shall not include transmission-related rulemakings or notices of inquiry proceedings, except those related to siting or reliability.

**Evergy Metro Inc.**



**A-11 13 Month Average Balance and BOY-EOY Average Balances**

**I. Plant Additions & Accumulated Depreciation Balances**

| Line No. | | Gross Plant (Note 1) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End. Balance Dec Y1 | Jan Y2 | Feb Y2 | Mar Y2 | April Y2 | May Y2 | June Y2 | July Y2 | Aug Y2 | Sept Y2 | Oct Y2 | Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
| 1 | Production-Steam | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | Production-Other | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 3 | Transmission | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 4 | Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 5 | General Plant | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 6 | Intangible & Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | Accumulated Depreciation and Amortization | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End. | | | | | | | | | | | | End. | 13 |

| | | Balance Dec Y1 | Jan Y2 | Feb Y2 | Mar Y2 | April Y2 | May Y2 | June Y2 | July Y2 | Aug Y2 | Sept Y2 | Oct Y2 | Nov Y2 | Balance Dec Y2 | Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Production-Steam | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | Production-Other | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 10 | Transmission | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 11 | Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 12 | General Plant | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 | Intangible & Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Net Plant** (Gross Plant less Accumulated Depreciation and Amortization)

| | | End. Balance Dec Y1 | - Jan Y2 | - Feb Y2 | - Mar Y2 | - April Y2 | - May Y2 | - June Y2 | - July Y2 | - Aug Y2 | - Sept Y2 | - Oct Y2 | - Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | Production-Steam | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Production-Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | Transmission | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | Distribu | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **tion** | | | | | | | | | | | | | | |
| 19 | **General Plant** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | **Intangible & Other** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | **Total** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:
1. When calculating the "Actual Gross Revenue Requirement", use the actual 13 month account balances for the year being trued-up.

**Evergy Metro Inc.**



**A-11 13 Month Average Balance and BOY-EOY Average Balances**
**II. Adjustments to Rate Base**

| | **Reserve Funds** | | **BOY Balance Relevant Year** | **EOY Balance Relevant Year** | **Average Balance** | **100% Non-Trans. Related** | **100 % Trans. Related** | **Plant Related** | **Labor Related** |
|---|---|---|---|---|---|---|---|---|---|
| 22 | **(Non-Escrowed) (Note A)** | | (112.28.d) | (112.28.c) | | | | | |
| 23 | Account 228.2 -Res. for Inj. & Dmges | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23a | | | | | $ - | - | - | - | - |
| 23b | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23c | | | | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | **Wages & Salary Allocator** | | | | 0.00<br>0% |
| 23d | | | | | |
| | **Gross Plant Allocator** | | | 0.00<br>0% | |
| 23e | | | | | |
| | **Direct Assign Allocator** | 100.000<br>% | | | |
| 23f | | | | | |
| | | $ | $ | $ | $ |
| 23g | | - | - | - | - |

Note: Each non-escrowed reserve fund will be allocated based on Non-transmission, 100% Transmission, Plant Allocator, or Wages & Salary Allocator, as appropriate.

| | | End. Balance<br>Dec Y1 | -<br>Jan Y2 | -<br>Feb Y2 | -<br>Mar Y2 | -<br>April Y2 | -<br>May Y2 | -<br>June Y2 | -<br>July Y2 | -<br>Aug Y2 | -<br>Sept Y2 | -<br>Oct Y2 | -<br>Nov Y2 | End. Balance<br>Dec Y2 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24 | **Unamortized Abandoned Trans. Plt.** | | | | | | | | | | | | | | |
| 25 | Account 182.1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | | | | | | | | | | | | | | | |
| 27 | **CWIP Regulatory Liability for Transmission** | | | | | | | | | | | | | | |
| 28 | Account 254 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | | | | | | | | | | | | | | | |
| 30 | **Land Held for Future Use** | | | | | | | | | | | | | | |
| 31 | Trans. Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**III. Working Capital -Material & Supplies, Stores Expense and**

**Prepayments**

| | | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance |
|---|---|---|---|---|
| 32 | **Material & Supplies** | (227, x, b) | (227, x, c) | |
| 33 | Production O&M | $ - | $ - | $ - |
| 34 | Transmission O&M | - | - | - |
| 35 | Distribution O&M | - | - | - |
| | | | | |
| 36 | Prod. Construction | - | - | - |
| 37 | Trans. Construction | - | - | - |
| 38 | Dist. Construction | - | - | - |
| 39 | Total Material & Supplies | $ - | $ - | $ - |

| | | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance |
|---|---|---|---|---|
| 40 | **Stores Expense** | (227.16. d) | (227.16. c) | |
| 41 | Total Stores Expense | $ - | $ - | $ - |

| | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance |
|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 42 | **Prepayments** | (111.57.d) | (111.57.c) | |
| 43 | Total Prepayments | $ - | $ - | $ - |

**Worksheet TU - True-up Adjustment and Timeline**

**EMe**



**Timeline**

| Step | Month | Year | Action |
|---|---|---|---|
| 1 | | Year 0 | EMe populates the formula rate using projected costs for Year 1 |
| 2 | | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Sept | Year 1 | EMe populates the formula rate using projected costs for Year 2 |
| 5 | Sept | Year 1 | Post results of Step 4 |
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | Jun | Year 2 | EMe populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |
| 9 | Jun | Year 2 | Post results from Step 7 and Step 8 |
| 10 | Sept | Year 2 | EMe populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |
| 11 | Sept | Year 2 | Post results of Step 10 |

**Reconciliation details**

| | | | |
|---|---|---|---|
| 1 | | Year 0 | EMe populates the formula rate using projected costs for Year 1 |
| 2 | | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Sept | Year 1 | EMe populates the formula rate using projected costs for Year 2 |
| 5 | Sept | Year 1 | Post results of Step 4 |

| | | | |
|---|---|---|---|
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | Jun | Year 2 | EMe populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |

| | | BPF Rev Req | Balance Portfolio Rev Req | ITP / Priority Project 1 Rev Req. | ITP / Priority Project 2 Rev Req. | Zonal Rev Req | Total Rev. Req. |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 8a | Actual Revenue Requirements from Step 7 | $ - | $ - | $ - | $ - | $ - | $ - |
| 8b | Projected Revenue Requirements from Step 1 (Note C) | - | - | - | - | - | $ - |
| 8c | True-up Amount (before interest) | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| 9 | Jun | Year 2 | Post results from Step 7 and Step 8 |
| 10 | Sept | Year 2 | EMe populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |



**Interest Calculation**

| | Short term Interest Rate (Notes A and F) | | Avg. Ann Short Term Int |
|---|---|---|---|
| 11 | Other Interest Exp.(Notes, p.117) | (Note A) | - |
| 12 | Notes Payable (Acct. 231-daily balances wksht.) | (Note A) | - |
| 13 | No. of Months | | 12 |
| 14 | Annual Short-term Int Rate | (line 11 / line 12 ) | 0.0000 % |

**FERC Quarterly Interest Rate**

| | | | |
|---|---|---|---|
| 15 | Qtr 3 (Previous Year) | | 0.0000 % |
| 16 | Qtr 4 (Previous Year) | | 0.0000 % |
| 17 | Qtr 1 (Current Year) | | 0.0000 % |
| 18 | Qtr 2 (Current Year) | | 0.0000 % |
| 19 | Average of the last 4 quarters | (Lines 15-18 / 4) | 0.0000 % |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 20 | Interest Rate Used for True-up adjustment (Note B) | 0.0000% | 0.0000 % | 0.0000% | 0.0000 % | 0.0000% | |

| | | BPF True-Up | Balance Portfolio True-up | ITP / Priority Project 1 True-up | ITP / Priority Project 2 True-up. | Zonal True-up | Total True-up |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 21 | True-Up Amount (line 8c) (Note D) | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | Interest on True-up Amount ([Average Interest Rate / 12 months]*24 months] | - | - | - | - | - | - |
| 23 | **True-up Adjustment (Note E)** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

**Note:**

A The short term interest rate is based on a 12 month rate ending June of the year in which the Annual Update is prepared, with denominator calculated using daily balances and the numerator based on Form 3Q.

B Use the lower of line 14 and line 19 if the True-up Amount (line 21) is greater than or equal to zero. Use line 19 if the True-up amount (line 21) is less than zero.

C Enter the Projected Revenue Requirement for the Actual period without a true-up adjustment plus any adjustments, either positive or negative, resulting from corrections of prior years.

D If the annual update is for a partial year, not 12 months, then the amount on line 21 shall be prorated to represent the number of months in the partial year.

E If the annual update is for a partial year, monthly interest will be multiplied by 18 plus one-half of the months in the partial year.

F The numerator and denominator of the short-term interest rate calculation will reflect consistent debt components.

**RTO Project Summary - Summary of RTO Directed Projects**
**Evergy Metro Inc.**

**Revenue Requirement of SPP Projects included in EMe's Projected Revenue Requirements (Note D):**
For the 12 months ended - December 31, 20XX



| | | | Development of Applicable Carrying Charges | | | |
|---|---|---|---|---|---|---|
| | | | Base Plan Projects | Balanced Portfolio Projects | ITP /Priority Project -1 | ITP /Priority Project - 2 |
| | | | $ | $ | $ | $ |
| 1 | Projected 12 mo avg non-incentive depr. exp. | (P-1, page 2, line 28) | - | - | - | - |
| | Total Allocated Transmission-Related Plant | | $ | $ | $ | $ |
| 2 | in Service | (Projected Gross Rev Req, page 1, line 1) | - | - | - | - |
| 3 | Less: Gross Plant - Incentive Projects | (Projected Gross Rev Req, page 4, line 34-37) | - | - | - | - |
| | Total Non-incentive Transmission-Related | | $ | $ | $ | $ |
| 4 | Plant in Service | (line 2 - line 3) | - | - | - | - |
| | | | $ | $ | $ | $ |
| 5 | Rate Base Adjustments | (Projected Gross Rev Req, page 1, line 18) | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6 | Projected 13 mo. Avg. Non-incentive Gross Plant | (P-1, page 2, line 29) | - | - | - | - |
| 7 | Net Transmission Plant | (Projected Gross Rev Req, page 1, line 9) | - | - | - | - |
| 8 | Non Incentive Net Plant(deduct Incentive Plt, as applicable) | (line 7 - net incentive plt) | - | - | - | - |
| 9 | O&M Expenses | (Projected Gross Rev Req, page 2, line 7) | - | - | - | - |
| 10 | Revenue Credits (specific SPP project type) | (Projected Net Rev Req, page 1, line 9-12) | - | - | - | - |
| 11 | Other Taxes | (Projected Gross Rev Req, page 2, line 18) | - | - | - | - |
| 12 | Effective Tax Rate | (Projected Gross Rev Req.: Page 2, Line 20) | 0.00% | 0.00% | 0.00% | 0.00% |
| 13 | Income Taxes | (Projected Gross Rev Req, page 2, line 25) | - | - | - | - |
| 14 | Effective Tax Rate for Incentive Adder | (Wksht A-9, p.1, Summary, lines 5, 13, 16, & 20) | 0.00% | 0.00% | 0.00% | 0.00% |
| 15 | Incentive Net Plant | (Proj Gross Rev Req, p.4, line 34 thru 37) | - | - | - | - |
| 16 | True-up Amount | (TU, page 1, line 23) | $ - | $ - | $ - | $ - |
| 17 | Rate Base Adjustments as a Percentage of Net Plant | (line 5 / line 7) | 0.00% | 0.00% | 0.00% | 0.00% |
| 18 | O&M Expenses as a Percentage of Net Plant | (line 9 / line 7) | 0.00% | 0.00% | 0.00% | 0.00% |
| 19 | Ratio of Revenue Credits to Actual Projects Revenue | (line 10 / line T1 below) | 0.00% | 0.00% | 0.00% | 0.00% |
| 20 | Other Taxes as a Percentage of Net Plant | (line 11 / line 7) | 0.00% | 0.00% | 0.00% | 0.00% |
| 21 | Return as a Percentage of Net Plant | (Proj Gross Rev Req, p.4, line 21) | 0.00% | 0.00% | 0.00% | 0.00% |
| 22 | Income Taxes as a Percentage of Net Plant | (line 13 / line 7) | 0.00% | 0.00% | 0.00% | 0.00% |
| 23 | Ratio of Common Stock to Total Debt | (Proj Gross Rev Req, p.4, line 20) | 0.00% | 0.00% | 0.00% | 0.00% |
| 24 | Ratio of True-up amount to Actual Projects Revenue | (line 16 / line T1 below) | 0.00% | 0.00% | 0.00% | 0.00% |

**Base Plan Projects**

For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any BPF project approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each BPF project.





| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O & M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Gross Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
| | | | | **(a - b)** | **(line 1 / line 6)** | **1.5 * (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)*i +(f* j)** | **(I - Adder)*line 12 +Adder *line 14** | **(e / 1.5)** | **(g+h+l +m +n)** | **(o * line 24)** | **(o + p)** | **(o * line 19)** | **(q + r)** |
| **Actual Projects ( From Wksht A-7)** | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | | | | | | | | | | | | | | | | | | | | |
| T 1 | **Total of Actual Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Accum Depr | Projected Net Plant | O & M Expenses | Other Taxes | Non-Incentive Return | Weighted Return Adder | CWIP Balance | Total Return | Income Taxes | Projected Depr Expense | Rev. Req w/o True-up | True-up Adjustment | Revenue Requirement | Revenue Credits | Net Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (a - b) | | (Wksht P-4) | (a - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f+k)*i+(f*j) | (I - Adder)*line 12 +Adder *line 14 | (P-4) | (g+h+l+m+n) | zero | (o + p) | zero | (q + r) |
| | **Projected projects (From Wksht P-4)** | | | | | | | | | | | | | | | | | | | | |
| 0 | | | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 | P.xx | | $ | $ | $ | 0.00 | $ | $ | $ | $ | 0.00 | 0.00 | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| xx - xx | x | - | - | - | % | - | - | - | - | % | % | - | - | - | - | - | - | - | - | - |
| T 2 | **Total of Projected Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T 3 | **Total (lines T1 + T2)** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Balanced Portfolio Projects**

For the 12 months ended - December 31, 20XX



Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any Balance Portfolio Projects approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each Balance Portfolio Projects.

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| **a** | **b** | **c** | **d** | **e** | **f** | **g** | **h** | **i** | **j** | **k** | **l** | **m** | **n** | **o** | **p** | **q** | **r** | **s** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Plant in** | **Accum** | **Actual Net** | **Depreciation** | **Projected** | **Projected Net** | **O&M** | **Other** | **Non-Incentive** | **Weighted** | **CWIP** | **Total** | **Income** | **Projected Depr** | **Rev. Req** | **True-up** | **Gross Revenue** | **Revenue** | **Net Revenue** |

| | Project ID | Project Description | Service | Depreciation | Plant | Rate | Accum Depr | Plant | Expenses | Taxes | Return | Return Adder | Balance | Return | Taxes | Expense | w/o True-up | Adjustment | Requirement | Credits | Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Actual Projects ( From Wksht A-7)** | | | | (a - b) | (line 1 / line 6) | 1.5 * (a * d) | (a - b - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f+k)*i+(f*j) | (I - Adder)*line 12 +Adder *line 14 | (e / 1.5) | (g+h+l+m+n) | (o * line 24) | (o + p) | (o * line 19) | (q + r) |
| 20xx-x | P.xx | Project 1 | $ - | $ - | $ - | 0.000% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xx | Project 2 | $ - | $ - | $ - | 0.000% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xx | | $ - | $ - | $ - | 0.000% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T1 | **Total of Actual Non-Incentive Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Accum Depr | Projected Net Plant | O&M Expenses | Other Taxes | Non-Incentive Return | Weighted Return Adder | CWIP Balance | Total Return | Income Taxes | Projected Depr Expense | Rev. Req w/o True-up | True-up Adjustment | Revenue Requirement | Revenue Credits | Net Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Project ID** | **Project Description** | **Service** | **Depreciation** | **Plant** | **Rate** | **Accum Depr** | **Plant** | **Expenses** | **Taxes** | **Return** | **Adder** | **Balance** | **Return** | **Taxes** | **Expense** | **w/o True-up** | **Adjustment** | **Requirement** | **Credits** | **Requirement** |

| | Projected projects (From Wksht P-4) | | | | (a - b) | | (Wksht P-4) | (a - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f+k)*i+(f*j) | (I - Adder)*line 12 +Adder *line 14 | (P-4) | (g+h+l+m+n) | zero | (o + p) | zero | (q + r) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-x | P.xx x | Project 1 | $ - | | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xx x | Project 2 | $ - | | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | | | $ - | - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T2 | **Total of Projected Non-Incentive Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total Non-Incentive Projects (lines T2 + T3)** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**ITP/Priority Projects-1**

For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.

Note B: The depreciation

rate is calculated by: line 1/line 6.
Note C: To be completed with any ITP/Priority Projects approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each ITP/Priority Projects.

| | | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project ID** | **Project Description** | | **Plant in Service** | **Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O & M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Gross Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
| | **Actual Projects ( From Wksht A-7)** | | | | **(a - b)** | **(line 1 / line 6)** | **1.5 * (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)*i +(f* j)** | **(I - Adder)*line 12 +Adder *line 14** | **(e / 1.5)** | **(g+h+l +m +n)** | **(o * line 24)** | **(o + p)** | **(o * line 19)** | **(q + r)** |
| 20xx-x | P.xxx | Project 1 | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xxx | Project 2 | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xxx | | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1 | **Total of Actual Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O & M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
| | **Projected projects (From Wksht P-4)** | | | | **(a - b)** | | **(Wksht P-4)** | **(a - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)*i +(f* j)** | **(I - Adder)*line 12 +Adder *line 14** | **(P-4)** | **(g+h+l+m+n)** | **zero** | **(o + p)** | **zero** | **(q + r)** |
| 20xx-x | P.xx | Project 1 | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xx | Project 2 | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | | | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T2 | **Total of Projected Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total (lines T1 + T2)** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**ITP/Priority Projects-2**

For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any ITP/Priority Projects approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each ITP/Priority Projects.

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| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project ID** | **Project Description** | **Plant in Service** | **Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O & M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Gross Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
| | | | | **(a - b)** | **(line 1 / line 6)** | **1.5* (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)*i +(f* j)** | **(I - Adder)*line 12 +Adder *line 14** | **(e / 1.5)** | **(g+h+l +m +n)** | **(o * line 24)** | **(o + p)** | **(o * line 19)** | **(q + r)** |

| | Actual Projects ( From Wksht A-7) | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-x | P.xxx | Project 1 | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xxx | Project 2 | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xxx | | $ - | $ - | $ - | 0.00 00% | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T1 | **Total of Actual Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Accum Depr | Projected Net Plant | O & M Expenses | Other Taxes | Non-Incentive Return | Weighted Return Adder | CWIP Balance | Total Return | Income Taxes | Projected Depr Expense | Rev. Req w/o True-up | True-up Adjustment | Revenue Requirement | Revenue Credits | Net Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (a - b) | | (Wksht P-4) | (a - b - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f+k)*i +(f* j) | (I - Adder)*line 12 +Adder *line 14 | (P-4) | (g+h+l +m +n) | zero | (o + p) | zero | (q + r) |
| | **Projected projects (From Wksht P-4)** | | | | | | | | | | | | | | | | | | | | |
| 20xx-x | P.xxx | Project 1 | $ - | - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-xx | P.xx | Project 2 | $ - | | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xx | | $ - | | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.00 % | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | | $ - | | | | | | | |
| T2 | **Total of Projected Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total (lines T1 + T2)** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Net Revenue Requirements
For the 12 months ended - December 31, 20XX



Evergy Metro Inc.
(EMe)

| Line No. | | (1) | (2) | (3) | (4) | (5) Amount |
|---|---|---|---|---|---|---|
| **A.** | **GROSS REVENUE REQUIREMENT** | | (with Approved Incentives, if any) | | | |
| 1 | | Total Transmission Facilities | (Projected Gross Rev Req, p.2, line 27) | | | $ - |
| 2 | | Base Plan Gross Revenue Requirements | (Wksht. RTO, Base Plan Section, line T3 ) | $ - | | |
| 3 | | Balanced Portfolio Gross Revenue Requirement | (Wksht. RTO, Balance Port. Section, line T3 ) | - | | |
| 4 | | ITP/Priority Projects-1 Gross Revenue Requirement | (Wksht. RTO, ITP-1 Section, line T3 ) | - | | |
| 5 | | ITP/Priority Projects-2 Gross Revenue Requirement | (Wksht. RTO, ITP-2 Section, line T3 ) | - | | |

| | | | | | |
|---|---|---|---|---|---|
| 6 | Sponsored Gross Revenue Requirements | (Wksht. SFP, line T3) | - | | |
| 7 | Total | (sum line 2 thru line 6) | | | $ - |
| 8 | Zonal Gross Revenue Requirement | ( line 1 minus line 7) | | | $ - |
| | **REVENUE CREDITS** | | | | |
| 9 | Base Plan Gross Revenue Credit | (Wksht P-2, line 16) | $ - | | |
| 10 | Balanced Portfolio Revenue Credit | (Wksht P-2, line 17) | - | | |
| 11 | ITP/Priority Projects-1 Revenue Credit | (Wksht P-2, line 18) | - | | |
| 12 | ITP/Priority Projects-2 Revenue Credit | (Wksht P-2, line 19) | - | | |
| 13 | Total | (sum line 9 thru line 12) | | $ - | |
| 14 | Zonal Gross Revenue Credit | (Wksht P-2, line 15) | | | $ - |
| | **NET REVENUE REQUIREMENT AFTER REVENUE CREDITS AND BEFORE TRUE-UP** | | | | |
| 15 | Base Plan Net Revenue Requirements | ( line 2 minus line 9) | $ - | | |
| 16 | Balanced Portfolio Net Revenue Requirement | ( line 3 minus line 10) | - | | |
| 17 | ITP/Priority Projects-1 Net Revenue Requirement | ( line 4 minus line 11) | - | | |
| 18 | ITP/Priority Projects-2 Net Revenue Requirement | ( line 5 minus line 12) | - | | |
| 19 | Total | (sum line 15 thru line 18) | | $ - | |
| 20 | Zonal Net Revenue Requirement | ( Line 8 minus line 14) | | | $ - |
| | **TRUE-UP ADJUSTMENTS** | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | $ | |
| 21 | | Total Transmission Facilities | (Wksht TU, line 23) | | | - | |
| | | | | $ | | | |
| 22 | | Base Plan True-Up | (Wksht TU, line 23) | - | | | |
| 23 | | Balanced Portfolio True-Up | (Wksht TU, line 23) | - | | | |
| 24 | | ITP/Priority Projects-1 True-UP | (Wksht TU, line 23) | - | | | |
| 25 | | ITP/Priority Projects-2 True-UP | (Wksht TU, line 23) | - | | | |
| | | | | | $ | | |
| 26 | | Total | (sum line 22 thru line 25) | | - | | |
| | | | | | | | $ |
| 27 | | Zonal Net True-Up Revenue Requirement | ( line 21 minus line 26) | | | | - |
| | | **NET REVENUE REQUIREMENT** | | | | | |
| | | | | $ | | | |
| 28 | | Base Plan Net Revenue Requirements | ( line 15 plus line 22) | - | | | |
| 29 | | Balanced Portfolio Net Revenue Requirement | ( line 16 plus line 23) | - | | | |
| 30 | | ITP/Priority Projects-1 Net Revenue Requirement | ( line 17 plus line 24) | - | | | |
| 31 | | ITP/Priority Projects-2 Net Revenue Requirement | ( line 18 plus line 25) | - | | | |
| | | | | | $ | | |
| 32 | | Total | (sum line 28 thru line 31) | | - | | |
| | | | | | | | $ |
| 33 | | Zonal Net Revenue Requirement | ( Line 20 plus line 27) | | | | - |
| **B.** | **Point-to-Point Service** | | | | | | |
| | | Projected EMe Zone 6 SPP Average 12-Mo. | | | | | M |
| 34 | | Peak Demand (Wksht P-3, line 15) | | | | - | W |
| | | | | | | $ | |
| 35 | | Annual Point-to-Point Rate in $/MW - Year | ( Line 33 / line 34) | | | - | |
| 36 | | Monthly Point-to-Point Rate in $/MW - Month | ( Line 35 / 12 months) | | | $ | |

| | | | | |
|---|---|---|---|---|
| | | | | $ - |
| 37 | | Weekly Point-to-Point Rate in $/MW- Weekly | ( Line 35 / 52 weeks) | $ - |
| 38 | | Daily On-Peak Point-to-Point Rate in $/MW - Day | ( Line 35 / 260 days) | $ - |
| 39 | | Daily Off-Peak Point-to-Point Rate in $/MW - Day | ( Line 35 / 365 days) | $ - |
| 40 | | Hourly On-Peak Point-to-Point Rate in $/MW - Hour | ( Line 38 / 16 hours) | $ - |
| 41 | | Hourly Off-Peak Point-to-Point Rate in $/MW - Hour | ( Line 39 / 24 hours) | $ - |
| | **C.** | **Facility Carrying Charge** | | |
| 42 | | Total Trans. Facilities Gross Rev. Req., without Incentives | (Line 21 + Projected Gross Rev Req, p.2, line 29) | $ - |
| 43 | | Net Transmission Plant | ( Projected Gross Rev Req, p.1, line 9) | $ - |
| 44 | | Projected and Trued Up Facilities Carrying Charges | ( line 42 / line 43) | 0.0000% |
| 45 | | Monthly Facility Carrying Charge | ( line 44 divided by 12 months) (Note 2) | 0.0000% |

**NOTES**

1. The Facility Carrying Charge and Monthly Facility Carrying Charge on Page 1, lines 44 and 45 are to be used to compute the revenue requirements for facilities directly assigned to a customer.

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Metro Inc.
(EMe)

Projected
Page 1 of 5

| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| Line | **Form No. 1** | | | | | |

| No. | RATE BASE: | Page, Line, Col. | EMe | EMe Total | Allocator | | Transmission (4)*(6) |
|---|---|---|---|---|---|---|---|
| | PLANT IN SERVICE | | | | | | |
| | | | $ | $ | | | $ |
| 1 | Transmission | (Wksht P-1, p.2 Line 29) | - | - | TP | 0.00000 | - |
| 2 | General | (Act. Gross Rev Req, p.1, line 5) | - | - | W/S | 0.00000 | - |
| 3 | Intangible & Other | (Act. Gross Rev Req, p.1, line 6) | - | - | W/S | 0.00000 | - |
| 4 | TOTAL GROSS PLANT | (Sum Line 1 to Line 3) | $ - | $ - | | | $ - |
| | ACCUMULATED DEPRECIATION | | | | | | |
| | | | $ | $ | | | $ |
| 5 | Transmission | (Wksht P-1, p.2 Line 29) | - | - | DR | 0.00000 | - |
| 6 | General | (Act. Gross Rev Req, p.1, line 12) | - | - | W/S | 0.00000 | - |
| 7 | Intangible & Other | (Act. Gross Rev Req, p.1, line 13) | - | - | W/S | 0.00000 | - |
| 8 | TOTAL ACCUM. DEPRECIATION | (Sum Line 5 to Line 7) | $ - | $ - | | | $ - |
| | NET PLANT IN SERVICE | | | | | | |
| | | | $ | $ | | | $ |
| 9 | Transmission | ( Line 1 less Line 5) | - | - | | | - |
| 10 | General | ( Line 2 less Line 6) | - | - | | | - |
| 11 | Intangible & Other | ( Line 3 less Line 7) | - | - | | | - |
| 12 | TOTAL NET PLANT | (Sum Line 9 to Line 11) | $ - | $ - | | | $ - |
| | ADJUSTMENTS TO RATE BASE | | | | | | |
| | Accumulated Deferred | | $ | $ | | | $ |
| 13 | Income Taxes | (Act. Gross Rev Req, p.1, line 22) | - | - | DA | 1.00000 | - |
| 14 | Reserve Funds (Non-Escrowed) | (Act. Gross Rev Req, p.1, line 23) | - | - | DA | 1.00000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 15 | Unamortized Abandoned Transmission Plant | (Act. Gross Rev Req, p.1, line 24 - Amortization) | - | - | DA | 1.00000 | - |
| 16 | CWIP Regulatory Liability for Transmission Proj. | (Act. Gross Rev Req, p.1, line 26) | - | - | DA | 1.00000 | - |
| 17 | CWIP for Incentive Transmission Projects | (Worksheet P-1, Line 34) | - | - | DA | 1.00000 | - |
| | TOTAL | | $ - | $ - | | | $ - |
| 18 | ADJUSTMENTS | (Sum Line 13 to Line 17) | - | - | | | - |
| | LAND HELD FOR | | $ - | $ - | | | $ - |
| 19 | FUTURE USE | (Act. Gross Rev Req, p.1, line 28) | - | - | DA | 1.00000 | - |
| | WORKING CAPITAL | | | | | | |
| | | | $ - | $ - | | | $ - |
| 20 | CWC | calculated (Note C) | - | - | | | - |
| 21 | Materials & Supplies | (Act. Gross Rev Req, p.1, line 30) | - | - | TP | 0.00000 | - |
| 22 | Stores Expense | (Act. Gross Rev Req, p.1, line 31) | - | - | W/S | 0.00000 | - |
| 23 | Prepayments (Account 165) | (Act. Gross Rev Req, p.1, line 32) | - | - | W/S | 0.00000 | - |
| | TOTAL WORKING | | $ - | $ - | | | $ - |
| 24 | CAPITAL | (sum Line 21 to Line 23) | - | - | | | - |
| | | | | | | | $ - |
| 25 | Rate Base | (sum Line 12, 18 , 19 & 24) | | | | | - |

Rate Formula Template
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Evergy Metro Inc.
(EMe)



| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| Line No. | **Reference** | **EMe** | **EMe Total** | | | **Transmis** |

| | | | | | Allocator | | sion (4)*(6) |
|---|---|---|---|---|---|---|---|
| | **O&M** | | | | | | |
| | | | $ | $ | | | |
| 1 | Transmission | (Wksht P-2, Line 3) | - | - | | | |
| 2 | Less Account 561 | (Wksht P-2, Line 4) | - | - | | | |
| 3 | Less Account 565 | (Wksht P-2, Line 5) | - | - | | | |
| 3a | Less: Trans. Lease Payments & Facility Chge | (Wksht P-2, Line 5a) | - | - | | | |
| 4 | Total Transmission O&M | ( Line 1 less Line 2 , 3 & 3a) | - | - | TP | 0.00000 | $ - |
| | | | $ | $ | | | $ |
| 5 | A&G -Adjusted | (Wksht P-2, Line 6) | - | - | W/S | 0.00000 | - |
| 5a | Less: Actual PBOP | ( A-10 (Act A&G) line 9 ) | - | - | W/S | 0.00000 | - |
| 5b | Plus: PBOP (Projected 2010) | (Actual Gross Rev Req, Page 5, Note R) | - | - | W/S | 0.00000 | - |
| 5c | Plus: Advertising - Safety | (Wksht P-2, Line 6a) | - | - | W/S | 0.00000 | - |
| 5d | Plus: Advertising - Transmission | (Wksht P-2, Line 6b) | - | - | DA | 1.00000 | - |
| 5e | Plus: Research - Transmission | (Wksht P-2, Line 6c) | - | - | DA | 1.00000 | - |
| 5f | Plus: Regulatory Exp -Transmission | (Wksht P-2, Line 6d) | - | - | DA | 1.00000 | - |
| 5g | Plus: Corporate Visibility -Transmission | (Wksht P-2, Line 6e) | - | - | W/S | 0.00000 | - |
| 6 | Transmission Lease Payments & Facility Charges | (Wksht P-2, Line 7) | - | - | DA | 1.00000 | - |
| | | | $ | $ | | | $ |
| 7 | TOTAL O&M | ( Sum Lines 4, 5 & 5b thru 6, less 5a) | - | - | | | - |
| | **DEPRECIATION EXPENSE** | | | | | | |
| | | | $ | $ | | | $ |
| 8 | Transmission | (Wksht P-1, p.2 Line 28) | - | - | TP | 0.00000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | General | (Act. Gross Rev Req, p.2, line 9) | - | - | W/S | 0.00000 | - |
| 10 | Intangible & Other | (Act. Gross Rev Req, p.2, line 10) | - | - | W/S | 0.00000 | - |
| 11 | Amortization of Abandon Transmission Plant | (Act. Gross Rev Req, p.2, line 11) | - | - | DA | 1.00000 | - |
| | TOTAL | | $ | $ | | | $ |
| 12 | DEPRECIATION | (Sum Line 8 to Line 11) | - | - | | | - |
| | **TAXES OTHER THAN INCOME TAXES (Note G)** | | | | | | |
| | LABOR RELATED | | $ | $ | | | $ |
| 13 | Payroll | (Wksht P-2, Line 9) | - | - | W/S | 0.00000 | - |
| 14 | Highway and vehicle | (Wksht P-2, Line 10) | - | - | W/S | 0.00000 | - |
| | PLANT RELATED | | | | | | |
| 15 | Property | (Wksht P-2, Line 11) | - | - | GP | 0.00000 | - |
| 16 | Gross Receipts | (Wksht P-2, Line 12) | - | - | NA | | - |
| 17 | Other | (Wksht P-2, Line 13) | - | - | GP | 0.00000 | - |
| | TOTAL OTHER | | $ | $ | | | $ |
| 18 | TAXES | (Sum Line 13 to Line 17) | - | - | | | - |
| | **INCOME TAXES** | | | | | | |
| 19 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | (FIT, SIT & p are as given in Note H) | | | 0.00% | | |
| 20 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | WCLTD=(page 5, line 21) | | | 0.00% | | |
| 21 | GRCF = 1 / (1 - T) = (from line 23) | | | | - | | |
| | Amortized Investment | | $ | $ | | | |
| 22 | Tax Credit | (Act. Gross Rev Req, p.2, line 22) | - | - | | | |
| *22a* | ***(Excess)/Deficient Deferred Income*** | *(Act. Gross Rev Req, p.5, line 22a)* | *$* - | *$* - | | | |

***Taxes***

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | Income Tax Calculation | (Line 20*(Line 25 of Page 1)*( Line 21 of Page 4)+Line 26 of page 4 ) | | NA | | $ - |
| 24 | ITC adjustment | ( Line 21 X Line 22) | - | NP = | 0.00000 | - |
| *24a* | ***(Excess)/Deficient Deferred Income Tax Adjustment*** | *(Line 21 * line 22a)* | - | *DA* | *1.00000* | - |
| 25 | Total Income Taxes | (Sum Line 23, 24*, & 24a))* | $ - | | | $ - |
| 26 | **RETURN** | ((Line 25 of Page 1)*( Line 21 of Page 4 ) + (Line 25 - Line 26) of page 4 ) | | NA | | $ - |
| 27 | **GROSS REV. REQ. WITH INCENTIVES** | (Sum line 7, 12, 18, 25 & 26 ) | | | | $ - |
| 28 | LESS: Gross Rev. Req. for Incentives | ( Line 40 of page 4 ) | | | | - |
| 29 | **GROSS REV. REQ. WITHOUT INCENTIVES** | ( Line 27 less Line 28) | | | | $ - |

Rate Formula Template
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**SUPPORTING CALCULATIONS**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|
| Line | **Form No. 1** | | | | | |

| No. | | Page, Line, Col. | EMe | EMe Total | Allocator | | Transmission (4)*(6) |
|---|---|---|---|---|---|---|---|
| | **TRANSMISSION PLANT INCLUDED IN FORMULA** | | | | | | |
| 1 | Total transmission plant | (Page 3, Line 7 ) | $ - | $ - | | | $ - |
| 2 | Less: Net Substation, 34kV, & Radial Lines to Distr. Plt. | (Act. Gross Rev Req, p.3, line 2) | - | - | | | - |
| 3 | Less: Total GSU in Transmission Plant | (Act. Gross Rev Req, p.3, line 3) | - | - | | | - |
| 4 | Transmission plant included in rates | ( Line 1 less Line 2 & 3) | | | | | $ - |
| 5 | Percentage of transmission plant included in rates | Line 4 divided by Line 1) | | | TP= | 0.00000 | |
| | **GROSS AND NET PLANT ALLOCATORS** | | | | | | |
| | GROSS PLANT IN SERVICE | (ACTUAL HISTORICAL COST) | | | | | |
| 6 | Production | (Act. Gross Rev Req, p.3, line 6) | $ - | $ - | NA | | |
| 7 | Transmission | (Act. Gross Rev Req, p.3, line 7) | - | - | DA | 1.00000 | $ - |
| 8 | Less: Excluded Plant | (Act. Gross Rev Req, p.3, line 8) | | | | | - |
| 9 | Distribution | (Act. Gross Rev Req, p.3, line 9) | - | - | NA | | |
| 10 | General & Intangible | (Act. Gross Rev Req, p.3, line 10) | - | - | W/S | 0.00000 | - |
| 11 | TOTAL GROSS PLANT | (sum Line 6, 7, 9 & 10 less line 8) | $ - | $ - | GP = | 0.00000 | $ - |
| | ACCUMULATED DEPRECIATION | (ACTUAL HISTORICAL COST) | | | | | |
| 12 | Production | (Act. Gross Rev Req, p.3, line 12) | $ | $ | NA | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | - | - | | | |
| | | | | | | | $ |
| 13 | Transmission | (Act. Gross Rev Req, p.3, line 13) | - | - | DA | 1.00000 | - |
| 14 | Less: Excluded Plant | (Act. Gross Rev Req, p.3, line 14) | | | | | - |
| 15 | Distribution | (Act. Gross Rev Req, p.3, line 15) | - | - | NA | | |
| 16 | General & Intangible | (Act. Gross Rev Req, p.3, line 16) | - | - | W/S | 0.00000 | - |
| 17 | TOTAL ACCUM. DEPRECIATION | (sum Line 12, 13, 15 & 16 less line 14) | $ - | $ - | DR = | 0.00000 | $ - |
| | NET PLANT IN SERVICE | (ACTUAL HISTORICAL COST) | | | | | |
| | | | $ | $ | | | |
| 18 | Production | ( Line 6 less line 12) | - | - | | | |
| | | | | | | | $ |
| 19 | Transmission | ( Line 7 less line 13) | - | - | | | - |
| 20 | Less: Excluded Plant | ( Line 8 less line 14) | - | - | | | - |
| 21 | Distribution | ( Line 9 less line 15) | - | - | | | |
| 22 | General & Intangible | ( Line 10 less line 16) | - | - | | | - |
| 23 | TOTAL NET PLANT | (sum Line 18, 19, 21 & 22 less line 20) | $ - | $ - | NP = | 0.00000 | $ - |

Rate Formula Template
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Evergy Metro Inc.
**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) **Form No. 1** **Page, Line, Col.** | (3) **EMe** | (4) **EMe Total** | (5) **Allocator** | (6) | (7) **Transmission (5)*(6)** |
|---|---|---|---|---|---|---|---|
| | **WAGES & SALARY ALLOCATOR (W&S)** | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | $ | | | | |
| 1 | Production | (Act. Gross Rev Req, p.4, line 1) | 0 | - | | | | |
| 2 | Transmission | (Act. Gross Rev Req, p.4, line 2) | 0 | - | TP= | 0.00000 | | 0 |
| 3 | Distribution | (Act. Gross Rev Req, p.4, line 3) | 0 | - | | | | |
| 4 | Other | (Act. Gross Rev Req, p.4, line 4) | 0 | - | | | | |
| | | | | $ | | | $ | |
| 5 | Total | (Sum Line 1 to Line 4) | 0 | - | | | - | |
| 5a | Wage & Salary Allocator Calculation | (Col 7, Line 5 divided by Col 4, Line 5) | | | WS= | 0.00000 | | |
| | | | $ | $ | | | | |
| 6 | Interest on Long-Term Debt | (Act. Gross Rev Req, p.4, line 6) | - | - | | | | |
| 7 | Amort. of Debt Disc. and Expense | (Act. Gross Rev Req, p.4, line 7) | - | - | | | | |
| 8 | Amortization of Loss on Reacquired Debt | (Act. Gross Rev Req, p.4, line 8) | - | - | | | | |
| 9 | Less: Amort. of Premium on Debt-Credit | (Act. Gross Rev Req, p.4, line 9) | - | - | | | | |
| 10 | Less: Amort. of Gain on Reacquired Debt-Credit | (Act. Gross Rev Req, p.4, line 10) | - | - | | | | |
| | | | $ | $ | | | $ | |
| 11 | Long Term Interest | (Sum Line 6 to 8, less 9 & 10) | - | - | | | - | |
| | | | $ | $ | | | $ | |
| 12 | **Preferred Dividends** | (Act. Gross Rev Req, p.4, line 12) | - | - | | | - | |
| | **Development of Common Stock:** | | | | | | | |
| | | | $ | $ | | | $ | |
| 13 | Proprietary Capital | (Act. Gross Rev Req, p.4, line 13) | - | - | | | - | |
| 14 | Less Preferred Stock | (Act. Gross Rev Req, p.4, line 14) | - | - | | | - | |
| 15 | Less Noncontrolling Interest | (Act. Gross Rev Req, p.4, line 15) | - | - | | | - | |
| 16 | Less: OCI Account 219 | (Act. Gross Rev Req, p.4, line 16) | - | - | | | - | |
| | | | $ | $ | | | $ | |
| 17 | Common Stock | ( Sum Line 13 Less 14, 15 & 16) | - | - | | | - | |

| | | | EMe | EMe Total | % | | Cost (Note P) | | Weighted |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | W | |
| | | | | | | | | C | |
| | | | | | | | | L | |
| | | | | | | | | T | |
| | | | $ | $ | 0.00 | | | D | |
| 18 | Long Term Debt | (Act. Gross Rev Req, p.4, line 18) | - | - | % | | - | = | 0.0000 |
| | | | | | 0.00 | | | | |
| 19 | Preferred Stock | (Act. Gross Rev Req, p.4, line 19) | - | - | % | | - | | 0.0000 |
| | | | | | 0.00 | | | | |
| 20 | Common Stock | ( Page 4, Line 17) | - | - | % | | 0.1110 | | 0.0000 |
| | | | $ | $ | 0.00 | | | R | |
| 21 | Total | (Sum Line 18 thru Line 20) | - | - | % | | | = | 0.00000 |
| | **GROSS REV. REQUIREMENT FOR INCENTIVE PROJECTS Plant Granted Incentive ROE Adder:** | | | | | | | | |
| | | | $ | $ | | | | | |
| 22 | Total Incentive Plant | (Wksht P-1, Page 1, Line 34) | - | - | | | | | |
| 23 | Less: Total Accumulated Depreciation | (Wksht P-1, Page 1, Line 34) | - | - | | | | | |
| | | | $ | $ | | | | | |
| 24 | Net Incentive Plant | ( Line 22 less Line 23) | - | - | | | | | |
| | | | | | | | $ | | |
| 25 | Incentive Return Including Taxes | (Wsht P-1, Page 1, Line 37) | | | | | - | | |
| | | | | $ | | | | | |
| 26 | Taxes Included in Incentive Return | ( Line 25 times page 2, line 19) | | - | | | | | |
| | **Construction Work In Progress:** | | | | | | | | |
| | | | $ | $ | | | | | |
| 27 | Total CWIP | (Page 1, Line 17) | - | - | | | | | |
| | | | | | | | $ | | |
| 28 | Incentive Return Including Taxes | (Wksht P-1, Page 1, Line 36) | | | | | - | | |
| | **Abandoned Plant:** | | | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Unamortized Abandoned | | $ | | | |
| 29 | Transmission Plant | (Page 1, Line 15) | - | | | |
| | Tax-Adjusted Return | | | $ | | |
| 30 | on Abandoned Plant | ( Line 21 X Line 29 X (1 + EIT)) | | - | | |
| | Amortization Expense | | | | | |
| 31 | for Abandoned Plant | (Page 2, Line 11) | | - | | |
| | Total Recovery for | | | | $ | |
| 32 | Abandoned Plant | (Sum line 30 thru line 31) | | | - | |
| | **TOTAL GROSS REV. REQUIREMENT FOR** | | | | | $ |
| 33 | **INCENTIVE PROJ.** | (Sum line 25 , 28 & 32) | | | | - |

| | **INCENTIVE PLANT (excludes CWIP and Abandoned Plant)** | | **Gross Plant** | **Acum Depr** | **Net Plant** |
|---|---|---|---|---|---|
| | Incentive Plant: Projected Base Plan | | | | |
| 34 | Funded | (RTO Project Smry) | - | - | - |
| | Incentive Plant: Projected Balanced | | | | |
| 35 | Portfolio | (RTO Project Smry) | - | - | - |
| | Incentive Plant: Projected ITP / Priority | | | | |
| 36 | Project-1 | (RTO Project Smry) | - | - | - |
| | Incentive Plant: Projected ITP / Priority | | | | |
| 37 | Project-2 | (RTO Project Smry) | - | - | - |
| | Incentive Plant: Projected Sponsor | | | | |
| 38 | Funded | (RTO Project Smry) | - | - | - |
| | | | $ | $ | $ |
| 39 | Total Incentive Plant | (sum Line 34 to Line 38) | - | - | - |

Note: Incentive gross plant and accumulated depreciation values, if applicable, will be calculated by cell references to the RTO Project Smry and Spon Proj Smry tabs.

| | | | |
|---|---|---|---|
| | | | $ |
| 40 | **Incentive Return** | (Wksht P-1, Page 1, Line 37) | - |

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Evergy Metro Inc.
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**NOTES**

A Beginning in 2009, included in page 256 notes of the FERC Form 1, the long term interest expense and preferred dividends and a 13-month average balance for long-term debt, preferred stock and common equity of Great Plains Energy will be provided. This information will be the reference for the capital structure and weighted cost of long term debt and preferred stock.

B (Hold future use)

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 7, col. 7.

D (Hold future use)

E (Hold future use)

F (Hold future use)

G (Hold future use)

H The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "percentage of federal income tax deductible for state income tax purposes". Furthermore, a utility that elected to utilize amortization of tax credits against taxable income rather than book tax credits to Account 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 2, line 21). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. KCMO Earnings Tax is not included in the calculation of the Composite State Income Tax Rate.

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00% | Federal Income Tax Rate |
| | SIT= | 0.00% | Composite State Income Tax Rate or Composite SIT |
| | p = | 0.00% | Percentage of federal income tax deductible for state income tax purposes |

The Composite State Income Tax Rate reflects the effective rate for each tax jurisdiction:

| | Apportionment Factor | Rate | Effective Rate | % of FIT Deductible | Portion of Fed Tax Deductible = p |
|---|---|---|---|---|---|
| Missouri | 0.00% | 0.00% | 0.0000% | 0.00% | 0.0000% |
| Kansas | 0.00% | 0.00% | 0.00 | 0.00% | 0.0000% |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | 00% | | |
| | | | | 0.00 | | |
| | KS City | 0.00% | 0.00% | 00% | 0.00% | 0.0000% |
| | | | Composite State Income Tax Rate | 0.00 00% | | |
| | | | | Composite Portion of FIT Deduction for State Returns | | 0.0000% |

**ALLOCATION FACTORS**

| Line No. | Allocators | Description | Location of Calculation or First Use of Allocator |
|---|---|---|---|
| 1 | **TP** | Percentage of transmission plant included in rate base. | Page 3, line 5, col 6 |
| 2 | **W/S** | Percentage of transmission labor included in rates | Page 4, line 5a, col 6 |
| 3 | **DA** | Direct assignment | First used on page 1, line 13, col 6 |
| 4 | **GP** | Ratio of allocated transmission, general, & intangible plant to total gross plant. | Page 3, line 11, col 6 |
| 5 | **NA** | Not applicable for the transmission formula rate. | First used on page 2, line 16, col 6 |
| 6 | **NP** | Ratio of net transmission, general, & intangible plant to total net plant. | Page 3, line 23, col 6 |
| 7 | **DR** | For depreciation reserve, non-excluded facilities divided by total transmission (actual year) | Page 3, line 17, col 6 |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Schedule 1 Revenue Requirements
For the 12 months ended - December 31, 20XX

Page 1 of 1

Evergy Metro Inc.
(EMe)

| Line No. | (1) | (2) Reference | (3) | (4) Amount |
|---|---|---|---|---|

**A. Projected Schedule 1 ARR**

| | | | | |
|---|---|---|---|---|
| 1 | Total Load Dispatch & Scheduling | (Wksht P-2, Line 4 ) | $ | - |
| 2 | Less: Sch., Syst. Control and Dispatch Services | (Actual Sch 1 Rev Req, line 2)*(Col. 5 / Col. 3, line 4 of P-2) | | - |
| 3 | Less: Transmission Service Studies | (Actual Sch 1 Rev Req, line 3)*(Col. 5 / Col. 3, line 4 of P-2) | | - |
| 4 | Less: Reliability, Planning & Stds Dev. Services | (Actual Sch 1 Rev Req, line 4)*(Col. 5 / Col. 3, line 4 of P-2) | | - |
| 5 | Total | (Line 1 less Line 2 thru Line 4) | $ | - |
| 6 | Less: PTP Service Credit | (Actual Sched 1 Rev Req, Line 6) | | - |
| 7 | Revenue Requirement for Schedule 1 | (Line 5 - Line 6) | $ | - |
| 8 | Prior Year True-Up | (Line 22 Below ) | | - |
| 9 | Net Schedule 1 Revenue Requirement for Zone | (Line 7 + Line 8) | $ | - |

**B. Projected Schedule 1 Rate Calculations**

| | | | | |
|---|---|---|---|---|
| 10 | EMe 12-CP. Peak Demand | (Wksht P-3, line 15) | | - |
| 11 | Annual Point-to-Point Rate in $/MW - Year | (Line 9 / Line 10) | $ | - |
| 12 | Monthly Point-to-Point Rate $/MW - Month | (Line 11 / 12) | $ | - |
| 13 | Weekly Point-to-Point Rate $/MW - Week | (Line 11 / 52) | $ | - |
| 14 | Daily Point-to-Point Rate $/MW - Day | (Line 11 / 365) | $ | - |
| 15 | Hourly Point-to-Point Rate $/MW - Hour | (Line 11 / 8760) | $ | - |

**C. Schedule 1 True-UP**

| | | | |
|---|---|---|---|
| 16 | Actual Period Revenue Requirement | (Actual Sched 1 Rev Req, Line 7) | $ - |

| | | | |
|---|---|---|---|
| 17 | Projected Period Revenue Requirement | Schedule 1 Proj. for the Actual Period ( Note C) | - |
| 18 | Revenue Requirement True-Up | (Line 16 minus Line 17) | $ - |
| 19 | Interest on True-Up: | | |
| 20 | If Actual Revenue Req. > Projected Revenue Req. | Line 18 X (Min(ST I-Rate or FERC I-Rate)/12) X24 (Note A) | $ - |
| 21 | If Actual Revenue Req. < Projected Revenue Req. | Line 18 X (FERC Interest Rate/12) X 24 (Note B) | $ - |
| 22 | Total Annual True-Up Adjustment | (Sum Line 18 thru Line 21) | $ - |

**Notes:**

A The interest rate for an undercharge is the same rate used in the True -UP schedule.

B The interest rate for an overcharge is the same rate used in the True -UP schedule.

C Enter the Projected Revenue Requirement for the Actual period, pending the Actual data.

**Worksheet P1 - Projected Transmission Plant**
**Evergy Metro Inc.**
For the 12 months ended - December 31, 20XX

Page 1 of 4

Page 2 of 4

Page 3 of 4

**Total Incentive Plant**

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | **Project:** | **Project:** | **Project:** | **Project:** | **Project:** | **Project :** |
| 2 | Type: Deprec. Rate | Type: Deprec. Rate | Type: Deprec. Rate | Type: Deprec. Rate | Type: Deprec. Rate | Type: Deprec. Rate(A) |
| 3 | Base Plan Projects 0.0000% | Balanced Portfolio Project 0.00% | ITP/Priority Project-1 0.00% | ITP/Priority Project-2 0.00% | Sponsored Project 0.00% | 0.00% |

| | | |

| | | |

| | | |

| | | |

| | | |

| | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Incentive ROE Adder** | **ed<br><br>Return<br><br>on<br><br>Incentive<br><br>ROE<br><br>Adder** | **ed<br><br>Return<br><br>on<br><br>Incentive<br><br>ROE<br><br>Adder** | **ed<br><br>Return<br><br>on<br><br>Incentive<br><br>ROE<br><br>Adder** | **ed<br><br>Return<br><br>on<br><br>Incentive<br><br>ROE<br><br>Adder** | **entive ROE Adder** | **ed<br><br>Return<br><br>on<br><br>Incentive<br><br>ROE<br><br>Adder** |

**Worksheet P1 - Projected Transmission Plant**
**For the 12 months ended - December 31, 20XX**



| **Total Incentive, non-incentive and SPP Plant Total Plant Additions** | | **Projected Plant** |
|---|---|---|

| | Year | Gross Plant | Depreciation | Accum. Dep. | | Projected Plant Additions ( C ) | Plant in Service | Plant Depreciation Accrual ( B ) | Plant Accumulated Depreciation |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | 0.00000% | |
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | Plant Balances as of Dec 31, 20xx | | $ - | | $ |

| | (a) | (b) | ( c) | (d) | (e) | (f) | (h) | (i) | (j) | (k) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | - | | | | - |
| 4 | Jan Y1 | | $ - | $ - | $ - | Jan Y1 | $ - | $ - | $ - | $ - |
| 5 | Feb Y1 | | $ - | $ - | $ - | Feb Y1 | $ - | $ - | $ - | $ - |
| 6 | Mar Y1 | | $ - | $ - | $ - | Mar Y1 | $ - | $ - | $ - | $ - |
| 7 | Apr Y1 | | $ - | $ - | $ - | Apr Y1 | $ - | $ - | $ - | $ - |
| 8 | May Y1 | | $ - | $ - | $ - | May Y1 | $ - | $ - | $ - | $ - |
| 9 | Jun Y1 | | $ - | $ - | $ - | Jun Y1 | $ - | $ - | $ - | $ - |
| 10 | Jul Y1 | | $ - | $ - | $ - | Jul Y1 | $ - | $ - | $ - | $ - |
| 11 | Aug Y1 | | $ - | $ - | $ - | Aug Y1 | $ - | $ - | $ - | $ - |
| 12 | Sept Y1 | | $ - | $ - | $ - | Sept Y1 | | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | - | - |
| 13 | Oct Y1 | | $ | - | $ | - | $ | - | Oct Y1 | | | | | $ - | $ | $ - | $ - |
| 14 | Nov Y1 | | $ | - | $ | - | $ | - | Nov Y1 | | | | | $ - | $ | $ - | $ - |
| 15 | Dec Y1 | | $ | - | $ | - | $ | - | Dec Y1 | | $ | - | | $ - | $ | $ - | $ - |
| 16 | Jan Y2 | | $ | - | $ | - | $ | - | Jan Y2 | | $ | - | | $ - | $ | $ - | $ - |
| 17 | Feb Y2 | | $ | - | $ | - | $ | - | Feb Y2 | | | | | $ - | $ | $ - | $ - |
| 18 | Mar Y2 | | $ | - | $ | - | $ | - | Mar Y2 | | | | | $ - | $ | $ - | $ - |
| 19 | Apr Y2 | | $ | - | $ | - | $ | - | Apr Y2 | | | | | $ - | $ | $ - | $ - |
| 20 | May Y2 | | $ | - | $ | - | $ | - | May Y2 | | | | | $ - | $ | $ - | $ - |
| 21 | Jun Y2 | | $ | - | $ | - | $ | - | Jun Y2 | | | | | $ - | $ | $ - | $ - |
| 22 | Jul Y2 | | $ | - | $ | - | $ | - | Jul Y2 | | $ | - | | $ - | $ | $ - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | Aug Y2 | | $ | - | $ | - | $ | - | Aug Y2 | | | $ | - | $ | $ - |
| 24 | Sept Y2 | | $ | - | $ | - | $ | - | Sept Y2 | | | $ | - | $ | $ - |
| 25 | Oct Y2 | | $ | - | $ | - | $ | - | Oct Y2 | | | $ | - | $ | $ - |
| 26 | Nov Y2 | | $ | - | $ | - | $ | - | Nov Y2 | $ | - | $ | - | $ | $ - |
| 27 | Dec Y2 | | $ | - | $ | - | $ | - | Dec Y2 | $ | - | $ | - | $ | $ - |
| 28 | 12 Mon Tot | | | | $ | - | | | 12-Month Depreciation Accrual | | | | | $ | |
| 29 | 13 Mon Avg | | $ | - | | | $ | - | 13-Month Average Balance | | | $ | - | | $ - |

Notes: **(A)** Project Incentives as provided by Commission approval.

**(B)** Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2) divided by 12 months.

**( C )** Projected transmission plant will include those projects in P-4 and P-5, as well as other transmission projects.

**Worksheet P2 - Projected Expenses and Revenue Credits**
**Evergy Metro Inc.**
For the 12 months ended - December 31, 20XX

| Line | (1) | (2) | (3) EMe Actual Costs | (4) Ratio of Expense To Net Plant in Service | (5) Projected Costs |
|---|---|---|---|---|---|
| | | | | (Ratio of Cost to total) | (Ratio * Proj. Net Plant) |
| 1 | Net Plant in Service | (Actual Gross Rev, p. 1, ln 21, col 7) | $0 | | |
| 2 | Projected Net Plant in Service | (Projected Gross Rev, p 1, ln 12) | | | $ - |
| | **Operation and Maintenance Expenses** | | | | |
| 3 | Transmission | (Actual Gross Rev, p2, ln 1) | $ - | - | - |
| 4 | Less Account 561 | (Actual Gross Rev, p2, ln 2) | - | - | - |
| 5 | Less Account 565 | (Actual Gross Rev, p2, ln 3) | - | - | - |
| 5a | Less: Trans. Lease Pmts & Facility Chges | (Actual Gross Rev, p2, ln 3a) | - | | - |
| 6 | A&G -Adjusted per Wksht A-10 | (A-10 Act A&G, line 8) | - | - | - |
| 6a | Plus -Advertising Safety | (A-10 Act A&G, line 11) | - | - | - |
| 6b | Plus -Advertising -Transmission | (A-10 Act A&G, line 16) | - | - | - |
| 6c | Plus -Research Exp -Transmission | (A-10 Act A&G, line 21) | - | - | - |
| 6d | Plus -Regulatory Exp. -Transmission | (A-10 Act A&G, line 26) | - | - | - |
| 6e | Plus -Corporate Visibility -Transmission | (A-10 Act A&G, line 32) | - | - | - |
| 7 | Trans. Lease Pmts & Facility Charges | (Actual Gross Rev, p2, ln 6) | - | | - |
| 8 | Projected O&M | (sum ln 3, 6 thru 7 less ln 4 thru 5a) | $ - | | $ - |
| | **Other Taxes** | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | LABOR RELATED | | | | |
| 9 | Payroll | (Actual Gross Rev, p2, ln 13) | $ - | - | - |
| 10 | Highway and vehicle | (Actual Gross Rev, p2, ln 14) | - | - | - |
| | PLANT RELATED | | | - | - |
| 11 | Property (Note P) | (Actual Gross Rev, p2, ln 15) | - | - | - |
| 12 | Gross Receipts | (Actual Gross Rev, p2, ln 16) | - | - | - |
| 13 | Other | (Actual Gross Rev, p2, ln 17) | - | - | - |
| 14 | Projected Other Taxes | (sum line 9 thru line 13) | - | | - |

**P-2 Projected Revenue Credits**

| | | | |
|---|---|---|---|
| 15 | **Revenue Credits for Zonal Rev. Req.** | (Wksht A-1,p1,Line 39) | $ - |
| | **Revenue Credits for RTO - Directed Projects** | | |
| 16 | Base Plan | (Wksht A-1,p 2,Line 14) | $ - |
| 17 | Balanced Portfolio | (Wksht A-1,p 2,Line 15) | - |
| 18 | ITP/Priority Projects-1 | (Wksht A-1,p 2,Line 16) | - |
| 19 | ITP/Priority Projects-2 | (Wksht A-1,p 2,Line 17) | - |
| 20 | Total Schedule 11 Gross Revenue Requirement | | $ - |

**Worksheet P3 - Projected Transmission Network Load**
**Evergy Metro Inc.**
For the 12 months ended - December 31, 20XX

Line No.

1 Transmission Network Load

| | a | b | c | d | e | f |
|---|---|---|---|---|---|---|
| | **Month** | **Monthly Transmission Network Load as Percentage of the Average Total Network Load of January thru August. (Worksheet A-2)** | **Average Monthly Transmission Network Load for January thru August (col e, line 2 thru line 9)** | **Estimated Monthly Transmission Network Load for September thru December ( b X c)** | **Actual Load for January through August** | **Projected Transmission Network Load** |
| 2 | January | | | | - | - |
| 3 | February | | | | - | - |
| 4 | March | | | | - | - |
| 5 | April | | | | - | - |
| 6 | May | | | | - | - |
| 7 | June | | | | - | - |
| 8 | July | | | | - | - |
| 9 | August | | | | - | - |
| 10 | September | 0.00% | - | - | | - |
| 11 | October | 0.00% | - | - | | - |
| 12 | November | 0.00% | - | - | | - |
| 13 | December | 0.00% | - | - | | - |
| 14 | Total | | | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 15 | 12-CP | | | | | - |

Note: **Column b** is the monthly transmission network load for September, October, November and December as a percentage of the average of the monthly transmission network load values for January through August, based on monthly load values in Worksheet A-2.

**Column c** is average (January thru August) of monthly transmission network load in column e.

**Column f** contains actual load values for January-August and projected load values for September - December.

**Worksheet P4 - Projected Transmission Plant Related Projects - RTO Directed Projects**
**EMe**
For the 12 months ended - December 31, 20XX



| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Total Base Plan Funded Projects** | | | | | **Project:** | **1** | | **Project:** | **2.** | | **Project:** | **3.** | | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | |
| 3 | | | | | | Deprec. Rate: ( C ) | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | |
| 4 | | | | | | Beginning Bal: | $ - | | Beginning Bal: | $ - | | Beginning Bal: | $ - | | |
| 5 | | **Total** | | | | Beginning Dep: | - | | Beginning Dep: | | | Beginning Dep: | | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | |
| 7 | | | | | | | | | $ - | | | $ - | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Feb Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Mar Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Aug Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Sept Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Nov Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Dec Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Jan Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Feb Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Mar Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Apr Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Jun Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Jul Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Aug Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | Sept Y2 | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Oct | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 9 | Oct Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Nov Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | 13 Mon | $ | $ | $ | | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 2 | Avg | - | - | - | | | - | - | - | | - | - | - | | - | - | - |
| 3 | | | | | | | 12 Mon | | | | 12 Mon | | | | 12 Mon | | |
| 3 | 12 Mon Depr Exp | | $0 | | | | Depr Exp | | $0 | | Depr Exp | | $0 | | Depr Exp | | $0 |

**Notes:**

**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.

**(B)** P-4 projects will be included in total projected transmission projects for P-1



| | **Total Balanced Portfolio Projects** | | | | | **Project:** | 1 | | **Project:** | 2 | | **Project:** | 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| 9 | Feb Y1 | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Mar Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Aug Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Sept Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Nov Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Dec Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Jan Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Feb Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Mar Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Apr Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Jun Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Jul Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Aug Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Sept Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Oct Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Nov Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | 13 Mon | $ | $ | $ | | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 2 | Avg | - | - | - | | | - | - | - | | - | - | - | | - | - | - |
| 3 | | | | | | | 12 Mon | | | | 12 Mon | | | | 12 Mon | | |
| 3 | 12 Mon Depr Exp | | $0 | | | | Depr Exp | | $0 | | Depr Exp | | $0 | | Depr Exp | | $0 |

**Notes:**
**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-4 projects will be included in total projected transmission projects for P-1



| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Total ITP / Priority Projects-** | | | | | | | | | | | | | | | | |
| 1 | **1** | | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Feb Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Mar Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Aug Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Sept Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Nov Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Dec Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Jan Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Feb Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Mar Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Apr Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Jun Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Jul Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Aug Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Sept Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Oct Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 3 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Nov Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 3 | Dec Y2 | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

| | | | | | | | | | | | | | | | | | |
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| 1 | | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | 13 Mon | $ | $ | $ | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ | |
| 2 | Avg | - | - | - | | - | - | - | | - | - | - | | - | - | - | |
| 3 | | | | | | 12 Mon | | | | 12 Mon | | | | 12 Mon | | | |
| 3 | 12 Mon Depr Exp | | $0 | | | Depr Exp | | $0 | | Depr Exp | | $0 | | Depr Exp | | $0 | |

**Notes:**
**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-4 projects will be included in total projected transmission projects for P-1



| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Total ITP / Priority Projects-2** | | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) | Deprec. Rate: (B) | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: Beginning Dep: Beg Year-Mo.: | | | Beginning Bal: Beginning Dep: Beg Year-Mo.: | | | Beginning Bal: Beginning Dep: Beg Year-Mo.: | | |
| 5 | | **Total** | | | | | | | | | | | | |
| 6 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Feb Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Mar Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Aug Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Sept Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Nov Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Dec Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Jan Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Feb Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Mar Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Apr Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Jun Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Jul Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Aug Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Sept Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Oct Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 3 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Nov Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 3 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Dec Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 13 Mon | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Avg | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | | | 12 Mon | | | 12 Mon | | | 12 Mon | | | | | | |
| 3 | 12 Mon Depr Exp | | $0 | | Depr Exp | | $0 | Depr Exp | | $0 | Depr Exp | | $0 | | | | |

**Notes:**
**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-4 projects will be included in total projected transmission projects for P-1

## Worksheet P5 - Projected Transmission Plant Related to Sponsored Projects

**EMe**
For the 12 months ended -
December 31, 20XX



| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Total Sponsor Funded Projects** | | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| 9 | Feb Y1 | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Mar | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Mar Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Apr | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Apr Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | May | $ | $ | $ | May | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 2 | Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Jun | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 3 | Jun Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Jul | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 4 | Jul Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Aug | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 5 | Aug Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Sept | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 6 | Sept Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Oct | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 7 | Oct Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 8 | Nov Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 1 | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 9 | Dec Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Jan | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Jan Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Feb | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Feb Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Mar | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 2 | Mar Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Apr | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 3 | Apr Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | May | $ | $ | $ | May | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 4 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Jun | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 5 | Jun Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Jul | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 6 | Jul Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Aug | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 7 | Aug Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Sept | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 8 | Sept Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Oct | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 9 | Oct Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Nov Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | 13 Mon | $ | $ | $ | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ | |
| 2 | Avg | - | - | - | | - | - | - | | - | - | - | | - | - | - | |
| 3 | | | | | | 12 Mon | | | | 12 Mon | | | | 12 Mon | | | |
| 3 | 12 Mon Depr Exp | | $0 | | | Depr Exp | | $0 | | Depr Exp | | $0 | | Depr Exp | | $0 | |

**Notes:**
**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-5 projects will be included in total projected transmission projects for P-1

## Evergy Metro Inc.
## Formula Rate Implementation Protocols

### I. Annual Update

1. The formula rate template contained in Attachment H of the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("OATT"), Federal Energy Regulatory Commission ("FERC") Electric Tariff, Sixth Revised Volume No. 1 ("Formula") and these Formula Rate Implementation Protocols ("Protocols") together comprise the Evergy Metro Inc. ("EMe") filed rate (collectively, the "Formula Rate") for transmission service under the SPP OATT or the EMe OATT as applicable. EMe will follow the instructions specified in the Formula Rate to calculate annually its Annual Transmission Revenue Requirements ("ATRR") for Network Integration Transmission Service, rates for Point-to-Point transmission service, its ATRR associated with transmission upgrade projects having cost recovery under Schedule 11 of the SPP OATT, and rates for Ancillary Services Schedule 1 - Scheduling System Control and Dispatch Services, for posting by EMe and SPP, as applicable.

2. The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the same calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, as provided herein.

3. Each calendar year, EMe shall:

   (a) Calculate the ATRR by September 24 (or the next business day if September 24 is not a business day) for the next Rate Year in accordance with the Formula Rate ("Annual Update"). The Formula Rate specifies in detail the manner in which

      i. the most recent Form No. 1 data shall be used as inputs and the limited projections of transmission plant and associated

transmission depreciation expense, transmission O&M expense, A&G expense, revenue credits, and load will be forecast for the next Rate Year in the Annual Update; and

ii. any true-up calculated in accordance with the Formula Rate, including interest, ("True-Up Adjustment") for the prior Rate Year shall be incorporated into the Annual Update for the next Rate Year;

(b) Interest on any over-recovery or under-recovery of the net revenue requirements shall be calculated in accordance with the Formula true-up worksheet (Worksheet TU(True-Up)). Interest on an over-recovery or under-recovery of a revenue requirement shall be determined according to the Formula;

(c) Calculate the True-Up Adjustment for a given Rate Year and post it by June 1 (or the next business day if June 1 is not a business day) of the year following that Rate Year in accordance with the Formula Rate, which adjustment will be reflected in the next Annual Update. The True-Up Adjustment shall include a Formula template with the actual data for the prior Rate Year compared to the previously projected data for the same period;

(d) Calculate the ATRR values for transmission service for the next Rate Year which shall be the Annual Update for such Rate Year, plus or minus the True-up Adjustment from the previous Rate Year;

(e) Post such Annual Update (each September 24) and True-Up Adjustment (each June 1), as well as a populated Formula template in fully functional spreadsheets showing the calculation of such Annual Update and True-Up Adjustment with documentation supporting such calculation as provided in Section I.4, below, and, with respect to the Annual Update, information supporting the limited projections described in Section I.3.a.i., above, (which information shall include, but is not limited to, the following information for all transmission facilities included in the expected plant additions: (i) expected date of completion; (ii) percent completion status as of the date of the Annual Update; (iii) a one-line diagram of facilities exceeding $5 million in cost; (iv) the total installed cost of the facility; (v) the reason for the facility addition; and (vi) upgrade costs paid by a generator or paid by a transmission customer directly to EMe) in an accessible location on the SPP's website and OASIS (the date of such posting is referred to herein as the "Posting Date"). Any delay in the Posting Date will result in an equivalent extension of time for the submission of information requests discussed in Section II of these protocols;

(f) On the Posting Date, notify Interested Parties, on the SPP email exploder list titled "Service List", of the website address of the Annual Update and True-Up Adjustment postings. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general ("Interested Parties"). Interested Parties can contact SPP to subscribe to the SPP Service List;

(g) Make a good faith effort to respond within ten (10) business days to reasonable information requests submitted by Interested Parties for information and work papers supporting the Annual Update. Any such information request must be submitted within sixty (60) days of the Posting Date of the Annual Update and shall be limited (as listed in Sections II.3(a) through (g)) to that which is appropriate to determine if EMe has properly calculated the Annual Update and whether the costs included in the Annual Update are appropriately recovered under the terms of the Formula Rate and the Formula Rate has been applied according to its terms; and

(h) Provide its Interested Parties, via e-mail based on the SPP Service List, at least thirty (30) days (all references herein to days shall be

calendar days unless specified otherwise) advance notice of a public meeting to be held no sooner than ten (10) days after the Posting Date of the Annual Update and no later than October 16 each year, to explain and answer questions regarding the Annual Update for the next calendar year ("Annual Update Customer Meeting"). EMe shall provide an option for Interested Parties to remotely access this Annual Update Customer Meeting (remote access options may include video conferencing, webinar, internet conferencing, or other appropriate remote access options as determined by EMe). EMe shall modify the Annual Update to reflect any changes that it and the participating transmission customers all agree upon by no later than November 20 and shall cause the revised Annual Update to be posted in the same manner as the original Annual Update.

4. The True-Up Adjustment for the prior Rate Year shall:

(a) Be based upon EMe's FERC Form No. 1 for that Rate Year, and, to the extent specified in the Formula Rate, upon the books and records of EMe (EMe's FERC Form No. 1, books, and records all to be maintained consistently with FERC's Uniform System of Accounts ("USoA") and FERC accounting policies and practices);

(b) Be calculated pro rata based on the months during the Rate Year when the ATRR was in effect by multiplying the Annual True-Up Adjustment by the number of months that the ATRR was in effect divided by 12;

(c) Include a variance analysis of, at minimum, actual revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected revenue requirement that was calculated for the prior Rate Year with an explanation of material changes.

(d) As and to the extent specified in the Formula Rate, provide sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the actual ATRR for the applicable Rate Year and are not otherwise available directly from the FERC Form No. 1;

(e) Include an identification of (i) any changes in EMe accounting policies, practices, and procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or Form No. 1 reporting requirements) from those in effect during the calendar year upon which the most recent ATRR was based and that, in EMe's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next three years; (ii) any changes in the SPP OATT from the provisions of the SPP OATT in effect during the calendar year upon which the most recent ATRR was based and that, in EMe's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next three years; and (iii) any change, and the dollar value of the change, in the classification of any transmission facility under Attachment AI of the SPP OATT (including the costs of any reclassified facility) that EMe has made in the applicable True-Up Adjustment or Annual Update; and

(f) Be subject to review and challenge in accordance with the procedures set forth in these Formula Rate Implementation Protocols.

5. A change to the Formula Rate inputs related to extraordinary property losses, return on equity, depreciation rates for each regulatory jurisdiction that are used to calculate the composite rates applied in the Formula Rate, or Post Employment Benefits Other than Pensions may not be made absent an appropriate Federal Power Act Section 205 or 206 filing with the FERC.

6. If EMe files any corrections or modifications to its FERC Form No. 1 prior to the Posting Date of its Annual Update and such corrections or

modifications would affect the True-Up Adjustment for a prior Rate Year, the True-Up Adjustment for each Rate Year(s) affected by the corrections or modifications shall be updated to reflect the corrected or modified FERC Form No. 1 and the Annual Update shall incorporate the change in such True-Up Adjustment(s), with interest. Corrections or modifications to a FERC Form No. 1 filed after the Posting Date of an Annual Update and not included in a revised Annual Update by November 20 shall be incorporated in the next True-Up Adjustment or Annual Update, as applicable. EMe shall report in a timely manner to the FERC, the applicable state commissions, and all parties required by FERC regulations any corrections or modifications to its FERC Form No. 1, that affect materially the past or present implementation of the Formula Rate, whether such corrections or modifications have the effect of increasing or decreasing the resulting transmission rates.

**II. Review Procedures for Annual Update and True-Up Adjustment**

Each Annual Update and True-Up Adjustment for the prior Rate Year shall be subject to the following review procedures ("Annual Review Procedures") (if any of the dates provided for herein fall on a Saturday, Sunday or Federal bank holiday, then the due date shall be the first business day thereafter):

1. Review procedures specific to the Annual Update are stated in Sections I.3(e) through (h).

2. Each year, EMe will, with at least thirty (30) days' notice utilizing the SPP Service List, convene a meeting of its Interested Parties, no sooner than ten (10) days after the Posting Date of the True-Up Adjustment and no later than July 8, at EMe's offices in Kansas City, Missouri, to discuss the True-Up Adjustment ("True-Up Customer Meeting"). EMe shall provide an option for Interested Parties to remotely access this True-Up Customer Meeting (remote access options may include video conferencing, webinar, internet conferencing, or other appropriate remote access options as determined by EMe).

3. Interested Parties may begin submitting information requests immediately following the Posting Date of the True-Up Adjustment and will have one-hundred five (105) days after June 1 to serve reasonable information requests on EMe for information and work papers supporting the True-Up Adjustment for the prior Rate Year. Such information and document requests shall be limited to what is necessary to determine:

   (a) the extent or effect of an Accounting Change;

   (b) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these Protocols;

   (c) the proper application of the formula rate and procedures in these Protocols;

   (d) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;

   (e) the prudence of actual costs and expenditures;

   (f) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

   (g) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

Without limiting the generality of the foregoing, such information requests may include questions related to the data described in Sections I.4(a) and (c) and Section I.6 above.

4. EMe shall make a good faith effort to respond to information requests pertaining to a True-Up Adjustment within ten (10) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

5. To the extent EMe and any Interested Party(ies) are unable to resolve disputes related to information requests for the Annual Update or True-up Adjustment submitted in accordance with these Formula Rate Implementation Protocols, EMe or any Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Formula Rate Implementation Protocols and consistent with the FERC's discovery rules.

6. Any Interested Party shall have until the later of one-hundred fifty (150) days after June 1 or thirty (30) days after EMe's last response to reasonable information requests submitted pursuant to Section II.3 above to notify EMe in writing of any specific challenges to the True-Up Adjustment ("Informal Challenges"). Any Interested Party shall have until the later of November 24 or thirty (30) days after EMe's last response to reasonable information requests submitted pursuant to Section II.3 above to notify EMe in writing of any specific challenges to the Annual Update ("Informal Challenges"). Challenges to the Formula Rate itself shall not be considered Informal Challenges for purposes of these Annual Review Procedures.

**III. Resolution of Challenges**

1. If EMe and any Interested Party(ies) have not resolved all Informal Challenges identified pursuant to Section II.6 above within sixty (60) days after the deadline in Section II.6 for written notification of Issues, senior management of the Interested Party(ies) and EMe shall make a good faith effort to resolve any outstanding Informal Challenges ("Senior Management Review").

2. (a) If EMe's and any Interested Party's(ies') senior management are unable to resolve all Informal Challenges within thirty (30) days after the Senior Management Review commences, the Interested Party(ies) may file a challenge to the Annual Update or True-Up Adjustment ("Formal Challenge"). Challenges to the Formula Rate itself shall not be considered "Formal Challenges" for purposes of these Annual Review Procedures.

    i. Deadline for Formal Challenge notice is the later of thirty (30) days after Senior Management Review or March 1.

    ii. Any Interested Party may notify EMe in writing of a Formal Challenge to the Annual Update or True-Up Adjustment.

    (b) All information produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the Federal Power Act, or in any proceeding before the U.S. Court of Appeals to review a FERC decision involving the Formula Rate. EMe may, however, designate any response to an information request as confidential if the information conveyed is not publicly available. Interested Parties' representatives shall treat such response as

confidential in connection with any of the proceedings discussed in this section; provided, however, that when so used, such response shall initially be filed under seal (unless the claim of confidentiality is waived by EMe), subject to a later determination by the presiding authority that the material is, in whole or in part, not entitled to confidential treatment.

(c) The Informal as well as Formal Challenges shall be limited (as listed in Sections II.3(a) through (g)) to that which is appropriate to determine if EMe has properly calculated the Annual Update or True-Up and whether the costs included in the Annual Update or True-Up are appropriately recovered under the terms of the Formula Rate and the Formula Rate has been applied according to its terms.

(d) The notification for the Informal and Formal Challenges should contain sufficient information to present the issue in question, as well as sufficient contact information.

i. The written notification should be addressed to:

Regulatory Affairs –Transmission
Evergy Metro Inc.
P.O. Box 418679
Kansas City, MO 64141-9679

ii. E-mail notifications can be made to:

Regulatory.affairs@evergy.com

(e ) Notification for Formal Challenges can also be made as provided in Section IV.

3. In any proceeding ordered by the FERC in response to a Formal Challenge, EMe will bear the burden of proof in accordance with applicable FERC precedent as it may be modified by the FERC.

4. Any refunds or surcharges resulting from an Informal Challenge or Formal Challenge not resolved by November 20 shall be calculated, with interest, from the effective date of the challenged True-Up Adjustment, and shall be reflected in the True-Up Adjustment and Annual Update for the next Rate Year.

5. In the event that EMe identifies an error in an Annual Update or True-Up Adjustment (or a FERC Form No. 1 or successor form which is used as an input to the Formula Rate), or is required by applicable law or a court or regulatory body to correct an error, EMe shall correct such error in good faith and without regard to whether the correction increases or decreases EMe's revenue requirements. There will be no mid-year rate adjustments. Any such correction will be implemented in the True-Up Adjustment and Annual Update for the next Rate Year, with interest. Nothing in these Protocols should or may be construed as preventing an Interested Party or the FERC from contesting such correction.

**IV. Informational Filing**

1. By March 15 of each year, EMe shall submit to FERC an informational filing ("Informational Filing") of its projected net revenue requirement for the Rate Year, including its Annual Update and True-Up Adjustment. If March 15 falls on a holiday or weekend day, the filing will be made the next business day. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that EMe has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, EMe shall provide notice of the Informational Filing via an email exploder list and by posting the docket number assigned to EMe's Informational Filing on the SPP website and OASIS.

2. Any challenges to the implementation of the Attachment H-EMe Formula Rate must be made through the challenge procedures described in Section III of these Protocols or in a separate complaint proceeding. For any known challenges still working through the challenge procedures and not known to be a Formal Challenge by the March 15 Informational Filing, Interested Parties can also file protests or comments to EMe's annual Informational Filing.

**V. Joint Meeting with Transmission Owners**

Each year EMe shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

**VI. Miscellaneous**

1. Nothing in these Protocols limits or deprives EMe, the FERC or any Interested Party of any rights it may otherwise have under any applicable provision of the Federal Power Act. The provisions of these Protocols addressing review and challenge of the Annual Update or True-Up Adjustment are not intended to nor shall be construed as limiting EMe's, FERC's or any party's rights under any applicable provision of the Federal Power Act.

2. Notwithstanding the provisions of Section VI.1, before EMe or any Interested Party may bring any new action at the FERC involving the Formula Rate, senior management of such Interested Party(ies) and EMe shall make a good faith effort to resolve any outstanding issues. If EMe's and any Interested Party's(ies') senior management are unable to resolve all issues within thirty (30) days, then EMe or the Interested Party(ies) may bring such action. For the avoidance of doubt, the advance notice and negotiation requirement in this Section VI.2 shall not apply to Formal Challenges (as to which the Senior Management Review provisions in Section III apply) nor shall the requirement bar an Interested Party from intervening in, filing a protest under FPA § 206 in, or fully participating in any proceeding initiated by the FERC *sua sponte* or otherwise properly initiated before the FERC.

# Addendum 11 to Attachment H – Part 1A

Evergy Missouri West Inc. (EMW)

Rate Formula Template

Table of Contents

Overview
The formula is calculated in two steps. The first step is to fill out Tabs A-1 thru A-11, and the Actual Gross Rev Req tab with data from the previous year's Form 1. This data input results in the calculation of the actual annual transmission revenue requirement (Actual ATRR) for the previous year, as shown in the Actual Net Rev Req tab. The results of this calculation are presented to the customers for review no later than June 1 each year.

The TU (True-up) tab uses the Actual ATRR from the Actual Net Rev Req tab and compares it to the Projected ATRR (without the True-up for a prior year) that customers were billed for the same period. Interest is added to the difference and the adjusted true-up then is included in the Projected Net Rev Req tab.

The projected O&M and plant balances are calculated in Tabs P-1 thru P-5. These sheets feed into the Projected Gross Rev Req tab and ultimately into the Projected Net Rev Req tab. The RTO Projects Smry tab retrieves project specific data from other tabs to calculate the amount of revenue requirements associated with those projects which are contained in the total Projected Gross Revenue Requirement amount. The Spon Projects Smry tab does the same process for Sponsored projects. The total revenue requirements for these two groups of upgrades and revenue credits are subtracted from the EMW total revenue requirement to obtain the Zonal ATRR (line 20, before true-up). This calculation is shown on the Projected Net Rev Req tab. This tab also calculates the point-to-point zonal rates. SPP rates are set on the trued up Base Plan Net Revenue Requirements, Balanced Portfolio Net Revenue Requirements, and ITP/Priority Projects Net Revenue Requirements as well as the trued up Zonal Net Revenue Requirements. The specific charges are defined under the SPP Open Access Transmission Tariff.

Cells highlighted in yellow are data input cells. Some cells may reference the results from other calculations in the formula. Such cell references may change from year to year, requiring manual adjustment of the reference or the direct entry of the proper value.

| **Filed Page** | Tab | Description |
|---|---|---|

| | | |
|---|---|---|
| **2** | Summary | Summary of projected revenue requirements, point to point rates, and Schedule 1 rates. |
| **3** | Actual Net Rev Req | Actual net revenue requirements for most recent calendar year |
| **4-8** | Actual Gross Rev Req | Actual gross revenue requirements for most recent calendar year |
| **9** | Actual Sch 1 Rev Req | Actual revenue requirements for Schedule 1 |
| **10-11** | A-1 (Act. Rev. Credits) | Actual revenue credits |
| **12** | A-2 (Act. Divisor) | Actual transmission system load |
| **13-14** | A-3 (Act ADIT) | Actual Accumulated Deferred Income Taxes (ADIT) |
| ***15-17*** | *A3-2 (Act. ADIT wkst)* | *Deficient/Excess Deferred Income Taxes* |
| ***18-20*** | A-4 (Act. Excluded Assets) | Assets excluded from transmission rate base |
| ***21*** | A-5 (Act. Depreciation Rate) | Depreciation rates for each account |
| ***22*** | A-6 (Act. Taxes Other) | Actual taxes other than income taxes |
| ***23-27*** | A-7 (Act. RTO Directed Projects) | Actual RTO-directed projects: Base Plan, Balanced Portfolio, and ITP/Priority Projects |
| ***28*** | A-8 (Act. Sponsored Projects) | Actual sponsor-funded projects |
| ***29-35*** | A-9 (Act. Incentive Plant) | Actual incentive returns |
| ***36*** | A-10 (Act. A&G) | Actual Administrative and General Expenses |
| ***37-38*** | A-11 (Act. 13-Mo & BOY and EOY Aver.) | Actual 13-Month averages and BOY-EOY averages for rate base items |

| | | |
|---|---|---|
| ***39-40*** | TU (True-up) | True-up adjustment and interest calculation |
| ***41-49*** | RTO Project Smry | Actual and projected RTO-directed projects |
| ***50-52*** | Spon Project Smry | Actual and projected sponsor-funded projects |
| ***53*** | Projected Net Rev Req | Projected net revenue requirements for next calendar year |
| ***54-58*** | Projected Gross Rev Req | Projected gross revenue requirements for next calendar year |
| ***59*** | Projected Schedule 1 Rev Req | Projected revenue requirements for Schedule 1 |
| ***60-63*** | P-1 (Proj Trans Plant) | Projected transmission plant for next calendar year and incentive returns |
| ***64*** | P-2 (Proj. Exp. & Rev. Credits) | Projected expenses and revenue credits for next calendar year |
| ***65*** | P-3 (Proj. Trans. Network Load) | Projected transmission system load |
| ***66-69*** | P-4 (Proj. RTO Projects) | Projected RTO-directed projects:  Base Plan, Balanced Portfolio, ITP/Priority Projects |
| ***70*** | P-5 (Proj. Sponsored. Projects) | Projected sponsor-funded projects |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.
(EMW)

| | Line No. | (1) | (2) | (3) | (4) | (5) Amount | |
|---|---|---|---|---|---|---|---|
| **A.** | | **Net Revenue Requirement Including True-Up** | | | | | |
| | 1 | Base Plan Net Revenue Requirements | (Projected Net Rev Req, ln 28) | | $ - | | |
| | 2 | Balanced Portfolio Net Revenue Requirement | (Projected Net Rev Req, ln 29) | | - | | |
| | 3 | ITP/Priority Projects-1 Net Revenue Requirement | (Projected Net Rev Req, ln 30) | | - | | |
| | 4 | ITP/Priority Projects-2 Net Revenue Requirement | (Projected Net Rev Req, ln 31) | | - | | |
| | 5 | Total | (sum line 1 thru line 4) | | | $ - | |
| | 6 | Zonal Net Revenue Requirement | (Projected Net Rev Req, ln 33) | | | | $ - |
| **B.** | | **Point-to-Point Service** | | | | | |
| | 7 | EMW12-CP. Peak Demand | (Wksht. P-3, line 15) | | | | - MW |
| | 8 | Annual Point-to-Point Rate in $/MW - Year | ( Line 6 / line 7) | | | $ - | |
| | 9 | Monthly Point-to-Point Rate in $/WM - Month | ( Line 8 / 12 months) | | | $ - | |
| | 10 | Weekly Point-to-Point Rate in $/MW - Weekly | ( Line 8 / 52 weeks) | | | $ - | |
| | 11 | Daily On-Peak Point-to-Point Rate in $/MW - Day | ( Line 8 / 260 days) | | | $ - | |
| | 12 | Daily Off-Peak Point-to-Point Rate in $/WM - Day | ( Line 8 / 365 days) | | | $ - | |
| | 13 | Hourly On-Peak Point-to-Point Rate in $/MW - Hour | ( Line 11 / 16 hours) | | | $ - | |
| | 14 | Hourly Off-Peak Point-to-Point Rate in $/WM - Hour | ( Line 12 / 24 hours) | | | $ - | |
| **C.** | | **Schedule 1 ARR** | | | | | |
| | 15 | Net Schedule 1 Revenue Requirement for Zone | (Projected Sch 1 Rev Req, ln 9) | | | $ - | |
| **D** | | **Schedule 1 Rate Calculations** | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 16 | EMW12-CP. Peak Demand | (Wksht. P-3, line 15) | | - | MW |
| 17 | Annual Point-to-Point Rate in $/MW - Year | (Line 15 / Line 16) | $ | - | |
| 18 | Monthly Point-to-Point Rate in $/MW - Month | (Line 17 / 12) | $ | - | |
| 19 | Weekly Point-to-Point Rate in $/MW - Week | (Line 17 / 52) | $ | - | |
| 20 | Daily Point-to-Point Rate in $/MW - Day | (Line 17 / 365) | $ | - | |
| 21 | Hourly Point-to-Point Rate in $/MW - Hour | (Line 17 / 8760) | $ | - | |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Net Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.
(EMW)



| Line No. | (1) | (2) Reference | (3) | (4) | (5) | (6) Amount |
|---|---|---|---|---|---|---|
| | **REVENUE REQUIREMENTS** | (incl. Approved Incentives, if any) | | | | |
| 1 | Total Transmission Facilities | (Act Gross Rev, p. 2, ln 27, col. 7) | | | | $ - |
| 2 | Base Plan Gross Revenue Requirements | (Wksht. A-7, ln 4) | $ - | | | |
| 3 | Balanced Portfolio Revenue Requirement | (Wksht. A-7, ln 8) | - | | | |
| 4 | ITP/Priority Projects-1 Revenue Requirement | (Wksht. A-7, ln 12) | - | | | |
| 5 | ITP/Priority Projects-2 Revenue Requirement | (Wksht. A-7, ln 16) | - | | | |
| 6 | Sponsored Gross Revenue Requirements | (Wksht. A-8, ln 4) | - | | | |
| 7 | Total | (sum line 2 thru line 6) | | $ - | | $ - |
| 8 | Zonal Gross Revenue Requirement | ( line 1 minus line 7) | | | | $ - |
| | **REVENUE CREDITS** | | | | | |
| 9 | Base Plan Gross Revenue Credit | (Wksht. A-1, p.2 line 14) | $ - | | | |
| 10 | Balanced Portfolio Revenue Credit | (Wksht. A-1, p.2 line 15) | - | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 11 | ITP/Priority Projects-1 Revenue Credit | (Wksht. A-1, p.2 line 16) | | - | | |
| 12 | ITP/Priority Projects-2 Revenue Credit | (Wksht. A-1, p.2 line 17) | | - | | |
| 13 | Total | (sum line 9 thru line 12) | | | $ - | |
| 14 | Zonal Gross Revenue Credit | (Wksht. A-1, p.1 line 39) | | | | $ - |
| | **NET REVENUE REQUIREMENT** | | | | | |
| 15 | Base Plan Net Revenue Requirements | ( line 2 minus line 9) | $ | - | | |
| 16 | Balanced Portfolio Net Revenue Requirement | ( line 3 minus line 10) | | - | | |
| 17 | ITP/Priority Projects-1 Net Revenue Requirement | ( line 4 minus line 11) | | - | | |
| 18 | ITP/Priority Projects-2 Net Revenue Requirement | ( line 5 minus line 12) | | - | | |
| 19 | Total | (sum line 15 thru line 18) | | | $ - | |
| 20 | Zonal Net Revenue Requirement | ( line 8 minus line 14) | | | | $ - |
| 21 | Total Transmission Net Plant | (Act Gross Rev, p. 1, ln 16 less ln 17) | | | | $ - |
| 22 | Total Facilities Rev. Requirement without Incentives | (Act Gross Rev, p. 2, ln 29 ) | | | | $ - |
| 23 | Actual Facilities Carrying Charge | ( line 22 / line 21) | | | | 0.0000% |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West, Inc.
(EMW)

Actual Gross Rev
Page 1 of 5

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| Line No. | **RATE BASE:** | **Form No. 1 Page, Line, Col.** | **EMW** | **EMW Total** | | **Allocator** | **Transmission** (Col 4 times Col 6) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | PLANT IN SERVICE | | | | | | |
| | | (Wksht. A-11, p.1, | $ | $ | | | |
| 1 | Production | Line 1 & 2) | - | - | | | |
| | | (Wksht. A-11, p.1, | | | | | $ |
| 2 | Transmission | Line 3) | - | - | DA | 1.00000 | - |
| | | (Wksht. A-4, p.1, Line | | | | | |
| 3 | Less: Excluded Plant | 30 Note I & K) | | | | | - |
| | | (Wksht. A-11, p.1, | | | | | |
| 4 | Distribution | Line 4) | - | - | | | |
| | General | (Wksht. A-11, p.1, | | | | | |
| 5 | | Line 5) | - | - | W/S | 0.00000 | - |
| | Intangible & Other | (Wksht. A-11, p.1, | | | | | |
| 6 | | Line 6) | - | - | W/S | 0.00000 | - |
| | | (sum line 1, 2, 4, 5 & 6 | $ | $ | | | $ |
| 7 | TOTAL GROSS PLANT | less line 3) | - | - | | | - |
| | ACCUMULATED DEPRECIATION | (Note Q) | | | | | |
| | | (Wksht. A-11, p.1, | $ | $ | | | |
| 8 | Production | Line 8 & 9) | - | - | | | |
| | | (Wksht. A-11, p.1, | | | | | $ |
| 9 | Transmission | Line 10) | - | - | DA | 1.00000 | - |
| | | (Wksht. A-4, p.1, Line | | | | | |
| 10 | Less: Excluded Plant | 30 Note I & K) | | | | | - |
| | | (Wksht. A-11, p.1, | | | | | |
| 11 | Distribution | Line 11) | - | - | | | |
| | | (Wksht. A-11, p.1, | | | | | |
| 12 | General | Line 12) | - | - | W/S | 0.00000 | - |
| | Intangible & Other | (Wksht. A-11, p.1, | | | | | |
| 13 | | Line 13) | - | - | W/S | 0.00000 | - |
| | | (sum lines | $ | $ | | | $ |
| 14 | TOTAL ACCUM. DEPRECIATION | 8,9,11,12&13 less 10) | - | - | | | - |
| 15 | NET PLANT IN SERVICE | | | | | | |
| | | | $ | $ | | | |
| 16 | Production | ( line 1- line 8) | - | - | | | |
| | | | | | | | $ |
| 17 | Transmission | ( line 2- line 9) | - | - | | | - |
| 18 | Less: Excluded Plant | ( line 3- line 10) | - | - | | | - |
| 19 | Distribution | ( line 4- line 11) | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | - | - | | | |
| 20 | General | ( line 5- line 12) | - | - | | | - |
| 21 | Intangible & Other | ( line 6- line 13) | - | - | | | - |
| | | (sum lines 15,16,18,19 & 20 less | $ | $ | | | $ |
| 22 | TOTAL NET PLANT | 17) | - | - | | | - |
| | ADJUSTMENTS TO RATE BASE | | | | | | |
| | | (Wksht. A-3, p.1, Line | $ | $ | | | |
| 23 | Accumulated Deferred Income Taxes | 9*b*) | - | - | DA | 1.00000 | - |
| 24 | Reserve Funds (Non-Escrowed) | (Wksht. A-11, p.2, Line 23g) | - | - | DA | 1.00000 | - |
| 25 | Unamortized Abandoned Transmission Plant | (Wksht. A-11, p.2, Line 25, Note S) | - | - | DA | 1.00000 | - |
| 26 | CWIP for Incentive Transmission Projects | (Wksht. A-9, p.1, Line 24, Note T) | - | - | DA | 1.00000 | - |
| 27 | CWIP Regulatory Liability for Transmission Projects | (Wksht. A-11, p.2, Line 28, Note T) | - | - | DA | 1.00000 | - |
| | | (sum lines 23 thru line | $ | $ | | | $ |
| 28 | TOTAL ADJUSTMENTS | 27) | - | - | | | - |
| | | (Wksht. A-11, p.2, | $ | $ | | | $ |
| 29 | LAND HELD FOR FUTURE USE | lines 31 Note B) | - | - | DA | 1.00000 | - |
| | WORKING CAPITAL | | | | | | |
| | | | | | | | $ |
| 30 | CWC | calculated (Note C) | | | | | - |
| | | (Wksht. A-11, p.1, | $ | $ | | | |
| 31 | Materials & Supplies | Line 34 & 37) | - | - | TP | 0.00000 | - |
| 32 | Stores Expense | (Wksht. A-11, p.2, Line 41) | - | - | W/S | 0.00000 | - |
| 33 | Prepayments (Account 165) | (Wksht. A-11, p.2, Line 43) | - | - | W/S | 0.00000 | - |
| | | (sum line 30 thru line | $ | $ | | | $ |
| 34 | TOTAL WORKING CAPITAL | 33) | - | - | | | - |
| 35 | Rate Base | (sum lines 22, 28 , 29 | | | | | $ |

& 34) -

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.

(EMW)



| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMW | (4) EMW Total | (5) Allocator | (6) | (7) Transmission (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|
| | **O&M** | | | | | | |
| | | | $ | $ | | | |
| 1 | Transmission | 321.112.b | - | - | | | |
| 2 | Less Account 561 | 321.84.b thru 321.92.b | - | - | | | |
| 3 | Less Account 565 | 321.96.b (Note D) | - | - | | | |
| 3a | Less: Transmission Leases & Facility Charges | ( 321.Notes) | - | - | | | |
| | | ( line 1 less lines 2 | $ | $ | | | $ |
| 4 | Total Transmission O&M | thru 3a) (Note F) | - | - | TP | 0.00000 | - |
| 5 | A&G -Adjusted | (Wkshts. A-10, line 8) | - | - | W/S | 0.00000 | - |
| 5a | Less: Actual PBOP | (Wkshts. A-10, line 9) (Note R) | - | - | W/S | 0.00000 | - |
| 5b | Plus: PBOP (Projected 2010 per Note R) | (Wkshts. A-10, line 10) (Note R) | - | - | W/S | 0.00000 | - |
| 5c | Plus: Safety Advertising | (Wkshts. A-10, line 11) | - | - | W/S | 0.00000 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5d | Plus: Advertising -Transmission | (Wkshts. A-10, line 16) | - | - | DA | 1.00000 | - |
| 5e | Plus: Research -Transmission | (Wkshts. A-10, line 21) | - | - | DA | 1.00000 | - |
| 5f | Plus: Regulatory Exp -Transmission | (Wkshts. A-10, line 26) | - | - | DA | 1.00000 | - |
| 5h | Plus: Corporate Visibility - Transmission | (Wkshts. A-10, line 32) | - | - | W/S | 0.00000 | - |
| 6 | Transmission Lease Payments & Facility Charges | (Note E) | - | - | DA | 1.00000 | - |
| 7 | TOTAL O&M | (sum lines 4, 5, 5b thru 6 less 5a ) | $ - | $ - | | | $ - |
| | **DEPRECIATION EXPENSE** | (Note Q) | | | | | |
| 8 | Transmission | 336.7.f | $ - | $ - | TP | 0.00000 | $ - |
| 9 | General | 336.10.f | - | - | W/S | 0.00000 | - |
| 10 | Intangible & Other | 336.1f | - | - | W/S | 0.00000 | - |
| 11 | Amortization of Abandoned Transmission Plant | Acct. 407 (Note S) | - | - | DA | 1.00000 | - |
| 12 | TOTAL DEPRECIATION | (sum line 8 thru line 11) | $ - | $ - | | | $ - |
| | **TAXES OTHER THAN INCOME TAXES** | (Note G) | | | | | |
| | LABOR RELATED | | | | | | |
| 13 | Payroll | (Wksht A-6, line 8) | $ - | $ - | W/S | 0.00000 | $ - |
| 14 | Highway and vehicle | (Wksht A-6, line 8) | - | - | W/S | 0.00000 | - |
| | PLANT RELATED | | | | | | |
| 15 | Property | (Wksht A-6, line 8, Note M) | - | - | GP | 0.00000 | - |
| 16 | Gross Receipts | (Wksht A-6, line 8) | - | - | NA | | - |
| 17 | Other | (Wksht A-6, line 8) | - | - | GP | 0.00000 | - |
| 18 | TOTAL OTHER TAXES | (sum line 13 thru line 17) | $ - | $ - | | | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **INCOME TAXES** | (Note H) | | | | | |
| 19 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | | | 0.00% | | | |
| 20 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | | | 0.00% | | | |
| 21 | GRCF = 1 / (1 - T) | (GRCF = 1 / (1-T from Line 19)) | | - | | | |
| 22 | Amortized Investment Tax Credit | (266.8f) (enter negative) | $ - | $ - | | | |
| *22 a* | *(Excess)/Deficient Deferred Income Taxes* | *(Wksht A3-2, Note U)* | *$* - | *$* - | | | |
| 23 | Income Tax Calculation | (Line 20*(Line 35 of Page 1)*( Line 21 of Page 4 ) + Line 26 of Page 4 ) | | | | | $ - |
| 24 | ITC adjustment | ( line 21 X line 22) | | - | NP = | 0.00000 | - |
| *24 a* | *(Excess)/Deficient Deferred Income Tax Adjustment* | *(Line 21 X line 22a)* | | *$-* | *DA* | *1.00000* | - |
| 25 | Total Income Taxes | ( line 23 plus line 24 *plus line 24a*) | | | | | $ - |
| 26 | **RETURN** | ((Line 35 of Page 1)*( Line 21 of Page 4 ) + (Line 25 - Line 26) of Page 4 ) | | | | | $ - |
| 27 | **GROSS REV. REQUIREMENT WITH INCENTIVES** | (sum line 7, 12, 18, 25 & 26) | | $ - | | | $ - |
| 28 | LESS: Gross Revenue Requirements for Incentives | ( line 35 of page 4 ) | | | | | - |
| 29 | **GROSS REV. REQUIREMENT** | ( line 27 less line 28) | | $ - | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements

For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.

(EMW)



**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMW | (4) EMW Total | (5) Allocator | (6) | (7) Transmission (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|
| | **TRANSMISSION PLANT INCLUDED IN FORMULA** | | | | | | |
| | | | $ | $ | | | $ |
| 1 | Total transmission plant | (Line 7 of Page 3 ) | - | - | | | - |
| 2 | Less: Net Substation, 34kV, & Radial Lines to Distr. Plt. | (Wksht A-4, ln 28) (Note I) | - | - | | | - |
| 3 | Less: Total GSU in Transmission Plant | (Wksht. A-4, ln 7) (Note K) | - | - | | | - |
| | | | $ | $ | | | $ |
| 4 | Transmission plant included in rates | ( line 1 less line 2 & 3) | - | - | | | - |
| 5 | Percentage of transmission plant included in rates | ( line 4 / line 1) | | | TP= | 0.00000 | |
| | **GROSS AND NET PLANT ALLOCATORS** | | | | | | |
| | GROSS PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | |
| | | | $ | $ | | | |
| 6 | Production | ( page 1, line 1 ) | - | - | NA | | |
| | | | | | | | $ |
| 7 | Transmission | ( page 1, line 2 ) | - | - | DA | 1.00000 | - |
| 8 | Less: Excluded Plant | ( page 1, line 3 ) | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | - |
| 9 | Distribution | ( page 1, line 4 ) | - | - | | | |
| 10 | General & Intangible | ( page 1, line 5 & 6 ) | - | - | W/S | 0.00000 | 0 |
| | | (sum Line 6, 7, 9 & 10 | $ | $ | | | $ |
| 11 | TOTAL GROSS PLANT | less Line 8) | - | - | GP = | 0.00000 | - |
| | ACCUMULATED DEPRECIATION (ACTUAL HISTORICAL COST) (Note Q) | | | | | | |
| | | | $ | $ | | | |
| 12 | Production | ( page 1, line 8 ) | - | - | NA | | |
| 13 | Transmission | ( page 1, line 9 ) | - | - | DA | 1.00000 | $ - |
| 14 | Less: Excluded Plant | ( page 1, line 10 ) | | - | | | - |
| 15 | Distribution | ( page 1, line 11 ) | - | - | | | |
| 16 | General & Intangible | ( page 1, line 12 & 13 ) | - | - | W/S | 0.00000 | 0 |
| | | (sum Line 12, 13, 15 & | $ | $ | | | $ |
| 17 | TOTAL ACCUM. DEPRECIATION | 16 less Line 14) | - | - | | | - |
| | NET PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | |
| | | | $ | $ | | | |
| 18 | Production | ( line 6 less 12) | - | - | | | |
| 19 | Transmission | ( line 7 less 13) | - | - | | | $ - |
| 20 | Less Excluded Plant | ( line 8 less 14) | - | - | | | - |
| 21 | Distribution | ( line 9 less 15) | - | - | | | |
| 22 | General & Intangible | ( line 10 less 16) | - | - | | | 0 |
| | | (sum Line 18, 19, 21 & | $ | $ | | | $ |
| 23 | TOTAL NET PLANT | 22 less Line 20) | - | - | NP = | 0.00000 | - |

Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.

(EMW)



**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMW | (4) EMW Total | (5) Allocator | (6) | (7) Transmission (Col 4 times Col 6) |
|---|---|---|---|---|---|---|---|
| | **WAGES & SALARY ALLOCATOR (W&S)** | | $ | $ | TP | Allocation | |
| 1 | Production | 354.20.b | $ - | $ - | | - | |
| 2 | Transmission | 354.21.b | 0 | - | 0.0000 0 | - | |
| 3 | Distribution | 354.23.b | 0 | - | | - | W&S Allocator ($ / Allocation) |
| 4 | Other | 354.24,25,26.b | 0 | - | | - | |
| 5 | Total | (sum line 1 thru line 4) | $ - | $ - | | 0 | |
| 5a | Wage & Salary Allocator Calculation | (Col 6, Line 5 divided by Col 4, Line 5) | | | | | WS = 0.00000 |
| | **RETURN (R)** | (Note N) | | | | | |
| 6 | Interest on Long-Term Debt | 256 & 257 notes | $ | $ | | | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | - | | - | | | | - |
| 7 | Amort. of Debt Disc. and Expense | 256 & 257 notes | - | | - | | | | - |
| 8 | Amortization of Loss on Reacquired Debt | 256 & 257 notes | - | | - | | | | - |
| 9 | Less: Amort. of Premium on Debt-Credit | 256 & 257 notes | - | | - | | | | - |
| 10 | Less: Amort. of Gain on Reacquired Debt-Credit | 256 & 257 notes | - | | - | | | | - |
| 11 | Long Term Interest | (sum line 6 to 8, less 9 & 10) | $ - | | $ - | | | | $ - |
| 12 | **Preferred Dividends** | 256 & 257 notes | $ - | | $ - | | | | $ - |
| | **Development of Common Stock:** | (Note N) | | | | | | | |
| 13 | Proprietary Capital | 256 & 257 notes | $ - | | $ - | | | | $ - |
| 14 | Less Preferred Stock | 256 & 257 notes | | 0 | - | | | | - |
| 15 | Less Noncontrolling Interest | 256 & 257 notes (Note O) | | 0 | - | | | | - |
| 16 | Less OCI Account 219 | 256 & 257 notes | - | | - | | | | - |
| 17 | Common Stock | ( line 13 Less 14, 15 & 16) | $ - | | $ - | | | | $ - |
| | | | $ | | $ | % | Cost (Note P) | | Weighted |
| 18 | Long Term Debt | 256 & 257 notes | $ - | | $ - | 0.0 0% | - | WCLTD = | 0.0000 |
| 19 | Preferred Stock | 256 & 257 notes | - | | - | 0.0 0% | - | | 0.0000 |
| 20 | Common Stock | 256 & 257 notes | - | | - | 0.0 0% | - | | 0.0000 |
| 21 | Total | (sum line 18 thru line 20) | $ - | | $ - | 0.0 0% | | R = | 0.00000 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **GROSS REV. REQUIREMENT FOR INCENTIVE PROJECTS** | | | | | |
| | **Plant Granted Incentive ROE Adder:** | | | | | |
| | | | $ | $ | | |
| 22 | Total Incentive Plant | ( Wksht A-9, line 22) | - | - | | |
| 23 | Less: Total Accumulated Depreciation | ( Wksht A-9, line 22) | - | - | | |
| | | | $ | $ | | |
| 24 | Net Incentive Plant | ( line 22 less line 23) | - | - | | |
| 25 | Incentive Return Including Taxes | ( Wksht A-9, p. 1, line 24) | | | $ | - |
| 26 | Taxes Included in Incentive Return | ( line 25 *( page 2, line 19) | | $ - | | |
| 27 | **Construction Work In Progress:** | | | | | |
| 28 | Total CWIP | ( Wksht A-9, p. 1, line 24 Note T) | $ - | $ - | | |
| 29 | Incentive Return Including Taxes | ( Wksht A-9, p. 1, line 24 ) | | | $ | - |
| 30 | **Abandoned Plant:** | | | | | |
| 31 | Unamortized Abandoned Transmission Plant | ( line 25 of page 2) (Note S) | $ - | | | |
| 32 | Tax-Adjusted Return on Abandoned Plant | ( line 21 X line 31 X ( 1 +EIT) | | $ - | | |
| 33 | Amortization Expense for Abandoned Plant | (Line 11 of page 2) | | - | | |
| 34 | Total Recovery for Abandoned Plant | (sum line 32 thru line 33) | | | $ | - |
| 35 | TOTAL GROSS REV. REQ. FOR INCENTIVE PROJ. | (sum line 25 , 29 & 34) | | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Actual Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.

Actual Gross Rev

General Note: References to pages in this formula rate are indicated as:
(page#, line#, col.#).
References to data from FERC Form 1 are indicated as:
page#.line#.col

| Note Letter | |
|---|---|
| **A** | Reserved for future use. |
| **B** | Includes only Transmission plant. |
| **C** | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 2, line 7, col. 7. |
| **D** | Prepayments are the electric related prepayments booked to Account No. 165 and reported on FERC Form 1, p. 111, ln. 57.c. Expenses recorded in Account 565, Transmission of Electricity by Others, are not recoverable through the formula rate. |
| **E** | Lease and joint facilities charges included on line 6, page 2 of 5, are those costs attributable to transmission facilities. |
| **F** | Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT. |
| **G** | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template. |
| **H** | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "percentage of federal income tax deductible for state income tax purposes". Furthermore, a utility that elected to utilize amortization of tax credits against taxable income rather than book tax credits to Account 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 2, line 21). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. KCMO Earnings Tax is not included in the calculation of the Composite State Income Tax Rate. |

| Inputs Required: | | | |
|---|---|---|---|
| | FIT = | 0.00% | Federal Income Tax Rate |
| | SIT= | 0.00% | Composite State Income Tax Rate or Composite SIT |
| | p = | 0.00% | Percentage of federal income tax deductible for state income tax purposes |

The Composite State Income Tax Rate reflects the effective rate for each tax jurisdiction, as well as the Composite Portion of FIT Deduction in State Returns:

| | Apportionment Factor | Rate | Effective Rate | % of FIT Deductible | Portion of Fed Tax Deductible = p |
|---|---|---|---|---|---|
| Missouri | 0.00% | 0.00% | 0.0000% | 0.00% | 0.000 0% |
| Kansas | 0.00% | 0.00% | 0.0000% | 0.00% | 0.000 0% |
| KS City | 0.00% | 0.00% | 0.0000% | 0.00% | 0.000 0% |
| Composite State Income Tax Rate | | | 0.0000% | | |
| Composite Portion of FIT Deduction for State Returns | | | | | 0.000 0% |

I Removes transmission plant determined by Commission order to be excluded from RTO transmission rate base under Docket No. EL08-89-000 (to the extent FERC Form 1 balances are not adjusted).

J Unless otherwise specified, OATT refers to the EMW and SPP OATTs.

K Removes generator step-up facilities determined by Commission order to be excluded from RTO transmission rate base under Docket No. EL08-89-000 (to the extent FERC Form 1 balances are not adjusted).

L Reserved for future use.

M If the transmission related component of property tax is specifically identified in Form 1, then a TP allocator shall be used. Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the Form 1.

N Beginning in 2009, included in page 256 notes of the FERC Form 1, the long term interest expense and preferred dividends and a 13-month average balance for long-term debt, preferred stock and common equity of Great Plains Energy will be provided. This information will be the reference for the capital structure and weighted cost of long term debt and preferred stock.

O The Noncontrolling Interest represents a third party's 50% investment in one of GPE's consolidated subsidiaries reported on the consolidated balance sheet's equity section separate from the parent's equity, as required by generally accepted accounting principles effective January 1, 2009.

P The approved ROE is 11.1%. No change in ROE may be made absent a filing with FERC. Any incentive ROEs approved by the Commission are shown by project in Worksheet A-9.

Q The current depreciation rates used to calculate depreciation expense and accumulated depreciation balances are shown in worksheet A-5.

| | | |
|---|---|---|
| **R** | The Post-Employment Benefits Other than Pensions (PBOP) expense projected for FY 2010 set forth below will be used in lieu of the actual PBOP in 2009 and subsequent years absent a filing with FERC that alters the amount. | |
| | Post-Employment Benefits Other than Pensions | $4,775, 222 |
| **S** | The Unamortized Abandoned Transmission Plant can only be included in rate base if authorized by the Commission. | |
| **T** | CWIP balances only included as authorized by the Commission. Regulatory liability offsets AFUDC accrual where CWIP is not included in state-regulated rate base. | |
| ***U*** | *Includes the amortization of any excess/deficient income taxes resulting from changes to income tax rates (including changes in apportionment) and other actions take by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T).* | |
| ***V*** | Reserved for future use. | |

**ALLOCATION FACTORS**

| Line No. | Allocators | Description | Location of Calculation or First Use of Allocator |
|---|---|---|---|
| 1 | **TP** | Percentage of transmission plant included in rate base. | Page 3, line 5, col 6 |
| 2 | **W/S** | Percentage of transmission labor included in rates | Page 4, line 5a, col 7 |
| 3 | **DA** | Direct assignment | First used on page 1, line 2, col 6 |
| 4 | **GP** | Ratio of allocated transmission, general, & intangible plant to total gross plant. | Page 3, line 11, col 6 |
| 5 | **NA** | Not applicable for the transmission formula rate. | First used on page 2, line 16, col 6 |
| 6 | **NP** | Ratio of net transmission, general, & intangible plant to total net plant. | Page 3, line 23, col 6 |

For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.
(EMW)

| Line No. | (1) | (2) Reference | (3) | (4) Amount | |
|---|---|---|---|---|---|
| **A.** | **Schedule 1 ARR** | | | | |
| 1 | Total Load Dispatch & Scheduling | (Act. Gross Rev Req, p.2, ln 2) | $ | - | |
| 2 | Less: Scheduling, System Control and Dispatch Services | (321.88.b) | | - | |
| 3 | Less: Transmission Service Studies | (321.90.b) | | - | |
| 4 | Less: Reliability, Planning & Standards Dev. Services | (321.92.b) | | - | |
| 5 | Total | (Line 1 Less Line 2 thru Line 4) | $ | - | |
| 6 | Less: PTP Service Credit | (Wksht A-1, Page 1, Line 26) | | - | |
| 7 | Net Schedule 1 Revenue Requirement for Zone | (Line 5 - Line 6) | $ | - | |
| **B.** | **Schedule 1 Rate Calculations** | | | | |
| 8 | EMW 12-CP. Peak Demand | (Wksht A-2, Line 14) | | - | MW |
| 9 | Annual Point-to-Point Rate in $/MW - Year | (Line 7 / Line 8) | $ | - | |
| 10 | Monthly Point-to-Point Rate in $/MW - Month | (Line 9 / 12) | $ | - | |
| 11 | Weekly Point-to-Point Rate in $/MW - Week | (Line 9 / 52) | $ | - | |
| 12 | Daily Point-to-Point Rate in $/MW - Day | (Line 9 / 365) | $ | - | |
| 13 | Hourly Point-to-Point Rate in $/MW - Hour | (Line 9 / 8760) | $ | - | |

**Worksheet A-1 Revenue Credits**
Evergy Missouri West Inc.

| | | | Total Company | | Non-Trans. | Transmission |
|---|---|---|---|---|---|---|
| 1 | I. | **Rent from Electric Property, Account 454** | | | | |
| | | Account 4540001 - Other Rev -Rent Electric | | | $ | $ |
| 2 | | Property | $ - | | - | - |
| 3 | | Transmission: | | | | |
| 4 | | Farm Land Rental | - | | | |
| 5 | | Rental From Cell Phone Attachers | - | | | |
| 6 | | Equipment / Facilities Rental | - | | | |
| | | Rental Substation Property -Cell | | | | |
| 7 | | Towers | - | | | |
| 8 | | Other Rental | - | | | |
| | | | | $ | | |
| 9 | | Total Transmission | | - | | |
| | | (Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and | | | | |
| 10 | | explanations in Section V, Notes below.) | | | | |
| 11 | | | | | | |
| | | **Other Operating Revenues To Reduce Revenue** | | | | $ |
| 12 | II. | **Requirement** | | | | - |
| 13 | | | | | | |
| | | **Revenues from Transmission of Electricity for Others,** | | | | $ |
| 14 | III. | **Account 456.1** | | | | - |
| | | (Provide data sources and necessary explanations Section V, | | | | |
| 15 | | Notes below.) | | | | |
| 16 | | **Less:** | | | | |
| | | TO's LSE Direct Assignment Revenue | | | $ | |
| 17 | | Credits | | | - | |
| | | TO's LSE Sponsored Upgrade Revenue | | | | |
| 18 | | Credits | | | - | |
| | | TO's LSE Sch. 11 Rev. from Sponsored or Direct Assign | | | | |
| 19 | | Facilities - Network Credits | | | - | |
| | | TO's LSE Sch. 11 Rev. from Sponsored or Direct Assign | | | | |
| 20 | | Facilities - PtP Credits | | | - | |
| | | TO's LSE Network Upgrades for Generation | | | | |
| 21 | | Interconnection - Credits | | | - | |
| | | Point-To-Point Revenue for GFAs Associated | | | | |
| 22 | | with Load Included in the Divisor | | | - | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 23 | | Network Service Revenue (Schedule 9) Associated With Load Included in the Divisor | | | | | - | |
| 24 | | Revenue Associated with Transmission Plant Excluded From SPP Tariff | | | | | - | |
| 25 | | Wholesale Distribution Revenue | | | | | - | |
| 26 | | Schedule 1 Revenue | (Point-to-Point Subtotal: | $ | - | ) | - | |
| 27 | | Schedule 2 Revenue | | | | | - | |
| 28 | | Schedules 3-6 Revenue | | | | | - | |
| 29 | | Zonal Network Revenue for TO's Facilities Under Schedule 11 -(Note 2) | | | | | | |
| 30 | | Region-wide Network Revenue for TO's Facilities Under Schedule 11 -(Note 2) | | | | | - | |
| 31 | | Zonal Point-to-Point Revenue for TO's Facilities Under Schedule 11 -(Note 2) | | | | | - | |
| 32 | | Region-wide Point-to-Point Revenue for TO's Facilities Under Schedule 11 - (Note 2) | | | | | - | |
| 33 | | Other -(Note 3) | | | | | - | |
| 34 | | Other | | | | | - | |
| 35 | | | | | | | | |
| 36 | | **Total Adjustments** | | | | | | $ - |
| 37 | | **Net 456.1 Account Activity** | | | | | | $ - |
| 38 | | | | | | | | |
| 39 | **IV.** | **Total Revenue Credits to Apply to Zonal Revenue Requirement** | | | | | | $ - |
| 40 | | | | | | | | |
| 41 | **V.** | **Notes** | | | | | | |
| 42 | | (1) Data for this worksheet came from | | | | | | |

| | | |
|---|---|---|
| | | the FERC Form 1 and the Company's General Ledger. |
| 43 | (2) | Includes any revenue from direct assignment to a customer of costs of a Base Plan, Balanced Portfolio, Priority or ITP project. |
| 44 | (3) | SPP and MISO charges incorrectly recorded in 456.1. |
| 45 | (4) | If long-term firm point-to-point service terminates prior to end of calendar year, the associated revenue is credited rather than including reservation in divisor. |



**A-1 Revenue Credits for Schedule 11 Revenue Requirements**

**EMW -Detailed Revenue Credits -FY 20XX**

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | **Revenue Received for TO's Facilities Under Schedule 11** | | (Sum Line 29 thru Line 32 on Page 1) | | | $ - |
| 2 | | | | | | |
| 3 | **Allocation of Revenue to Facility Groups:** | | (a) | (b) | (d) | (e) |
| 4 | | | **Net Rev. Req with True-Up** | **Percentage Allocation** | | **Revenue Allocation** |
| 5 | | | **(Note A)** | | | |
| 6 | | Base Plan | $ - | 0.0000 % | | $ - |
| 7 | | Balanced Portfolio | - | 0.0000 % | | - |
| 8 | | ITP/Priority Projects-1 | - | 0.0000 % | | - |
| 9 | | ITP/Priority Projects-2 | - | 0.0000 % | | - |
| 10 | | Total Schedule 11 Gross Revenue Requirement | $ - | 0.0000 % | | $ - |
| 11 | | | | | | |

**Determine Net Revenue to Apply as Credit:**

| | | | Revenue Credit |
|---|---|---|---|
| | | (Line 6 col (a) less | $ |
| | Base Plan | Line 6 col (e)) | - |
| | | (Line 7 col (a) less | |
| | Balanced Portfolio | Line 7 col (e)) | - |
| | | (Line 8 col (a) less | |
| | ITP/Priority Projects-1 | Line 8 col (e)) | - |
| | | (Line 9 col (a) less | |
| | ITP/Priority Projects-2 | Line 9 col (e)) | - |
| | Total Schedule 11 Gross | (Sum Line 14 thru | $ |
| | Revenue Requirement | Line 17 ) | - |

Note:
**A**. The Net Revenue Requirement with True-up from Projection for Actual Period, Schedule "Projected Net Rev Req".

**Worksheet A-2 -Divisor**

**Evergy Missouri West Inc.**

Page 1 of 1

**Determination of Transmission Network Load (MW)**
**For the 12 months ended -**
**December 31, 20XX**

**I. EMW (source -FN1, page 400)**

| Line No. | Date | Hour Ending | EMW's Native System Peak Load | Adjustment | Adjusted EMW's Native System Peak Load | Plus: 3rd Party Network Load (incl. gen.) | Reserve for Future Use | Plus: Grandfather Agreements | Reserve for Future Use | Reserve for Future Use | Less: Load Not Connected to the EMW Transmission System | EMW's Transmission System Load (e-f+g+h+i+j-k) | Average Transmission Network Load for January thru August | Percentage of Aver. Jan - Aug Load |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
| 1 | | 0 | - | - | - | - | - | | | | | - | - | |
| 2 | | 0 | - | - | - | - | - | | | | | - | - | |
| 3 | | 0 | - | - | - | - | - | | | | | - | - | |
| 4 | | 0 | - | - | - | - | - | | | | | - | - | |
| 5 | | 0 | - | - | - | - | - | | | | | - | - | |
| 6 | | 0 | - | - | - | - | - | | | | | - | - | |
| 7 | | 0 | - | - | - | - | - | | | | | - | - | |
| 8 | | 0 | - | - | - | - | - | | | | | - | - | |
| 9 | | 0 | - | - | - | - | - | | | | | - | | 0.00% |
| 10 | | 0 | - | - | - | - | - | | | | | - | | 0.00% |
| 11 | | 0 | - | - | - | - | - | | | | | - | | 0.00% |
| 12 | | 0 | - | - | - | - | - | | | | - | - | | 0.00% |
| 13 | Total | | - | n/a | - | - | - | - | - | - | - | - | - | |
| 14 | 12-CP | | - | n/a | - | - | - | - | - | - | - | - | | |

Notes:

Column (**n**) :This column reflects the relationship of the actual load for each month (September, October, November and December) as a percentage of the average transmission network load for January through August. For example, the September percentage in column **(n)** is equal to the September load in column (**l**) divided by the 8-month average of column (**m**) shown on line 13.



**Worksheet A-3 - ADIT**

**Evergy Missouri West Inc.**
**Allocation of ADIT**
For the 12 months ended - December 31, 20XX

| Line No. | Summary | Total ADIT Allocated to Transmission (b + c + d) | 100% NonTrans. Related (a) | 100% Transmission Related (b) | Plant Related ( c ) | Labor Related (d) |
|---|---|---|---|---|---|---|
| | | | $ | $ | $ | $ |
| 1 | **ADIT-255** | | - | - | - | - |
| 2 | **ADIT-282** | | - | - | - | - |
| 3 | **ADIT-283** | | - | - | - | - |
| 4 | **ADIT-190** | | - | - | - | - |
| | | | $ | $ | $ | $ |
| 5 | **Subtotal** | | - | - | - | - |
| 6 | **Wages & Salary Allocator** | | | | | 0.000% |
| 7 | **Gross Plant Allocator** | | | | 0.000% | |
| 8 | **Direct Assign** | | | 100.000 | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Allocator** | | | | % | | | |
| | | | | $ | $ | $ | $ | |
| 9 | **ADIT *Subtotal*** | $ - | | - | - | - | - | |
| *9a* | ***EDIT Adjustment*** | - | | | | | | |
| *9b* | ***ADIT Total*** | *$-* | | | | | | |

| | | | | | (A) | (B) *100%* | (C) *100%* | (D) | (E) | *(F)* |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **ADIT-Account 190 (Note 1)** | **BOY Balance Prior Year** | **EOY Balance Current Year** | **Average Balance** | **NonTrans. Related** | **Transmission Related** | **Plant Related** | **Labor Related** | ***Description*** |
| | 1902 00 | *Accumulated Deferred Income Tax Utility Oper Other* | | | | | | | | |
| 10 | | | $ | $ | $ | | | | $ | |
| 11 | | Accrued Bonus | - | - | - | | | | - | |
| 12 | | Accrued Property Taxes | - | - | - | | | - | | |
| 13 | | Accrued Sales Tax | - | - | - | | | - | | |
| 14 | | Amortization of CIAC | - | - | - | - | | | | |
| 15 | | Bad Debt | - | - | - | - | | | | |
| 16 | | Accrued Severance | - | - | - | | | | - | |
| 17 | | BH Purchase Price Adj | - | - | - | - | | | | |
| 18 | | Blackhill Transaction costs | - | - | - | - | | | | |
| 19 | | Capital Loss Carryforward | - | - | - | - | | | | |
| 20 | | Customer Advances | - | - | - | - | | | | |
| 21 | | Emission Allowance Proceeds | - | - | - | - | | | | |
| 22 | | Deferred | | | - | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Compensation | - | - | | | | | | | - |
| 23 | | Injuries and Damages Reserves | - | - | | - | | | | | - |
| 24 | | Generation Maintenance Accrual | - | - | | - | - | | | | |
| 25 | | Debt Fair Value Adjustment | - | - | | - | - | | | | |
| 26 | | Current Federal and State NOL Benefits | - | - | | - | - | | | | |
| 27 | | Rail Car Leases | - | - | | - | - | | | | |
| 28 | | Other Accrued Expense | - | - | | - | - | | | | |
| 29 | | Vacation Accrual | - | - | | - | | | | | - |
| 30 | | | | | | - | | | | | |
| 31 | 1902 01 | Current Deferred State Asset Val Allowance | - | - | | - | - | | | | |
| 32 | 1903 00 | Non Current Federal NOL Benefits | - | - | | - | - | | | | |
| 33 | 1903 01 | Non Current State NOL Benefits | - | - | | - | - | | | | |
| 34 | 1903 50 | Tax Valuation Allowance | - | - | | - | - | | | | |
| 35 | 1905 00 | AMT and GBC Credit Carryforward | - | - | | - | - | | | | |
| 36 | 1906 01 | FAS 109 | - | - | | - | - | | | | |
| 37 | **Subtotal - (p234, Notes)** | | $ - | $ - | $ | - | $ - | $ | $ | $ | $ - |
| 38 | **Less FASB 109 Above if not separately removed** | | - | - | | - | - | | | | |
| 39 | **Less FASB 106 Above if not separately removed** | | - | - | | - | - | - | - | | |
| 40 | **Total** | | $ - | $ - | $ | - | $ - | $ - | $ - | $ | $ - |

**Worksheet A-3 - ADIT**

**Evergy Missouri West Inc.**

**Allocation of ADIT**

For the 12 months ended - December 31, 20XX



| | | | | | | | (A) | (B) | (C) | (D) | (E) | (F) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ***ADIT- Account 255 (Note 1)*** | **BOY Balance Prior Year** | **EOY Balance Current Year** | | | **Average Balance** | ***100% NonTrans. Related*** | ***100% Transmission Related*** | ***Plant Related*** | ***Labor Related*** | ***Description*** |
| | | *Accumulated Deferred Income Tax Other Property* | | | | | | | | | | |
| 1 | 2550 00 | ITC: Electric | $ - | $ - | | $ | - | | | $ - | | |
| 2 | 2550 00 | ITC: Steam | - | - | | | - | - | | | | |
| 3 | | | | | | | - | | | | | |
| 4 | **Subtotal ( p.267.Notes)** | | $ - | $ - | | $ | - | $ - | $ - | $ - | $ - | |
| 5 | **Less FASB 109 Above if not separately removed** | | - | - | | | - | - | - | - | | |
| 6 | **Less FASB 106 Above if not separately removed** | | - | - | | | - | - | - | - | | |
| 7 | **Total** | | $ - | $ - | | $ | - | $ - | $ - | $ - | $ - | |
| | | ***ADIT- Account 281 & 282 (Note 1)*** | **BOY Balance Prior Year** | **EOY Balance Current Year** | | | **Average Balance** | ***100% NonTrans. Related*** | ***100% Transmission Related*** | ***Plant Related*** | ***Labor Related*** | ***Description*** |
| | | *Accumulated Deferred Income Tax Other Property* | | | | | | | | | | |
| 8 | 2826 | Total Plant | $ | $ | | $ | - | | | $ | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | | | - | - | | | | | | - | | |
| 9 | | CIAC | - | - | | | - | $ - | | | | |
| 10 | | Unrecovered Transmission CIAC (**Note 2**) | - | - | | | - | | $ - | | | |
| 11 | 2821 37 | ADFIT Capitalized Interest | - | - | | | - | | | - | | |
| 12 | 2822 37 | ADSIT Capitalized Interest | - | - | | | - | | | - | | |
| 13 | 2821 51 | ADFIT Amort Rehab Credit | - | - | | | - | - | | | | |
| 14 | 2824 10 | FIN 48 Non-Current Tax Liability | - | - | | | - | - | | | | |
| 15 | 2826 01 | FASB 109 | - | - | | | - | - | | | | |
| 16 | | | | | | | - | | | | | |
| 17 | **Subtotal ( p.275.Notes)** | | $ - | $ - | $ | - | | $ - | $ - | $ - | $ - | |
| 18 | **Less FASB 109 Above if not separately removed** | | - | - | | | - | - | | | | |
| 19 | **Less FASB 106 Above if not separately removed** | | - | - | | | - | - | - | - | | |
| 20 | **Total** | | $ - | $ - | $ | - | | $ - | $ - | $ - | $ - | |

| | *ADIT-Account 283 (Note 1)* | BOY Balance Prior Year | EOY Balance Current Year | Average Balance | *100% NonTrans. Related* | *100% Transmission Related* | *Plant Related* | *Labor Related* | *Description* |
|---|---|---|---|---|---|---|---|---|---|
| 21 | *Accumulated Deferred Income Tax Other Utility* | | | | | | | | |
| 22 | 28 33 00 *Deferred Tax Miscellaneous:* | | | | | | | | |
| 23 | Retail Regulatory Assets/Liabilities | $ - | $ - | $ - | $ - | | | | |
| 24 | Deferred Legal Expense | - | - | - | - | | | | |
| 25 | Emission Allowance Amortization | - | - | - | - | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 26 | Environment costs | - | - | | - | | | | |
| 27 | FASB 106 Postretirement Benefits | - | - | | | | | | - |
| 28 | Fuel Clause Adjustment | - | - | | - | | | | |
| 29 | Injuries & Damages - Noncurrent | - | - | | - | | | | |
| 30 | Pension OCI | - | - | | - | | | | |
| 31 | Other Accrued Expense | - | - | | - | | | | |
| 32 | Partnership Income / Loss | - | - | | - | | | | |
| 33 | Pension | - | - | | | | | | - |
| 34 | Sublease -Everest | - | - | | - | | | | |
| 35 | Tax Interest | - | - | | - | | | | |
| 36 | Unamort Discount Adjustment | - | - | | | | | - | |
| 37 | Unamort Debt Exp Adjustment | - | - | | | | | - | |
| 38 | Loss on Reacq Debt Amort | - | - | | | | | - | |
| 39 | Amort of Loss on Debt Retirement | - | - | | | | | - | |
| 40 | | | | | | | | | |
| 41 | 28 35 10 FIN 48 Non-Current Liability | - | - | | | - | | | |
| | | $ - | $ - | | | $ - | $ - | $ - | $ - |
| 42 | **Subtotal (p.277.Notes)** | - | - | $ - | | - | - | - | - |
| 43 | **Less FASB 109 Above if not separately removed** | | | | | | | | |
| 44 | **Less FASB 106 Above if not separately removed** | - | - | | | - | - | - | - |
| | **To** | $ - | $ - | | | $ - | $ - | $ - | $ - |
| 45 | **tal** | - | - | $ - | | - | - | - | - |
| | **NOTES:** | | | | | | | | |

**1** ADIT items in each account will be in the same order as the prior year with any new line items, relative to the prior year, to be highlighted and added at the end of the list of items for each account. A line item maybe deleted when the amount for the line item has been zero through one complete rate cycle.

**2** ADIT impacts related to Contributions in Aid of Construction (CIAC) shall be designated as non-transmission related unless both of the following conditions apply: a) the facility for which the CIAC is paid is a Transmission Facility pursuant to Attachment AI of the SPP Open Access Transmission Tariff, and b) the FERC-approved tariffs or rate schedules under which the payment is made do not provide for full recovery by EMWof the ADIT impacts. More generally, ADIT items that are to be treated as 100% Non-Transmission should be so treated on the basis of the actual tax item, not based on the title used.

Evergy Missouri West Inc. *Worksheet A3-2*

*Accumulated Excess / Deficient Deferred Income Taxes("EDIT")*

*Actuals- For the 12 months ended 12/31/20XX*

| | | | 12/31 | xxxx | xxxx | 12/31 | | | 12/31/xx | xx | 12/31 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No. | | (a | (b) | (c) | (d) | (e) | (f | | | (g) | (h) | (i | (j |
| Line No. | | Item | BOY Balanc | Current Period | Current Period Other Activity | EOY Balanc | Allocato | BOY Allocat | Amortization Exp/(Ben) Allocated | | EOY Allocat | Amort Perio | Explanation |
| | | **190 EDIT INCLUDED WITHIN ACCOUNTS** | | | | | | | | | | | |
| 10 | | 190200 Accumulated Deferred Income Tax | | | | | | | | | | | |
| 11 | | Accrued Bonus | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 12 | | Accrued Property Taxes | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 13 | | Accrued Sales Tax | - | - | - | - | GP | 10.670 | - | | - | - | 10-yr Plant |
| 14 | | Amortization of CIAC | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 15 | | Bad Debt | - | - | - | - | GP | 10.670 | - | | - | - | 10-yr Plant |
| 16 | | Accrued Severance | - | - | - | - | W/S | 4.956 | - | | - | - | 10-yr Labor |
| 17 | | BH Purchase Price Adj | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 18 | | Blackhill Transaction costs | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 19 | | Capital Loss Carryforward | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 20 | | Customer Advances | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 21 | | Emission Allowance Proceeds | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 22 | | Deferred Compensation | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 23 | | Injuries and Damages Reserves | - | - | - | - | W/S | 4.956 | - | | - | - | 10-yr Labor |
| 24 | | Accrued Maintenance | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 25 | | Debt Fair Value Adjustment | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 26 | | Current Federal and State NOL Benefits | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 27 | | Rail Car Leases | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 28 | | Other Accrued Expense | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29 | | Vacation Accrual | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29 | | Accrued Other Taxes | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29 | | Unamortized Debt Expense | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29 | | Unamortized Discount Adjustment | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29 | | Sublease Everest | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29 | | Fuel Adjustment Clause -Retail Asset | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |
| 29f | | FIN48 | - | - | - | - | NA | 0.000 | - | | - | - | 10-yr NonTr |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | | Tax Interest | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29 | | Deferred Liability -Lease 1 KC Place | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29i | | MO LIH Credit | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29j | | Pension OCI | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29 | | Retail Regulated Liabilities | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29l | | Inventory Writeoff | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29 | | Unrealized Gain/Loss | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29 | | FAS 106 | - | - | - | - | W/S | 4.956 | - | - | - | 10-yr | Labor |
| 29 | | Excess Deferred Taxes | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29 | | Excess Deferred Taxes MO Rate Change | - | - | - | - | GP | 10.670 | - | - | - | TBD | Plant |
| 30 | | | - | - | - | - | | | - | | | | |
| 31 | 190201 | Current Deferred State Asset Val | - | - | - | - | GP | 10.670 | - | - | - | 10-yr | Plant |
| 32 | 190300 | Non Current Federal NOL Benefits | - | - | - | - | NA | 0.000 | - | - | - | ARAM | NonTr |
| 32 | | Federal NOL Benefits | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 33 | 190301 | Non Current State NOL Benefits | - | - | - | - | NA | 0.000 | - | - | - | ARAM | NonTr |
| 33 | | State NOL Benefits | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 33 | | Non Current State NOL Benefits (MO Rate | - | - | - | - | NA | 0.000 | - | - | - | TBD | NonTr |
| 34 | 190350 | Tax Valuation Allowance | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 35 | 190500 | AMT and GBC Credit Carryforward | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 36 | 190601 | FAS 109 | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 36 | 190602 | FAS 109 | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 36b | 190603 | FAS 109 | - | - | - | - | NA | 0.000 % | - | - | - | 10-yr | NonTrans |
| | | **Total 190 EDIT** | - | - | - | - | | | - | - | - | | |
| | | **283 EDIT INCLUDED WITHIN & 254** | | | | | | | | | | | |
| 21 | | Accumulated Deferred Income Tax | | | | | | | | | | | |
| 22 | 283300 | Deferred Tax Miscellaneous: | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 23 | | Retail Regulatory | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 24 | | Deferred Legal Expense | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 25 | | Emission Allowance Amortization | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 26 | | Environment Accruals | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 27 | | FASB 106 Postretirement Benefits | - | - | - | - | W/S | 4.956 | - | - | - | 10-yr | Labor |
| 28 | | Fuel Clause Adjustment | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 29 | | Injuries & Damages - Noncurrent | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 30 | | Pension OCI | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 31 | | Other Accrued Expense | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 32 | | Partnership Income / Loss | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 33 | | Pension | - | - | - | - | W/S | 4.956 | - | - | - | 10-yr | Labor |
| 34 | | Sublease -Everest | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 35 | | Tax Interest | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 36 | | Unamort Discount Adjustment | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 37 | | Unamort Debt Exp Adjustment | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 38 | | Loss on Reacq Debt Amort | - | - | - | - | GP | 10.67 | - | - | - | 10-yr | Plant |
| 39 | | Amort of Loss on Debt Retirement | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39 | | Excess Deferred Taxes | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39a | | Excess Deferred Taxes ( MO Rate | - | - | - | - | NA | 0.000 | - | - | - | TBD | NonTr |
| 39a | 283510 | FIN 48 Non-Current Liability - | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39b | 283410 | FIN 48 Non-Current Liability - | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39c | | SJLP Synergies/Subsequent | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39d | | Unrealized Gain/Loss | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39e | 283601 | ADIT Other FASB 109 | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39f | | Amort of Debt Retirement | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39g | 283602 | ADIT Other FASB 109 | - | - | - | - | NA | 0.000 | - | - | - | 10-yr | NonTr |
| 39h | 283603 | ADIT Other FASB 109 Adjustments | - | - | - | - | NA | 0.000 % | - | - | - | 10-yr | NonTrans |
| | | **Total 283 EDIT** | - | - | - | - | | | - | - | - | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ***282 EDIT INCLUDED WITHIN 2 & 254*** | | | | | | | | | | |
| *7a* | *281000 Total Plant* | - | - | - | - | *GP* | *10.670* | - | - | - | *ARAM* | *Plant* |
| *7b* | *Total Plant MO Rate Change* | - | - | - | - | *GP* | *10.670* | - | - | - | *ARAM* | *Plant* |
| | | - | - | - | - | | | - | | | | |
| *1* | *282611 Total Plant* | - | - | - | - | *GP* | *10.670* | - | - | - | *ARAM* | *Plant* |
| *41a* | *Total Plant Protected* | - | - | - | - | *GP* | *10.670* | - | - | - | *ARAM* | *Plant* |
| *41b* | *Total Plant Unprotected* | - | - | - | - | *GP* | *10.670* | - | - | - | *ARAM* | *Plant* |
| *41c* | *Total Plant MO Rate Change* | - | - | - | - | *GP* | *10.670* | - | - | - | *TBD* | *Plant* |
| *41d* | *Total Plant Cutoff* | - | - | - | - | *GP* | *10.670* | - | - | - | *TBD* | *Plant* |
| *41e* | *Total Plant Sibley Retirement* | - | - | - | - | *GP* | *10.670* | - | - | - | *TBD* | *Plant* |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| *2* | *CIAC* | - | - | - | - | *GP* | *10.670* | - | - | - | *ARAM* | *Plant* |
| *3* | *Unrecovered Transmission CIAC* | - | - | - | - | *DA* | *100.00* | - | - | - | *ARAM* | *Trans* |
| *8* | *282601 FASB 109* | - | - | - | - | *NA* | *0.000%* | - | - | - | *ARAM* | *NonTr* |
| *15a* | *Excess Deferred Taxes* | - | - | - | - | *NA* | *0.000%* | - | - | - | *ARAM* | *NonTr* |
| *16* | | | | | | | | | | | | |
| | ***Total 281/282 EDIT*** | - | - | - | - | | | - | - | - | | |
| | ***Total Excess/Deficient Deferred Income Taxes*** | - | - | - | - | | | - | - | - | | |

| ***EDIT Amortization :*** | ***Total*** | ***Allocator*** | ***Rate*** | ***Allocated*** | ***Average Allocated EDIT Balance*** - |
|---|---|---|---|---|---|
| ***Total 190*** | - | *See above* | *See above* | - | |
| ***EDIT Total*** | - | *W/S* | *4.956%* | - | |
| ***283 EDIT*** | - | *GP* | *10.670%* | - | |
| ***Total 281/282 EDIT*** | - | | | - | |

*Note*

*A* *Each EDIT item is categorized into 1 of 5 categories. The selected category will will determine the Allocator applied to the EDIT balance.*

*1) NonTrans: The EDIT balance is 100% unrelated to the Transmission of electricity and the NA Allocator is applied.*

*2) Retail: The EDIT balance is 100% related to retail operations and the NA Allocator is applied.*

*3) Trans: The EDIT balance is 100% related to transmission operations and the DA Allocator is applied.*

*4) Plant: The EDIT balance is related to Property, Plant, & Equipment "PP&E" and the GP Allocator is applied.*

*5) Labor: The EDIT balance is labor related and the W/S Allocator is applied.*

*B* *Includes the impact of tax rate changes enacted during the period and adjustments to prior year activity.*

*C EDIT balances exclude income tax gross-ups recorded to accounts 182.3 and 254*

**Worksheet A-4 - Excluded Assets**

**Evergy Missouri West Inc.**

**Assets Transferred from Transmission Rate Base**



At December 31, 20xx

| Line No. | | 13 -Month Average Balance | | |
|---|---|---|---|---|
| 1 | **I. GSU Values Transferred from Transmission** | | | |
| 2 | | **Asset** | **Reserve** | **Net** |
| 3 | | | | |
| 4 | **GSU:** | | | |
| 5 | MPS | $ - | $ - | $ - |
| 6 | SJLP | - | - | - |
| 7 | Total GSUs in Transmission Plant | $ - | $ - | $ - |
| 8 | | | | |
| 9 | **II. Radial Lines, 34kV and Substation Facilities Transferred** | | | |
| 1 | **Radial Lines** | | | |

| | | | | | |
|---|---|---|---|---|---|
| 10 | | | | | |
| 11 | | $ | | | $ |
| 11 | MPS | - | $ | - | - |
| 11 | | | | | |
| 12 | SJLP | - | | - | - |
| 11 | | $ | | | $ |
| 13 | Total | - | $ | - | - |
| 11 | | | | | |
| 14 | | | | | |
| 11 | **Substation Facilities Transf to** | | | | |
| 15 | **Distribution Plt.** | | | | |
| 11 | | $ | | | $ |
| 16 | MPS | - | $ | - | - |
| 11 | | | | | |
| 17 | SJLP | - | | - | - |
| 11 | | $ | | | $ |
| 18 | Total | - | $ | - | - |
| 11 | | | | | |
| 19 | | | | | |
| 12 | | | | | |
| 20 | **34kV Lines** | | | | |
| 12 | | $ | | | $ |
| 11 | MPS | - | $ | - | - |
| 12 | | | | | |
| 12 | SJLP | - | | - | - |
| 12 | | $ | | | $ |
| 13 | Total | - | $ | - | - |
| 12 | **Less: Substation Facilities Transf** | | | | |
| 14 | **to Trans. Plant** | | | | |
| 12 | | $ | | | $ |
| 15 | MPS | - | $ | - | - |
| 12 | | | | | |
| 16 | SJLP | - | | - | - |
| 12 | | $ | | | $ |
| 17 | Total | - | $ | - | - |
| 12 | Net Substation, 34kV, & Radial Lines to | $ | | | $ |
| 18 | Dist. Plt | - | $ | - | - |
| 12 | | | | | |
| 19 | | | | | |
| 13 | **III. Net Transfer From** | $ | | | $ |
| 10 | **Trans. (ln 7+ln 28)** | - | $ | - | - |

**IV. 13 Month Average - Gross Plant**



| Line No. | | Gross Plant | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End. Balance Dec Y1 | Jan Y2 | Feb Y2 | Mar Y2 | April Y2 | May Y2 | June Y2 | July Y2 | Aug Y2 | Sept Y2 | Oct Y2 | Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
| 31 | **GSU:** | | | | | | | | | | | | | | |
| 32 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 34 | **Total** | | | | | | | | | | | | | | $ - |
| 35 | **Radial Lines:** | | | | | | | | | | | | | | |
| 36 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 37 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 38 | **Total** | | | | | | | | | | | | | | $ - |
| 39 | **Substation Facilities - Transf from Distribution Plant** | | | | | | | | | | | | | | |
| 40 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 41 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 42 | **Total** | | | | | | | | | | | | | | $ - |
| 43 | **34kV Lines** | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 44 | | $ | $ | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 44 | **MPS** | - | - | $ - | - | - | - | - | - | - | - | - | - | - | - |
| 44 | | | | | | | | | | | | | | | $ |
| 45 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 44 | | | | | | | | | | | | | | | $ |
| 46 | **Total** | | | | | | | | | | | | | | - |
| | **Less: Substation** | | | | | | | | | | | | | | |
| 44 | **Facilities Tranf to** | | | | | | | | | | | | | | |
| 47 | **Transmission Plant** | | | | | | | | | | | | | | |
| 44 | | $ | $ | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 48 | **MPS** | - | - | $ - | - | - | - | - | - | - | - | - | - | - | - |
| 44 | | | | | | | | | | | | | | | |
| 49 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 45 | | | | | | | | | | | | | | | $ |
| 50 | **Total** | | | | | | | | | | | | | | - |
| 45 | | $ | $ | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 51 | **Total -Excluded Assets** | - | - | $ - | - | - | - | - | - | - | - | - | - | - | - |

**V. 13 Month Average -Accumulated Deprecation**

| | | Accumulated Depreciation | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **End. Balance Dec Y1** | **Jan Y2** | **Feb Y2** | **Mar Y2** | **April Y2** | **May Y2** | **June Y2** | **July Y2** | **Aug Y2** | **Sept Y2** | **Oct Y2** | **Nov Y2** | **End. Balance Dec Y2** | **13 Months Avg Balance** |
| 45 | | | | | | | | | | | | | | | |
| 52 | **GSU:** | | | | | | | | | | | | | | |
| 45 | | $ | $ | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 53 | **MPS** | - | - | $ - | - | - | - | - | - | - | - | - | - | - | - |
| 45 | | | | - | | | | | | | | | | | $ |
| 54 | **SJLP** | - | - | | - | - | - | - | - | - | - | - | - | - | - |
| 45 | | | | | | | | | | | | | | | $ |
| 55 | **Total** | | | | | | | | | | | | | | - |
| 45 | | | | | | | | | | | | | | | |
| 56 | **Radial Lines:** | | | | | | | | | | | | | | |
| 45 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 57 | **MPS** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 45 | **SJLP** | | | - | | | | | | | | | | | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | - | - | | - | - | - | - | - | - | - | - | - | - | - |
| 59 | **Total** | | | | | | | | | | | | | | $ - |
| 60 | **Substation Facilities - Transf from Distribution Plant** | | | | | | | | | | | | | | |
| 61 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 62 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 63 | **Total** | | | | | | | | | | | | | | $ - |
| 64 | **34kV Lines** | | | | | | | | | | | | | | |
| 65 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 66 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 67 | **Total** | | | | | | | | | | | | | | $ - |
| 68 | **Less: Substation Facilities Tranf to Transmission Plant** | | | | | | | | | | | | | | |
| 69 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 70 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 71 | **Total** | | | | | | | | | | | | | | $ - |
| 72 | **Total -Excluded Assets** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**VI. 13 Month Average -Net Plant**



| | **Net Plant** (Gross Plant less Accumulated Depreciation) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **End. Balance Dec Y1** | **Jan Y2** | **Feb Y2** | **Mar Y2** | **April** | **May Y2** | **June** | **July Y2** | **Aug Y2** | **Sept Y2** | **Oct Y2** | **Nov** | **End. Balance Dec Y2** | **13 Months Avg Bala** |

| | | | | | | Y2 | | Y2 | | | | | Y2 | | nce |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 73 | **GSU:** | | | | | | | | | | | | | | |
| 74 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 75 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 76 | **Total** | | | | | | | | | | | | | | $ - |
| 77 | **Radial Lines:** | | | | | | | | | | | | | | |
| 78 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 79 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 80 | **Total** | | | | | | | | | | | | | | $ - |
| 81 | **Substation Facilities - Transf from Distribution Plant** | | | | | | | | | | | | | | |
| 82 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 83 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 84 | **Total** | | | | | | | | | | | | | | $ - |
| 85 | **34kV Lines** | | | | | | | | | | | | | | |
| 86 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 87 | **SJLP** | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |
| 88 | **Total** | | | | | | | | | | | | | | $ - |
| 89 | **Less: Substation Facilities Tranf to Transmission Plant** | | | | | | | | | | | | | | |
| 90 | **MPS** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 91 | **SJLP** | | | - | | | | | | | | | | | $ |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | - | - | | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 2 | **Total** | | | | | | | | | | | | | | | $ - |
| 9 3 | **Total -Excluded Assets** | $ - | $ - | $ | - | $ - | - | - | - | - | - | - | - | - | - | $ - |

**Worksheet A-5 - Weighted Depreciation Rates -EMW**

At December 31, 20XX

| | | | MPS | | SJLP | | ECORP | | EMWComposite (Note 1) | |
|---|---|---|---|---|---|---|---|---|---|---|
| **LN** | **A/C** | **Description** | Alloc | Tot Rate | Alloc | Tot Rate | Alloc | Tot Rate | Alloc | Tot Rate |
| 1 | 301 | Organization (Note 2) | 0.0000% | 4.63% | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | **4.63%** |
| 2 | 302 | Franchises | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | **0.00%** |
| 3 | 303 | Misc Intangible Plant | 0.0000% | 2.50% | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | **2.50%** |
| 4 | 30301 | Misc Intangible Plant (Note 3) | 0.0000% | 1.92% | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | **1.92%%** |
| 5 | 30302 | Misc Intangible Plant -Software (Note 4) | 0.0000% | 20.00% | 0.0000% | 20.00% | 0.0000% | 20.00% | 0.0000% | **20.00%** |
| | 30309 | Misc Intangible Plant – Transmission | 0.0000% | 0.00% | 0.0000% | 6.56% | 0.0000% | 0.00% | 0.0000% | **6.56%** |
| 6 | 30310 | Misc Intangible Plant – Iatan Hwy & Bridge | 0.0000% | 0.00% | 0.0000% | 2.10% | 0.0000% | 2.10% | 0.0000% | **2.10%** |
| 7 | 35004 | Land Rights | 0.0000% | 1.19% | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | **1.19%** |
| 8 | 352 | Structures and Improvements | 0.0000% | 1.83% | 0.0000% | 1.83% | 0.0000% | 1.83% | 0.0000% | **1.83%** |
| 9 | 353 | Station Equipment | 0.0000% | 1.70% | 0.0000% | 1.70% | 0.0000% | 1.70% | 0.0000% | **1.70%** |
| 10 | 354 | Towers and Fixtures | 0.0000% | 1.85% | 0.0000% | 1.85% | 0.0000% | 0.00% | 0.0000% | **1.85%** |
| 11 | 355 | Poles and Fixtures | 0.0000% | 2.93% | 0.0000% | 2.93% | 0.0000% | 2.93% | 0.0000% | **2.93%** |
| 12 | 356 | Overhead Conductors and Devices | 0.0000% | 2.32% | 0.0000% | 2.32% | 0.0000% | 2.32% | 0.0000% | **2.32%** |
| 13 | 357 | Underground Conduit | 0.0000% | 0.00% | 0.0000% | 1.70% | 0.0000% | 0.00% | 0.0000% | **1.70%** |
| 14 | 358 | Underground Conductors and Devices | 0.0000% | 2.49% | 0.0000% | 2.49% | 0.0000% | 0.00% | 0.0000% | **2.49%** |
| 15 | 389 | Land and Land Rights | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | 0.00% | 0.0000% | **0.00%** |
| 16 | 390 | Structures and Improvements | 0.0000% | 2.73% | 0.0000% | 2.73% | 0.0000% | 2.22% | 0.0000% | **2.56%** |
| 17 | 391 | Office Furniture and Equipment | 0.0000% | 5.00% | 0.0000% | 5.00% | 0.0000% | 5.00% | 0.0000% | **5.00%** |
| 18 | 39106 | Gen Plt-SJ OffMachines1987 | 0.0000% | 0.00% | 0.0000% | 4.17% | 0.0000% | 0.00% | 0.0000% | **4.17%** |
| 19 | 39102 | Gen Plt-Computer Hardware | 0.0000% | 12.50% | 0.0000% | 12.50% | 0.0000% | 12.50% | 0.0000% | **12.50%** |
| 20 | 39104 | Gen Plt-Software | 0.0000% | 11.11% | 0.0000% | 11.11% | 0.0000% | 11.11% | 0.0000% | **11.11%** |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 21 | 392 | Transportation Equipment | 0.0000% | 11.25% | 0.0000% | 11.25% | 0.0000% | 12.50% | 0.0000% | **11.25%** |
| 22 | 393 | Stores Equipment | 0.0000% | 4.00% | 0.0000% | 4.00% | 0.0000% | 4.00% | 0.0000% | **4.00%** |
| 23 | 394 | Tools, Shop and Garage Equipment | 0.0000% | 4.00% | 0.0000% | 4.00% | 0.0000% | 4.00% | 0.0000% | **4.00%** |
| 24 | 395 | Laboratory Equipment | 0.0000% | 3.30% | 0.0000% | 3.30% | 0.0000% | 3.30% | 0.0000% | **3.30%** |
| 25 | 396 | Power Operated Equipment | 0.0000% | 4.45% | 0.0000% | 4.45% | 0.0000% | 4.45% | 0.0000% | **4.45%** |
| 26 | 397 | Communication Equipment | 0.0000% | 3.70% | 0.0000% | 3.70% | 0.0000% | 3.70% | 0.0000% | **3.70%** |
| 27 | 398 | Miscellaneous Equipment | 0.0000% | 4.00% | 0.0000% | 4.00% | 0.0000% | 4.00% | 0.0000% | **4.00%** |
| 28 | 39901 | Other Tangible Property (Note 5) | 0.0000% | 2.35% | 0.0000% | 2.22% | 0.0000% | 0.00% | 0.0000% | **2.30%** |

**Notes:**

**1** The SJLP depreciation rates will be applied to the SJLP facilities and the MPS depreciation rates will be applied to the MPS facilities. The ECORP (joint MPS and SJLP) rates differ from the MPS and SJLP rates for some accounts, where approved. The EMW FERC Form No. 1 will identify the depreciable balances for MPS, SJLP, and ECORP separately on pages 337.x or in the notes to pages 337.x. The composite depreciation rate in each account reflects an asset-based weighting of the rates among MPS, SJLP, and ECORP.

**2** The amortization rate for MPS Account 301 is recalculated each year based on a fixed end of life of FY2023, starting in FY2009.

**3** The amortization rate for MPS Account 30301 is recalculated each year based on a fixed end of life of FY2061.

**4** Account 30302 contains computer software. The amortization rate will be set at 20% effective July 2010. Due to the corporate transition, the rates applied in 2008 and 2009 were 12.5% and 11.11%, respectively.

**5** The MPS and SJLP amortization rates for this account are recalculated each year based on the remaining useful lives and relative balances of the retirement obligations of General Plant facilities.

**6** The above account numbers reflect account numbering as shown in the 2009 FN1. Some accounts were renumbered between 2008 and 2009 in order to make the EMW numbers more consistent with the EMe system. The following table reflects the numbering changes between the 2008 and 2009 FN1s:

| 2008 | 2009 |
|---|---|
| 303.2 | 303 |
| 303.1 | 30301 |
| 303 | 30302 |
| 350 | 35004 |

| | |
|---|---|
| 391.1 | 391 |
| 391.11 | 39106 |
| 391.3 | 39102 |
| 391.4 | 39104 |
| 399.1 | 39901 |

# Addendum 11 to Attachment H – Part 1B

**Worksheet A-6 - Taxes Other Than Income Taxes**
**Evergy Missouri West Inc.**



***Taxes Other than Income***

| Line No. | | Electric Acct 408.1, 409.1 ( I ) | Excluded | Adjusted | Payroll | Highway & Vehicle | Property | Gross Reciepts, Uses & KC Earning Tax | Other | Other Misc | Total of Cost Distribution |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Ad Valorem | - | - | - | | | - | | | | - |
| 2 | Excise | - | - | - | | - | | | | | - |
| 3 | Franchise -Corporate | - | - | - | | | | - | | | - |
| 4 | Payroll | - | - | - | - | | | | | | - |
| 5 | Transaction | - | - | - | | | | - | | | - |
| 6 | KC Earnings | - | | - | | | | - | | | - |
| 7 | Miscellaneous | - | - | - | | | | | - | | - |
| 8 | Page 263, (i) | - | - | - | - | - | - | - | - | - | - |
| 9 | **(Reference to Act. Gross Rev Req Wksht)** | | | | (P. 2, ln 13) | (P.2, ln 14) | (P.2, ln 15) | (P.2, ln 16) | (P.2, ln 17) | (P.2, ln 17) | (P.2, ln 18) |
| 10 | | | | | | | | | | | |
| 11 | Federal | - | | | | | | | | | |
| 12 | State | | | | | | | | | | |
| 13 | Missouri | | | | | | | | | | |

| | | |
|---|---|---|
| | | - |
| 14 | Kansas | |
| 15 | | |
| 16 | Page 263, ln 41, (i) | - |

**Worksheet A-7 - Actual RTO Directed Transmission Projects**
**Evergy Missouri West Inc.**
For the 12 months ended -
December 31, 20XX



**Summary of Actual RTO Directed Transmission Projects**

| | Base Plan Project Descripton | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 1 | 1 | | $ - | 0.0000% | $ - | $ - | $ - |
| 2 | 2 | | $ - | 0.0000% | $ - | $ - | $ - |
| 3 | 3 | | $ - | 0.0000% | $ - | $ - | $ - |
| 4 | Total | | $ - | | $ - | $ - | $ - |

| | Balanced Portfolio Project Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 5 | 1 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 6 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 8 | Total | | $ - | | $ - | $ - | $ - |

| | ITP/ Priority Project-1 Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 9 | 1 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 10 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 11 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 12 | Total | | $ - | | $ - | $ - | $ - |

| | ITP/ Priority Project-2 Description | In-Service | Net Plant | Actual Facility Carrying Chge | Actual Rev Reg | Actual Incentive Rev Reg (A-9) | Total Actual Rev Reg |
|---|---|---|---|---|---|---|---|
| 13 | 1 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 14 | 2 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 15 | 3 | 0 | $ - | 0.0000% | $ - | $ - | $ - |
| 16 | Total | | $ - | | $ - | $ - | $ - |

**Calculation of Net Plant for BPF Projects:**



| | | **Project:** *1* | **Project:** *2* | **Project:** |
|---|---|---|---|---|
| 1 | | SPP Proj. | SPP Proj. | SPP Proj. |
| 2 | | ID | ID | ID |

| | | | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | | | | | | | | | | | |
| 4 | | | Prior Yr | Dec | | $ - | | | $ - | | | $ - | | |
| 5 | | | Current Yr | Jan | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 6 | | | Current Yr | Feb | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 7 | | | Current Yr | Mar | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 8 | | | Current Yr | Apr | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 9 | | | Current Yr | May | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 10 | | | Current Yr | Jun | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 11 | | | Current Yr | Jul | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 12 | | | Current Yr | Aug | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 13 | | | Current Yr | Sep | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 14 | | | Current Yr | Oct | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 15 | | | Current Yr | Nov | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 16 | | | Current Yr | Dec | | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 17 | | | | | | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - |
| 18 | | | | | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Total Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| 21 | 2008 | $ - | $ - | $ - | 2008 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | 2009 | | | | 2009 | | | | | | |
| 23 | 2010 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | 2011 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | 2012 | $ - | $ - | $ - | 2012 | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | 2013 | $ - | $ - | $ - | 2013 | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | 2014 | $ - | $ - | $ - | 2014 | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | 2015 | $ - | $ - | $ - | 2015 | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | 2016 | $ - | $ - | $ - | 2016 | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | 2017 | $ - | $ - | $ - | 2017 | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | 2018 | $ - | $ - | $ - | 2018 | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | 2019 | $ - | $ - | $ - | 2019 | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | 2020 | $ - | $ - | $ - | 2020 | $ - | $ - | $ - | $ - | $ - | $ - |
| 34 | 2021 | $ - | $ - | $ - | 2021 | $ - | $ - | $ - | $ - | $ - | $ - |
| 35 | 2022 | $ - | $ - | $ - | 2022 | $ - | $ - | $ - | $ - | $ - | $ - |
| 36 | 2023 | $ - | $ - | $ - | 2023 | $ - | $ - | $ - | $ - | $ - | $ - |
| 37 | 2024 | $ - | $ - | $ - | 2024 | $ - | $ - | $ - | $ - | $ - | $ - |
| 38 | 2025 | $ - | $ - | $ - | 2025 | $ - | $ - | $ - | $ - | $ - | $ - |
| 39 | 2026 | $ - | $ - | $ - | 2026 | $ - | $ - | $ - | $ - | $ - | $ - |
| 40 | 2027 | $ - | $ - | $ - | 2027 | $ - | $ - | $ - | $ - | $ - | $ - |
| 41 | 2028 | $ - | $ - | $ - | 2028 | $ - | $ - | $ - | $ - | $ - | $ - |
| 42 | 2029 | $ - | $ - | $ - | 2029 | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | | - | - | - | - | - | - | |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 43 | 2030 | - | - | - | 2030 | - | - | - | - | - | - | |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ | |
| 44 | 2031 | - | - | - | 2031 | - | - | - | - | - | - | |
| 45 | | | | | | | | | | | | |

46 Notes: (A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)

47 (B) This rate will reflect any future FERC approved depreciation rates.

48 (C) BPF projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1.

49 (D) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

50 (E) Accumulated Depreciation will be brought forward from the prior year for each project.

**Calculation of Net Plant for Balanced Portfolio Projects:**



| | | | | **Project:** *1* | | | **Project:** *2* | | | **Project:** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | |
| 2 | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 4 | | Prior Yr | Dec | $ - | | | $ - | | | $ - | | |
| 5 | | Current Yr | Jan | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 6 | | Current Yr | Feb | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 7 | | Current | Mar | $ | 0.0000% | $ | $ | 0.0000% | $ | $ | 0.0000% | $ |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Yr | | | - | | - | - | | - | - | | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 8 | | | Yr | Apr | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 9 | | | Yr | May | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 10 | | | Yr | Jun | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 11 | | | Yr | Jul | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 12 | | | Yr | Aug | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 13 | | | Yr | Sep | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 14 | | | Yr | Oct | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 15 | | | Yr | Nov | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 16 | | | Yr | Dec | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | | | | | | | | | | | Sum | |
| | | | | | | | Sum lines | $ | | Sum lines | $ | | lines 5 - | $ |
| 17 | | | | | | | 5 - 16 | - | | 5 - 16 | - | | 16 | - |
| | | | | | | Prior Years | | | Prior Years | | | Prior Years | | |
| 18 | | | **Total** | | | Acc Dep: | - | | Acc Dep: | - | | Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| | 200 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 21 | 8 | - | - | - | 08 | - | - | - | - | - | - | - | - | - |
| | 200 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 22 | 9 | - | - | - | 09 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 23 | 0 | - | - | - | 10 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 24 | 1 | - | - | - | 11 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 25 | 2 | - | - | - | 12 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 26 | 3 | - | - | - | 13 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 27 | 4 | - | - | - | 14 | - | | - | - | | - | - | | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 201 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 28 | 5 | - | - | - | 15 | - | - | - | - | - | - | |
| | 201 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 29 | 6 | - | - | - | 16 | - | - | - | - | - | - | |
| | 201 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 30 | 7 | - | - | - | 17 | - | - | - | - | - | - | |
| | 201 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 31 | 8 | - | - | - | 18 | - | - | - | - | - | - | |
| | 201 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 32 | 9 | - | - | - | 19 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 33 | 0 | - | - | - | 20 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 34 | 1 | - | - | - | 21 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 35 | 2 | - | - | - | 22 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 36 | 3 | - | - | - | 23 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 37 | 4 | - | - | - | 24 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 38 | 5 | - | - | - | 25 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 39 | 6 | - | - | - | 26 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 40 | 7 | - | - | - | 27 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 41 | 8 | - | - | - | 28 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 42 | 9 | - | - | - | 29 | - | - | - | - | - | - | |
| | 203 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 43 | 0 | - | - | - | 30 | - | - | - | - | - | - | |
| | 203 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 44 | 1 | - | - | - | 31 | - | - | - | - | - | - | |
| 45 | | | | | | | | | | | | |

Notes:

46 (A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)

47 (B) This rate will reflect any future FERC approved depreciation rates.

(C) BPF projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire
48 project is completed and reported in the Form 1.
Balance Portfolio Projects with incentives granted by FERC should be
49 (D) included in Sheet A-9 as well as this sheet.
Accumulated Depreciation will be brought forward from the
50 (E) prior year for each project.

**Calculation of Net Plant for ITP / Priority Projects -1:**



| | | | | **Project:** *1* | | | **Project:** *2* | | | **Project:** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 2 | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 3 | | | | $ | | | $ | | | $ | | |
| 4 | | Prior Yr | Dec | - | | | - | | | - | | |
| 5 | | Current Yr | Jan | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 6 | | Current Yr | Feb | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 7 | | Current Yr | Mar | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 8 | | Current Yr | Apr | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 9 | | Current Yr | May | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 10 | | Current Yr | Jun | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 11 | | Current Yr | Jul | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 12 | | Current Yr | Aug | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - | $ - | 0.0000% | $ - |
| 13 | | Current | Sep | $ | 0.0000% | $ | $ | 0.0000% | $ | $ | 0.0000% | $ |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Yr | | | - | | - | - | | - | - | | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 14 | | | Yr | Oct | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 15 | | | Yr | Nov | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | Current | | | $ | | $ | $ | | $ | $ | | $ |
| 16 | | | Yr | Dec | | - | 0.0000% | - | - | 0.0000% | - | - | 0.0000% | - |
| | | | | | | | | | | | | | | |
| | | | | | | | Sum lines | $ | | Sum lines | $ | | Sum lines 5 - | $ |
| 17 | | | | | | | 5 - 16 | - | | 5 - 16 | - | | 16 | - |
| | | | | | | Prior Years | | | Prior Years | | | Prior Years | | |
| 18 | | | **Total** | | | Acc Dep: | - | | Acc Dep: | - | | Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| | 2008 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 21 | | | | | | | | | | | | | | |
| | 2009 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 22 | | | | | | | | | | | | | | |
| | 2010 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 23 | | | | | | | | | | | | | | |
| | 2011 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 24 | | | | | | | | | | | | | | |
| | 2012 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 25 | | | | | | | | | | | | | | |
| | 2013 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 26 | | | | | | | | | | | | | | |
| | 2014 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 27 | | | | | | | | | | | | | | |
| | 2015 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 28 | | | | | | | | | | | | | | |
| | 2016 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 29 | | | | | | | | | | | | | | |
| | 2017 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 30 | | | | | | | | | | | | | | |
| | 2018 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 31 | | | | | | | | | | | | | | |
| | 2019 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 32 | | | | | | | | | | | | | | |
| | 2020 | $ - | $ - | $ - | 2020 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 33 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 34 | 1 | - | - | - | 21 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 35 | 2 | - | - | - | 22 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 36 | 3 | - | - | - | 23 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 37 | 4 | - | - | - | 24 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 38 | 5 | - | - | - | 25 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 39 | 6 | - | - | - | 26 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 40 | 7 | - | - | - | 27 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 41 | 8 | - | - | - | 28 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 42 | 9 | - | - | - | 29 | - | - | - | - | - | - | |
| | 203 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 43 | 0 | - | - | - | 30 | - | - | - | - | - | - | |
| | 203 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 44 | 1 | - | - | - | 31 | - | - | - | - | - | - | |
| 45 | | | | | | | | | | | | |

Notes:

(A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)

(B) This rate will reflect any future FERC approved depreciation rates.

(C) BPF projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1.

(D) ITP/Priority Project -1 with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

(E) Accumulated Depreciation will be brought forward from the prior year for each project.

**Calculation of Net Plant for ITP / Priority Projects -2**

| | | | | **Project:** *1* | | | **Project:** *2* | | | **Project:** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 2 | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 3 | | | | $ - | | | $ - | | | $ - | | |
| 4 | Prior Yr | Dec | | | | $ - | | | $ - | | | $ - |
| 5 | Current Yr | Jan | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 6 | Current Yr | Feb | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 7 | Current Yr | Mar | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 8 | Current Yr | Apr | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 9 | Current Yr | May | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 10 | Current Yr | Jun | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 11 | Current Yr | Jul | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 12 | Current Yr | Aug | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 13 | Current Yr | Sep | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 14 | Current Yr | Oct | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 15 | Current Yr | Nov | | | 0.0000% | $ - | | 0.0000% | $ - | | 0.0000% | $ - |
| 16 | Current Yr | Dec | | - | 0.0000% | $ - | - | 0.0000% | $ - | - | 0.0000% | $ - |
| 17 | | | | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - | | Sum lines 5 - 16 | $ - |
| 18 | **Total** | | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | |

| | Year | Gross Plant | Accm. Deprec. | Net Plant | Year | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | | | | | | | | | | | | | | |
| 20 | 200 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 21 | 8 | - | - | - | 08 | - | - | - | - | - | - | - | - | - |
| | 200 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 22 | 9 | - | - | - | 09 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 23 | 0 | - | - | - | 10 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 24 | 1 | - | - | - | 11 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 25 | 2 | - | - | - | 12 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 26 | 3 | - | - | - | 13 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 27 | 4 | - | - | - | 14 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 28 | 5 | - | - | - | 15 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 29 | 6 | - | - | - | 16 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 30 | 7 | - | - | - | 17 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 31 | 8 | - | - | - | 18 | - | | - | - | | - | - | | - |
| | 201 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 32 | 9 | - | - | - | 19 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 33 | 0 | - | - | - | 20 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 34 | 1 | - | - | - | 21 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 35 | 2 | - | - | - | 22 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 36 | 3 | - | - | - | 23 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 37 | 4 | - | - | - | 24 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 38 | 5 | - | - | - | 25 | - | | - | - | | - | - | | - |
| | 202 | $ | $ | $ | 20 | $ | | $ | $ | | $ | $ | | $ |
| 39 | 6 | - | - | - | 26 | - | | - | - | | - | - | | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 40 | 7 | - | - | - | 27 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 41 | 8 | - | - | - | 28 | - | - | - | - | - | - | |
| | 202 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 42 | 9 | - | - | - | 29 | - | - | - | - | - | - | |
| | 203 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 43 | 0 | - | - | - | 30 | - | - | - | - | - | - | |
| | 203 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | |
| 44 | 1 | - | - | - | 31 | - | - | - | - | - | - | |
| 45 | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | |

Notes:

47 (A) Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)

48 (B) This rate will reflect any future FERC approved depreciation rates.

49 (C) BPF projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1.

50 (D) ITP/Priority Project -1 with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

51 (E) Accumulated Depreciation will be brought forward from the prior year for each project.

**Worksheet A-8 - Actual Sponsored Upgrades**
**Evergy Missouri West Inc.**
For the 12 months ended - December 31, 20XX



**Summary of Actual Sponsored Projects**

| | | (a) | (b) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| **Sponsored Project Description** | **In-Service** | **Net Plant** | **Actual Facility Carrying Charge** | **Rev Reg** | **Actual Incentive Rev Reg (A-9 Incentive Proj)** | **Total Actual Sponsored Rev Reg** |

| | | | | (a*b) | | (d + e) |
|---|---|---|---|---|---|---|
| | | $ | | $ | $ | $ |
| 1 | 1 | - | 0.0000% | - | - | - |
| | | $ | | $ | $ | $ |
| 2 | 2 | - | 0.0000% | - | - | - |
| | | $ | | $ | $ | $ |
| 3 | 3 | - | 0.0000% | - | - | - |
| | Tot | $ | | $ | $ | $ |
| 4 | al | - | | - | - | - |

**Calculation of Net Plant for Sponsored Upgrade:**

| 1 | | | | **Project:** ***1*** | | | **Project:** ***2*** | | | **Project:** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 (notes A & B) | Depreciation Expense |
| 4 | | Prior Yr | Dec | $0 | | | $0 | | | $0 | | |
| | | Current | | | | $ | | | $ | | | $ |
| 5 | | Yr | Jan | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 6 | | Yr | Feb | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 7 | | Yr | Mar | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 8 | | Yr | Apr | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 9 | | Yr | May | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 10 | | Yr | Jun | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 11 | | Yr | Jul | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 12 | | Yr | Aug | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 13 | | Yr | Sep | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |
| | | Current | | | | $ | | | $ | | | $ |
| 14 | | Yr | Oct | $0 | 0.0000% | - | $0 | 0.0000% | - | $0 | 0.0000% | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | | Current Yr | Nov | | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 16 | | Current Yr | Dec | | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - | $0 | 0.0000% | $ - |
| 17 | | | | | | | $ - | | | $ - | | | $ - |
| 18 | | **Total** | | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | | Prior Years Acc Dep: | - | |
| 19 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 20 | | | | | | | | | | | | | | |
| 21 | 2008 | $ - | $ - | $ - | 2008 | $ - | - | $ - | $ - | - | $ - | $ - | - | $ - |
| 22 | 2009 | $ - | $ - | $ - | 2009 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 23 | 2010 | $ - | $ - | $ - | 2010 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 24 | 2011 | $ - | $ - | $ - | 2011 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 25 | 2012 | $ - | $ - | $ - | 2012 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 26 | 2013 | $ - | $ - | $ - | 2013 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 27 | 2014 | $ - | $ - | $ - | 2014 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 28 | 2015 | $ - | $ - | $ - | 2015 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 29 | 2016 | $ - | $ - | $ - | 2016 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 30 | 2017 | $ - | $ - | $ - | 2017 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 31 | 2018 | $ - | $ - | $ - | 2018 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 32 | 2019 | $ - | $ - | $ - | 2019 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 33 | 2020 | $ - | $ - | $ - | 2020 | $ - | | $ - | $ - | | $ - | $ - | | $ - |
| 34 | 2021 | $ - | $ - | $ - | 2021 | $ - | | $ - | $ - | | $ - | $ - | | $ - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 35 | 2022 | - | - | - | 2022 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 36 | 2023 | - | - | - | 2023 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 37 | 2024 | - | - | - | 2024 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 38 | 2025 | - | - | - | 2025 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 39 | 2026 | - | - | - | 2026 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 40 | 2027 | - | - | - | 2027 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 41 | 2028 | - | - | - | 2028 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 42 | 2029 | - | - | - | 2029 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 43 | 2030 | - | - | - | 2030 | - | - | - | - | - | - |
| | | $ | $ | $ | | $ | $ | $ | $ | $ | $ |
| 44 | 2031 | - | - | - | 2031 | - | - | - | - | - | - |
| 45 | | | | | | | | | | | |

**Notes:**

46

47 **(A)** Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2)

48 **(B)** This rate will reflect any future FERC approved depreciation rates.

49 **(C)** Sponsored Upgrade Projects that have been completed and whose costs are in the Form 1 should be entered on this page as well as any CWIP balance for those projects with CWIP incentive. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Form 1.

50 **(D)** Sponsored Projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

51 **(E)** Accumulated Depreciation will be brought forward from the prior year for each project.

**Worksheet A-9 - Actual Incentive Plant**
**Evergy Missouri West Inc.**
For the 12 months ended - December 31, 20XX

**Summary of Actual Incentive Projects**



| | Description - Zonal Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 2 | 2 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 3 | | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 4 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - Base Plan Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | 1 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 6 | 2 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 7 | | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 8 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - Sponsor Funded Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 9 | 1 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 10 | 2 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 11 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 12 | Total | | $ - | $ - | $ - | | | $ - | $ - |

| | Description of Balanced Portfolio Projects | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 13 | 1 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 14 | 2 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 15 | | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 16 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - ITP/ Priority Project-1 | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 16 | 1 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 17 | 2 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 18 | | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 19 | Total | | | $ - | $ - | $ - | | | $ - | $ - |

| | Description - ITP/ Priority Project-2 | In-Service Date | | CWIP | Tax-Adjusted Return on CWIP | Incentive Net Plant | Incentive Rate - Weighted ROE | Effective Income Tax Rate | Tax-Adjusted Return on Incentive Plant | Total CWIP & Incentive Plant Return |
|---|---|---|---|---|---|---|---|---|---|---|
| 20 | 1 | | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 21 | 2 | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 22 | | $ - | $ - | $ - | 0.0000 % | 0.0000 % | $ - | $ - |
| 23 | Total | $ - | $ - | $ - | | | $ - | $ - |
| 24 | Total for All Incentive Projects | $ - | $ - | $ - | | | $ - | $ - |



**Zonal Projects**

| | | | | Project 1 | | | | | Project 2 | | | | | Project 3 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | ROE Adder: | 0.00 % | | | | ROE Adder: | 0.00 % | | | | ROE Adder: | 0.00 % |
| 2 | | | | SPP Proj. ID | | | Weighted ROE: | 0.00 % | | | | Weighted ROE: | 0.00 % | | | | Weighted ROE: | 0.00 % |
| 3 | | | | | | | Adder EIT: | 0.00 % | | | | Adder EIT: | 0.00 % | | | | Adder EIT: | 0.00 % |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| 5 | Prior Yr | Dec | $ - | $ - | | | | | $ - | $ - | | | | $ - | $ - | | | |
| 6 | Current Yr | Jan | $ - | $ - | 0.00 00% | $ - | | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 7 | Current Yr | Feb | $ - | $ - | 0.00 00% | $ - | | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 8 | Cu | Ma | $ | $ | 0.00 | $ | | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | rrent Yr | r | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | Apr | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 9 | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | May | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 10 | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 11 | Yr | Jun | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 12 | Yr | Jul | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | Aug | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 13 | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | Sep | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 14 | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 15 | Yr | Oct | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | Nov | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 16 | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| | Current | Dec | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.000 | $ | |
| 17 | Yr | | - | - | 00% | - | | - | - | 00% | - | | - | - | 0% | - | |
| 18 | | | | | Sum lines | $ - | | | | Sum lines | $ - | | | | Sum lines | $ - | |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | 6 - 17 | | | | | | | 6 - 17 | | | | | | 6 - 17 | | | | |
| 19 | | | **Total** | | | | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum Depr** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | | | |
| 21 | | | | | | | | | | | | | | | | | | | | | | | | | |
| 22 | 2008 | $ - | $ - | $ - | $ - | $ - | 2008 | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | $ - | $ - | - | $ - | $ - | | | |
| 23 | 2009 | $ - | $ - | $ - | $ - | $ - | 2009 | | | | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | | | | | | | | | |
| | 2020 | 2021 | | | | | | | | | |
| | 2021 | 2022 | | | | | | | | | |
| | 2022 | 2023 | | | | | | | | | |
| | 2023 | 2024 | | | | | | | | | |
| | 2024 | 2025 | | | | | | | | | |
| | 2025 | 2026 | | | | | | | | | |
| | 2026 | 2027 | | | | | | | | | |
| | 2027 | 2028 | | | | | | | | | |
| | 2028 | 2029 | | | | | | | | | |
| | 2029 | 2030 | | | | | | | | | |
| | 2030 | 2031 | | | | | | | | | |

**(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the FERC.

**Base Plan Funded Projects**

Page 3 of 7

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project:** | **1** | ROE Adder: | 0.00% | **Project:** | **2** | ROE Adder: | 0.00% | **Project:** | **3** | ROE Adder: | 0.00% |
| SPP Proj. | | Weighte | 0.00 | | | Weighte | 0.00 | | | Weighte | 0.00 |

| | | | | ID | | | d ROE: Adder EIT: | 00 % 0.00 % | | | | d ROE: Adder EIT: | % 0.00 % | | | | d ROE: Adder EIT: | % 0.00 % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | | | | | | | | | | | | | | | |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| 5 | | Prior Yr | Dec | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | | | |
| 6 | | Current Yr | Jan | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | |
| 7 | | Current Yr | Feb | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | |
| 8 | | Current Yr | Mar | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | |
| 9 | | Current Yr | Apr | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | |
| 10 | | Current Yr | May | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | |
| 11 | | Current Yr | Jun | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | |
| 12 | | Cu | Jul | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | | $ | $ | 0.00 | $ | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | rrent Yr | | - | - | | 00% | - | | - | - | | 00% | - | | - | - | | 00% | - | | | | | |
| 13 | | | | | | | Current Yr | Aug | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | | | | |
| 14 | | | | | | | Current Yr | Sep | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | | | | |
| 15 | | | | | | | Current Yr | Oct | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | | | | |
| 16 | | | | | | | Current Yr | Nov | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | | | | |
| 17 | | | | | | | Current Yr | Dec | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | $ - | $ - | | 0.00 00% | $ - | | | | | |
| 18 | | | | | | | | | | | | Sum lines 6 - 17 | $ - | | | | | Sum lines 6 - 17 | $ - | | | | | Sum lines 6 - 17 | $ - | | | | | |
| 19 | | | | | **Total** | | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | | | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21 | | | | | | | | | | | | | | | | | | | | | | | |
| | | $ | $ | $ | $ | $ | | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | |
| 22 | 2008 | - | - | - | - | - | 2008 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | $ | | | | | | | | | | | | | | | | | | | | | |
| 23 | 2009 | - | | | | | 2009 | | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | | |
| 34 | 2020 | | | | | | 2020 | | | | | | | | | | | | | | | | |
| 35 | 2021 | | | | | | 2021 | | | | | | | | | | | | | | | | |
| 36 | 2022 | | | | | | 2022 | | | | | | | | | | | | | | | | |
| 37 | 2023 | | | | | | 2023 | | | | | | | | | | | | | | | | |
| 38 | 2024 | | | | | | 2024 | | | | | | | | | | | | | | | | |
| 39 | 2025 | | | | | | 2025 | | | | | | | | | | | | | | | | |
| 40 | 2026 | | | | | | 2026 | | | | | | | | | | | | | | | | |
| 41 | 2027 | | | | | | 2027 | | | | | | | | | | | | | | | | |
| 42 | 2028 | | | | | | 2028 | | | | | | | | | | | | | | | | |
| 43 | 2029 | | | | | | 2029 | | | | | | | | | | | | | | | | |
| 44 | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | | | | | | | | | |

**(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by
46 the FERC.

**Sponsor Funded Projects**

Page 4 of 7

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | **Projec** | **1** | | ROE | 0.0 | | **Projec** | **2** | | ROE | 0.0 | | **Projec** | **3** | | ROE | 0.0 |

| | | | | **t:** | | | Adder: | 0% | | **t:** | | | Adder: | 0% | | **t:** | | | Adder: | 0% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Weighted ROE: | 0.000% | | | | | Weighted ROE: | 0.000% | | | | | Weighted ROE: | 0.000% |
| 2 | | | | SPP Proj. ID | | | | | | | | | | | | | | | | |
| | | | | | | | Adder | 0.00% | | | | | Adder | 0.00% | | | | | Adder | 0.00% |
| 3 | | | | | | | EIT: | % | | | | | EIT: | % | | | | | EIT: | % |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | | |
| 5 | Prior Yr Current Yr | Dec | $ - | $ - | | | | $0.00 | $ - | | | | $0.00 | $ - | | | | | | |
| 6 | Current Yr | Jan | $ - | $ - | 0.00% | $ - | | $0.00 | $ - | 0.00% | $ - | | $0.00 | $ - | 0.000% | $ - | | | | |
| 7 | Current Yr | Feb | $ - | $ - | 0.00% | $ - | | $0.00 | $ - | 0.00% | $ - | | $0.00 | $ - | 0.000% | $ - | | | | |
| 8 | Current Yr | Mar | $ - | $ - | 0.00% | $ - | | $0.00 | $ - | 0.00% | $ - | | $0.00 | $ - | 0.000% | $ - | | | | |
| 9 | Current Yr | Apr | $ - | $ - | 0.00% | $ - | | $0.00 | $ - | 0.00% | $ - | | $0.00 | $ - | 0.000% | $ - | | | | |
| 10 | Current Yr | May | $ - | $ - | 0.00% | $ - | | $0.00 | $ - | 0.00% | $ - | | $0.00 | $ - | 0.000% | $ - | | | | |
| 11 | Current Yr | Jun | $ - | $ - | 0.00% | $ - | | $0.00 | $ - | 0.00% | $ - | | $0.00 | $ - | 0.000% | $ - | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Yr Current | | | | | | | | | | | | | | | | | | | | |
| 12 | | | | | | Yr Current | Jul | $ - | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.000 0% | $ - | | |
| 13 | | | | | | Yr Current | Aug | $ - | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.000 0% | $ - | | |
| 14 | | | | | | Yr Current | Sep | $ - | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.000 0% | $ - | | |
| 15 | | | | | | Yr Current | Oct | $ - | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.000 0% | $ - | | |
| 16 | | | | | | Yr Current | Nov | $ - | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.000 0% | $ - | | |
| 17 | | | | | | Yr Current | Dec | $ - | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.00 00% | $ - | | $0.00 0 | $ - | | 0.000 0% | $ - | | |
| 18 | | | | | | | | | | | Sum lines 6 - 17 | $ - | | | | | Sum lines 6 - 17 | $ - | | | | | Sum lines 6 - 17 | $ - | | |
| 19 | | | | | | | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | |
| 20 | **Year** | **CWIP** | **Gross Pla** | **Accum. De** | **Total Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | | | | |

| | | | n t | p r. | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| | | $ | $ | $ | $ | $ | | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ |
| 22 | 2008 | - | - | - | - | - | 2008 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | 2009 | | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |
| 34 | 2020 | | | | | | 2020 | | | | | | | | | | | | | | | |
| 35 | 2021 | | | | | | 2021 | | | | | | | | | | | | | | | |
| 36 | 2022 | | | | | | 2022 | | | | | | | | | | | | | | | |
| 37 | 2023 | | | | | | 2023 | | | | | | | | | | | | | | | |
| 38 | 2024 | | | | | | 2024 | | | | | | | | | | | | | | | |
| 39 | 2025 | | | | | | 2025 | | | | | | | | | | | | | | | |
| 40 | 2026 | | | | | | 2026 | | | | | | | | | | | | | | | |
| 41 | 2027 | | | | | | 2027 | | | | | | | | | | | | | | | |
| 42 | 2028 | | | | | | 2028 | | | | | | | | | | | | | | | |
| 43 | 2029 | | | | | | 2029 | | | | | | | | | | | | | | | |
| 44 | | | | | | | | | | | | | | | | | | | | | | |

**(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the
45 FERC.



**Balanced Portfolio Project**

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | **Projec** | **1** | ROE | 0.0 | | | **Projec** | **2** | ROE | 0.0 | | | **Projec** | **3** | ROE | 0.0 |

| | | | | **t:** | | | Adder: | 0% | | **t:** | | | Adder: | 0% | | **t:** | | | Adder: | 0% |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Weighted | 0.000 | | | | | Weighted | 0.000 | | | | | Weighted | 0.000 |
| | | | | SPP Proj. ID | | | ROE: | 0% | | | | | ROE: | 0% | | | | | ROE: | 0% |
| 2 | | | | | | | Adder | 0.00 | | | | | Adder | 0.00 | | | | | Adder | 0.00 |
| 3 | | | | | | | EIT: | 0% | | | | | EIT: | 0% | | | | | EIT: | 0% |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| | Prior Yr | Dec | | $ - | $ - | | | | | $ - | $ - | | | | | $ - | $ - | | | |
| 5 | Current Yr | Jan | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.000% | $ - | |
| 6 | Current Yr | Feb | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.000% | $ - | |
| 7 | Current Yr | Mar | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.000% | $ - | |
| 8 | Current Yr | Apr | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.000% | $ - | |
| 9 | Current Yr | May | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.000% | $ - | |
| 10 | Current Yr | Jun | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.00% | $ - | | | $ - | $ - | 0.000% | $ - | |
| 11 | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Yr | | | | | | | | | | | | | | | | | |
| 12 | | | | | | Current Yr | Jul | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 13 | | | | | | Current Yr | Aug | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 14 | | | | | | Current Yr | Sep | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 15 | | | | | | Current Yr | Oct | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 16 | | | | | | Current Yr | Nov | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 17 | | | | | | Current Yr | Dec | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | $ - | $ - | 0.0000% | $ - | | |
| 18 | | | | | | | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | |
| 19 | | | | | | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Total Accum. De** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

**ITP / Priority Projects - 1:**

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | **Project: 1** | | ROE Adder: | 0.00% | | | **Project: 2** | | ROE Adder: | 0.00% | | | **Project: 3** | | ROE Adder: | 0.00% |
| 2 | | | | | SPP Proj. ID | | Weighted ROE: | 0.00% | | | | | Weighted ROE: | 0.00% | | | | | Weighted ROE: | 0.00% |
| 3 | | | | | | | Adder EIT: | 0.00% | | | | | Adder EIT: | 0.00% | | | | | Adder EIT: | 0.00% |
| 4 | | | | | CWIP Balance | Plant Balance by Month | Depr ec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Depr ec. Rate / 12 | Depreciation Expense | | | CWIP Balance | Plant Balance by Month | Depr ec. Rate / 12 | Depreciation Expense | |
| 5 | Prior Yr | Dec | $ - | $ - | | | | | | $ - | $ - | | | | | $ - | $ - | | | |
| 6 | Current Yr | Jan | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.000 0% | $ - | | |
| 7 | Current Yr | Feb | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.000 0% | $ - | | |
| 8 | Current Yr | Mar | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.000 0% | $ - | | |
| 9 | Current Yr | Apr | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.0000% | $ - | | | $ - | $ - | 0.000 0% | $ - | | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | Current Yr | May | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 11 | | Current Yr | Jun | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 12 | | Current Yr | Jul | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 13 | | Current Yr | Aug | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 14 | | Current Yr | Sep | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 15 | | Current Yr | Oct | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 16 | | Current Yr | Nov | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 17 | | Current Yr | Dec | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 18 | | | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | | | | Sum lines 6 - 17 | $ - | |
| 19 | **Total** | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | |

| | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | | | | | | | | | | | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| | | $ | $ | $ | $ | $ | | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ |
| 22 | 2008 | - | - | - | - | - | 2008 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | 2009 | | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |
| 34 | 2020 | | | | | | 2020 | | | | | | | | | | | | | | | |
| 35 | 2021 | | | | | | 2021 | | | | | | | | | | | | | | | |
| 36 | 2022 | | | | | | 2022 | | | | | | | | | | | | | | | |
| 37 | 2023 | | | | | | 2023 | | | | | | | | | | | | | | | |
| 38 | 2024 | | | | | | 2024 | | | | | | | | | | | | | | | |
| 39 | 2025 | | | | | | 2025 | | | | | | | | | | | | | | | |
| 40 | 2026 | | | | | | 2026 | | | | | | | | | | | | | | | |
| 41 | 2027 | | | | | | 2027 | | | | | | | | | | | | | | | |
| 42 | 2028 | | | | | | 2028 | | | | | | | | | | | | | | | |
| 43 | 2029 | | | | | | 2029 | | | | | | | | | | | | | | | |
| 44 | 2030 | | | | | | 2030 | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | | | | | | | | | |

**(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the FERC.



**ITP / Priority Projects - 2:**

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | **Project:** | **1** | ROE Adder: | 0.00% | | **Project:** | **2** | ROE Adder: | 0.00% | | **Project:** | **3** | ROE Adder: | 0.00% |
| 2 | | | | SPP Proj. ID | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% | | | | Weighted ROE: | 0.00% |
| 3 | | | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% | | | | Adder EIT: | 0.00% |
| 4 | | | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | CWIP Balance | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense |
| 5 | Prior Yr | Dec | | $ - | $ - | | | | $ - | $ - | | | | $ - | $ - | | |
| 6 | Current Yr | Jan | | $ - | $ - | 0.000% | $ - | | $ - | $ - | 0.000% | $ - | | $ - | $ - | 0.000% | $ - |
| 7 | Current Yr | Feb | | $ - | $ - | 0.000% | $ - | | $ - | $ - | 0.000% | $ - | | $ - | $ - | 0.000% | $ - |
| 8 | Current | Ma | | $ - | $ - | 0.000% | $ - | | $ - | $ - | 0.000% | $ - | | $ - | $ - | 0.000% | $ - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Current Yr | | | | | | | | | | | | | | | | |
| 9 | Current Yr | Apr | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 10 | Current Yr | May | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 11 | Current Yr | Jun | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 12 | Current Yr | Jul | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 13 | Current Yr | Aug | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 14 | Current Yr | Sep | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 15 | Current Yr | Oct | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 16 | Current Yr | Nov | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 17 | Current Yr | Dec | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.00 00% | $ - | | $ - | $ - | 0.000 0% | $ - | |
| 18 | | | | | Sum lines 6 - | $ - | | | | Sum lines 6 - | $ - | | | | Sum lines 6 - 17 | $ - | |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | 17 | | | | | 17 | | | | | | | | |
| 19 | | | **Total** | | | | | | Prior Years Acc Dep: | $ - | | | | Prior Years Acc Dep: | $ - | | | | | Prior Years Acc Dep: | $ - | | | |
| 20 | **Year** | **CWIP** | **Gross Plant** | **Accum. Depr.** | **Net Plant** | **Incentive RR** | **Year** | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR | CWIP | Gross Plant | Accm. Deprec. | Net Plant | Incentive RR |
| 21 | | | | | | | | | | | | | | | | | | | | | | |
| | | $ | $ | $ | $ | $ | | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ | | $ | $ |
| 22 | 2008 | - | - | - | - | - | 2008 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | 2009 | | | | | | 2009 | | | | | | | | | | | | | | | |
| 24 | 2010 | | | | | | 2010 | | | | | | | | | | | | | | | |
| 25 | 2011 | | | | | | 2011 | | | | | | | | | | | | | | | |
| 26 | 2012 | | | | | | 2012 | | | | | | | | | | | | | | | |
| 27 | 2013 | | | | | | 2013 | | | | | | | | | | | | | | | |
| 28 | 2014 | | | | | | 2014 | | | | | | | | | | | | | | | |
| 29 | 2015 | | | | | | 2015 | | | | | | | | | | | | | | | |
| 30 | 2016 | | | | | | 2016 | | | | | | | | | | | | | | | |
| 31 | 2017 | | | | | | 2017 | | | | | | | | | | | | | | | |
| 32 | 2018 | | | | | | 2018 | | | | | | | | | | | | | | | |
| 33 | 2019 | | | | | | 2019 | | | | | | | | | | | | | | | |
| 34 | 2020 | | | | | | 2020 | | | | | | | | | | | | | | | |
| 35 | 2021 | | | | | | 2021 | | | | | | | | | | | | | | | |
| 36 | 2022 | | | | | | 2022 | | | | | | | | | | | | | | | |
| 37 | 2023 | | | | | | 2023 | | | | | | | | | | | | | | | |
| 38 | 2024 | | | | | | 2024 | | | | | | | | | | | | | | | |
| 39 | 2025 | | | | | | 2025 | | | | | | | | | | | | | | | |
| 40 | 2026 | | | | | | 2026 | | | | | | | | | | | | | | | |
| 41 | 2027 | | | | | | 2027 | | | | | | | | | | | | | | | |
| 42 | 2028 | | | | | | 2028 | | | | | | | | | | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 43 | 2029 | 2029 | | | |
| 44 | 2030 | 2030 | | | |
| 45 | | | | | |
| 46 | | | | | |

**(A)** Special incentive (Depreciation Rate, ROE or CWIP) may be utilized for specific incentive transmission projects if approved by the
47 FERC.

# Addendum 11 to Attachment H – Part 2

**Worksheet A-10 Administrative & General Expense**



**Evergy Missouri West Inc.**

For the 12 months ended - December 31, 20XX

| | Source | Description | | | Annual Expense | Allocation Method | Allocation Rate | Allocated |
|---|---|---|---|---|---|---|---|---|
| 1 | 323.197.b | Administrative & General Expense | | | $ - | W/S | 0.0000 % | $ - |
| 2 | 323.191.b | Less: General Advertising Costs | | | - | W/S | 0.0000 % | $ - |
| 3 | 323.189.b | Less: Regulatory Commission Expenses | | | - | W/S | 0.0000 % | $ - |
| 4 | 335 | Less: Corporate Visibility Expenses | | | | W/S | 0.0000 % | $ - |
| 5 | 335 | Less: Misc Nuclear Expenses ( included in Account 930.2) | | | | W/S | 0.0000 % | $ - |
| 6 | 353 | Less: Experimental & Gen. Research Exp. | | | | W/S | 0.0000 % | $ - |
| 7 | 335 | Less: Industry Association Dues | | | | W/S | 0.0000 % | $ - |
| 8 | | | Subtotal | | - | | | - |
| 9 | | Less: Actual PBOP | | | - | W/S | 0.0000 % | $ - |
| 10 | | Plus: PBOP (Projected 2010 to be used for FY2009 and following) | | | - | W/S | 0.0000 % | $ - |
| 11 | 335 | Plus Safety Advertising | | | - | W/S | 0.0000 % | $ - |
| 12 | 335 | Plus:General Advertising: | | | | | | |
| 13 | | Transmission Facilities Siting | | $ - | | | | |
| 14 | | Transmission Vegetation Management | | $ - | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 15 | | Transmission Reliability | $ - | | | | | |
| 16 | | Total Advertising for Transmission | $ - | $ - | DA | 100.00 % | $ - | |
| 17 | 353 | Plus: Transmission Specific Research & Experimental | | | | | | |
| 18 | | Project #1 | $ - | | | | | |
| 19 | | Project #2 | $ - | | | | | |
| 20 | | | $ - | | | | | |
| 21 | | Total Research & Experimental Expenses | $ - | $ - | DA | 100.00 % | $ - | |
| 22 | 350 | Plus Transmission Related Reg. Comm. Exp. | | | | | | |
| 23 | | Formula Rate | $ - | | | | | |
| 24 | | Other-Specifically Assignable to Transmission | - | | | | | |
| 25 | | | - | | | | | |
| 26 | | Total Transmission Regulatory Expense | $ - | - | DA | 100.00 % | $ - | |
| 27 | 335 | Plus: Corporate Visibility Expenses: | | | | | | |
| 28 | | Regulatory | $ - | | | | | |
| 29 | | Reporting | $ - | | | | | |
| 30 | | Compliance | $ - | | | | | |
| 31 | | Shareholder Communications | $ - | | | | | |
| 32 | | Total Corporate Visibility Expenses | $ - | $ - | WS | 0.00% | $ - | |
| 33 | | Total A&G Expense | | $ - | | | $ - | |

**Notes:**

None of the following expenses shall be recovered directly or indirectly through the formula rate:

**A.** Industry association dues (*e.g.*, EEI and EPRI).

**B.** The following charges to Account 930.2: nuclear power research expenses, miscellaneous general expenses related to Wolf Creek Nuclear Generating Station; Nuclear Energy Institute fees, assessments and other costs; and any other nuclear-related expenses.

**C.** Other experimental and general research expenditures (other than those related to transmission which shall be directly assigned to transmission).

**D.** Expenses to Maintain Corporate Visibility (except such costs related to regulatory, reporting, compliance, and shareholder communications).

**E.** Regulatory Commission expenses, other than FERC transmission-related dockets which shall be directly assigned to transmission. Transmission-related dockets shall not include transmission-related rulemakings or notices of inquiry proceedings, except those related to siting or reliability.

**Evergy Missouri West Inc.**



**A-11 13 Month Average Balance and BOY-EOY Average Balances**

**I. Plant Additions & Accumulated Depreciation Balances**

| Line No. | | Gross Plant (Note 1) | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | End. Balance Dec Y1 | Jan Y2 | Feb Y2 | Mar Y2 | April Y2 | May Y2 | June Y2 | July Y2 | Aug Y2 | Sept Y2 | Oct Y2 | Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
| 1 | **Production-Steam** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | **Production-Other** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 3 | **Transmission** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 4 | **Distribution** | | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 5 | **General Plant** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 6 | **Intangible & Other** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 7 | **Total** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Accumulated Depreciation and Amortization**

| | | End. Balance Dec Y1 | - Jan Y2 | - Feb Y2 | - Mar Y2 | - April Y2 | - May Y2 | - June Y2 | - July Y2 | - Aug Y2 | - Sept Y2 | - Oct Y2 | - Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | **Production-Steam** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | **Production-Other** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 10 | **Transmission** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 11 | **Distribution** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 12 | **General Plant** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 13 | **Intangible & Other** | - | - | - | - | - | - | - | - | - | - | - | - | - | 0 |
| 14 | **Total** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Net Plant** (Gross Plant less Accumulated Depreciation and Amortization)

| | End. Balance Dec Y1 | - Jan Y2 | - Feb Y2 | - Mar Y2 | - April Y2 | - May Y2 | - June Y2 | - July Y2 | - Aug Y2 | - Sept Y2 | - Oct Y2 | - Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | **Production-Steam** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | **Production-Other** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 17 | **Transmission** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 18 | **Distribution** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | **General Plant** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 20 | **Intangible & Other** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 21 | **Total** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Notes:
1. When calculating the "Actual Gross Revenue Requirement", use the actual 13 month account balances for the year being trued-up.

**Evergy Missouri West Inc.**



**A-11 13 Month Average Balance and BOY-EOY Average Balances**

**II. Adjustments to Rate Base**

| | | | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance | 100% Non-Trans. Related | 100% Trans. Related | Plant Related | Labor Related |
|---|---|---|---|---|---|---|---|---|---|
| 22 | **Reserve Funds (Non-Escrowed) (Note A)** | | (112.28.d) | (112.28.c) | | | | | |
| 23 | Account 228.2 -Res. for Inj. & Damages | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23a | | | | | $ - | - | - | - | - |
| 23b | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23c | | | | | | | | | |
| 23d | | | | **Wages & Salary Allocator** | | | | | 0.000 % |

| | | | | | |
|---|---|---|---|---|---|
| | **Gross Plant Allocator** | | 0.00 0% | | |
| 23e | **Direct Assign Allocator** | 100.0 00% | | | |
| 23f | | | | | |
| 23g | | $ - | $ - | $ - | $ - |

Note: Each non-escrowed reserve fund will be allocated based on Non-transmission, 100% Transmission, Plant Allocator, or Wages & Salary Allocator, as appropriate.

| | | End. Balance Dec Y1 | - Jan Y2 | - Feb Y2 | - Mar Y2 | - April Y2 | - May Y2 | - June Y2 | - July Y2 | - Aug Y2 | - Sept Y2 | - Oct Y2 | - Nov Y2 | End. Balance Dec Y2 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24 | **Unamortized Abandonned Trans. Plt.** | | | | | | | | | | | | | | |
| 25 | Account 182.1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | | | | | | | | | | | | | | | |
| 27 | **CWIP Regulatory Liability for Transmission** | | | | | | | | | | | | | | |
| 28 | Account 254 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | | | | | | | | | | | | | | | |
| 30 | **Land Held for Future Use** | | | | | | | | | | | | | | |
| 31 | Trans. Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**III. Working Capital -Material & Supplies, Stores Expense and Prepayments**

| | BOY Balance | EOY Balance | Average |
|---|---|---|---|

| | | Relevant Year | Relevant Year | Balance |
|---|---|---|---|---|
| 32 | **Material & Supplies** | (227, x, b) | (227, x, c) | |
| 33 | Production O&M | $ - | $ - | $ - |
| 34 | Transmission O&M | - | - | - |
| 35 | Distribution O&M | - | - | - |
| | | | | |
| 36 | Prod. Construction | - | - | - |
| 37 | Trans. Construction | - | - | - |
| 38 | Dist. Construction | - | - | - |
| 39 | Total Material & Supplies | $ - | $ - | $ - |

| | | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance |
|---|---|---|---|---|
| 40 | **Stores Expense** | (227.16.d) | (227.16.c) | |
| 41 | Total Stores Expense | $ - | $ - | $ - |

| | | BOY Balance Relevant Year | EOY Balance Relevant Year | Average Balance |
|---|---|---|---|---|
| 42 | **Prepayments** | (111.57.d) | (111.57.c) | |
| 43 | Total Prepayments | $ - | $ - | $ - |

**Worksheet TU - True-up Adjustment and Timeline**

**Evergy Missouri West Inc.**



**Timeline**

| Step | Month | Year | Action |
|---|---|---|---|
| 1 | | Year 0 | EMW populates the formula rate using projected costs for Year 1 |
| 2 | | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Sept | Year 1 | -EMW populates the formula rate using projected costs for Year 2 |
| 5 | Sept | Year 1 | Post results of Step 4 |
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | Jun | Year 2 | -EMW populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |
| 9 | Jun | Year 2 | Post results from Step 7 and Step 8 |
| 10 | Sept | Year 2 | -EMW populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |
| 11 | Sept | Year 2 | Post results of Step 10 |

**Reconciliation details**

| | | | |
|---|---|---|---|
| 1 | | Year 0 | -EMW populates the formula rate using projected costs for Year 1 |
| 2 | | Year 0 | Post results of Step 1 |
| 3 | Jan | Year 1 | Results of Step 2 go into effect. |
| 4 | Sept | Year 1 | EMW populates the formula rate using projected costs for Year 2 |
| 5 | Sept | Year 1 | Post results of Step 4 |
| 6 | Jan | Year 2 | Results of Step 5 go into effect. |
| 7 | Jun | Year 2 | EMW populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |

| | | BP F Rev Req | Balance Portfolio Rev Req | ITP / Priority Project 1 Rev Req. | ITP / Priority Project 2 Rev Req. | Zonal Rev Req | Total Rev. Req. |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| 8a | Actual Revenue Requirements from Step 7 | $ - | $ - | $ - | $ - | $ - | $ - |
| 8b | Projected Revenue Requirements from Step 1 (Note C) | - | - | - | - | - | $ - |
| 8c | True-up Amount (before interest) | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| 9 | Jun | Year 2 | Post results from Step 7 and Step 8 |
| 10 | Sept | Year 2 | EMW populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |



**Interest Calculation**

| | Short term Interest Rate (Notes A and F) | | Avg. Ann Short Term Int |
|---|---|---|---|
| 11 | Other Interest Exp.(Notes, p.117) | (Note A) | - |
| 12 | Notes Payable (Acct. 231-daily balances wksht.) | (Note A) | - |
| 13 | No. of Months | | - |
| 14 | Annual Short-term Int Rate | (line 11 / line 12 ) | 0.0000 % |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **FERC Quarterly Interest Rate** | | | | | | | |
| 15 | Qtr 3 (Previous Year) | | | 0.0000 % | | | | |
| 16 | Qtr 4 (Previous Year) | | | 0.0000 % | | | | |
| 17 | Qtr 1 (Current Year) | | | 0.0000 % | | | | |
| 18 | Qtr 2 (Current Year) | | | 0.0000 % | | | | |
| 19 | Average of the last 4 quarters | (Lines 15-18 / 4) | | 0.0000 % | | | | |
| 20 | Interest Rate Used for True-up adjustment (Note B) | | 0.0000 % | 0.0000 % | 0.0000 % | 0.0000 % | 0.0000% | |

| | | **BPF True-Up** | **Balance Portfolio Rev Req** | **ITP / Priority Project 1 Rev Req.** | **ITP / Priority Project 2 Rev Req.** | **Zonal Rev Req** | **Total True-up** |
|---|---|---|---|---|---|---|---|
| | | **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | **(6)** |
| 21 | True-Up Amount (line 8c) (Note D) | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | Interest on True-up Amount ([Average Interest Rate / 12 months]*24 months] | - | - | - | - | - | - |
| 23 | **True-up Adjustment (Note E)** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

**Note:**

A The short term interest rate is based on a 12 month rate ending June of the year in which the Annual Update is prepared, with denominator calculated using daily balances and the numerator based on Form 3Q.

B Use the lower of line 14 and line 19 if the True-up Amount (line 21) is greater than or equal to zero. Use line 19 if the True-up amount (line 21) is less than zero.

C Enter the Projected Revenue Requirement for the Actual period without a true-up adjustment plus any adjustments, either positive or negative, resulting from corrections of prior years.

D If the annual update is for a partial year, not 12 months, then the amount on line 21 shall be prorated to represent the number of months in the partial year.

E If the annual update is for a partial year, monthly interest will be multiplied by 18 plus one-half of the months in the partial year.

F The numerator and denominator of the short-term interest rate calculation will reflect consistent debt components.

**RTO Project Summary - Summary of RTO Directed Projects**



**Evergy Missouri West Inc.**

**Revenue Requirement of SPP Projects included in KCP&L-EMW's Projected Revenue Requirements (NoteD):**

For the 12 months ended - December 31, 20XX

| | | | Development of Applicable Carrying Charges | | | |
|---|---|---|---|---|---|---|
| | | | Base Plan Projects | Balanced Portfolio Projects | ITP /Priority Project - 1 | ITP /Priority Project -2 |
| 1 | Projected 12 mo avg non-incentive depr. exp. | (P-1, page 2, line 28) | $ - | $ - | $ - | $ - |
| 2 | Total Allocated Transmission-Related Plant in Service | (Projected Gross Rev Req, page 1, line 1) | $ - | $ - | $ - | $ - |
| 3 | Less: Gross Plant - Incentive Projects | (Projected Gross Rev Req, page 4, line 34-37) | - | - | - | - |
| 4 | Total Non-incentive Transmission-Related Plant in Service | (line 2 - line 3) | $ - | $ - | $ - | $ - |
| 5 | Rate Base Adjustments | (Projected Gross Rev Req, page 1, line 18) | $ - | $ - | $ - | $ - |
| 6 | Projected 13 mo. Avg. Non-incentive Gross Plant | (P-1, page 2, line 29) | - | - | - | - |
| | Net Transmission Plant | (Projected Gross Rev Req, page 1, line 9) | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 7 | | | - | | - | | - | - |
| 8 | Non Incentive Net Plant(deduct Incentive Plt, as applicable) | (line 7 - Incentive Net Plt) | - | | - | | - | - |
| 9 | O&M Expenses | (Projected Gross Rev Req, page 2, line 7) | - | | - | | - | - |
| 10 | Revenue Credits (specific SPP project type) | (Projected Net Rev Req, page 1, line 9-12) | - | | - | | - | - |
| 11 | Other Taxes | (Projected Gross Rev Req, page 2, line 18) | - | | - | | - | - |
| 12 | Effective Tax Rate | (Projected Gross Rev Req.: Page 2, Line 20) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 13 | Income Taxes | (Projected Gross Rev Req, page 2, line 25) | - | | - | | - | - |
| 14 | Effective Tax Rate for Incentive Adder | (Wksht A-9, p.1, Summary, lines 5, 13, 16, & 20) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 15 | Incentive Net Plant | (Proj Gross Rev Req, p.4, line 34 thru 37) | - | | - | | - | - |
| 16 | True-up Amount | (TU, page 1, line 23) | $ - | | $ - | | $ - | $ - |
| 17 | Rate Base Adjustments as a Percentage of Net Plant | (line 5 / line 7) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 18 | O&M Expenses as a Percentage of Net Plant | (line 9 / line 7) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 19 | Ratio of Revenue Credits to Actual Projects Revenue | (line 10 / line T1 below) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 20 | Other Taxes as a Percentage of Net Plant | (line 11 / line 7) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 21 | Return as a Percentage of Net Plant | (Proj Gross Rev Req, p.4, line 21) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 22 | Income Taxes as a Percentage of Net Plant | (line 13 / line 7) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 23 | Ratio of Common Stock to Total Debt | (Proj Gross Rev Req, p.4, line 20) | | 0.00% | | 0.00% | 0.00% | 0.00% |
| 24 | Ratio of True-up amount to Actual Projects Revenue | (line 16 / line T1 below) | | 0.00% | | 0.00% | 0.00% | 0.00% |

For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any BPF project approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each BPF project.

| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Dep Expen** | **Rev. Req/ o Tr** | **True-up Adjus** | **Gross Rev Requi** | **Rev Requi Credi** | **Net Rev Requi** |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | se | ue-up | tment | rement | ts | rement |
| **Actual Projects (Inputs from Worksheet A-7)** | | | **(a - b)** | **(line 1 / line 6)** | **1.5 * (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f + k)*i +(f*j)** | **(I - Adder) * line 12 + Adder * line 14** | **(e / 1.5)** | **(g + h + l + m + n)** | **(o * line 24)** | **(o + p)** | **(o * line 19)** | **(q + r)** |
| 1 | $ - | $ - | $ - | 0.0000% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | $ - | $ - | $ - | 0.0000% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | $ | $ | $ | 0.00 | $ | $ | $ | $ | 0.00 | 0.00 | $ | $ | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | 00% | - | - | - | - | % | % | - | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | | | | | | | | | | | | | | | | | | | |
| T1 | **Total of Actual Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Accum Depr | Projected Net Plant | O&M Expenses | Other Taxes | Non-Incentive Return | Weighted Return Adder | CWIP Balance | Total Return | Income Taxes | Projected Dep Expense | Rev. Req w/o True-up | True-up Adjustment | Revenue Requirement | Credits | Net Revenue Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | (a - b) | | (Worksheet P-4) | (a - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicab | (P-1 as applicable) | (f + k) *i | (I - Ad | (P - 4 | (g + h | zero | (o + p | zero | (q + r |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | **le)** | | **+(f*j)** | **der)*line12+Adder*line14** | | **+l+m+n)** | | | **)** | | **)** |
| | **Projected projects (Inputs from Worksheet P-4)** | | | | | | | | | | | | | | | | | | | | | |
| 2010-4 | 1 | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | $ - | $ - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T2 | **Total of Projected Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total (lines T1 +** | $ | $ | $ | | $ | $ | $ | $ | | | $ | | $ | | | | | | | | |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **T2)** | - | - | - | - | - | - | - | - | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |





**Balanced Portfolio Projects**
For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any Balance Portfolio Projects approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each Balance Portfolio Projects.

| a | b | c | d | e | f | g | h | i | j | k | l | m | n | O | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Plant in** | **Accum** | **Actual Net** | **Depreciati** | **Projected** | **Project e** | **O&M** | **Other** | **Non-Incce** | **Weighted** | **CWIP** | **Total** | **Income** | **Project e** | **Rev. Req** | **True-up** | **Gross Revenue** | **Revenue** | **Net Revenue** |

| Project ID | Project Description | Service | Depreciation | Plant | Rate | Accum Depr | Plant Net | Expenses | Taxes | Return | Return Adder | Balance | Return | Taxes | dDepr Expense | w/o True-up | Adjustment | Requirement | Credits | Requirement |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (line 16) | | (a - b) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f + k) * i + (f * j) | (I - Adder)*line 12 + Adder *line 14 | (e / 1.5) | (g+h+l+m+n) | (o * line 24) | (o + p) | (o * line 19) | (q + r) |
| | **Actual Projects (Inputs from Worksheet A-7)** | | | | | | | | | | | | | | | | | | | |
| 20xx-xx | P.xx | Project 1 | $ - | $ - | $ - | 0.000% | $ - | $ - | $ - | $ - | 0.000% | 0.0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xx | Project 2 | $ - | $ - | $ - | 0.000 | $ - | $ - | $ - | $ - | 0.000% | 0.0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| x | | | | | % | | | | | | | | | | | | | | | |
| 2 | | | | | 0. | | | | | | | | | | | | | | | |
| 0 | | | | | 0 | | | | | 0 | | | | | | | | | | |
| x | | | | | 0 | | | | | . | | | | | | | | | | |
| x | | | | | 0 | | | | | 0 | | | | | | | | | | |
| - | P.x | $ | $ | $ | 0 | $ | $ | $ | $ | 0 | 0.0 | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| x | xx | - | - | - | % | - | - | - | - | % | 0% | - | - | - | - | - | - | - | - | - |
| T 1 | **Total of Actual Non-Incentive Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Dep Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | (a - b) | | (Worksheet P-4) | (a - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f + k) * i + | (I - Adder)*line 12 | (P - 4) | (g+h+l+m+n) | zero | (o + p) | zero | (q + r) |

| | | | | | | | | | | | | | | (f * j) | + Adder *line 14 | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Projected projects (Inputs from Worksheet P-4)** | | | | | | | | | | | | | | | | | | | | | |
| 20xx-xx | P.xx | Project 1 | $ - | | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 20xx-xx | P.xx | Project 2 | $ - | | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 20xx-xx | | | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| T2 | **Total of Projected Non-Incentive Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| T3 | **Total Non-Incentive Projects (lines T2 + T3)** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |

**ITP/Priority Projects-1**





For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any ITP/Priority Projects approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each ITP/Priority Projects-1.

| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project ID** | **Project Description** | **Plant in Service** | **Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Gross Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
| | | | | **(a - b)** | **(line 1 / line 6)** | **1.5 * (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)* i+(f *j)** | **(I - Adder)*line 12 + Add** | **(e / 1.5)** | **(g+h+l+m+n)** | **(o * line 24)** | **(o + p)** | **(o * line 19)** | **(q + r)** |
| **Actual Projects (Inputs from** | | | | | | | | | | | | | | | | | | | | |

**Worksheet A-7)** **er*line 14**

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20xx-x | P.xxx | Project 1 | $ - | $ - | $ - | 0.0000 % | $ - | $ - | $ - | $ - | 0.00% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xxx | Project 2 | $ - | $ - | $ - | 0.0000 % | $ - | $ - | $ - | $ - | 0.00% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | P.xxx | | $ - | $ - | $ - | 0.0000 % | $ - | $ - | $ - | $ - | 0.00% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T1 | **Total of Actual Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Projected** | | | | **(a - b)** | | **(Worksheet P-4)** | **(a - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)*i+(f*j)** | **(I - Adder)*line 12 +** | **(P-4)** | **(g+h+l+m+n)** | **zero** | **(o + p)** | **zero** | **(q + r)** |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **projects (Inputs from Worksheet P-4)** | | | | | | | | | | | | | **Adder*line 14** | | | | | | | |
| 20xx-xx | P.xxx | Project 1 | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-xx | P.xxx | Project 2 | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20xx-x | | | $ - | - | $ - | 0.00% | $ - | $ - | $ - | $ - | 0.00% | 0.00% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T2 | **Total of Projected Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total (lines T1 + T2)** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**ITP/Priority Projects -2**

For the 12 months ended - December 31, 20XX

Note A: All line references are to the "RTO Project Summary" worksheet, page 1.
Note B: The depreciation rate is calculated by: line 1/line 6.
Note C: To be completed with any ITP/Priority Projects approved by the Southwest Power Pool.
Note D: This tab shows the amount in column **s** that SPP is required to recover for each ITP/Priority Project-2.

| | | | a | b | c | d | e | f | g | h | i | j | k | L | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Project ID** | **Project Description** | **Plant in Service** | **Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Gross Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
| | **Actual Projects (Inputs from Worksheet A-7)** | | | | **(a - b)** | **(line 1 / line 6)** | **1.5* (a * d)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k) *i+(f *j)** | **(I - Adder)*line 12 + Adder*line 14** | **(e / 1.5)** | **(g+h +l+m +n)** | **(o * line 24)** | **(o + p)** | **(o * line 19)** | **(q + r)** |
| 20 | P.x | Pr | $ | $ | $ | 0.000 | $ | $ | $ | $ | 0.0 | 0.00 | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| xx | xx | oje | - | - | - | 0% | - | - | - | - | 0% | % | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -x | | ct 1 Pr oje | | | | | | | | | | | | | | | | | | |
| 20 xx -x | P.x xx | ct 2 | $ - | $ - | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.0 0% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 xx -x | P.x xx | | $ - | $ - | $ - | 0.000 0% | $ - | $ - | $ - | $ - | 0.0 0% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T 1 | **Total of Actual Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** | **Revenue Credits** | **Net Revenue Requirement** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | **(a - b)** | | **(Worksheet P-4)** | **(a - b - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k) *i+(f *j)** | **(I - Adder)*line 12 + Adder*line 14** | **(P-4)** | **(g+h +l+m +n)** | **zero** | **(o + p)** | **zero** | **(q + r)** |
| | **Projected projects (Inputs from Worksheet P-4)** | | | | | | | | | | | | | | | | | | | | |
| 20 xx -x | P.x xx | Pr oje ct 1 | $ - | - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 20 xx | P.x xx | Pr oje | $ - | - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -x | ct 2 | | | | | | | | | | | | | | | | | | | |
| 20xx-xx | P.x xx | $ - | - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.00 % | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | $ - | | | | | | | |
| T2 | **Total of Projected Projects** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total (lines T1 + T2)** | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

## Sponsor Funded Project Summary

**Revenue Requirement for Sponsor Funded Projects (SFP) included in EMW's Projected Revenue Requirements**

For the 12 months ended - December 31, 20XX



| | | | **Development of Applicable Carrying Charges** |
|---|---|---|---|
| | | | $ |
| 1 | Projected 12 mo avg non-incentive depr. exp. | (P-1, page 2, line 28) | - |
| 2 | Total Allocated Transmission-Related Plant in Service | (Projected Gross Rev Req, page 1, line 1) | $ - |
| 3 | Less: Gross Plant - Incentive Projects | (Projected Gross Rev Req, page 4, line 38) | - |
| 4 | Total Non-incentive Transmission-Related Plant in Service | (line 2 - line 3) | $ - |

| | | | $ | |
|---|---|---|---|---|
| 5 | Rate Base Adjustments | (Projected Gross Rev Req, page 1, line 18) | - | |
| 6 | Projected 13 mo. Avg. Non-incentive Gross Plant | (P-1, page 2, line 29) | - | |
| 7 | Net Transmission Plant | (Projected Gross Rev Req, page 1, line 9) | - | |
| 8 | Non Incentive Net Plant (deduct Incentive Plt, as applicable) | (line 7 - Net Incentive Plt) | - | |
| 9 | O&M Expenses | (Projected Gross Rev Req, page 2, line 7) | - | |
| 10 | Revenue Credits (only SFP) | (Projected Net Rev Req, page 1) | - | |
| 11 | Other Taxes | (Projected Gross Rev Req, page 2, line 18) | - | |
| 12 | Effective Tax Rate | (Projected Gross Rev Req.: Page 2, Line 20) | | 0.00% |
| 13 | Income Taxes | (Projected Gross Rev Req, page 2, line 25) | - | |
| 14 | Effective Tax Rate for Incentive Adder | (Wksht A-9, p.1, Summary, line 9) | | 0.00% |
| 15 | Incentive Net Plant | (Proj Gross Rev Req, p.4, line 38) | - | |
| 16 | True-up Amount | | | |
| 17 | Rate Base Adjustments as a Percentage of Net Plant | (line 5 / line 7) | | 0.00% |
| 18 | O&M Expenses as a Percentage of Net Plant | (line 9 / line 7) | | 0.00% |
| 19 | Hold for Future Use | | | |
| 20 | Other Taxes as a Percentage of Net Plant | (line 11 / line 7) | | 0.00% |
| 21 | Return as a Percentage of Net Plant | (Proj Gross Rev Req, p.4, line 21) | | 0.00% |
| 22 | Income Taxes as a Percentage of Net Plant | (line 13 / line 7) | | 0.00% |
| 23 | Ratio of Common Stock to Total Debt | (Projected Gross Rev Req, p. 4, line 20) | | 0.00% |
| 24 | Ratio of True-up amount to Actual Projects Revenue | (line 16a / line T1 below) | | 0.00% |

**Sponsor Funded Project Summary**





**Revenue Requirement for Sponsor Funded Projects (SFP) included in EMW's Projected Revenue Requirements**

For the 12 months ended - December 31, 20XX

Note A: All line references are to "Spon Project Sumry" worksheet, page 1.

Note B: The depreciation rate is calculated by: line 1/line 6.

Note C: To be completed with any projects sponsored by the host transmission owner.

| | | a | b | c | d | e | f | g | h | i | j | k | l | m | n | o | p | q | r | s |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project ID | Project Description | Plant in Service | Actual Accum Depreciation | Actual Net Plant | Depreciation Rate | Projected Accum Depr | Projected Net Plant | O & M Expenses | Other Taxes | Non-Incentive Return | Weighted Return Adder | CWIP Balance | Total Return | Income Taxes | Projected Depr Expense | Rev. Req w/o True-up | True-up Adjustment | Gross Revenue Requirement | Revenue Credits | Net Revenue Requirement |
| | | | | (a - b) | (line 1 / line 6) | 1.5 * (a * d) | (a - b - e) | (f * line 18) | (f * line 20) | (line 21) | (P-1 as applicable) | (P-1 as applicable) | (f+k)*i +(f *j) | (I - Adder)*line 12 + Add | (e / 1.5) | (g+h +l+ m+n ) | (o * line 24) | (o + p) | | (q + r) |
| **Actual Projects (Inputs from** | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Worksheet A-8)** | | | | | | | | | | | | | **er*line 14** | | | | | | | |
| 20xx-xx | P.xxx | Project 1 | $ - | $ - | $ - | 0.0000 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.0 0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 20xx-xx | P.xxx | Project 2 | $ - | $ - | $ - | 0.0000 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.0 0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 20xx-xx | P.xxx | . | $ - | $ - | $ - | 0.0000 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.0 0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| T1 | **Total of Actual Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| **Project ID** | **Project Description** | **Plant in Service** | **Actual Accum Depreciation** | **Actual Net Plant** | **Depreciation Rate** | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **Non-Incentive Return** | **Weighted Return Adder** | **CWIP Balance** | **Total Return** | **Income Taxes** | **Projected Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Revenue Requirement** | **Revenue Credits** | **Revenue Requirement** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **(a - b)** | | **(Worksheet P-5)** | **(a - e)** | **(f * line 18)** | **(f * line 20)** | **(line 21)** | **(P-1 as applicable)** | **(P-1 as applicable)** | **(f+k)*i +(f *j)** | **(I - Adder)*line 12 + Add** | **(P-5)** | **(g+h+l+m+n)** | **zero** | **(o + p)** | | **(q + r)** |
| | **Projected projects (Inputs from** | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Worksheet P-5)** | | | | | | | | | | | | | **er*li ne 14** | | | | | | | |
| 20xx-xx | P.xxx | Project 1 | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.0 0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 20xx-xx | P.xxx | Project 2 | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.0 0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 20xx-xx | P.xxx | | $ - | $ - | $ - | 0.00 % | $ - | $ - | $ - | $ - | 0.0 0% | 0.0 0% | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| T2 | **Total of Projected Projects** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| T3 | **Total (lines T1 + T2)** | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | | Rate Formula Template | | | | | |
| | | Utilizing FERC Form 1 Data | | | | | |
| | | Projected Net Revenue Requirements | | | | | |
| | | For the 12 months ended - December 31, 20XX | | | | Page 1 of 1 | |
| | | | | | | | |
| | | Evergy Missouri West Inc. | | | | | |
| | | (EMW) | | | | | |
| | | (1) | (2) | (3) | (4) | (5) | |

| Line No. | | | | | | Amount | |
|---|---|---|---|---|---|---|---|
| **A.** | **GROSS REVENUE REQUIREMENT** | (with Approved Incentives, if any) | | | | | |
| 1 | Total Transmission Facilities | (Projected Gross Rev Req, p.2, line 27) | | | | $ - | |
| | | | | | | | |
| 2 | Base Plan Gross Revenue Requirements | (Wksht. RTO, Base Plan Section, line T3 ) | $ - | | | | |
| 3 | Balanced Portfolio Gross Revenue Requirement | (Wksht. RTO, Balance Port. Section, line T3 ) | - | | | | |
| 4 | ITP/Priority Projects-1 Gross Revenue Requirement | (Wksht. RTO, ITP-1 Section, line T3 ) | - | | | | |
| 5 | ITP/Priority Projects-2 Gross Revenue Requirement | (Wksht. RTO, ITP-2 Section, line T3 ) | - | | | | |
| 6 | Sponsored Gross Revenue Requirements | (Wksht. SFP, line T3) | - | | | | |
| 7 | Total | (sum line 2 thru line 6) | | | | $ - | |
| | | | | | | | |
| 8 | Zonal Gross Revenue Requirement | ( line 1 minus line 7) | | | | $ - | |
| | | | | | | | |
| | **REVENUE CREDITS** | | | | | | |
| 9 | Base Plan Gross Revenue Credit | (Wksht P-2, line 16) | $ - | | | | |
| 10 | Balanced Portfolio Revenue Credit | (Wksht P-2, line 17) | - | | | | |
| 11 | ITP/Priority Projects-1 Revenue Credit | (Wksht P-2, line 18) | - | | | | |
| 12 | ITP/Priority Projects-2 Revenue Credit | (Wksht P-2, line 19) | - | | | | |
| 13 | Total | (sum line 9 thru line 12) | | $ - | | | |
| | | | | | | | |
| 14 | Zonal Gross Revenue Credit | (Wksht P-2, line 15) | | | | $ - | |
| | | | | | | | |
| | **NET REVENUE REQUIREMENT AFTER REVENUE CREDITS AND BEFORE TRUE-UP** | | | | | | |
| 15 | Base Plan Net Revenue Requirements | ( line 2 minus line 9) | $ | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | - | | | |
| 16 | Balanced Portfolio Net Revenue Requirement | ( line 3 minus line 10) | - | | | |
| 17 | ITP/Priority Projects-1 Net Revenue Requirement | ( line 4 minus line 11) | - | | | |
| 18 | ITP/Priority Projects-2 Net Revenue Requirement | ( line 5 minus line 12) | - | | | |
| 19 | Total | (sum line 15 thru line 18) | | $ - | | |
| | | | | | | |
| 20 | Zonal Net Revenue Requirement | ( Line 8 minus line 14) | | | $ - | |
| | | | | | | |
| | **TRUE-UP ADJUSTMENTS** | | | | | |
| 21 | Total Transmission Facilities | (Wksht TU, line 23) | | $ - | | |
| | | | | | | |
| 22 | Base Plan True-Up | (Wksht TU, line 23) | $ - | | | |
| 23 | Balanced Portfolio True-Up | (Wksht TU, line 23) | - | | | |
| 24 | ITP/Priority Projects-1 True-UP | (Wksht TU, line 23) | - | | | |
| 25 | ITP/Priority Projects-2 True-UP | (Wksht TU, line 23) | - | | | |
| 26 | Total | (sum line 22 thru line 25) | | $ - | | |
| | | | | | | |
| 27 | Zonal Net True-Up Revenue Requirement | ( line 21 minus line 26) | | | $ - | |
| | | | | | | |
| | **NET REVENUE REQUIREMENT** | | | | | |
| 28 | Base Plan Net Revenue Requirements | ( line 15 plus line 22) | $ - | | | |
| 29 | Balanced Portfolio Net Revenue Requirement | ( line 16 plus line 23) | - | | | |
| 30 | ITP/Priority Projects-1 Net Revenue Requirement | ( line 17 plus line 24) | - | | | |
| 31 | ITP/Priority Projects-2 Net Revenue Requirement | ( line 18 plus line 25) | - | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 32 | Total | (sum line 28 thru line 31) | | $ - | | |
| | | | | | | |
| 33 | Zonal Net Revenue Requirement | ( Line 20 plus line 27) | | | $ - | |
| | | | | | | |
| **B.** | **Point-to-Point Service** | | | | | |
| 34 | Projected EMW Zone 9 SPP Aver. 12-Mo. Peak Demand (Wksht P-3, line 15) | | | | - | MW |
| | | | | | | |
| 35 | Annual Point-to-Point Rate in $/MW - Year | ( Line 33 / line 34) | | | $ - | |
| 36 | Monthly Point-to-Point Rate in $/MW - Month | ( Line 35 / 12 months) | | | $ - | |
| 37 | Weekly Point-to-Point Rate in $/MW- Weekly | ( Line 35 / 52 weeks) | | | $ - | |
| 38 | Daily On-Peak Point-to-Point Rate in $/MW - Day | ( Line 35 / 260 days) | | | $ - | |
| 39 | Daily Off-Peak Point-to-Point Rate in $/MW - Day | ( Line 35 / 365 days) | | | $ - | |
| 40 | Hourly On-Peak Point-to-Point Rate in $/MW - Hour | ( Line 38 / 16 hours) | | | $ - | |
| 41 | Hourly Off-Peak Point-to-Point Rate in $/MW - Hour | ( Line 39 / 24 hours) | | | $ - | |
| | | | | | | |
| **C.** | **Facility Carrying Charge** | | | | | |
| 42 | Total Trans. Facilities Gross Rev. Req., without Incentives | (Line 21 + Projected Gross Rev Req, p.2, line 29) | | | $ - | |
| | | | | | | |
| 43 | Net Transmission Plant | ( Projected Gross Rev Req, p.1, line 9) | | | $ - | |
| | | | . | | | |
| 44 | Projected and Trued Up Facilities Carrying Charges | ( line 42 / line 43) | | | 0.0000% | |
| | | | | | | |
| 45 | Monthly Facility Carrying Charge | ( line 44 divided by 12 months) (Note 2) | | | 0.0000% | |
| **NOTES:** | | | | | | |
| | The Facility Carrying Charge and Monthly Facility Carrying Charge on Page 1, lines 44 and 45 are to be used to compute the revenue requirements for facilities directly assigned to a customer. | | | | | |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.
(EMW)



| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| Line No. | **RATE BASE:** | **Form No. 1 Page, Line, Col.** | **EMW** | **EMW Total** | **Allocator** | | **Transmission (4)*(6)** |
| | PLANT IN SERVICE | | | | | | |
| | | | $ | $ | | 0.0000 | $ |
| 1 | Transmission | (Wksht P-1, p.2 Line 29) | - | - | TP | 0 | - |
| | General | | | | | 0.0000 | |
| 2 | | (Act. Gross Rev Req, p.1, line 5) | - | - | W/S | 0 | - |
| | Intangible & Other | | | | | 0.0000 | |
| 3 | | (Act. Gross Rev Req, p.1, line 6) | - | - | W/S | 0 | - |
| | | | $ | $ | | | $ |
| 4 | TOTAL GROSS PLANT | (Sum Line 1 to Line 3) | - | - | | | - |
| | ACCUMULATED DEPRECIATION | | | | | | |
| | | | $ | $ | | 0.0000 | $ |
| 5 | Transmission | (Wksht P-1, p.2 Line 29) | - | - | DR | 0 | - |
| | General | | | | | 0.0000 | |
| 6 | | (Act. Gross Rev Req, p.1, line 12) | - | - | W/S | 0 | - |
| | | | | | | 0.0000 | |
| 7 | Intangible & Other | (Act. Gross Rev Req, p.1, line 13) | - | - | W/S | 0 | - |
| 8 | TOTAL ACCUM. | (Sum Line 5 to Line 7) | $ | $ | | | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | DEPRECIATION | | - | - | | | - |
| | NET PLANT IN SERVICE | | | | | | |
| | | | $ | $ | | | $ |
| 9 | Transmission | ( Line 1 less Line 5) | - | - | | | - |
| 10 | General | ( Line 2 less Line 6) | - | - | | | - |
| 11 | Intangible & Other | ( Line 3 less Line 7) | - | - | | | - |
| | | | $ | $ | | | $ |
| 12 | TOTAL NET PLANT | (Sum Line 9 to Line 11) | - | - | | | - |
| | ADJUSTMENTS TO RATE BASE | | | | | | |
| | Accumulated Deferred | | $ | $ | | 1.0000 | $ |
| 13 | Income Taxes | (Act. Gross Rev Req, p.1, line 23) | - | - | DA | 0 | - |
| 14 | Reserve Funds (Non-Escrowed) | (Act. Gross Rev Req, p.1, line 24) | - | - | DA | 1.0000 0 | - |
| 15 | Unamortized Abandoned Transmission Plant | (Act. Gross Rev Req, p.1, line 25 - Amortization) | - | - | DA | 1.0000 0 | - |
| 16 | CWIP Regulatory Liability for Transmission Proj. | (Act. Gross Rev Req, p.1, line 27) | - | - | DA | 1.0000 0 | - |
| 17 | CWIP for Incentive Transmission Projects | (Worksheet P-1, Line 34) | - | - | DA | 1.0000 0 | - |
| | | | $ | $ | | | $ |
| 18 | TOTAL ADJUSTMENTS | (Sum Line 13 to Line 17) | - | - | | | - |
| | LAND HELD FOR FUTURE | | $ | $ | | 1.0000 | $ |
| 19 | USE | (Act. Gross Rev Req, p.1, line 29) | - | - | DA | 0 | - |
| | WORKING CAPITAL | | | | | | |
| | | | $ | $ | | | $ |
| 20 | CWC | calculated (Note C) | - | - | | | - |
| 21 | Materials & Supplies | (Act. Gross Rev Req, p.1, line 31) | - | - | TP | 0.0000 0 | - |
| 22 | Stores Expense | (Act. Gross Rev Req, p.1, line 32) | - | - | W/S | 0.0000 0 | - |
| 23 | Prepayments (Account 165) | (Act. Gross Rev Req, p.1, line 33) | - | - | W/S | 0.0000 0 | - |
| 24 | TOTAL WORKING CAPITAL | (sum Line 21 to Line 23) | $ | $ | | | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | - | - | | | - |
| 25 | Rate Base | (sum Line 12, 18 , 19 & 24) | | | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
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For the 12 months ended - December 31, 20XX

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Evergy Missouri West Inc.

| Line No. | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| | | **Reference** | **EMW** | **EMW Total** | **Allocator** | | **Transmission (4)*(6)** |
| | **O&M** | | | | | | |
| | | | $ | $ | | | |
| 1 | Transmission | (Wksht P-2, Line 3) | - | - | | | |
| 2 | Less Account 561 | (Wksht P-2, Line 4) | - | - | | | |
| 3 | Less Account 565 | (Wksht P-2, Line 5) | - | - | | | |
| 3a | Less: Trans. Lease Payments & Facility Chge | (Wksht P-2, Line 5a) | - | - | | | |
| 4 | Total Transmission O&M | ( Line 1 less Line 2 , 3 & 3a) | - | - | TP | 0.0000 0 | $ - |
| | | | $ | $ | | 0.0000 | $ |
| 5 | A&G -Adjusted | (Wksht P-2, Line 6) | - | - | W/S | 0 | - |
| 5a | Less: Actual PBOP | ( A-10 (Act A&G) line 9 ) | - | - | W/S | 0.0000 0 | - |
| 5b | Plus: PBOP (Projected 2010) | (Actual Gross Rev Req, Page 5, Note R) | - | - | W/S | 0.0000 0 | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | 0.0000 | |
| 5c | Plus: Advertising -Safety | (Wksht P-2, Line 6a) | - | - | W/S | 0 | - |
| | Plus: Advertising - | | | | | 1.0000 | |
| 5d | Transmission | (Wksht P-2, Line 6b) | - | - | DA | 0 | - |
| | Plus: Research - | | | | | 1.0000 | |
| 5e | Transmission | (Wksht P-2, Line 6c) | - | - | DA | 0 | - |
| | Plus: Regulatory Exp - | | | | | 1.0000 | |
| 5f | Transmission | (Wksht P-2, Line 6d) | - | - | DA | 0 | - |
| | Plus: Corporate Visibility - | | | | | 0.0000 | |
| 5g | Transmission | (Wksht P-2, Line 6e) | - | - | W/S | 0 | - |
| | Transmission Lease | | | | | 1.0000 | |
| 6 | Payments & Facility Charges | (Wksht P-2, Line 7) | - | - | DA | 0 | - |
| | | ( Sum Lines 4, 5 & 5b thru 6, less | $ | $ | | | $ |
| 7 | TOTAL O&M | 5a) | - | - | | | - |
| | **DEPRECIATION EXPENSE** | | | | | | |
| | | | $ | $ | | 0.0000 | $ |
| 8 | Transmission | (Wksht P-1, p.2 Line 28) | - | - | TP | 0 | - |
| | | | | | | 0.0000 | |
| 9 | General | (Act. Gross Rev Req, p.2, line 9) | - | - | W/S | 0 | - |
| | Intangible & Other | | | | | 0.0000 | |
| 10 | | (Act. Gross Rev Req, p.2, line 10) | - | - | W/S | 0 | - |
| 11 | Amortization of Abandon Transmission Plant | (Act. Gross Rev Req, p.2, line 11) | - | - | DA | 1.0000 0 | - |
| | | | $ | $ | | | $ |
| 12 | TOTAL DEPRECIATION | (Sum Line 8 to Line 11) | - | - | | | - |
| | **TAXES OTHER THAN INCOME TAXES (Note G)** | | | | | | |
| | LABOR RELATED | | | | | | |
| | | | $ | $ | | 0.0000 | $ |
| 13 | Payroll | (Wksht P-2, Line 9) | - | - | W/S | 0 | - |
| | | | | | | 0.0000 | |
| 14 | Highway and vehicle | (Wksht P-2, Line 10) | - | - | W/S | 0 | - |
| | PLANT RELATED | | | | | | |
| | | | | | | 0.0000 | |
| 15 | Property | (Wksht P-2, Line 11) | - | - | GP | 0 | - |
| 16 | Gross Receipts | (Wksht P-2, Line 12) | - | - | NA | | - |
| 17 | Other | (Wksht P-2, Line 13) | | | GP | 0.0000 | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | - | - | | | 0 | - |
| | | | $ | $ | | | | $ |
| 18 | TOTAL OTHER TAXES | (Sum Line 13 to Line 17) | - | - | | | | - |
| | **INCOME TAXES** | | | | | | | |
| 19 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | (FIT, SIT & p are as given in Note H) | | 0.00% | | | | |
| 20 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | WCLTD=(page 5, line 21) | | 0.00% | | | | |
| 21 | GRCF = 1 / (1 - T) = (from line 23) | | | - | | | | |
| | | | $ | $ | | | | |
| 22 | Amortized Investment Tax Credit | (Act. Gross Rev Req, p.2, line 22) | - | - | | | | |
| *22 a* | ***(Excess)/Deficient Deferred Income Taxes*** | *(Act. Gross Rev Req, p.5, line 22a)* | *$* - | *$* - | | | | |
| 23 | Income Tax Calculation | (Line 20*(Line 25 of Page 1)*( Line 21 of Page 4)+Line 26 of page 4 ) | | | | NA | | $ - |
| 24 | ITC adjustment | ( Line 21 X Line 22) | | - | | NP = | 0.0000 0 | - |
| *24 a* | ***(Excess)/Deficient Deferred Income Tax Adjustment*** | *(Line 21 * line 22a)* | | - | | *DA* | *1.0000 0* | - |
| | | | | $ | | | | $ |
| 25 | Total Income Taxes | (Sum Line 23, 24, *& 24a*) | | - | | | | - |
| 26 | **RETURN** | ((Line 25 of Page 1)*( Line 21 of Page 4 ) + (Line 25 - Line 26) of page 4 ) | | | | NA | | $ - |
| 27 | **GROSS REV. REQ. WITH INCENTIVES** | (Sum line 7, 12, 18, 25 & 26 ) | | | | | | $ - |
| 28 | LESS: Gross Rev. Req. for Incentives | ( Line 40 of page 4 ) | | | | | | - |
| 29 | **GROSS REV. REQ. WITHOUT INCENTIVES** | ( Line 27 less Line 28) | | | | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

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Evergy Missouri West Inc.

**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMW | (4) EMW Total | (5) Allocator | (6) | (7) Transmission (4)*(6) |
|---|---|---|---|---|---|---|---|
| | **TRANSMISSION PLANT INCLUDED IN FORMULA** | | | | | | |
| | | | $ | $ | | | $ |
| 1 | Total transmission plant | ( Page 3, Line 7, col. 3) | - | - | | | - |
| 2 | Less: Net Substation, 34kV, & Radial Lines to Distr. Plt. | (Act. Gross Rev Req, p.3, line 2) | - | - | | | - |
| 3 | Less: Total GSU in Transmission Plant | (Act. Gross Rev Req, p.3, line 3) | - | - | | | - |
| 4 | Transmission plant included in rates | ( Line 1 less Line 2 & 3) | | | | | $ - |
| 5 | Percentage of transmission plant included in rates | Line 4 divided by Line 1) | | | TP= | 0.00000 | |
| | **GROSS AND NET PLANT ALLOCATORS** | | | | | | |
| | GROSS PLANT IN SERVICE | (ACTUAL HISTORICAL COST) | | | | | |
| | | | $ | $ | | | |
| 6 | Production | (Act. Gross Rev Req, p.3, line 6) | - | - | NA | | |
| 7 | Transmission | (Act. Gross Rev Req, p.3, line 7) | - | - | DA | 1.00000 | $ - |
| 8 | Less: Excluded Plant | (Act. Gross Rev Req, p.3, line 8) | | | | | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | Distribution | (Act. Gross Rev Req, p.3, line 9) | - | - | NA | | |
| | General & Intangible | | | | | 0.0000 | |
| 10 | | (Act. Gross Rev Req, p.3, line 10) | - | - | W/S | 0 | - |
| | | | $ | $ | | 0.0000 | $ |
| 11 | TOTAL GROSS PLANT | (sum Line 6, 7, 9 & 10 less line 8) | - | - | GP = | 0 | - |
| | ACCUMULATED DEPRECIATION | (ACTUAL HISTORICAL COST) | | | | | |
| | | | $ | $ | | | |
| 12 | Production | (Act. Gross Rev Req, p.3, line 12) | - | - | NA | | |
| | | | | | | 1.0000 | $ |
| 13 | Transmission | (Act. Gross Rev Req, p.3, line 13) | - | - | DA | 0 | - |
| 14 | Less: Excluded Plant | (Act. Gross Rev Req, p.3, line 14) | | | | | - |
| 15 | Distribution | (Act. Gross Rev Req, p.3, line 15) | - | - | NA | | |
| | | | | | | 0.0000 | |
| 16 | General & Intangible | (Act. Gross Rev Req, p.3, line 16) | - | - | W/S | 0 | - |
| | TOTAL ACCUM. | (sum Line 12, 13, 15 & 16 less line | $ | $ | | 0.0000 | $ |
| 17 | DEPRECIATION | 14) | - | - | DR = | 0 | - |
| | NET PLANT IN SERVICE | (ACTUAL HISTORICAL COST) | | | | | |
| | | | $ | $ | | | |
| 18 | Production | ( Line 6 less line 12) | - | - | | | |
| | | | | | | | $ |
| 19 | Transmission | ( Line 7 less line 13) | - | - | | | - |
| 20 | Less: Excluded Plant | ( Line 8 less line 14) | - | - | | | - |
| 21 | Distribution | ( Line 9 less line 15) | - | - | | | |
| 22 | General & Intangible | ( Line 10 less line 16) | - | - | | | - |
| | | (sum Line 18, 19, 21 & 22 less line | $ | $ | | 0.0000 | $ |
| 23 | TOTAL NET PLANT | 20) | - | - | NP = | 0 | - |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Gross Revenue Requirements
For the 12 months ended - December 31, 20XX

Projecte

Evergy Missouri West Inc.
**SUPPORTING CALCULATIONS**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) EMW | (4) EMW Total | (5) Allocator | (6) | (7) Transmission (5)*(6) |
|---|---|---|---|---|---|---|---|
| | **WAGES & SALARY ALLOCATOR (W&S)** | | | | | | |
| 1 | Production | (Act. Gross Rev Req, p.4, line 1) | | $ 0 - | | | |
| 2 | Transmission | (Act. Gross Rev Req, p.4, line 2) | | 0 - | TP= | 0.0000 0 | 0 |
| 3 | Distribution | (Act. Gross Rev Req, p.4, line 3) | | 0 - | | | |
| 4 | Other | (Act. Gross Rev Req, p.4, line 4) | | 0 - | | | |
| 5 | Total | (Sum Line 1 to Line 4) | | $ 0 - | | | $ - |
| 5a | Wage & Salary Allocator Calculation | (Col 7, Line 5 divided by Col 4, Line 5) | | | WS= | 0.0000 0 | |
| | **RETURN (R)** | | | | | | |
| 6 | Interest on Long-Term Debt | (Act. Gross Rev Req, p.4, line 6) | $ - | $ - | | | |
| 7 | Amort. of Debt Disc. and Expense | (Act. Gross Rev Req, p.4, line 7) | - | - | | | |
| 8 | Amortization of Loss on Reacquired Debt | (Act. Gross Rev Req, p.4, line 8) | - | - | | | |
| 9 | Less: Amort. of Premium on Debt-Credit | (Act. Gross Rev Req, p.4, line 9) | - | - | | | |
| 10 | Less: Amort. of Gain on Reacquired Debt-Credit | (Act. Gross Rev Req, p.4, line 10) | - | - | | | |
| 11 | Long Term Interest | (Sum Line 6 to 8, less 9 & 10) | $ - | $ - | | | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | $ | $ | | | | $ |
| 12 | **Preferred Dividends** | (Act. Gross Rev Req, p.4, line 12) | - | - | | | | - |
| | **Development of Common Stock:** | | | | | | | |
| | | | $ | $ | | | | $ |
| 13 | Proprietary Capital | (Act. Gross Rev Req, p.4, line 13) | - | - | | | | - |
| 14 | Less Preferred Stock | (Act. Gross Rev Req, p.4, line 14) | - | - | | | | - |
| 15 | Less Noncontrolling Interest | (Act. Gross Rev Req, p.4, line 15) | - | - | | | | - |
| 16 | Less: OCI Account 219 | (Act. Gross Rev Req, p.4, line 16) | - | - | | | | - |
| | | | $ | $ | | | | $ |
| 17 | Common Stock | ( Sum Line 13 Less 14, 15 & 16) | - | - | | | | - |
| | | | **EMW** | **EMW Total** | % | | (Note P) | Weighted |
| | | | $ | $ | | | | |
| 18 | Long Term Debt | (Act. Gross Rev Req, p.4, line 18) | - | - | 0.00% | WCLTD= | - | 0.0000 |
| 19 | Preferred Stock | (Act. Gross Rev Req, p.4, line 19) | - | - | 0.00% | | - | 0.0000 |
| 20 | Common Stock | ( Page 4, Line 17) | - | - | 0.00% | | 0.1110 | 0.0000 |
| | | | $ | $ | | | | |
| 21 | Total | (Sum Line 18 thru Line 20) | - | - | 0.00% | R= | | 0.00000 |
| | **GROSS REV. REQUIREMENT FOR INCENTIVE PROJECTS Plant Granted Incentive ROE Adder:** | | | | | | | |
| | | | $ | $ | | | | |
| 22 | Total Incentive Plant | (Wksht P-1, Page 1, Line 34) | - | - | | | | |
| 23 | Less: Total Accumulated Depreciation | (Wksht P-1, Page 1, Line 34) | - | - | | | | |
| | | | $ | $ | | | | |
| 24 | Net Incentive Plant | ( Line 22 less Line 23) | - | - | | | | |
| 25 | Incentive Return Including Taxes | (Wsht P-1, Page 1, Line 37) | | | | | $ - | |
| 26 | Taxes Included in Incentive Return | ( Line 25 times page 2, line 19) | | $ - | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Construction Work In Progress:** | | | | | | |
| 27 | Total CWIP | (Page 1, Line 17) | $ - | $ - | | | |
| 28 | Incentive Return Including Taxes | (Wksht P-1, Page 1, Line 36) | | | | $ - | |
| | **Abandoned Plant:** | | | | | | |
| 29 | Unamortized Abandoned Transmission Plant | (Page 1, Line 15) | $ - | | | | |
| 30 | Tax-Adjusted Return on Abandoned Plant | ( Line 21 X Line 29 X (1 + EIT)) | | $ - | | | |
| 31 | Amortization Expense for Abandoned Plant | (Page 2, Line 11) | | $ - | | | |
| 32 | Total Recovery for Abandoned Plant | (Sum line 30 thru line 31) | | | | $ - | |
| 33 | **TOTAL GROSS REV. REQUIREMENT FOR INCENTIVE PROJ.** | (Sum line 25 , 28 & 32) | | | | | $ - |
| | **INCENTIVE PLANT (excludes CWIP and Abandoned Plant)** | | **Gross Plant** | **Acum Depr** | **Net Plant** | | |
| 34 | Incentive Plant: Projected Base Plan Funded | (RTO Project Smry) | - | - | - | | |
| 35 | Incentive Plant: Projected Balanced Portfolio | (RTO Project Smry) | - | - | - | | |
| 36 | Incentive Plant: Projected ITP / Priority Project-1 | (RTO Project Smry) | - | - | - | | |
| 37 | Incentive Plant: Projected ITP / Priority Project-2 | (RTO Project Smry) | - | - | - | | |
| 38 | Incentive Plant: Projected Sponsor Funded | (RTO Project Smry) | - | - | - | | |
| 39 | Total Incentive Plant | (sum Line 34 to Line 38) | $ - | $ - | $ - | | |
| | Note: Incentive gross plant and accumulated depreciation values, if applicable, will be calculated by cell references to the RTO Project Smry and Spon Proj Smry tabs. | | | | | | |
| 40 | **Incentive Return** | (Wksht P-1, Page 1, Line 37) | | | | | $ - |

Rate Formula Template
Utilizing FERC Form 1 Data
Projected Gross Revenue Requirements

For the 12 months ended - December 31, 20XX



Evergy Missouri West Inc.

**NOTES**

A Beginning in 2009, included in page 256 notes of the FERC Form 1, the long term interest expense and preferred dividends and a 13-month average balance for long-term debt, preferred stock and common equity of Great Plains Energy will be provided. This information will be the reference for the capital structure and weighted cost of long term debt and preferred stock.

B (Hold future use)

Cash Working Capital assigned to transmission is one-eighth of

C O&M allocated to transmission at page 2, line 7, col. 7.

D (Hold future use)

E (Hold future use)

F (Hold future use)

G (Hold future use)

H The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "percentage of federal income tax deductible for state income tax purposes". Furthermore, a utility that elected to utilize amortization of tax credits against taxable income rather than book tax credits to Account 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 2, line 21). When FIT or SIT statutory tax rate changes take effect on other than a calendar year basis, the statutory rates to be used in the formula rate template shall be weighted averages for the calendar year determined by weighting the statutory tax rates by the number days each such tax rate was in effect during the calendar year for which the costs are being determined. KCMO Earnings Tax is not included in the calculation of the Composite State Income Tax Rate.

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00% | Federal Income Tax Rate |
| | SIT= | 0.00% | Composite State Income Tax Rate or Composite SIT |
| | p = | 0.00% | Percentage of federal income tax deductible for state income tax purposes |

The Composite State Income Tax Rate reflects the effective rate for each tax jurisdiction, as well as the Composite Portion of FIT Deduction in State Returns:

| | % of FIT | Portion of Fed Tax |
|---|---|---|

| | Apportionment Factor | Rate | Effective Rate | Deductible | Deductible = p |
|---|---|---|---|---|---|
| Missouri | 0.00% | 0.00% | 0.0000% | 0.00% | 0.0000% |
| Kansas | 0.00% | 0.00% | 0.0000% | 0.00% | 0.0000% |
| KS City | 0.00% | 0.00% | 0.0000% | 0.00% | 0.0000% |
| | Composite State Income Tax Rate | | 0.0000% | | |
| | Composite Portion of FIT Deduction for State Returns | | | | 0.0000% |

**ALLOCATION FACTORS**

| Line No. | Allocators | Description | Location of Calculation or First Use of Allocator |
|---|---|---|---|
| 1 | **TP** | Percentage of transmission plant included in rate base. | Page 3, line 5, col 6 |
| 2 | **W/S** | Percentage of transmission labor included in rates | Page 4, line 5a, col 6 |
| 3 | **DA** | Direct assignment | First used on page 1, line 13, col 6 |
| 4 | **GP** | Ratio of allocated transmission, general, & intangible plant to total gross plant. | Page 3, line 11, col 6 |
| 5 | **NA** | Not applicable for the transmission formula rate. | First used on page 2, line 16, col 6 |
| 6 | **NP** | Ratio of net transmission, general, & intangible plant to total net plant. | Page 3, line 23, col 6 |
| 7 | **DR** | For depreciation reserve, non-excluded facilities divided by total transmission (actual year) | Page 3, line 17, col 6 |

For the 12 months ended - December 31, 20XX

Evergy Missouri West Inc.
(EMW)

| Line No. | (1) | (2) Reference | (3) | (4) Amount |
|---|---|---|---|---|
| **A. Projected Schedule 1 ARR** | | | | |
| 1 | Total Load Dispatch & Scheduling | (Wksht P-2, Line 4 ) | | $ - |
| 2 | Less: Scheduling, System Control and Dispatch Services | (Actual Sch 1 Rev Req, line 2)*(Col. 5 / Col. 3, line 4 of P-2) | | - |
| 3 | Less: Transmission Service Studies | (Actual Sch 1 Rev Req, line 3)*(Col. 5 / Col. 3, line 4 of P-2) | | - |
| 4 | Less: Reliability, Planning & Standards Development Services | (Actual Sch 1 Rev Req, line 4)*(Col. 5 / Col. 3, line 4 of P-2) | | - |
| 5 | Total | (Line 1 less Line 2 thru Line 4) | | $ - |
| 6 | Less: PTP Service Credit | (Actual Sched 1 Rev Req, Line 6) | | - |
| 7 | Revenue Requirement for Schedule 1 | (Line 5 - Line 6) | | $ - |
| 8 | Prior Year True-Up | (Line 22 Below ) | | - |
| 9 | Net Schedule 1 Revenue Requirement for Zone | (Line 7 + Line 8) | | $ - |
| **B. Projected Schedule 1 Rate Calculations** | | | | |
| 10 | EMW 12-CP. Peak Demand | (Wksht P-3, line 15) | | - |
| 11 | Annual Point-to-Point Rate in $/MW - Year | (Line 9 / Line 10) | | $ - |
| 12 | Monthly Point-to-Point Rate $/MW - Month | (Line 11 / 12) | | $ - |
| 13 | Weekly Point-to-Point Rate $/MW - Week | (Line 11 / 52) | | $ - |

| | | | |
|---|---|---|---|
| 14 | Daily Point-to-Point Rate $/MW - Day | (Line 11 / 365) | $ - |
| 15 | Hourly Point-to-Point Rate $/MW - Hour | (Line 11 / 8760) | $ - |

**C. Schedule 1 True-UP**

| | | | |
|---|---|---|---|
| 16 | Actual Period Revenue Requirement | (Actual Sched 1 Rev Req, Line 7) | $ - |
| 17 | Projected Period Revenue Requirement | Schedule 1 Proj. for the Actual Period ( Note C) | - |
| 18 | Revenue Requirement True-Up | (Line 16 minus Line 17) | $ - |
| 19 | Interest on True-Up: | | |
| 20 | If Actual Revenue Req. > Projected Revenue Req. | Line 18 X (Min(ST I-Rate or FERC I-Rate)/12) X24 (Note A) | $ - |
| 21 | If Actual Revenue Req. < Projected Revenue Req. | Line 18 X (FERC Interest Rate/12) X 24 (Note B) | $ - |
| 22 | Total Annual True-Up Adjustment | (Sum Line 18 thru Line 21) | $ - |

**Notes:**

| | |
|---|---|
| A | The interest rate for an undercharge is the same rate used in the True -UP schedule. |
| B | The interest rate for an overcharge is the same rate used in the True -UP schedule. |
| C | Enter the Projected Revenue Requirement for the Actual period, pending the Actual data. |

# Worksheet P1 - Projected Transmissi

# on Plant

## Evergy Missouri West Inc.

For the 12 months ended - December 31, 20XX



| | | Total Incentive Plant | Project: Type: | Project: Type: | Project: Type: | Project: Type: | Project: Type: | Project: Type: |
|---|---|---|---|---|---|---|---|---|
| 1 | | | Base Plan Projects | Balanced Portfolio Project | ITP/Priority Project-1 | ITP/Priority Project-2 | Sponsored Project | |
| 2 | | | D | D | D | D | D | D |
| 3 | | | 0. | 0 | 0. | 0. | 0. | 0 |

| | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | **Total** | | | | | | Bal: Beginning Dep: Beginning Year: | - | | | | Bal: Beginning Dep: Beginning Year: | | | | | Bal: Beginning Dep: Beginning Year: | | | | | Bal: Beginning Dep: Beginning Year: | - | | | | Bal: Beginning Dep: Beginning Year: | | | | |
| 8 | **Year** | **CWIP (AA)** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Net Plant** | **CWIP (AA)** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Net Plant** | **CWIP (AA)** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Net Plant** | **CWIP (AA)** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Net Plant** | **CWIP (AA)** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Net Plant** | **CWIP (AA)** | **Gross Plant** | **Depreciation** | **Accum. Dep.** | **Net Plant** | **Year** |
| | | | $ | | | | | $ | | | | | $ | | | | | $ | | | | | $ | | | | | $ | | | | |

| | | |

| | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22 | Feb Y2 | $ - | $ - | $ - | $ - | Feb Y2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | Mar Y2 | $ - | $ - | $ - | $ - | Mar Y2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | Apr Y2 | $ - | $ - | $ - | $ - | Apr Y2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | May Y2 | $ - | $ - | $ - | $ - | May Y2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | Jun Y2 | $ - | $ - | $ - | $ - | Jun Y2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | Jul Y2 | $ - | $ - | $ - | $ - | Jul Y2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | Aug | $ - | $ - | $ - | $ - | Aug | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | |

| | g | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 35 | **Total Approved Project Incentives:** | | | | | | | | | | | | | | | | | |
| 36 | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - | **Tax-Adjusted Return on CWIP** | $ - |
| 37 | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - | **Tax-Adjusted Return on Incentive ROE Adder** | $ - |

# Worksheet P1 - Projected Transmission Plant

**For the 12 months ended - December 31, 20XX**



| **Total Incentive, non-incentive and SPP Plant Total Plant Additions** | | | | | **Projected Plant** | | | |
|---|---|---|---|---|---|---|---|---|
| **Year** | **Gross** | **Depreciat** | Accum. | | Projected Plant Additions | Plant in | Plant Depreciation Accrual | Plant Accumulated Depreciation |

| | | | Plant | ion | Dep. | | ( C ) | Service | (B) | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | 0.0000% | |
| 2 | | | | | | | | | | |
| 3 | | | | | | Plant Balances as of Dec 31, 20xx | | $ - | | $ - |
| | (a) | (b) | ( c) | (d) | (e) | (f) | (h) | (i) | (j) | (k) |
| | | | | | | - | | | | |
| | Jan | | $ | $ | $ | | $ | $ | $ | $ |
| 4 | Y1 | | - | - | - | Jan Y1 | - | - | - | - |
| | Feb | | $ | $ | $ | | $ | $ | $ | $ |
| 5 | Y1 | | - | - | - | Feb Y1 | - | - | - | - |
| | Mar | | $ | $ | $ | | $ | $ | $ | $ |
| 6 | Y1 | | - | - | - | Mar Y1 | - | - | - | - |
| | Apr | | $ | $ | $ | | $ | $ | $ | $ |
| 7 | Y1 | | - | - | - | Apr Y1 | - | - | - | - |
| | May | | $ | $ | $ | | $ | $ | $ | $ |
| 8 | Y1 | | - | - | - | May Y1 | - | - | - | - |
| | Jun | | $ | $ | $ | | $ | $ | $ | $ |
| 9 | Y1 | | - | - | - | Jun Y1 | - | - | - | - |
| 1 | Jul | | $ | $ | $ | | $ | $ | $ | $ |
| 0 | Y1 | | - | - | - | Jul Y1 | - | - | - | - |
| 1 | Aug | | $ | $ | $ | | $ | $ | $ | $ |
| 1 | Y1 | | - | - | - | Aug Y1 | - | - | - | - |
| 1 | Sept | | $ | $ | $ | | | $ | $ | $ |
| 2 | Y1 | | - | - | - | Sept Y1 | | - | - | - |
| 1 | Oct | | $ | $ | $ | | | $ | $ | $ |
| 3 | Y1 | | - | - | - | Oct Y1 | | - | - | - |
| 1 | Nov | | $ | $ | $ | | | $ | $ | $ |
| 4 | Y1 | | - | - | - | Nov Y1 | | - | - | - |
| 1 | Dec | | $ | $ | $ | | | $ | $ | $ |
| 5 | Y1 | | - | - | - | Dec Y1 | | - | - | - |
| 1 | Jan | | $ | $ | $ | | $ | $ | $ | $ |
| 6 | Y2 | | - | - | - | Jan Y2 | - | - | - | - |
| 1 | Feb | | $ | $ | $ | | | $ | $ | $ |
| 7 | Y2 | | - | - | - | Feb Y2 | | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Mar | | $ | $ | $ | | | $ | $ | $ |
| 8 | Y2 | | - | - | - | Mar Y2 | | - | - | - |
| 1 | Apr | | $ | $ | $ | | $ | $ | $ | $ |
| 9 | Y2 | | - | - | - | Apr Y2 | - | - | - | - |
| 2 | May | | $ | $ | $ | | | $ | $ | $ |
| 0 | Y2 | | - | - | - | May Y2 | | - | - | - |
| 2 | Jun | | $ | $ | $ | | | $ | $ | $ |
| 1 | Y2 | | - | - | - | Jun Y2 | | - | - | - |
| 2 | Jul | | $ | $ | $ | | $ | $ | $ | $ |
| 2 | Y2 | | - | - | - | Jul Y2 | - | - | - | - |
| 2 | Aug | | $ | $ | $ | | | $ | $ | $ |
| 3 | Y2 | | - | - | - | Aug Y2 | | - | - | - |
| 2 | Sept | | $ | $ | $ | | | $ | $ | $ |
| 4 | Y2 | | - | - | - | Sept Y2 | | - | - | - |
| 2 | Oct | | $ | $ | $ | | | $ | $ | $ |
| 5 | Y2 | | - | - | - | Oct Y2 | | - | - | - |
| 2 | Nov | | $ | $ | $ | | $ | $ | $ | $ |
| 6 | Y2 | | - | - | - | Nov Y2 | - | - | - | - |
| 2 | Dec | | $ | $ | $ | | $ | $ | $ | $ |
| 7 | Y2 | | - | - | - | Dec Y2 | - | - | - | - |
| | | | | | | | | | | |
| 2 | 12 Mon | | | $ | | | | | $ | |
| 8 | Tot | | | - | | 12-Month Depreciation Accrual | | | - | |
| 2 | 13 Mon | | $ | | $ | | | $ | | $ |
| 9 | Avg | | - | | - | 13-Month Aver. Balance | | - | | - |

Notes: **(A)** Project Incentives as provided by Commission approval.

**(B)** Actual transmission depreciation expense (Actual Gross Rev Req, page 2, line 8) divided by actual transmission plant in service (Actual Gross Rev Req, page 1, line 2) divided by 12 months.

**( C )** Projected transmission plant will include those projects in P-4 and P-5, as well as other transmission projects.

**Evergy Missouri West Inc.**
For the 12 months ended - December 31,
20XX

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|

| Line | | | EMW Actual Costs | Ratio of Expense To Net Plant in Service | Projected Costs |
|---|---|---|---|---|---|
| | | | | (Ratio of Cost to Total) | (Ratio * Proj. Net Plant) |
| 1 | Net Plant in Service | (Actual Gross Rev, p. 1, ln 21, col 7) | | $0 | |
| 2 | Projected Net Plant in Service | (Projected Gross Rev, p 1, ln 12) | | | $ - |
| | **Operation and Maintenance Expenses** | | | | |
| 3 | Transmission | (Actual Gross Rev, p2, ln 1) | $ - | - | - |
| 4 | Less Account 561 | (Actual Gross Rev, p2, ln 2) | - | - | - |
| 5 | Less Account 565 | (Actual Gross Rev, p2, ln 3) | - | - | - |
| 5a | Less: Trans. Lease Payments & Facility Charges | (Actual Gross Rev, p2, ln 3a) | - | | - |
| 6 | A&G -Adjusted per Wksht A-10 | (A-10 Act A&G, line 8) | - | - | - |
| 6a | Plus -Advertising Safety | (A-10 Act A&G, line 11) | - | - | - |
| 6b | Plus -Advertising -Transmission | (A-10 Act A&G, line 16) | - | - | - |
| 6c | Plus -Research Exp -Transmission | (A-10 Act A&G, line 21) | - | - | - |
| 6d | Plus -Regulatory Exp. -Transmission | (A-10 Act A&G, line 26) | - | - | - |
| 6e | Plus -Corporate Visibility -Transmission | (A-10 Act A&G, line 32) | - | - | - |
| 7 | Transmission Lease Payments & Facility Charges | (Actual Gross Rev, p2, ln 6) | - | | - |
| 8 | Projected O&M | (sum ln 3, 6 thru 7 less ln 4 thru 5a) | $ - | | $ - |
| | **Other Taxes** | | | | |
| | LABOR RELATED | | | | |

| | | | $ | | |
|---|---|---|---|---|---|
| 9 | Payroll | (Actual Gross Rev, p2, ln 13) | - | - | - |
| 10 | Highway and vehicle | (Actual Gross Rev, p2, ln 14) | - | - | - |
| | PLANT RELATED | | | - | - |
| 11 | Property (Note P) | (Actual Gross Rev, p2, ln 15) | - | - | - |
| 12 | Gross Receipts | (Actual Gross Rev, p2, ln 16) | - | - | - |
| 13 | Other | (Actual Gross Rev, p2, ln 17) | - | - | - |
| 14 | Projected Other Taxes | (sum line 9 thru line 13) | - | | - |

**P-2 Projected Revenue Credits**

| | | | $ |
|---|---|---|---|
| 15 | **Revenue Credits for Zonal Revenue Requirement** | (Wksht A-1, p.1, line 39) | - |
| | **Revenue Credits for RTO - Directed Projects** | | |
| 16 | Base Plan | (Wksht A-1,p 2,Line 14) | - |
| 17 | Balanced Portfolio | (Wksht A-1,p 2,Line 15) | - |
| 18 | ITP/Priority Projects-1 | (Wksht A-1,p 2,Line 16) | - |
| 19 | ITP/Priority Projects-2 | (Wksht A-1,p 2,Line 17) | - |
| 20 | Total Schedule 11 Gross Revenue Requirement | | $ - |

**Worksheet P3 - Projected Transmission Network Load**

**Evergy Missouri West Inc.**

For the 12 months ended - December 31, 20XX

Line No.

1 Transmission Network Load

| | a | b | c | d | e | f |
|---|---|---|---|---|---|---|
| | **Month** | **Monthly Transmission Network Load as Percentage of the Average Total Network Load of January thru August. (Worksheet A-2)** | **Average Monthly Transmission Network Load for January thru August (col e, line 2 thru line 9)** | **Estimated Monthly Transmission Network Load for September thru December ( b X c)** | **Actual Load for January through August** | **Projected Transmission Network Load** |
| 2 | January | | | | - | - |
| 3 | February | | | | - | - |
| 4 | March | | | | - | - |
| 5 | April | | | | - | - |
| 6 | May | | | | - | - |
| 7 | June | | | | - | - |
| 8 | July | | | | - | - |
| 9 | August | | | | - | - |
| 10 | September | 0.00% | - | - | | - |
| 11 | October | 0.00% | - | - | | - |
| 12 | November | 0.00% | - | - | | - |
| 13 | December | 0.00% | - | - | | - |
| 14 | Total | | | | | - |
| 15 | 12-CP | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | - |

Note: **Column b** is the monthly transmission network load for September, October, November and December as a percentage of the average of the monthly transmission network load values for January through August, based on monthly load values in Worksheet A-2.

**Column c** is average (January thru August) of monthly transmission network load in column e.

**Column f** contains actual load values for January-August and projected load values for September - December.

**Worksheet P4 - Projected Transmission Plant Related Projects - RTO Directed Projects**
**Evergy Missouri West Inc.**
For the 12 months ended -
December 31, 20XX



| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Total Base Plan Funded Projects** | | | | | **Project:** | 1 | | **Project:** | 2 | | **Project:** | 3 | | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | |
| 3 | | | | | | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | |
| 4 | | | | | | Beginning Bal: | $ - | | Beginning Bal: | $ - | | Beginning Bal: | | | |
| 5 | | **Total** | | | | Beginning Dep: | - | | Beginning Dep: | | | Beginning Dep: | | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | |
| 7 | | | | | | | | | $ - | | | $ - | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Feb Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Mar Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | Aug Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | Sept Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Nov Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 1 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Dec Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Jan Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | Feb Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Mar Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | Apr Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | Jun Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | Jul Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | Aug Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - |
| 2 | Sept Y2 | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 2 | | $ | $ | $ | Oct | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 9 | Oct Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Nov Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | 13 Mon | $ | $ | $ | | $ | | $ | $ | | $ | $ | | $ | $ | | $ |
| 2 | Avg | - | - | - | | - | | - | - | | - | - | | - | - | | - |
| 3 | | | | | | 12 Mon | | | | | 12 Mon | | | | 12 Mon | | |
| 3 | 12 Mon Depr Exp | | $0 | | | Depr Exp | | $0 | | | Depr Exp | | $0 | | Depr Exp | | $0 |

**Notes:**

**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.

**(B)** P-4 projects will be included in total projected transmission projects for P-1



| | **Total Balanced Portfolio Projects** | | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| 9 | Feb Y1 | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Mar Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Aug Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Sept Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Nov Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 1 | | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Dec Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | Jan Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | Feb Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | Mar Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | Apr Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | Jun Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | Jul Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | Aug Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | Sept Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |
| 2 | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | Oct Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 0 | Nov Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 1 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| 3 | 13 Mon | $ | $ | $ | | $ | | $ | $ | | $ | $ | | $ | $ | | |
| 2 | Avg | - | - | - | | - | | - | - | | - | - | | - | - | | |
| 3 | | | | | | 12 Mon | | | 12 Mon | | | | 12 Mon | | | | |
| 3 | 12 Mon Depr Exp | | $0 | | | Depr Exp | | $0 | Depr Exp | | | $0 | Depr Exp | | | $0 | |

**Notes:**
**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-4 projects will be included in total projected transmission projects for P-1

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Total ITP / Priority Projects-1** | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | |
| 2 | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000 % | (A) | Deprec. Rate: | 0.0000% | (A) |
| 4 | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Feb | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Mar | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 10 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 11 | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 12 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 13 | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 14 | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Aug | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 15 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Sept | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 16 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 17 | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Nov | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 18 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 19 | Dec Y1 | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Jan | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 20 | Jan Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Feb | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 21 | Feb Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Mar | $ | $ | $ | Mar | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 22 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Apr | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 23 | Apr Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | May | $ | $ | $ | May | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 24 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Jun | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 25 | Jun Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Jul | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 26 | Jul Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Aug | $ | $ | $ | Aug | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 27 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Sept | $ | $ | $ | Sept | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 28 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Oct | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 29 | Oct Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Nov | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 30 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 31 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | 13 Mon | $ | $ | $ | | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 32 | Avg | - | - | - | | | - | - | - | | - | - | - | | - | - | - |
| 33 | 12 Mon Depr Exp | | $0 | | | | 12 Mon Depr Exp | | $0 | | 12 Mon Depr Exp | | $0 | | 12 Mon Depr Exp | | $0 |

**Notes:**

**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.

**(B)** P-4 projects will be included in total projected transmission projects for P-1

**Total ITP / Priority Projects-2**

| | Total | | | | Project: 1 | | | Project: 2 | | | Project: 3 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| | | | | | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000 % | (A) | Deprec. Rate: | 0.0000% | (A) |
| | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| | | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | Year | Gross Plant | Accm. Deprec. | Net Plant | Year | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| | | | | | | $ - | | | $ - | | | $ - | | |
| | | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Jan Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Feb | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Mar | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Apr Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Jun Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Jul Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Aug | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Sept | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Oct Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Nov | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Dec Y1 | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | - | - | - | Y1 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Jan | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 20 | Jan Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Feb | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 21 | Feb Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Mar | $ | $ | $ | Mar | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 22 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Apr | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 23 | Apr Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | May | $ | $ | $ | May | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 24 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Jun | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 25 | Jun Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Jul | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 26 | Jul Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Aug | $ | $ | $ | Aug | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 27 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Sept | $ | $ | $ | Sept | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 28 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Oct | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 29 | Oct Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | Nov | $ | $ | $ | Nov | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 30 | Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | | $ | $ | $ | Dec | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 31 | Dec Y2 | - | - | - | Y2 | | - | - | - | | - | - | - | | - | - | - |
| | 13 Mon | $ | $ | $ | | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 32 | Avg | - | - | - | | | - | - | - | | - | - | - | | - | - | - |
| 33 | 12 Mon Depr Exp | | $0 | | | | 12 Mon Depr Exp | | $0 | | 12 Mon Depr Exp | | $0 | | 12 Mon Depr Exp | | $0 |

**Notes:**
**(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-4 projects will be included in total projected transmission projects for P-1

**Worksheet P5 - Projected Transmission Plant Related to Sponsored Projects**
**Evergy Missouri West Inc.**
For the 12 months ended -
December 31, 20XX



| | | Total Sponsor Funded Projects | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) | Deprec. Rate: | 0.0000% | (A) |
| 4 | | | | | | Beginning Bal: | | | Beginning Bal: | | | Beginning Bal: | | |
| 5 | | **Total** | | | | Beginning Dep: | | | Beginning Dep: | | | Beginning Dep: | | |
| 6 | | | | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | | Beg Year-Mo.: | | |
| | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant | Gross Plant | Accm. Deprec. | Net Plant |
| 7 | | | | | | $ - | | | $ - | | | $ - | | |
| | Jan | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Feb | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Mar | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 10 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Apr | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 11 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 12 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Jun | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 13 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |
| | Jul | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 14 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Aug | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 15 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Sept | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 16 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Oct | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 17 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Nov | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 18 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Dec | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 19 | Y1 | - | - | - | Y1 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Jan | $ | $ | $ | Jan | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 20 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Feb | $ | $ | $ | Feb | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 21 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Mar | $ | $ | $ | Mar | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 22 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Apr | $ | $ | $ | Apr | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 23 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | May | $ | $ | $ | May | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 24 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Jun | $ | $ | $ | Jun | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 25 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Jul | $ | $ | $ | Jul | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 26 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Aug | $ | $ | $ | Aug | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 27 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Sept | $ | $ | $ | Sept | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 28 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Oct | $ | $ | $ | Oct | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 29 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Nov | $ | $ | $ | Nov | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 30 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | Dec | $ | $ | $ | Dec | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 31 | Y2 | - | - | - | Y2 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 13 Mon | $ | $ | $ | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 32 | Avg | - | - | - | | - | - | - | - | - | - | - | - | - | - | - | - |
| 33 | 12 Mon Depr Exp | | | $0 | | 12 Mon Depr Exp | | $0 | | 12 Mon Depr Exp | | $0 | | 12 Mon Depr Exp | | $0 | |

Notes: **(A)** Projected transmission depreciation expense (P-1 (Trans Plant), page 4, line 28) divided by projected transmission plant in service (P-1 (Trans Plant), page 4, line 29) divided by 12.
**(B)** P-5 projects will be included in total projected transmission projects for P-1

**Evergy Missouri West Inc.**
**Formula Rate Implementation Protocols**

## I. Annual Update

1. The formula rate template contained in Attachment H of the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("OATT"), Federal Energy Regulatory Commission ("FERC") Electric Tariff, Sixth Revised Volume No. 1 ("Formula") and these Formula Rate Implementation Protocols ("Protocols") together comprise the Evergy Missouri West Inc. ("EMW") filed rate (collectively, the "Formula Rate") for transmission service under the SPP OATT or the EMW OATT as applicable. EMW will follow the instructions specified in the Formula Rate to calculate annually its Annual Transmission Revenue Requirements ("ATRR") for Network Integration Transmission Service, rates for Point-to-Point transmission service, its ATRR associated with transmission upgrade projects having cost recovery under Schedule 11 of the SPP OATT, and rates for Ancillary Services Schedule 1 - Scheduling System Control and Dispatch Services, for posting by EMW and SPP, as applicable.

2. The Formula Rate shall be applicable to service on and after January 1 of each calendar year through December 31 of the same calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, as provided herein.

3. Each calendar year, EMW shall:

   (a) Calculate the ATRR by September 24 (or the next business day if September 24 is not a business day) for the next Rate Year in accordance with the Formula Rate ("Annual Update"). The Formula Rate specifies in detail the manner in which

      i. the most recent Form No. 1 data shall be used as inputs and the limited projections of transmission plant and associated transmission depreciation expense, transmission O&M expense, A&G expense, revenue credits, and load will be forecast for the next Rate Year in the Annual Update; and

      ii. any true-up calculated in accordance with the Formula Rate, including interest, ("True-Up Adjustment") for the prior Rate Year shall be incorporated into the Annual Update for the next Rate Year;

   (b) Interest on any over-recovery or under-recovery of the net revenue requirements shall be calculated in accordance with the Formula true-up worksheet (Worksheet TU(True-Up)). Interest on an over-recovery or under-recovery of a revenue requirement shall be determined according to the Formula;

(c) Calculate the True-Up Adjustment for a given Rate Year and post it by June 1 (or the next business day if June 1 is not a business day) of the year following that Rate Year in accordance with the Formula Rate, which adjustment will be reflected in the next Annual Update. The True-Up Adjustment shall include a Formula template with the actual data for the prior Rate Year compared to the previously projected data for the same period;

(d) Calculate the ATRR values for transmission service for the next Rate Year which shall be the Annual Update for such Rate Year, plus or minus the True-up Adjustment from the previous Rate Year;

(e) Post such Annual Update (each September 24) and True-Up Adjustment (each June 1), as well as a populated Formula template in fully functional spreadsheets showing the calculation of such Annual Update and True-Up Adjustment with documentation supporting such calculation as provided in Section I.4, below, and, with respect to the Annual Update, information supporting the limited projections described in Section I.3.a.i., above, (which information shall include, but is not limited to, the following information for all transmission facilities included in the expected plant additions: (i) expected date of completion; (ii) percent completion status as of the date of the Annual Update; (iii) a one-line diagram of facilities exceeding $5 million in cost; (iv) the total installed cost of the facility; (v) the reason for the facility addition; and (vi) upgrade costs paid by a generator or paid by a transmission customer directly to EMW) in an accessible location on the SPP's website and OASIS (the date of such posting is referred to herein as the "Posting Date"). Any delay in the Posting Date will result in an equivalent extension of time for the submission of information requests discussed in Section II of these protocols;

(f) On the Posting Date, notify Interested Parties, on the SPP email exploder list titled "Service List", of the website address of the Annual Update and True-Up Adjustment postings. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general ("Interested Parties"). Interested Parties can contact SPP to subscribe to the SPP Service List;

(g) Make a good faith effort to respond within ten (10) business days to reasonable information requests submitted by Interested Parties for information and work papers supporting the Annual Update. Any such information request must be submitted within sixty (60) days of the Posting Date of the Annual Update and shall be limited (as listed in Sections II.3(a) through (g)) to that which is appropriate to determine if EMW has properly calculated the Annual Update and whether the costs included in the Annual Update are appropriately recovered under the terms of the Formula Rate and the Formula Rate has been applied according to its terms; and

(h) Provide its Interested Parties, via e-mail based on the SPP Service List, at least thirty (30) days (all references herein to days shall be calendar days unless specified otherwise) advance notice of a public meeting to be held no sooner than ten (10) days after the Posting Date of the Annual Update and no later than October 16 each year, to explain and answer questions regarding the Annual Update for the next calendar year ("Annual Update Customer Meeting"). EMW shall provide an option for Interested Parties to remotely access this Annual Update Customer Meeting (remote access options may include video conferencing, webinar, internet conferencing, or other appropriate remote access options as determined by EMW). EMW shall modify the Annual Update to reflect any changes that it and the participating transmission customers all agree upon by no later than November 20 and shall cause the revised Annual Update to be posted in the same manner as the original Annual Update.

4. The True-Up Adjustment for the prior Rate Year shall:

(a) Be based upon EMW's FERC Form No. 1 for that Rate Year, and, to the extent specified in the Formula Rate, upon the books and records of EMW (EMW's FERC Form No. 1, books, and records all to be maintained consistently with FERC's Uniform System of Accounts ("USoA") and FERC accounting policies and practices);

(b) Be calculated pro rata based on the months during the Rate Year when the ATRR was in effect by multiplying the Annual True-Up Adjustment by the number of months that the ATRR was in effect divided by 12;

(c) Include a variance analysis of, at minimum, actual revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected revenue requirement that was calculated for the prior Rate Year with an explanation of material changes.

(d) As and to the extent specified in the Formula Rate, provide sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the actual ATRR for the applicable Rate Year and are not otherwise available directly from the FERC Form No. 1;

(e) Include an identification of (i) any changes in EMW accounting policies, practices, and procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or Form No. 1 reporting requirements) from those in effect during the calendar year upon which the most recent ATRR was based and that, in EMW's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next three years; (ii) any changes in the SPP OATT from the provisions of the SPP OATT in effect during the calendar year upon which the most recent ATRR was based and that, in EMW's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next three years; and (iii) any change, and the dollar value of the change, in the classification of any transmission facility under Attachment AI of the SPP OATT (including the costs of any reclassified facility) that EMW has made in the applicable True-Up Adjustment or Annual Update; and

(f) Be subject to review and challenge in accordance with the procedures set forth in these Formula Rate Implementation Protocols.

5. A change to the Formula Rate inputs related to extraordinary property losses, return on equity, depreciation rates for each regulatory jurisdiction that are used to calculate the composite rates applied in the Formula Rate, or Post Employment Benefits Other than Pensions may not be made absent an appropriate Federal Power Act Section 205 or 206 filing with the FERC.

6. If EMW files any corrections or modifications to its FERC Form No. 1 prior to the Posting Date of its Annual Update and such corrections or modifications would affect the True-Up Adjustment for a prior Rate Year, the True-Up Adjustment for each Rate Year(s) affected by the corrections or modifications shall be updated to reflect the corrected or modified FERC Form No. 1 and the Annual Update shall incorporate the change in such True-Up Adjustment(s), with interest. Corrections or modifications to a FERC Form No. 1 filed after the Posting Date of an Annual Update and not included in a revised Annual Update by November 20 shall be incorporated in the next True-Up Adjustment or Annual Update, as applicable. EMW shall report in a timely manner to the FERC, the applicable state commissions, and all parties required by FERC regulations any corrections or modifications to its FERC Form No. 1, that affect materially the past or present implementation of the Formula Rate, whether such corrections or modifications have the effect of increasing or decreasing the resulting transmission rates.

**II. Review Procedures for Annual Update and True-Up Adjustment**

Each Annual Update and True-Up Adjustment for the prior Rate Year shall be subject to the following review procedures ("Annual Review Procedures") (if any of the dates provided for herein fall on a Saturday, Sunday or Federal bank holiday, then the due date shall be the first business day thereafter):

1. Review procedures specific to the Annual Update are stated in Sections I.3(e) through (h).

2. Each year, EMW will, with at least thirty (30) days' notice utilizing the SPP Service List, convene a meeting of its Interested Parties, no sooner than ten (10) days after the Posting Date of the True-Up Adjustment and no later than July 8, at EMW's offices in Kansas City, Missouri, to discuss the True-Up Adjustment ("True-Up Customer Meeting"). EMW shall provide an option for Interested Parties to remotely access this True-Up Customer Meeting (remote access options may include video conferencing, webinar, internet conferencing, or other appropriate remote access options as determined by EMW).

3. Interested Parties may begin submitting information requests immediately following the Posting Date of the True-Up Adjustment and will have one-hundred five (105) days after June 1 to serve reasonable information requests on EMW for information and work papers supporting the True-Up Adjustment for the prior Rate Year. Such information and document requests shall be limited to what is necessary to determine:

   (a) the extent or effect of an Accounting Change;

   (b) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these Protocols;

   (c) the proper application of the formula rate and procedures in these Protocols;

   (d) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;

   (e) the prudence of actual costs and expenditures;

   (f) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

   (g) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

   Without limiting the generality of the foregoing, such information requests may include questions related to the data described in Sections I.4(a) and (c) and Section I.6 above.

4. EMW shall make a good faith effort to respond to information requests pertaining to a True-Up Adjustment within ten (10) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day.

5. To the extent EMW and any Interested Party(ies) are unable to resolve disputes related to information requests for the Annual Update or

True-up Adjustment submitted in accordance with these Formula Rate Implementation Protocols, EMW or any Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master. The discovery master shall have the power to issue binding orders to resolve discovery disputes and compel the production of discovery, as appropriate, in accordance with the Formula Rate Implementation Protocols and consistent with the FERC's discovery rules.

6. Any Interested Party shall have until the later of one-hundred fifty (150) days after June 1 or thirty (30) days after EMW's last response to reasonable information requests submitted pursuant to Section II.3 above to notify EMW in writing of any specific challenges to the True-Up Adjustment ("Informal Challenges"). Any Interested Party shall have until the later of November 24 or thirty (30) days after EMW's last response to reasonable information requests submitted pursuant to Section II.3 above to notify EMW in writing of any specific challenges to the Annual Update ("Informal Challenges"). Challenges to the Formula Rate itself shall not be considered Informal Challenges for purposes of these Annual Review Procedures.

**III. Resolution of Challenges**

1. If EMW and any Interested Party(ies) have not resolved all Informal Challenges identified pursuant to Section II.6 above within sixty (60) days after the deadline in Section II.6 for written notification of Issues, senior management of the Interested Party(ies) and EMW shall make a good faith effort to resolve any outstanding Informal Challenges ("Senior Management Review").

2. (a) If EMW's and any Interested Party's(ies') senior management are unable to resolve all Informal Challenges within thirty (30) days after the Senior Management Review commences, the Interested Party(ies) may file a challenge to the Annual Update or True-Up Adjustment ("Formal Challenge"). Challenges to the Formula Rate itself shall not be considered "Formal Challenges" for purposes of these Annual Review Procedures.

    i. Deadline for Formal Challenge notice is the later of thirty (30) days after Senior Management Review or March 1.

    ii. Any Interested Party may notify EMW in writing of a Formal Challenge to the Annual Update or True-Up Adjustment.

    (b) All information produced pursuant to these Protocols may be included in any Formal Challenge, in any other proceeding concerning the Formula Rate initiated at FERC pursuant to the Federal Power Act, or in any proceeding before the U.S. Court of Appeals to review a FERC decision involving the Formula Rate. EMW may, however, designate any response to an information request as confidential if the information conveyed is not publicly available. Interested Parties' representatives shall treat such response as confidential in connection with any of the proceedings discussed in this section; provided, however, that when so used, such response shall initially be filed under seal (unless the claim of confidentiality is waived by EMW), subject to a later determination by the presiding authority that the material is, in whole or in part, not entitled to confidential treatment.

    (c) The Informal as well as Formal Challenges shall be limited (as listed in Sections II.3(a) through (g)) to that which is appropriate to determine if EMW has properly calculated the Annual Update or True-Up and whether the costs included in the Annual Update or True-Up are appropriately recovered under the terms of the Formula Rate and the Formula Rate has been applied according to its terms.

(d) The notification for the Informal and Formal Challenges should contain sufficient information to present the issue in question, as well as sufficient contact information.

i. The written notification should be addressed to:

Regulatory Affairs –Transmission
Evergy Missouri West Inc.
P.O. Box 418679
Kansas City, MO 64141-9679

ii. E-mail notifications can be made to:

Regulatory.affairs@evergy.com

(e) Notification for Formal Challenges can also be made as provided in Section IV.

3. In any proceeding ordered by the FERC in response to a Formal Challenge, EMW will bear the burden of proof in accordance with applicable FERC precedent as it may be modified by the FERC.

4. Any refunds or surcharges resulting from an Informal Challenge or Formal Challenge not resolved by November 20 shall be calculated, with interest, from the effective date of the challenged True-Up Adjustment, and shall be reflected in the True-Up Adjustment and Annual Update for the next Rate Year.

5. In the event that EMW identifies an error in an Annual Update or True-Up Adjustment (or a FERC Form No. 1 or successor form which is used as an input to the Formula Rate), or is required by applicable law or a court or regulatory body to correct an error, EMW shall correct such error in good faith and without regard to whether the correction increases or decreases EMW's revenue requirements. There will be no mid-year rate adjustments. Any such correction will be implemented in the True-Up Adjustment and Annual Update for the next Rate Year, with interest. Nothing in these Protocols should or may be construed as preventing an Interested Party or the FERC from contesting such correction.

**IV. Informational Filing**

1. By March 15 of each year, EMW shall submit to FERC an informational filing ("Informational Filing") of its projected net revenue requirement for the Rate Year, including its Annual Update and True-Up Adjustment. If March 15 falls on a holiday or weekend day, the filing will be made the next business day. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that EMW has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such

Informational Filing, EMW shall provide notice of the Informational Filing via an email exploder list and by posting the docket number assigned to EMW's Informational Filing on the SPP website and OASIS.

2. Any challenges to the implementation of the Attachment H-EMW Formula Rate must be made through the challenge procedures described in Section III of these Protocols or in a separate complaint proceeding. For any known challenges still working through the challenge procedures and not known to be a Formal Challenge by the March 15 Informational Filing, Interested Parties can also file protests or comments to EMW's annual Informational Filing.

**V. Joint Meeting with Transmission Owners**

Each year EMW shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

**VI. Miscellaneous**

1. Nothing in these Protocols limits or deprives EMW, the FERC or any Interested Party of any rights it may otherwise have under any applicable provision of the Federal Power Act. The provisions of these Protocols addressing review and challenge of the Annual Update or True-Up Adjustment are not intended to nor shall be construed as limiting EMW's, FERC's or any party's rights under any applicable provision of the Federal Power Act.

2. Notwithstanding the provisions of Section VI.1, before EMW or any Interested Party may bring any new action at the FERC involving the Formula Rate, senior management of such Interested Party(ies) and EMW shall make a good faith effort to resolve any outstanding issues. If EMW's and any Interested Party's(ies') senior management are unable to resolve all issues within thirty (30) days, then EMW or the Interested Party(ies) may bring such action. For the avoidance of doubt, the advance notice and negotiation requirement in this Section VI.2 shall not apply to Formal Challenges (as to which the Senior Management Review provisions in Section III apply) nor shall the requirement bar an Interested Party from intervening in, filing a protest under FPA § 206 in, or fully participating in any proceeding initiated by the FERC *sua sponte* or otherwise properly initiated before the FERC.

# Addendum 12 to Attachment H Part 1

AEP West SPP Member Transmission Companies

Calculation of Actual/ Projected Zonal Rate For Schedule 9

For the 2XXX Rate Year

**SPP Zone 1 Actual/ Projected AEP Revenue Requirements**

| Line No. | | | AEPTCo Annual Revenue Requirement | OKT Annual Revenue Requirement | SWT Annual Revenue Requirement |
|---|---|---|---|---|---|
| **A.** | **Network Service** | | | | |
| 1 | RATE YEAR REVENUE REQUIREMENT (w/o incentives) | (TCOS Line 1 ) | - | - | - |
| 2 | LESS: REVENUE CREDITS | (TCOS Line 2 ) | - | - | - |
| 3 | NETWORK CUSTOMER OWNED FACILITY CREDITS | (TCOS Line 3 ) | - | - | - |
| 4 | RATE YEAR ZONE 1 AEP NETWORK SERVICE REVENUE REQUIREMENT | (TCOS Line 4 ) | - | - | - |
| 5 | LESS: REVENUE REQUIREMENTS INCLUDED IN LINE 1 FOR: | | | | |
| 6 | BASE PLAN UPGRADES (W/O INCENTIVES) | (TCOS Line 5 ) | - | - | - |
| 7 | REQUESTED UPGRADES (W/O INCENTIVES) | (Worksheet F/G) | - | - | - |
| 8 | ECONOMIC UPGRADES (W/O INCENTIVES) | (Worksheet F/G) | - | - | - |
| 9 | SUBTOTAL | | - | - | - |
| 10 | EXISTING ZONAL ATRR (W/O INCENTIVES) | (Line 4- Line 9) | - | - | - |
| 11 | INCENTIVE REVENUE REQUIREMENT FOR ZONAL PROJECTS | (TCOS Line 13 ) | - | - | - |
| 12 | **RATE YEAR ZONAL ATRR (W/ INCENTIVES)** | **(Line 10 + Line 11)** | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | | - | - | - |
| 13 | Actual/Projected Rate Year AEP West Zone Average 12-Mo. Peak Demand, MW | (Load WS, ln 33) | - | - | - |
| 14 | **Monthly NITS Rate in $/MW - Month** | **(Line 12 / Line 13) /12** | - | - | - |

AEP West SPP Member Transmission Companies

Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

**SPP SCHEDULE 1 AEP Revenue Requirements**

| Line No. | | | **AEPTCo Annual Revenue Requirement** | **OKT Annual Revenue Requirement** | **SWT Annual Revenue Requirement** |
|---|---|---|---|---|---|
| **A.** | **Schedule 1 ARR For 2XXX Rate Year** | | | | |
| 1 | Total Load Dispatch & Scheduling (Account 561) (TCOS Line 65) | | - | - | - |
| 2 | Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b) | | - | | |
| 3 | Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b) | | - | | |
| 4 | Total 561 Internally Developed Costs | (Line 1 - Line 2 - Line 3) | - | - | - |
| 5 | Less: PTP Service Credit (prior year Sched 1 revenue from PTP transactions) | | - | | |
| 6 | ZONAL ARR FOR RATE YEAR | (Line 4 - Line 5) | - | - | - |
| **B.** | **Schedule 1 2XXX Rate Year Calculations** | | | | |
| 7 | Rate Year AEP West Zone SPP Average 12-Mo. Peak Demand | (Load WS, ln 20) | - | MW | |

| | | | |
|---|---|---|---|
| 8 | Annual Point-to-Point Rate in $/MW - Year | (Line 6 / Line 7) | - |
| 9 | Monthly Point-to-Point Rate (ln 8 / 12) $/MW - Month | (Line 8 / 12) | - |
| 10 | Weekly Point-to-Point Rate (ln 8 / 52) $/MW - Weekly | (Line 8 / 52) | - |
| 11 | Daily Off-Peak Point-to-Point Rate (ln 8 / 365) $/MW - Day | (Line 8 / 365) | - |
| 12 | Hourly Off-Peak Point-to-Point Rate (ln 8 / 8760) $/MW - Hour | (Line 8 / 8760) | - |

AEP Transmission
Formula Rate Template
Calculation of Schedule 11 Revenue Requirements For AEP Transmission Projects
For Projected Year 2XXX Including
2XXX-2 True-Up

**AEP Schedule 11 Revenue Requirement Including True-Up of Prior Collections**

**COMPANY NAME**

Note: Projects whose investment cost do NOT meet SPP's $100,000 threshold for 'regional' socialization are marked with an asterik "*" as SPP will only collect those ATRRs from the zone.

| (A) | (B) | (C ) | (D) | (E) | (F) | (G) = (E) + (F) | (H) | (I) | (J) = (H) - (I) | (K) | (L) | (M) = (K)-(L) | (N) | (O) | (P) = (J)+(M)+(N)+ (O) | (Q) = (G) + (P) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Projected ARR For 2XXX From WS-F** | | | **True-Up ARR From 2XXX-2 From Worksheet G** | | | | | | | | | |
| | | | | | | | **Base ARR** | | | **Incentive ARR** | | | | | | |
| **Sheet Name** | **Owner** | **Project Description** | **Year in Service** | **Base ARR** (WS-F) | **Incentive** | **Total** | **Actual Rate Year True Up Revenue Requirement** | **Projected Rate Year Revenue Requirement** | **TRUE-UP Adjustment** (WS-G) | **True-up** | **Projected** | **TRUE-UP Adjustment** (WS-G) | **Schedule 11 Revenue Credits and SPP Billing Adjustments** | **Interest** | **Total True Up net of revenue credits, including interest** | **Total ADJUSTED Revenue Requirement Effective 1/1/2XXX** |

| | |
|---|---|
| | **Company Total** |

**AEP West SPP Member Transmission Companies**
**Network Load for January Through December 2XXX**
**Based on West Zone-SPP Monthly Transmission System Firm Peak Demands for the Twelve Months Ended December 31, 2XXX**

**Combined Load Worksheet**
Unless noted (e.g., PSO), the loads reported on lines 1 through 20 are the customer's schedule 9 and 11 load.

| Line No. | | | January | February | March | April | May | June | July | August | September | October | November | December | | | 12 Month Average MW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Peak Day** | | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | **Day** | | | |
| | **Peak Hour** | | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | **Hour** | | | |
| | **SPP Load Responsibility** | | | | | | | | | | | | | | | | |
| 1 | **PSO (2)** | | | | | | | | | | | | | | - | | 0 |
| 2 | **SWEPCO excl Valley (2)** | | | | | | | | | | | | | | - | | 0 |
| 3 | **AECC (3)** | | | | | | | | | | | | | | - | | 0 |
| 4 | **AECC-MISO** | | | | | | | | | | | | | | - | | 0 |
| 5 | **WFEC (3)** | | | | | | | | | | | | | | - | | 0 |
| 6 | **OMPA (3)** | | | | | | | | | | | | | | - | | 0 |
| 7 | **OG&E - LSE** | | | | | | | | | | | | | | - | | 0 |
| 8 | **OG&E - TALL BEAR (3)** | | | | | | | | | | | | | | - | | 0 |
| 9 | **ETEC (3)** | | | | | | | | | | | | | | - | | 0 |
| 10 | **GREENBELT (3)** | | | | | | | | | | | | | | - | | 0 |
| 11 | **LIGHTHOUSE (3)** | | | | | | | | | | | | | | - | | 0 |
| 12 | **BENTONVILLE, AR (3)** | | | | | | | | | | | | | | - | | 0 |
| 13 | **PRESCOTT, AR (3)** | | | | | | | | | | | | | | - | | 0 |
| 14 | **MINDEN, LA (3)** | | | | | | | | | | | | | | - | | 0 |
| 15 | **HOPE, AR (3)** | | | | | | | | | | | | | | - | | 0 |
| 16 | **COFFEYVILLE, KS (3)** | | | | | | | | | | | | | | - | | 0 |
| 17 | **SWEPCO - VALLEY** | | | | | | | | | | | | | | - | | 0 |
| 18 | **AECI** | | | | | | | | | | | | | | - | | 0 |
| 19 | | | | | | | | | | | | | | | | | |
| 20 | **System Firm Peak Demands** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | 0.000 | Sched - 9 12CP | **0** |
| | **Supporting Data** | | | | | | | | | | | | | | | | |
| 21 | **PSO:** | PSO Native Load (2) (4) | | | | | | | | | | | | | | | |
| 22 | | KAMO | | | | | | | | | | | | | | | |
| 23 | | GRDA load on PSO no longer used as of Dec 2015 (5) | | | | | | | | | | | | | | | |
| 24 | | PSO E&W portion allocated to WFEC zone | | | | | | | | | | | | | | | |
| 25 | | 100% PSO E&W included in PSO native load | | | | | | | | | | | | | | | |
| 26 | | Allen Holdenville | | | | | | | | | | | | | | | |
| 27 | **PSO OATT Load Responsibility** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | 0.000 | | 0 |
| 28 | **SWEPCO:** | | | | | | | | | | | | | | | | |
| 29 | | SWEPCO Native Load (2)(5) | | | | | | | | | | | | | | | |
| 30 | | Dolet Hills Aux. Load (not self-generated) | | | | | | | | | | | | | | | |
| 31 | | Less: VALLEY | | | | | | | | | | | | | | | |
| 32 | **SWEPCO OATT Load Responsibility** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | 0.000 | | 0 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 33 | **TOTAL AEP Affiliate Schedule 11 Load** | | | | | | | | | | | | | pr yr | Sched - 11 12CP | **0** |
| | **AEP Schedule 11 Worksheet** | | | | | | | | | | | | | | | |
| 34 | PSO OATT Sched 9 load, Ln 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 35 | less GRDA load on PSO Jan-Nov(b) 2015 no longer used | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 36 | WFEC load already subtracted from PSO schedule 9 load line 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 37 | Subtotal PSO Schedule 11 load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 38 | SWEPCO Sched 11 load, Ln 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 39 | TOTAL AEP Affiliate Schedule 11 Load | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | 0 |
| 40 | **TOTAL AEP ZONAL SCHEDULE 11** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0.000 | | |

NOTES:

(1) Amounts are MW at the time of the AEP-SPP Internal (MLR) Peak

(2) At the generator, includes transmission losses.

(3) At the generator. Transmission losses added to metered values which include appropriate dist.& xfmr losses.

[4] PSO Native load includes PSO load on GRDA

(5) SWEPCO Native Load includes Valley

AEP West SPP Member Transmission Companies

Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

**COMPANY NAME**

| Line No. | | | | | | | Transmission Amount |
|---|---|---|---|---|---|---|---|
| 1 | REVENUE REQUIREMENT (w/o incentives) | (ln 117) | | | | | - |
| | | | Total | | Allocator | | |
| 2 | REVENUE CREDITS | (Note A) (Worksheet H) | - | | DA | 1.00000 | $ - |
| 3 | Network Customer Owned Facility Credits | Worksheet B | | | | | - |
| 4 | REVENUE REQUIREMENT For All Company Facilities | (ln 1 less ln 2 plus ln 3) | | | | | - |

**MEMO: The Carrying Charge Calculations on lines 7 to 12 below are used in calculating project revenue requirements billed through SPP Schedule 11.**
**The total non-incentive revenue requirement for these projects shown on line 5 is included in the total on line 4.**

| | | | | | | |
|---|---|---|---|---|---|---|
| 5 | Trued-Up / Projected Revenue Requirement for SPP BPU Regional Facilities (w/o incentives) (Worksheet F/G) | | - | DA | 1.00000 | $ - |
| 6 | NET PLANT CARRYING CHARGE (w/o incentives) (Note B) | | | | | |
| 7 | Annual Rate | (ln 1/ ln 37 x 100%) | | | | - |
| 8 | Monthly Rate | (ln 7 / 12) | | | | - |
| 9 | NET PLANT CARRYING CHARGE ON LINE 7 , W/O DEPRECIATION (w/o incentives) (Note B) | | | | | |
| 10 | Annual Rate | ( (ln 1 - ln 86) / ln 37 x 100%) | | | | - |

| | | | |
|---|---|---|---|
| 11 | NET PLANT CARRYING CHARGE ON LINE 9, W/O INCOME TAXES, RETURN (Note B) | | |
| 12 | Annual Rate | ( (ln 1 - ln 86 - ln 111 - ln 112) / ln 37 x 100%) | - |
| 13 | ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note C) (Worksheet F/G) | | - |

AEP West SPP Member Transmission Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

COMPANY NAME

| Line No. | (1) RATE BASE CALCULATION | (2) Data Sources (See "General Notes") | (3) TO Total NOTE D | (4) Allocator | | (5) Total Transmission |
|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | |
| 14 | Production | (Worksheet A-1 ln 14.B) | - | NA | 0.00000 | - |
| 15 | Less: Production ARO (Enter Negative) | (Worksheet A-1 ln 14.C) | - | NA | 0.00000 | - |
| 16 | Transmission | (Worksheet A-1 ln 14.D & Ln 121 | - | DA | | - |
| 17 | Less: Transmission ARO (Enter Negative) | (Worksheet A-1 ln 14.E) | - | TP | 1.00000 | - |
| 18 | Distribution | (Worksheet A-1 ln 14.F) | - | NA | 0.00000 | - |
| 19 | Less: Distribution ARO (Enter Negative) | (Worksheet A-1 ln 14.G) | - | NA | 0.00000 | - |
| 20 | General Plant | (Worksheet A-1 ln 28.B) | - | W/S | 0.00000 | - |
| 21 | Less: General Plant ARO (Enter Negative) | (Worksheet A-1 ln 28.C) | - | W/S | 0.00000 | - |
| 22 | Intangible Plant | (Worksheet A-1 ln 28.D) | - | W/S | 0.00000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | TOTAL GROSS PLANT | (sum lns 14 to 22) | - | GP= | **1.00000** | - |
| | | | | **GTD=** | **1.00000** | |
| 24 | ACCUMULATED DEPRECIATION AND AMORTIZATION | | | | | |
| 25 | Production | (Worksheet A-2 ln 14.B) | - | NA | 0.00000 | - |
| 26 | Less: Production ARO (Enter Negative) | (Worksheet A-2 ln 14.C) | - | NA | 0.00000 | - |
| 27 | Transmission | (Worksheet A-2 ln 14.D less 29.F) | - | **TP1=** | 0.00000 | - |
| 28 | Less: Transmission ARO (Enter Negative) | (Worksheet A-2 ln 14.E) | - | **TP1=** | 0.00000 | - |
| 29 | Distribution | (Worksheet A-2 ln 14.F) | - | NA | 0.00000 | - |
| 30 | Less: Distribution ARO (Enter Negative) | (Worksheet A-2 ln 14.G) | - | NA | 0.00000 | - |
| 31 | General Plant | (Worksheet A-2 ln 28.B) | - | W/S | 0.00000 | - |
| 32 | Less: General Plant ARO (Enter Negative) | (Worksheet A-2 ln 28.C) | - | W/S | 0.00000 | - |
| 33 | Intangible Plant | (Worksheet A-2 ln 28.D) | - | W/S | 0.00000 | - |
| 34 | TOTAL ACCUMULATED DEPRECIATION | (sum lns 25 to 33) | - | | | - |
| 35 | NET PLANT IN SERVICE | | | | | |
| 36 | Production | (ln 14 + ln 15 - ln 25 - ln 26) | - | | | - |
| 37 | Transmission | (ln 16 + ln 17 - ln 27 - ln 28) | - | | | - |
| 38 | Distribution | (ln 18 + ln 19 - ln 29 - ln 30) | - | | | - |
| 39 | General Plant | (ln 20 + ln 21 - ln 31 - ln 32) | - | | | - |
| 40 | Intangible Plant | (ln 22 - ln 33) | - | | | - |
| 41 | TOTAL NET PLANT IN SERVICE | (sum lns 36 to 40) | - | **NP=** | **1.00000** | - |
| 42 | DEFERRED TAX ADJUSTMENTS TO RATE BASE | (Note E) | | | | |
| 43 | Account No. 281.1 (enter negative) | 272-273.8.k | - | NA | | - |
| 44 | Account No. 282.1 (enter negative) | (Worksheet C, ln 4 C & ln 8 J) | - | DA | | - |
| 45 | Account No. 283.1 (enter negative) | (Worksheet C, ln 12 C & ln 14 J) | - | DA | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 46 | Account No. 190.1 | (Worksheet C, ln 18 C & ln 22 J) | - | DA | | - |
| 47 | Account No. 255 (enter negative) | (Worksheet C, ln 26 C & ln 28 J) | - | DA | | - |
| 48 | TOTAL ADJUSTMENTS | (sum lns 43 to 47) | - | | | - |
| 49 | PLANT HELD FOR FUTURE USE | (Worksheet A-1 ln 30.F) | - | DA | | - |
| 50 | REGULATORY ASSETS | (Worksheet S ln 10 cols. G and J) (Note W) | - | DA | | - |
| 51 | UNFUNDED RESERVES (ENTER NEGATIVE) (NOTE U) | (Worksheet R, ln 6 F) | - | W/S | 0.00000 | - |
| 52 | WORKING CAPITAL | (Note F) | | | | |
| 53 | Cash Working Capital | (1/8 * (ln 70 - Ln 69)) (Note G) | - | | | - |
| 54 | Transmission Materials & Supplies | (Worksheet D, pg 1 ln 1 E) | - | TP | 1.00000 | - |
| 55 | A&G Materials & Supplies | (Worksheet D, pg 1 ln 2 E) | - | W/S | 0.00000 | - |
| 56 | Stores Expense | (Worksheet D, pg 1 ln 3 E) | - | GP | 1.00000 | - |
| 57 | Prepayments (Account 165) - Labor Allocated | (Worksheet D, pg 1 ln 29 G) | - | W/S | 0.00000 | - |
| 58 | Prepayments (Account 165) - Gross Plant | (Worksheet D, pg 1 ln 29 F) | - | GP | 1.00000 | - |
| 59 | Prepayments (Account 165) - Transmission Only | (Worksheet D, pg 1 ln 29 E) | - | DA | 1.00000 | - |
| 60 | Prepayments (Account 165) - Unallocable | (Worksheet D, pg 1 ln 29 D) | - | NA | 0.00000 | - |
| 61 | TOTAL WORKING CAPITAL | (sum lns 53 to 60) | - | | | - |
| 62 | IPP CONTRIBUTIONS FOR CONSTRUCTION | (Note H) (Worksheet E, ln 8 B) | - | DA | 1.00000 | - |
| 63 | RATE BASE (sum lns 41, 48, 49, 50, 51, 61, 62) | | - | | | - |

AEP West SPP Member Transmission Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

COMPANY NAME

| Line No. | (1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION | (2) Data Sources (See "General Notes") | (3) TO Total | (4) Allocator | | (5) Total Transmission |
|---|---|---|---|---|---|---|
| | OPERATION & MAINTENANCE EXPENSE | | | | | |
| 64 | Transmission | 321.112.b | | | | |
| 65 | Less: Total Account 561 | (Note I) 321.84-92.b | | | | |
| 66 | Less: Account 565 | (Note J) 321.96.b | | | | |
| 67 | Less : Regulatory Amortizations / (Deferrals) | Worksheet S ln 2 (Note V) | - | | | |
| 68 | Plus: Includable 561 and 565 Expenses | Worksheet I ln 10 | - | | | |
| 69 | Plus : Approved Regulatory Amortizations / (Deferrals) | Worksheet S ln 4 (Note V) | - | | | |
| 70 | Total O&M Allocable to Transmission | (lns 64 - 65 - 66 - 67 + 68 + 69) | - | TP | 1.00000 | - |
| 71 | Administrative and General | 323.197.b (Note K, M) | | | | |
| 72 | Less: Acct. 924, Property Insurance | 323.185.b | | | | |
| 73 | Acct. 928, Reg. Com. Exp. | 323.189.b | - | | | |
| 74 | Acct. 930.1, Gen. Advert. Exp. | 323.191.b | - | | | |
| 75 | Acct. 930.2, Misc. Gen. Exp. | 323.192.b | - | | | |
| 76 | Regulatory Asset Amortizations / (Deferrals) | Worksheet S ln 6 (Note V) | - | | | |
| 77 | Balance of A & G | (ln 71 - sum ln 72 to ln 76) | - | W/S | 0.00000 | - |
| 78 | Plus: Acct. 924, Property Insurance | (ln 72) | - | GP | 1.00000 | - |
| 79 | Acct. 928 - Transmission Specific | Worksheet J ln 16.(E) (Note L) | - | TP | 1.00000 | - |
| 80 | Acct 930.1 - Only safety related ads -Direct | Worksheet J ln 22.(E) (Note L) | - | GP | 1.00000 | - |
| 81 | Acct 930.2 - Misc Gen. Exp. - Trans | Worksheet J ln 28.(E) (Note L) | - | DA | 1.00000 | - |
| 82 | Approved A&G Reg. Asset Amort. / (Deferrals) | Worksheet S ln 8 (Note V) | - | W/S | 0.00000 | - |
| 83 | A & G Subtotal | (sum lns 77 to 82) | - | | | - |
| 84 | TOTAL O & M EXPENSE | (ln 70 + ln 83) | - | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | - |
| 85 | DEPRECIATION AND AMORTIZATION EXPENSE | | | | | |
| 86 | Transmission | 336.7.b | | TP | 1.00000 | - |
| 87 | General | 336.10.b | | W/S | 0.00000 | - |
| 88 | Intangible | 336.1.d | | W/S | 0.00000 | - |
| 89 | TOTAL DEPRECIATION AND AMORTIZATION | (sum lns 86 to 88) | - | | | - |
| 90 | TAXES OTHER THAN INCOME | (Note N) | | | | |
| 91 | Labor Related | | | | | |
| 92 | Payroll | Worksheet L, Col. D | - | W/S | 0.00000 | - |
| 93 | Plant Related | | | | | |
| 94 | Property | Worksheet L, Col. C | - | GP | 1.00000 | - |
| 95 | Non-Allocable Taxes | Worksheet L, Col. F | - | NA | 0.00000 | - |
| 96 | Other | Worksheet L, Col. E | - | GP | 1.00000 | - |
| 97 | TOTAL OTHER TAXES | (sum lns 92 to 96) | - | | | - |
| 98 | INCOME TAXES | (Note O) | | | | |
| 99 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | - | | | |
| 100 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | | - | | | |
| 101 | where WCLTD=(ln 141) and WACC = (ln 144) | | | | | |
| 102 | and FIT, SIT & p are as given in Note O. | | | | | |
| 103 | GRCF=1 / (1 - T) = (from ln 99) | | - | | | |
| 104 | Amortized Investment Tax Credit (enter negative) | (FF1 p.114, ln 19.c) | | | | |
| 105 | Excess / (Deficit) Deferred Income Tax | Company Records (Note O) and WS C-*5, Ln 3 Col N, Ln 4 Col G* | | DA | | - |
| 106 | Tax Effect of Permanent and Flow Through Differences | Company Records (Note O) | | DA | | |
| 107 | Income Tax Prior to Adjustments | (ln 100 * ln 112) | - | | | - |
| 108 | ITC adjustment | (ln 103 * ln 104) | - | GP | 1.00000 | - |
| 109 | Excess / (Deficit) Deferred Income Tax | (ln 103 * ln 105) | - | DA | | - |
| 110 | Tax Effect of Permanent and Flow Through Differences | (ln 103 * ln 106) | - | DA | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 111 | TOTAL INCOME TAXES | (sum lns 107 to 110) | - | | | - |
| 112 | RETURN ON RATE BASE (Rate Base*WACC) | (ln 63 * ln 144) | - | | | - |
| 113 | INTEREST ON IPP CONTRIBUTION FOR CONST. (Note E) (Worksheet E, ln 2) | | - | DA | 1.00000 | - |
| 114 | REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX | | - | | | - |
| 115 | (sum lns 84, 89, 97, 111, 112, 113) | | | | | |
| 116 | TEXAS GROSS MARGIN TAX (Note P) (Worksheet K) | | - | DA | | - |
| 117 | REVENUE REQUIREMENT INCL GROSS MARGIN TAX | (ln 114 + 116) | - | | | - |

AEP West SPP Member Transmission Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year

COMPANY NAME

**SUPPORTING CALCULATIONS**

| ln No. | TRANSMISSION PLANT INCLUDED IN SPP TARIFF (Note W) | | | |
|---|---|---|---|---|
| 118 | Total transmission plant | (ln 16) | | - |
| 119 | Less transmission plant excluded from SPP Tariff (Worksheet A-1, ln 28 Col. (F)) (Note Q) | | | - |
| 120 | Less transmission plant included in OATT Ancillary Services (Worksheet A-1, ln 28, Col. (E)) (Note R) | | | - |
| 121 | Transmission plant included in SPP Tariff | (ln 118 - ln 119 - ln 120) | | - |
| 122 | Percent of transmission plant in SPP Tariff | (ln 121 / ln 118) | **TP =** | **1.00000** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 123 | WAGES & SALARY ALLOCATOR (W/S) | (Note S) | Direct Payroll | Payroll Billed from AEP Service Corp. | Total | | | |
| 124 | Production | 354.20.b | | | | NA | 0.00000 | |
| | | | | | - | | | - |
| 125 | Transmission | 354.21.b | | | | TP | 1.00000 | |
| | | | | | - | | | - |
| 126 | Regional Market Expenses | 354.22.b | | | | NA | 0.00000 | |
| | | | | | - | | | - |
| 127 | Distribution | 354.23.b | | | | NA | 0.00000 | |
| | | | | | - | | | - |
| 128 | Other (Excludes A&G) | 354.24,25,26.b | | | | NA | 0.00000 | |
| | | | | | - | | | - |
| 129 | Total | (sum lns 124 to 128) | - | - | 0 | | | |
| | | | | | | | | - |
| 130 | Transmission related amount | | | | | | | **W/S = 0.00000** |

**STAND ALONE (Note T)**

| | | | | | | |
|---|---|---|---|---|---|---|
| 131 | WEIGHTED AVERAGE COST OF CAPITAL (WACC) | | | | | $ |
| 132 | Long Term Interest | Long Term Interest (Worksheet M, ln. 37, col. (d)) | | | | - |
| 133 | Preferred Dividends | Preferred Stock Dividends (Worksheet M, ln. 57, col. (d)) | | | | - |
| 134 | Development of Common Stock: | | | | | Average |
| 135 | Proprietary Capital | (Worksheet M, ln. 14, col. (b)) | | | | - |
| 136 | Less Preferred Stock (ln 142) | (Worksheet M, ln. 14, col. (c)) | | | | - |
| 137 | Less Account 216.1 | (Worksheet M, ln. 14, col. (d)) | | | | - |
| 138 | Less Account 219 | (Worksheet M, ln. 14, col. (e)) | | | | - |
| 139 | Common Stock | (ln 135 - ln 136 - ln 137 - ln 138) | | | | - |
| 140 | | Rate Year Average Balances | | **Capital Structure Percentage** | Cost (Note T) | Weighted |
| 141 | Avg Long Term Debt (Worksheet M, ln. 28, col. (g)) | - | | 0.00% | 0.00% | 0.0000 |
| 142 | Avg Preferred Stock (Worksheet M, ln. 14, col. (c)) | - | | 0.00% | 0.00% | 0.0000 |

| | | | | | |
|---|---|---|---|---|---|
| 143 | Avg Common Stock (ln 139) | - | 0.00% | 10.50% | 0.0000 |
| 144 | Total (sum lns 141 to 143) | - | | | WACC = 0.0000 |

**PUBLIC SERVICE COMPANY OF OKLAHOMA (Note T)**

| | | | | | |
|---|---|---|---|---|---|
| 145 | WEIGHTED AVERAGE COST OF CAPITAL (WACC) | | | | $ |
| 146 | Long Term Interest | Long Term Interest (PSO Formula Worksheet M, ln. 37, col. (d)) | | | |
| 147 | Preferred Dividends | Preferred Stock Dividends (PSO Formula Worksheet M, ln. 57, col. (d)) | | | |
| 148 | Development of Common Stock: | | | | Average |
| 149 | Proprietary Capital | (PSO Worksheet M, ln. 14, col. (b)) | | | |
| 150 | Less Preferred Stock (ln 156) | (PSO Worksheet M, ln. 14, col. (c)) | | | |
| 151 | Less Account 216.1 | (PSO Worksheet M, ln. 14, col. (d)) | | | |
| 152 | Less Account 219 | (PSO Worksheet M, ln. 14, col. (e)) | | | |
| 153 | Common Stock | (ln 149 - ln 150 - ln 151 - ln 152) | | | - |
| 154 | | Rate Year Average Balances | **Capital Structure Percentage** | Cost (Note T) | Weighted |
| 155 | Avg Long Term Debt (PSO WS M, ln. 28, col. (g)) | | 0.00% | 0.00% | 0.0000 |
| 156 | Avg Preferred Stock (PSO WS M, ln. 14, col. (c)) | | 0.00% | 0.00% | 0.0000 |
| 157 | Avg Common Stock (ln 153) | - | 0.00% | 10.50% | 0.0000 |
| 158 | Total (sum lns 155 to 157) | - | | | WACC = 0.0000 |

AEP West SPP Member Transmission Companies
Transmission Cost of Service Formula Rate
Utilizing Actual / Projected Cost Data for the 2XXX Rate Year
COMPANY NAME

**Letter** **Notes**

General Note: True Up References to data from FERC Form 1 are indicated as: page#.line#.col.#. Rate Year Projections from Company forecasts.

A The revenue credits shall include a) amounts received directly from the SPP for PTP transmission services, b) direct assignment charges for transmission facilities, the cost of which has been included in the TCOS, and c) amounts from customers taking service under grandfathered agreements, where the demand is not included in the rate divisor. Revenues associated with FERC annual charges, gross receipts taxes, ancillary services or facilities excluded from the TCOS are not included as revenue credits. Revenue from Transmission Customers whose coincident peak loads are included in the DIVISOR of the load-ratio share calculation are not included as revenue credits. See Worksheet H for details.

B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for facilities and any upgrades.

C This additional revenue requirement is determined using a net plant carrying charge (fixed carrying charge or FCR) approach. Worksheet G shows the calculation of the trued-up revenue requirement for each project, based on an FCR rate calculated from inputs on this TCOS. Line 13 shows the incremental ARR for projects receiving incentives as accepted by FERC. These individual additional revenue requirements are summed for the true-up year, and included here.

D The gross plant, accumulated depreciation, and deferred tax balances included in rate base and depreciation expense are reduced by the removal of amounts related to Asset Retirement Obligations (AROs). This is to comply with the requirements of FERC Rulemaking RM02-7-000.

E The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense as discussed in Note N. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated to transmission. Transmission allocations are shown on Worksheet C.

F Identified as being transmission related or functionally booked to transmission.

G Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission on line 70.

H Consistent with Paragraph 657 of Order 2003-A, the amount on line is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 113.

I Line 65 Removes the expense booked to transmission accounts included in the development of OATT ancillary services rates, including all of Account No. 561.

J Removes cost of transmission service provided by others to the extent such service is not incurred to provide the SPP service at issue.

K General Plant and Administrative & General expenses may be functionalized based on allocators other than the W/S allocator. Full documentation must be provided.

L Expense reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable or allocable to transmission service. Worksheet J allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet H.

M Recoverable PBOP expense is based on actual annual PBOP costs, including charges from the AEP Service Corporation. The PBOP amounts are included in the Administrative and General total, and are based on current year expenses. The annual actuarial valuation report supporting the derivation of the PBOP expense, along with an explanation of PBOP derivation process, is submitted during the formula rate annual update.

N Includes only FICA, unemployment, property and other assessments charged in the current year. Gross Receipts tax, Sales & Use taxes, local franchise taxes, and taxes related to income are excluded.

O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (ln 99) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | | |
| | SIT= | - | (State Income Tax Rate or Composite SIT. Worksheet K) |
| | p = | - | (percent of federal income tax deductible for state purposes) |

Excess / (Deficit) Deferred Income Taxes will be amortized over the average remaining life of the assets to which it relates, unless the Commission requires a different amortization period. Recovery of permanent and flow through differences is limited to only the transmission functional portion of the tax difference

related to capitalized AFUDC Equity.

P The Texas Gross Margin tax is calculated on the Texas allocated revenue of the Company, reduced by cost of goods sold deduction to derive a "Gross Margin" for the Company. The tax rate of one percent is assessed on the resulting amount. The jurisdictional allocator is based on transmission demand allocators.

Q Removes plant excluded from the OATT because it does not meet the SPP's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.

R Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note Q.

S Includes functional wages & salaries incurred by parent company service corporation for support of the operating company.

T Long Term Debt cost rate = Long-Term Interest (ln 132) / Long Term Debt (ln 141). Preferred Stock cost rate = preferred dividends (ln 133) / preferred outstanding (ln 142).
Common Stock cost rate (ROE) = 10.5%, the rate accepted by FERC pursuant to the settlement filed in Docket Nos. EL17-76 and EL18-199. It includes an additional 50 basis points for remaining a member of the SPP RTO.
The capital structure of AEP Southwestern Transmission Co. will be based on the capital structure of SWEPCO until it establishes a stand alone capital structure.
AEP Oklahoma Transmission Company uses its own capital structure.
The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the capital structure. Details and calculations of the weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are computed on Worksheet M. The unamortized balance of eligible hedge gains/losses and related ADIT amounts shall not flow through the formula rate.

U The cost of service will make a rate base adjustment to remove unfunded reserves associated with contingent liabilities recorded to Accounts 228.1-228.4 from rate base.

V O&M and A&G shall be adjusted to remove all regulatory asset deferrals and amortizations that have not been approved by FERC for inclusion in cost of service, and then to add back in FERC approved amortizations and deferrals. Negative amounts in O&M or A&G represent deferrals. See Worksheet S.

W If the company submits a Section 205 filing proposing to make adjustments to this formula rate cost of service template to remove assets and costs related to transmission facilities constructed and operated specifically for the purpose of delivering the output of generation facilities, including generation tie-lines, which do not qualify under the SPP OATT for inclusion in transmission cost of service, challenges to such filing(s) shall be limited to the justness and reasonableness of such proposal.

Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet A-1** - Detailed Plant Balances
**COMPANY NAME**

| | | **Gross Plant In Service - Production** | | | | | |
|---|---|---|---|---|---|---|---|
| Line No | **Month** | **Production** | **Production ARO** | **Transmission** | **Transmission ARO** | **Distribution** | **Distribution ARO** |
| | **(a)** | **(b)** FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46 | **(c)** FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44 | **(d)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58 | **(e)** Acct. 359.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57 | **(f)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75 | **(g)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74 |
| 1 | December Prior to Rate Year | | | | | | |
| 2 | January | | | | | | |
| 3 | February | | | | | | |
| 4 | March | | | | | | |
| 5 | April | | | | | | |
| 6 | May | | | | | | |
| 7 | June | | | | | | |
| 8 | July | | | | | | |
| 9 | August | | | | | | |
| 10 | September | | | | | | |
| 11 | October | | | | | | |
| 12 | November | | | | | | |
| 13 | December of Rate Year | | | | | | |
| 14 | Average of the 13 Monthly Balances | - | - | - | - | - | - |

| | | **Gross Plant In Service - Distribution, General and Intangible, GSU, Excluded Plant** | | | | |
|---|---|---|---|---|---|---|
| Line No | **Month** | **General** | **General ARO** | **Intangible** | **OATT Ancillary Services (GSU)** | **Excluded Plant** |
| | **(a)** | **(b)** FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99 | **(c)** Acct. 399.1 FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98 | **(d)** FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5 | **(e)** Company Records | **(f)** Company Records |
| 15 | December Prior to Rate Year | | | | | |
| 16 | January | | | | | |
| 17 | February | | | | | |
| 18 | March | | | | | |
| 19 | April | | | | | |
| 20 | May | | | | | |
| 21 | June | | | | | |
| 22 | July | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | August | | | | | |
| 24 | September | | | | | |
| 25 | October | | | | | |
| 26 | November | | | | | |
| 27 | December of Rate Year | | | | | |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | - |

**Transmission Functional Plant Held For Future Use (Notes A and B)**

| Line No | Asset Description | Definite Plan for Future Use | Estimated in Service Year | 2XXX Rate Year Beginning balance | 2XXX Rate Year Ending balance | 2XXX Rate Year Averag |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 29A | | | | | | |
| 29B | | | | | | |
| 29C | | | | | | |
| 30 | Total | | | - | - | - |

Notes:

(A) Per the general instruction for Account No. 105 in 18 CFR Part 101.

(B) Include only the Transmission functional component of amounts reported page 214 of the FERC Form 1.

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet A-2** - Detailed Accumulated Depreciation Balances
**COMPANY NAME**

| | | **Accumulated Depreciation - Production** | | | | | |
|---|---|---|---|---|---|---|---|
| Line No | **Month** | **Production** | **Production ARO** | **Transmission** | **Transmission ARO** | **Distribution** | **Distribution ARO** |
| | **(a)** | **(b)** FF1, page 219, lns 20-24, Col. (b) | **(c)** Company Records (Included in total in Column (b)) | **(d)** FF1, page 219, ln 25, Col. (b) | **(e)** Company Records (Included in total in Column (b)) | **(f)** FF1, page 219, ln 26, Col. (b) | **(g)** Company Records (Included in total in Column (b)) |
| 1 | December Prior to Rate Year | | | | | | |
| 2 | January | | | | | | |
| 3 | February | | | | | | |
| 4 | March | | | | | | |
| 5 | April | | | | | | |
| 6 | May | | | | | | |
| 7 | June | | | | | | |
| 8 | July | | | | | | |
| 9 | August | | | | | | |
| 10 | September | | | | | | |
| 11 | October | | | | | | |
| 12 | November | | | | | | |
| 13 | December of Rate Year | | | | | | |
| 14 | Average of the 13 Monthly Balances | - | - | - | - | - | - |

| | | **Accumulated Depreciation- Distribution, General and Intangible, GSU, Excluded Plant** | | | | |
|---|---|---|---|---|---|---|
| Line No | **Month** | **General** | **General ARO** | **Intangible** | **OATT Ancillary Services (GSU)** | **Excluded Plant** |
| | **(a)** | **(b)** FF1, page 219, ln 28, Col. (b) | **(c)** Company Records (Included in total in Column (d)) | **(d)** FF1, page 200, ln 21, Col. (b) | **(e)** Company Records | **(f)** Company Records |
| 15 | December Prior to Rate Year | | | | | |
| 16 | January | | | | | |
| 17 | February | | | | | |
| 18 | March | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 19 | April | | | | | |
| 20 | May | | | | | |
| 21 | June | | | | | |
| 22 | July | | | | | |
| 23 | August | | | | | |
| 24 | September | | | | | |
| 25 | October | | | | | |
| 26 | November | | | | | |
| 27 | December of Rate Year | | | | | |
| 28 | Average of the 13 Monthly Balances | - | - | - | - | - |

| | | |
|---|---|---|
| 29 | Transmission Accumulated, net of GSU and Excluded- Ln 14 Col (d) less Ln 28 Cols. (e) & (f) | $0 |

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet B** - Third Party Facility Credits
**COMPANY NAME**

| Line No. | Source | Amount |
|---|---|---|
| 1 | Facility Credits under the SPP OATT | - |

Note: Under Section 30.9 of the SPP OATT, a network customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. Calculation of any credit under this subsection, pursuant to approval by FERC for inclusion in this formula rate for collection on behalf of the network customer, shall be addressed in either the Network Customer's Service Agreement or any other agreement between the parties.

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet C** - ADIT and ADITC Balances
**COMPANY NAME**

| Line No. | (A) Acc. No. | (B) Description | (C) YE Balance | (E) Exclusions * | (F) 100% Transmission Related | (G) PTD Plant Related | (H) Transmission & Distribution Plant Related | (I) Labor Related | (J) Total Included in Rate base (E)+(F)+(G)+(H) |
|---|---|---|---|---|---|---|---|---|---|
| | | **Note: Account 281 is not allocated to Transmission** | | | | | | | |
| | | **Account 282 - Form-1 page 274.2.b and 275.2.k** | | | | | | | |
| 1 | 282.1 | 2XXX Year End Tax Deferrals - WS C-1 | - | - | - | - | - | - | |
| 2 | 282.1 | 2XXX-1 Year End Tax Deferrals - WS C-2 | - | - | - | - | - | - | |
| 3 | | **Subtotal** | - | - | - | - | - | - | |
| 4 | | **Average Balance before Proration** | - | - | - | - | - | - | |
| 5 | | **Proration Adjustment - WS C-3, Ln 19** | | | | - | | | |
| 6 | | **Prorated Average balance** | - | - | - | - | - | - | |
| 7 | | **Transmission Allocator from TCOS** | | 0.0000% | 100.0000% | 100.0000% | 100.0000% | 0.0000% | |
| 8 | | **Allocated Total** | | - | - | - | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **Account 283 - Form-1 page 276.9.b and 277.9.k** | | | | | | | |
| 9 | 283.1 | 2XXX Year End Tax Deferrals - WS C-1 | - | - | - | - | - | - | |
| 10 | 283.1 | 2XXX-1 Year End Tax Deferrals - WS C-2 | - | - | - | - | - | - | |
| 11 | | **Subtotal** | - | - | - | - | - | - | |
| 12 | | **Average Balance** | - | - | - | - | - | - | |
| 13 | | **Transmission Allocator from TCOS** | | 0.0000% | 100.0000% | 100.0000% | 100.0000% | 0.0000% | |
| 14 | | **Allocated Total** | | - | - | - | - | - | - |
| | | **Account 190 - Form-1 page 234, Ln 8, Col. (b) & ( c)** | | | | | | | |
| 15 | 190.1 | 2XXX Year End Tax Deferrals - WS C-1 | - | - | - | - | - | - | |
| 16 | 190.1 | 2XXX-1 Year End Tax Deferrals - WS C-2 | - | - | - | - | - | - | |
| 17 | | **Subtotal** | - | - | - | - | - | - | |
| 18 | | **Average Balance before Proration** | - | - | - | - | - | - | |
| 19 | | **Proration Adjustment - WS C-3, Ln 38** | | | - | | | | |
| 20 | | **Prorated Average balance** | - | - | - | - | - | - | |
| 21 | | **Transmission Allocator from TCOS** | | 0.0000% | 100.0000% | 100.0000% | 100.0000% | 0.0000% | |
| 22 | | **Allocated Total** | | - | - | - | - | - | - |
| | | | | | | Pre 1971 ITC Includable in Rate Base | | | |
| | | **Account 255 - Form-1 page 266-267** | | | | | | | |
| 23 | 255.0 | Acc Defrd ITC - Federal - 12/31/2XXX (FF1 p. 267, Ln 2.h) | | | | - | | | |
| 24 | 255.0 | Acc Defrd ITC - Federal - 12/31/2XXX-1 (FF1 p. 266, Ln 2.b) | | | | - | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 25 | **Subtotal** | - | | | - | | | |
| 26 | **Average Balance** | - | | | - | | | |
| 27 | **Transmission Allocator from TCOS** | | | | 100.0000% | | | |
| 28 | **Allocated Total** | | N/A | N/A | - | N/A | N/A | - |

* Exclusions: Non-utility, fuel supply, off-system sales and other items as specified related to costs not included in rates.

AEP West SPP Member Transmission Companies

COMPANY
NAME

**WORKSHEET C-1** - END OF YEAR DETAIL OF DEFERRED INCOME TAX BALANCES

**AS OF DECEMBER 31, 2XXX**

| | | | | | Allocation Method | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Account** | **Line #** | **Description** | **Balance** | **Allocation Basis** | **Exclusions** | **100% Transmission** | **PTD Plant** | **T&D** | **Labor** |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 PROTECTED | | WS C-4 | | | | | |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 UNPROTECTED | | WS C-4 | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Forecast Adjustment to 282 | | | | | | | | |
| **282.1** | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL**<br>(absolute value Total Company Amount Ties to FF1 p.275(k) -- Acct 282 Electric) | **-** | | **-** | **-** | **-** | **-** | **-** |
| 2831001 | 960F | 960F-XS EXCESS ADFIT 283 UNPROTECTED | | WS C-4 | | | | | |
| | | Forecast Adjustment to 283 | | | | | | | | |
| **283.1** | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL**<br>(absolute value Total Company Amount Ties to FF1 p.277(k) -- Acct 283 Electric) | **-** | | **-** | **-** | **-** | **-** | **-** |
| | | Forecast Adjustment to 190 | | | | | | | | |
| **190.1** | | **TOTAL ELECTRIC ACCOUNT SUBTOTAL**<br>(Total Company Amount Ties to FF1 p.234(c) -- Electric) | **-** | | **-** | **-** | **-** | **-** | **-** |

AEP West SPP Member Transmission Companies

COMPANY NAME

**WORKSHEET C-2** -BEGINNING OF YEAR DETAIL OF DEFERRED INCOME TAX BALANCES

**AS OF DECEMBER 31, 2XXX -1**

| | | | | | Allocation Method | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Account** | **Line #** | **Description** | **Balance** | **Allocation Basis** | **Exclusions** | **100% Transmission** | **PTD Plant** | **T&D** | **Labor** |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 PROTECTED | | WS C-4 | | | | | |
| 2821001 | 960F | 960F-XS EXCESS ADFIT 282 UNPROTECTED | | WS C-4 | | | | | |

Forecast Adjustment to 282

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 282.1 | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** | - | | | | | - | - | - | |
| | (absolute value Total Company Amount Ties to FF1 p.275(k) -- Acct 282 Electric) | | | | | - | - | | | |

2831001 960F-XS EXCESS ADFIT 283 UNPROTECTED WS C-4
960F

Forecast Adjustment to 283

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 283.1 | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** | - | | | | | - | - | - | |
| | (absolute value Total Company Amount Ties to FF1 p.277(k) -- Acct 283 Electric) | | | | | - | - | | | |

Forecast Adjustment to 190

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 190.1 | **TOTAL ELECTRIC ACCOUNT SUBTOTAL** | - | | | | | - | - | - | |
| | (Total Company Amount Ties to FF1 p.234(c) -- Electric) | | | | | - | - | | | |

AEP West SPP Member Transmission Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet C-4 - Excess Deferred Federal Income Taxes**

**COMPANY NAME**

NOTES

Include only excess DFIT recorded in accounts which are included in the formula rate cost of service. These include one or more subaccounts within accounts 190.1, 282.1, and 283.1.

*NOTE A: In the event of future tax rate changes that will rely on settlement-based amortization amounts or periods, additional columns can be added to reflect those changes. Future settlements addressing the amortization of unprotected excess or deficient ADIT will not be reflected hereon without first obtaining Commission authorization in a section 205 filing under the Federal Power Act.*

*NOTE B: In the event that an initial unprotected, excess or deficient ADIT amount changes due to adjustments, residual balances will be amortized in the final year of the amortization period.*

| Line | (A) | (B) | | (C) | (D) | (E) | (F) | (G) |
|---|---|---|---|---|---|---|---|---|
| | | | | Account *(NOTE A)* | | | | |
| | **Unprotected ADIT Balances** | Source | Total | 1901001 | 2821001 | 2831001 | XXXXXXX | XXXXXXX |
| | ***Tax Rate Change Legislative Act*** | | | *TCJA of 2017* | *TCJA of 2017* | *TCJA of 2017* | | |
| 1 | Balance per Books- Transmission Function only (190 enter positive, 282/283 enter negative) *(NOTE B)* | Company records | - | - | | | | |
| 2 | Settlement Amortization period | *(NOTE C)* | | 5 | 5 | 5 | # | # |
| 3 | Annual Transmission Function Amortization | Line 1 / Line 2 | - | - | - | - | - | - |
| 4 | Rate Year Beginning Accumulated Amortization | Company records | - | - | | | | |
| 5 | Rate year Ending Accumulated Amortization | Line 3 + Line 4 | - | - | - | - | - | - |
| 6 | Rate Year Beginning Balance Per Books - Total Company | WS C-2 960F XS Unprotected | - | - | - | - | | |
| 7 | Rate Year Beginning Included Balance - 100% Transmission Function net of amortization | Line 1 - Line 4 | - | - | - | - | - | - |
| 8 | Worksheet C-2 Rate Base Excluded Balance | Line 6 - Line 7 | - | - | - | - | - | - |
| 9 | Rate Year Ending Balance Per Books - Total Company | WS C-1 960F XS Unprotected | - | - | - | - | | |
| 10 | Rate Year Ending Included Balance - 100% Transmission Function net of amortization | Line 1 - Line 5 | - | - | - | - | - | - |
| 11 | Worksheet C-1 Rate Base Excluded Balance | Line 9 - Line 10 | - | - | - | - | - | - |

| | | | | Account *(NOTE A)* | | |
|---|---|---|---|---|---|---|
| | **Protected ADIT Balances** | Source | Total | 2821001 | XXXXXXX | XXXXXXX |
| | ***Tax Rate Change Legislative Act*** | | | *TCJA of 2017* | | |
| 12 | Balance per Books- Transmission Function only (190 enter positive, 282/283 enter negative) | Company records | - | | | |
| 13 | Annual Transmission Function Amortization | Company records | - | | | |
| 14 | Beginning Accumulated Amortization | Company records | - | | | |
| 15 | Ending Accumulated Amortization | Line 13 + Line 14 | - | - | - | |
| 16 | WS C-2 Beginning Balance Per Books - Total Company | WS C-2 960F XS Protected | - | | | |
| 17 | Rate Year Ending Included Balance - 100% Transmission Function net of amortization | Line 12 - Line 14 | - | - | - | - |
| 18 | Worksheet C-2 Rate Base Excluded Balance | Line 16 - Line 17 | - | - | - | - |
| 19 | WS C-1 Ending Balance Net of Accumulated Amortization Per Books - Total Company | WS C-1 960F XS Protected | - | | | |
| 20 | Rate Year Ending Included Balance - 100% Transmission Function net of amortization | Line 12 - Line 15 | - | - | - | - |
| 21 | Worksheet C-1 Rate Base Excluded Balance | Line 19 - Line 20 | - | - | - | - |

| | **Annual Amortization of Excess ADIT** | | Transmission Function |
|---|---|---|---|
| 22 | Unprotected | Line 3 | - |
| 23 | Protected | Line 13 | - |
| 24 | Total | Line 22 + Line 23 | - |

*NOTE C: The following table presents supporting information regarding settlements reported on this page.*

| *Tax Rate Change Act* | *Settlement Reference* | *Protected Amortization Period* | *Unprotected Amortization Period* |
|---|---|---|---|
| *TCJA of 2017* | *ER18-194/195 Settlement* | *Average Rate Assumption Method* | *Five Years Starting 1/1/2018* |
| | | | |
| | | | |
| | | | |
| | | | |

*COMPANY NAME HERE*

*Worksheet C-5*
*Excess/ Deficient ADIT Worksheet for Total Company Balances*
*For Year Ended December 31, 20__*
*Debit/(Credit)*

| *A* | *B* | *C* | *D* | *E* | *F* | *G* | *H* |
|---|---|---|---|---|---|---|---|
| ***TOTAL COMPANY BALANCES*** | | | | | | | |
| *Line No.* | ***Account (NOTE A)*** | ***Description of Account*** | ***Protected Unprotected*** | ***Tax Rate Change Act*** | ***Excess/Deficient Balance at Remeasurement (NOTE C)*** | ***Amortization Methodology (NOTE D)*** | ***Amortization Period*** |
| | ***Deferred Tax Account (NOTE B)*** | | | | | | |
| *1a* | | | | | | | |
| *1b* | | | | | | | |
| *1c* | | | | | | | |
| *1d* | | | | | | | |
| *1e* | | | | | | | |
| *1f* | | | | | | | |
| *1g* | | | | | | | |
| *1h* | | | | | | | |
| *1i* | | | | | | | |
| *1j* | ***NOTE E*** | | | | | | |
| | ***Regulatory Deferral Accounts*** | | | | | | |
| *2a* | *182.3* | *Regulatory Asset* | | | | | |
| *2b* | *254* | *Regulatory Liability* | | | | | |
| *2c* | ***NOTE E*** | | | | | | |
| *3* | *Total For Accounting Entries (Sum of Lines 1a through 2_)* | | | | - | | |

| *I* | *J* | *K* | *L* | *M* | *N* | *O* | *P* | *Q* | *R* |
|---|---|---|---|---|---|---|---|---|---|

| *1/1/20__ Beginning Balances* | | | *Balance Sheet Entries* | | *Tax Expense Entries* | | *12/31/20__ Ending Balance* | | |
|---|---|---|---|---|---|---|---|---|---|
| ***Excess/(Deficient) ADIT Regulatory Offset*** | ***(Excess)/Deficient ADIT in Utility Deferrals*** | ***Balance Sheet Account Reclassifications NOTE I*** | ***182.3*** | ***254*** | ***410/411 Excess/Deficient Amortization NOTE H*** | ***410/411 Deferred Tax Expense/ (Benefit)*** | ***Excess/(Deficient) ADIT Regulatory Offset Sum of Cols (I) - (O)*** | ***(Excess)/Deficient ADIT in Utility Deferrals*** | ***Reference*** |
| | | | | | | | | | |
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| | | | | | | | - | | |
| | | | | | | | | | |
| - | - | - | - | | - | - | - | - | - |

*NOTE F*

*Amortization Amount by Tax Rate Change (NOTE G)*

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| | *Tax Rate Change Act* | *Settlement Amortization* | *Reference* | *Book Amortization* | *Reference* | *Amount Used in TRR* |
| *4a* | | *$* | | *$* | | *$* |
| *4b* | | *$* | | *$* | | *$* |
| *4c* | | *$* | | *$* | | *$* |
| *4d* | | *$* | | *$* | | *$* |
| *4x* | ***NOTE E*** | ***$*** | | ***$*** | | ***$*** |
| *4* | *Total* | *$* | | *$* | | *$* |
| | | | | | | *TCOS, Col (5), Ln 105* |

*The information provided on this worksheet reflects the activity on the books of the Company. In the event the Excess or Deficient ADIT associated with a specific tax rate change will be passed back or recovered on the basis of an approved settlement the Company will use WS C-4 for that purpose, as opposed to book amounts that are shown on this work sheet. See NOTE E and NOTE G below for a further description on how the Company will track future tax rate changes and ensure the proper net amount is recorded on line 105 in the TCOS of the formula.*

*NOTE A: In order to ensure ratebase neutrality, AEP utilizes the fourth digit of its seven digit FERC tax subaccount numbers to identify balances associated with utility operations vs. regulatory reporting requirements. A "1" in the fourth digit of a FERC tax account refers to the utility operations balances or activity. Accounts with the "1" designation will be included in the determination of ratebase to be recovered in the formula rate. A "4" in the fourth position of the account number indicates accounts used to track regulatory accounting requirements. The excess ADIT amounts recorded in accounts with the "4" designation will be contra to the "1" balance, which will ensure that in the formula rate the excess or deficiency amounts will be part of ratebase, but at the total FERC account level the tax liability or asset will be recorded at the current Federal FIT rate. The amounts recorded in the "4" accounts will be offset on a net basis in the regulatory asset or liability subaccount established for this purpose.*

*NOTE B: The amount of the FIT gross up to recorded on regulatory assets and liabilities will be reported on the first line of ADIT accounts provided for each specific change in tax rates.*

*NOTE C: The amounts of the remeasurement shown here are as of the effective date of the change in tax rates and will remain static on this workpaper. The derivation of this amount, along with the pre-remeasurement and post-remeasurement balances of ADIT, are presented in formula wokpaper(s) C-5-X.*

*NOTE D: {REFERENCE OR CITES TO APPROVAL OF AMORTIZATION PERIOD FOR UNPROTECTED EXCESS ADIT}*

*NOTE E: In the event of future tax rate changes, additional lines will be inserted above as required to reflect any new ADIT or regulatory deferral accounts that may be necessary to track that tax rate change.*

*NOTE F: The amount of excess amortization entries shown in lines 1a through 1j are shown as a debit or credit to the ADIT account from which it is being amortized. The totals in line 3 is the offset recorded to the 410/411 tax expense account.*

*NOTE G: Amortization expense determined on WS C-4 due to a settlement will supersede the amortization of excess and deficient ADIT included in Column N, Ln 3 of this worksheet, due to the primacy of settlement over book amounts in the determination of the revenue requirement.*

*NOTE H: Deficient remeasurement amounts will be recorded in 410.1 as a debit (expense) to cost of service; excess remeasurement amounts will be recorded in 411.1 as a credit to cost of service.*

*NOTE I. In the event that there are adjustments reported in column K of this worksheet that would result in changes to the initial unprotected excess or deficient ADIT amounts, AEP will provide supporting documentation for those adjustments to customers as a part of its annual update process.*

*AEP WEST TRANSMISSION COMPANIES*
*COMPANY NAME HERE ___*

*WORKSHEET C-5-X_*
*TAX REMEASUREMENT WORKSHEET*
*Debit/(Credit)*

***{TAX CHANGE LEGISLATION}***

| *A* | *B* | *C* | *D* | *E* | *F=E/C* | *G* | *H = E + G* | *I* | *J = C - H* |
|---|---|---|---|---|---|---|---|---|---|
| *Line No.* | *Utility Account* | *XX/XX/XX Pre-remeasurement Balance* | *Description / Reference* | *Remeasurement Amount (NOTE 1)* | *Remeasurement Percentage (NOTE 2)* | *Adjustments (NOTE 3)* | *Total Excess/Deficiency by Account (NOTE 4)* | *Protected/ Unprotected* | *ADIT Deferral After Remeasurement* |
| ***TOTAL COMPANY*** | | | | | | | | | |
| | *List ADIT Accounts* | | *{DESCRIPTION OF LINE ITEMS}* | | | | | | |
| *1* | | *$* | | *$* | *%* | | *$* | | *$* |
| *2* | | | | | | | | | |
| *3* | | | | | | | | | |
| *4* | | | | | | | | | |
| *5* | | | | | | | | | |
| *6* | | | | | | | | | |
| *7* | | | | | | | | | |
| *8* | | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| *9* | | | | | | | | |
| *10* | | | | | | | | |
| *9* | | | | | | | | |
| *10* | | | | | | | | |
| *11* | | | | | | | | |
| *12* | | | | | | | | |
| *13* | | | | | | | | |
| *14* | *Total* | *$* | *(Sum of Lns. )* | *$* | | *$* | *$* | *$* |

*GENERAL NOTE: This worksheet will summarize remeasurement adjustments in ADIT Accounts required by changes in either Federal or State Income Tax Rates. A new sheet will be included in the working formula for each change to tax rates that may occur while this formula rate is in effect. New pages will be designated by incrementing the suffix letter in the workpaper name (i.e. C-5-A, C-5-B, etc.)*

*NOTE 1: Amount of Remeasurement in Column E will be based on supporting workpapers showing the remeasurement of individual ADIT items in each tax deferral account, and will indicate whether each remeasured ADIT item will be treated as protected or unprotected. The resulting totals will be shown on this worksheet for each ADIT account.*

*NOTE 2: Remeasurement calculation may not equal ___% of the _{DATE OF REMEASUREMENT}_____ deferral balance because of specific ADIT items that are not subject to remeasurement.*

*NOTE 3: [NOTES/EXPLANATIONS OF AMOUNTS REPORTED IN COLUMN G, IF NECESSARY]*

*NOTE 4: Ties to each Transmission Companies' Workpaper C-5, Column F, showing the initial remeasurement value determined as a result of the _{TAX RATE LEGISLATION}_____.*

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet D** - Materials and Supplies and Prepayments
**COMPANY NAME**

| | (A) | (B) | ( C ) | (D) | (E) | (F) | (G) | (H) |
|---|---|---|---|---|---|---|---|---|
| | **Materials & Supplies** | | | | | | | |
| **Line Number** | | | **Source** | | **13 Month Average Balance for Rate Year** | | | |
| 1 | | Transmission Materials & Supplies | WS D, p. 2 of 2, Col. (D), line 1 | | - | | | |
| 2 | | General Materials & Supplies | WS D, p. 2 of 2, Col. (D), line 2 | | - | | | |
| 3 | | Stores Expense (Undistributed) - Account 163 | WS D, p. 2 of 2, Col. (D), line 3 | | - | | | |
| | **Prepayments Account 165** | | | | | | | |
| **Line Number** | **Acc. No.** | **Description** | **13 Month Average balance Source - Page 2 of 2. Col (D)** | **Excludable Balances** | **100% Transmission Related** | **Plant Related** | **Labor Related** | **Explanation** |
| 4 | 1650001 | Prepaid Insurance | - | | | | | |
| 5 | 1650004 | Prepaid Interest | - | | | | | |
| 6 | 1650005 | Prepaid Employee Benefits | - | - | | | | |
| 7 | 1650006 | Other Prepayments | - | - | | | | |
| 8 | 1650009 | Prepaid Carry Cost-Factored | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | - | - | | | |
| 9 | 1650010 | Prepaid Pension Benefits | | | | | - |
| | | | - | | | | |
| 10 | 165001116 | Prepaid Sales Taxes | | | | - | |
| | | | - | | | | |
| 11 | 165001216 | Prepaid Use Taxes | | | | | |
| | | | - | - | | | |
| 12 | 1650014 | FAS 158 Qual Contra Asset | | | | | |
| | | | - | - | | | |
| 13 | 1650016 | FAS 112 ASSETS | | | | | |
| | | | - | - | | | |
| 14 | 1650021 | Prepaid Insurance - EIS | | | | | |
| | | | - | | | | |
| 15 | 1650023 | Prepaid Leases | | | | | |
| | | | - | - | | | |
| 16 | 1650028 | Trinity Rail Car Lease - Non-current | | | | | |
| | | | - | - | | | |
| 17 | 1650031 | Prepaid OCIP Work Comp | | | | | - |
| | | | - | | | | |
| 18 | 1650032 | Prepaid OCIP Work Comp-Long Term | | | | | - |
| | | | - | | | | |
| 19 | 1650033 | Prepaid OCIP Work Comp-Affiliated | | | | | - |
| | | | - | | | | |
| 20 | 1650034 | Prepaid OCIP Work Comp-Affiliated Long Term | | | | | - |
| | | | - | | | | |
| 21 | 1650035 | PRW Without MED-D Benefits | | | | | - |
| | | | - | | | | |
| 22 | 1650036 | PRW for Med-D Benefits | | | | | - |
| | | | - | | | | |
| 23 | 1650037 | FAS158 Contra-PRW Exclude Med-D | | | | | |
| | | | - | - | | | |
| 24 | | | | | | | - |
| | | | - | | | | |
| 25 | | | | | | | |
| | | | - | - | | | |
| 26 | | | | | | | |
| | | | - | | | | |
| 27 | | | | | | | |
| | | | - | | | | |
| 28 | | | | | | | |
| | | | - | | | | |
| 29 | | | | | - | - | - |
| | | | - | - | | | |

Note 1: Prepayment Balance will not include: (i) federal and state income tax payments made to offset additional tax liabilities resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; (ii) outstanding income tax refunds due to the company resulting (or expected to result) from prior federal or state audits or from the filing of one or more amended income tax returns; or (iii) prepayments of federal or state income taxes which are

attributable to income
earned during periods prior to January 1 of the year depicted in the Balance Sheet (as described in USofA Account 236).

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
Worksheet D - Materials and Supplies and Prepayments
**COMPANY NAME**

**Materials & Supplies**

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **(A)** | **(B)** | **( C )** | **(D)** | **(E)** | **(F)** | **(G)** | **(H)** | **(I)** | **(J)** | **(K)** | **(L)** | **(M)** | **(N)** | **(O)** | **(P)** | **(Q)** |
| | | | | **Monthly Balances** | | | | | | | | | | | | |
| **Line Number** | **Description** | **Source - December Balances** | **13 Month Average** | December 2XXX-1 | January 2XXX | February 2XXX | March 2XXX | April 2XXX | May 2XXX | June 2XXX | July 2XXX | August 2XXX | September 2XXX | October 2XXX | November 2XXX | December 2XXX |
| 1 | Transmission Materials & Supplies | FF1, p. 227, ln 8, Col. (c & b) | - | | | | | | | | | | | | | |
| 2 | General Materials & Supplies | FF1, p. 227, ln 11, Col. (c & b) | - | | | | | | | | | | | | | |
| 3 | Stores Expense (Undistributed) - Account 163 | FF1, p. 227, ln 16, Col. (c & b) | - | | | | | | | | | | | | | |

**Prepayments Account 165**
Line item balances obtained from Company Records

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Monthly Balances** | | | | | | | | | | | | |
| **Line Number** | **Acc. No.** | **Description** | **13 Month Average** | December 2XXX-1 | January 2XXX | February 2XXX | March 2XXX | April 2XXX | May 2XXX | June 2XXX | July 2XXX | August 2XXX | September 2XXX | October 2XXX | November 2XXX | December 2XXX |
| 4 | 1650001 | Prepaid Insurance | - | | | | | | | | | | | | | |
| 5 | 1650004 | Prepaid Interest | - | | | | | | | | | | | | | |
| 6 | 1650005 | Prepaid Employee Benefits | - | | | | | | | | | | | | | |
| 7 | 1650006 | Other Prepayments | - | | | | | | | | | | | | | |
| 8 | 1650009 | Prepaid Carry Cost-Factored | - | | | | | | | | | | | | | |

| | | |

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet E** - IPP Credits
**COMPANY NAME**

| **Line Number** | **(A) Description** | **(B) 2XXX** |
|---|---|---|
| 1 | Net Funds from IPP Customers @ 12/31/2XXX-1 ("&C8&" FORM 1, P269, (B)) | |
| 2 | Interest Accrual (Company Records) | |
| 3 | Revenue Credits to Generators (Company Records) | |
| 4 | Other Adjustments (Company Records) | |
| 5 | Accounting Adjustment | |
| 6 | | |
| 7 | Net Funds from IPP Customers 12/31/2XXX (2XXX FORM 1, P269, (F)) | - |
| 8 | Average Balance for 2XXX ((ln 1 + ln 7)/2) | - |

AEP West SPP Member Transmission Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet F** - Calculation of PROJECTED Annual Revenue Requirement for Base Plan and Special-Billed Projects

**COMPANY NAME**

| Line Number | | | | | | |
|---|---|---|---|---|---|---|
| | **I.** | **Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Incentive.** | | | | |
| | | **A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects** | | | | |
| 1 | | ROE w/o incentives (TCOS, ln 143) | | | 10.50% | |
| 2 | | Project ROE Incentive Adder (Enter as whole number) | | | - | basis points |
| 3 | | ROE with additional 0 basis point incentive | | | 10.50% | **<==Incentive ROE** |
| 4 | | Determine R (cost of long term debt, cost of preferred stock and percent is from TCOS, lns 141 through 143) | | | | |
| 5 | | | % | Cost | Weighted cost | |
| 6 | | Long Term Debt | - | - | - | |
| 7 | | Preferred Stock | - | - | - | |
| 8 | | Common Stock | - | 10.50% | - | |
| 9 | | | | R = | - | |
| | | **B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for** | | | | |

Note: Worksheets F and G are both populated from the TCOS worksheet every update.

Worksheet F is only used in Projections. Worksheet G is used only in True-Ups.
These worksheets add up all of the individual SPP Base Plan projects, Requested Upgrades,
Economic Upgrades, or any other projects billed by SPP through other than the NITS rate.

SUMMARY OF PROJECTED ANNUAL BASE PLAN AND NON-BASE PLAN REVENUE REQUIREMENTS

| | | Rev Require | With Incentives | Incentive Amounts |
|---|---|---|---|---|
| ∑ Projected Year | 2XXX | - | - | $ - |

**Identified Projects.**

| | | |
|---|---|---|
| 10 | Rate Base (TCOS, ln 63) | - |
| 11 | R (from A. above) | - |
| 12 | Return (Rate Base x R) | - |

**NOTE:** **PART IV ---Projected Base Plan Project Tables are contained in a separate file**

**C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | |
|---|---|---|
| 13 | Return (from B. above) | - |
| 14 | Tax Rate (TCOS, ln 99) | - |
| 15 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | - |
| 16 | Income Tax Calculation (Return x EIT) | - |
| 17 | ITC Adjustment (TCOS, ln 108) | - |
| 18 | Excess DFIT Adjustment (TCOS, ln 109) | - |
| 19 | Tax Effect of Permanent and Flow Through Differences (TCOS, ln 110) | - |
| 20 | Income Taxes | - |

**II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.**

**A. Determine Net Revenue Requirement less return and Income Taxes.**

| | | |
|---|---|---|
| 21 | Net Revenue Requirement (TCOS, ln 117) | - |
| 22 | Return (TCOS, ln 112) | - |
| 23 | Income Taxes (TCOS, ln 111) | - |
| 24 | Gross Margin Taxes (TCOS, ln 116) | - |
| 25 | Net Revenue Requirement, Less Return and Taxes | - |

**B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.**

| | | |
|---|---|---|
| 26 | Net Revenue Requirement, Less Return and Taxes | |

| | | |
|---|---|---|
| 27 | Return (from I.B. above) | - |
| 28 | Income Taxes (from I.C. above) | - |
| 29 | Net Revenue Requirement, with 0 Basis Point ROE increase | - |
| 30 | Gross Margin Tax with Basis Point ROE Increase (II C. below) | - |
| 31 | Revenue Requirement w/ Gross Margin Taxes | - |
| 32 | Less: Depreciation (TCOS, ln 86) | - |
| 33 | Net Rev. Req, w/0 Basis Point ROE increase, less Depreciation | - |

**C. Determine Gross Margin Tax with hypothetical 0 basis point increase in ROE.**

| | | |
|---|---|---|
| 34 | Net Revenue Requirement before Gross Margin Taxes, with 0 | - |
| 35 | Basis Point ROE increase (II B. above) | |
| 36 | Apportionment Factor to Texas (Worksheet K, ln 12) | - |
| 37 | Apportioned Texas Revenues | - |
| 38 | Taxable Percentage of Revenue | |
| 39 | Taxable, Apportioned Margin | - |
| 40 | Texas Gross Margin Tax Rate | |
| 41 | Texas Gross Margin Tax Expense | - |
| 42 | Gross-up Required for Gross Margin Tax Expense | - |
| 43 | Total Additional Gross Margin Tax Revenue Requirement | - |

**D. Determine FCR with hypothetical 0 basis point ROE increase.**

| | | |
|---|---|---|
| 44 | Net Transmission Plant (TCOS, ln 37) | - |
| 45 | Net Revenue Requirement, with 0 Basis Point ROE increase | - |
| 46 | FCR with 0 Basis Point increase in ROE | - |
| 47 | Net Rev. Req, w / 0 Basis Point ROE increase, less Dep. | - |
| 48 | FCR with 0 Basis Point ROE increase, less Depreciation | - |
| 49 | FCR less Depreciation (TCOS, ln 10) | - |
| 50 | Incremental FCR with 0 Basis Point ROE increase, less Depreciation | - |

**III. Calculation of Composite Depreciation Rate**

| | | |
|---|---|---|
| 51 | Transmission Plant Average Balance for 2XXX (WS A-1 Ln 14 Col (d)) | - |
| 52 | Annual Depreciation Expense (TCOS, ln 86) | - |
| 53 | Composite Depreciation Rate | - |

| | | |
|---|---|---|
| 54 | Depreciable Life for Composite Depreciation Rate | - |
| 55 | Round to nearest whole year | - |

**'Worksheet F -- COMPANY NAME -- Calculation of Projected ARR for SPP Base Plan Upgrade Projects**

**IV. Determine the Revenue Requirement & Additional Revenue Requirement for facilities receiving incentives.**

**A. Facilities receiving incentives accepted by FERC in Docket No.**

**Project Description:**

| **DETAILS** | Project Number |
|---|---|

| | |
|---|---|
| **Current Projected Year ARR** | |
| **Current Projected Year ARR w/ Incentive** | |
| **Current Projected Year Incentive ARR** | - |

| | | | |
|---|---|---|---|
| Investment (EOY) | | Projected Year | **2XXX** |
| Service Year (yyyy) | | ROE increase accepted by FERC (Basis Points) | - |
| Service Month (1-12) | - | FCR w/o incentives, less depreciation | 0.00% |
| Useful life | - | FCR w/incentives approved for these facilities, less dep. | 0.00% |
| CIAC (Yes or No) | | Annual Depreciation Expense | - |

| **Year** | **Investment Beginning Balance** | **Depreciation Expense** | **Ending Balance** | **Annual Revenue Requirement** | **Annual Revenue Req't. with Incentives** | **Additional Rev. Requirement **** |
|---|---|---|---|---|---|---|
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| - | - | - | - | - | - | $ - |
| Project Totals | | | | - | - | - |

CUMMULATIVE HISTORY OF PROJECTED ANNUAL REVENUE REQUIREMENTS:
INPUT PROJECTED ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR
TEMPLATE BELOW TO MAINTAIN HISTORY OF PROJECTED ARRS OVER THE LIFE OF THE PROJECT.

| **PROJECTED Rev. Req't From Prior Year Template w/o Incentives** | **Project Rev Req't True-up w/o Incentives** | **PROJECTED Rev. Req't From Prior Year Template with Incentives **** | **Project Rev Req't True-up with Incentives **** | **True-up of Incentive with Incentives**** |
|---|---|---|---|---|
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |

**** This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project Each year the revenue requirement calculated for SPP should be incremented**

**by the amount of the incentive revenue calculated for that year on this project.**

AEP West SPP Member Transmission Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet G** - Calculation of TRUED-UP Annual Revenue Requirement for Base Plan and Special-Billed Projects

**COMPANY NAME**

**Line Number**

**I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Incentive.**

**A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects**

Note: Worksheets F and G are both populated from the TCOS worksheet every update.
Worksheet F is only used in Projections. Worksheet G is used only in True-Ups.

These worksheets add up all of the individual SPP Base Plan projects, Requested Upgrades,
Economic Upgrades, or any other projects billed by SPP through other than the NITS rate.

| | | | | | |
|---|---|---|---|---|---|
| 1 | ROE w/o incentives (TCOS, ln 143) | | | 10.50% | |
| 2 | Project ROE Incentive Adder (Enter as whole number) | | | - | basis points |
| 3 | ROE with additional 0 basis point incentive | | | 10.50% | **<==Incentive ROE** |
| 4 | Determine R (cost of long term debt, cost of preferred stock and percent is from TCOS, lns 141 through 143) | | | | |
| 5 | | % | Cost | Weighted cost | |
| 6 | Long Term Debt | - | - | - | |
| 7 | Preferred Stock | - | - | - | |
| 8 | Common Stock | - | 10.50% | - | |
| 9 | | | R = | - | |

| SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR SPP BPU & NON-BPU PROJECTS | | Rev Require | With Incentives | Incentive Amounts |
|---|---|---|---|---|
| True-Up Rate Year | 2XXX | | | |
| ∑ True Up Year Projected | WS-F | $ - | $ - | $ - |
| ∑ True-Up Year True-Up | WS-G | $ - | $ - | $ - |
| True-up Adjustment For 2XXX | | - | - | - |

**B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | |
|---|---|---|
| 10 | Rate Base (TCOS, ln 63) | - |
| 11 | R (from A. above) | - |
| 12 | Return (Rate Base x R) | - |

**NOTE:** **PART IV --- True-Up Base Plan Project Tables are contained in a separate file**

**C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.**

| | | |
|---|---|---|
| 13 | Return (from B. above) | |

| | | |
|---|---|---|
| | | - |
| 14 | Tax Rate (TCOS, ln 99) | |
| | | - |
| 15 | EIT=(T/(1-T)) * (1-(WCLTD/WACC)) = | - |
| 16 | Income Tax Calculation (Return x EIT) | - |
| 17 | ITC Adjustment (TCOS, ln 108) | |
| | | - |
| 18 | Excess DFIT Adjustment (TCOS, ln 109) | |
| | | - |
| 19 | Tax Effect of Permanent and Flow Through Differences (TCOS, ln 110) | - |
| 20 | Income Taxes | |
| | | - |

**II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.**

**A. Determine Net Revenue Requirement less return and Income Taxes.**

| | | |
|---|---|---|
| 21 | Net Revenue Requirement (TCOS, ln 117) | |
| | | - |
| 22 | Return (TCOS, ln 112) | |
| | | - |
| 23 | Income Taxes (TCOS, ln 111) | |
| | | - |
| 24 | Gross Margin Taxes (TCOS, ln 116) | |
| | | - |
| 25 | Net Revenue Requirement, Less Return and Taxes | - |

**B. Determine Net Revenue Requirement with hypothetical 0 basis point increase in ROE.**

| | | |
|---|---|---|
| 26 | Net Revenue Requirement, Less Return and Taxes | |
| | | - |
| 27 | Return (from I.B. above) | |
| | | - |
| 28 | Income Taxes (from I.C. above) | |
| | | - |
| 29 | Net Revenue Requirement, with 0 Basis Point ROE increase | - |
| 30 | Gross Margin Tax with Basis Point ROE Increase (II C. | |

| | | |
|---|---|---|
| | below) | - |
| 31 | Revenue Requirement w/ Gross Margin Taxes | - |
| 32 | Less: Depreciation (TCOS, ln 86) | - |
| 33 | Net Rev. Req, w/0 Basis Point ROE increase, less Depreciation | - |
| | **C. Determine Gross Margin Tax with hypothetical 0 basis point increase in ROE.** | |
| 34 | Net Revenue Requirement before Gross Margin Taxes, with 0 | - |
| 35 | Basis Point ROE increase (II B. above) | |
| 36 | Apportionment Factor to Texas (Worksheet K, ln 12) | - |
| 37 | Apportioned Texas Revenues | - |
| 38 | Taxable Percentage of Revenue | |
| 39 | Taxable, Apportioned Margin | - |
| 40 | Texas Gross Margin Tax Rate | |
| 41 | Texas Gross Margin Tax Expense | - |
| 42 | Gross-up Required for Gross Margin Tax Expense | - |
| 43 | Total Additional Gross Margin Tax Revenue Requirement | - |
| | **D. Determine FCR with hypothetical 0 basis point ROE increase.** | |
| 44 | Net Transmission Plant (TCOS, ln 37) | - |
| 45 | Net Revenue Requirement, with 0 Basis Point ROE increase | - |
| 46 | FCR with 0 Basis Point increase in ROE | - |
| 47 | Net Rev. Req, w / 0 Basis Point ROE increase, less Dep. | - |
| 48 | FCR with 0 Basis Point ROE increase, less Depreciation | - |
| 49 | FCR less Depreciation (TCOS, ln 10) | - |
| 50 | Incremental FCR with 0 Basis Point ROE increase, less Depreciation | - |
| | **III. Calculation of Composite Depreciation Rate** | |
| 51 | Transmission Plant Average Balance for 2XXX (WS A-1 Ln 14 Col (d)) | - |

| | | |
|---|---|---|
| 52 | Annual Depreciation Expense (TCOS, ln 86) | - |
| 53 | Composite Depreciation Rate | - |
| 54 | Depreciable Life for Composite Depreciation Rate | - |
| 55 | Round to nearest whole year | - |

**Worksheet G -- COMPANY NAME-- Calculation of Trued-Up ARR for SPP Base Plan Upgrade Projects**

**IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.**

**A. Facilities receiving incentives accepted by FERC in Docket No.**

| | **2XXX** | Rev Require | w/Incentives | Incentive Amounts |
|---|---|---|---|---|
| | Rate Year Projected (WS-F) | | | - |
| | Rate Year True-Up (WS-G) | | | - |
| | True-Up Adjustment | | | **-** |

**Project Description :**

| Details | Project Number | |
|---|---|---|
| Investment (EOY) | True-Up Year | **2XXX** |
| Service Year (yyyy) | ROE increase accepted by FERC (Basis Points) | - |
| Service Month (1-12) | FCR w/o incentives, less depreciation | 0.00% |
| Useful life | FCR w/incentives approved for these facilities, less dep. | 0.00% |
| CIAC (Yes or No) | Annual Depreciation Expense | |

CUMMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:
INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR
TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE LIFE OF THE PROJECT.

| **Investment** | **Beginning** | **Depreciation** | **Ending** | **Average** | **Annual Revenue** | **Annual Revenue Req't.** | **Incentive Rev.** | **BPU Rev. Req't.From Prior** | **BPU Rev Req't True-up** | **BPU Rev. Req't.From Prior Year** | **BPU Rev Req't True-up** | **True-up of Incentive** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|

| Year | Balance | Expense | Balance | Balance | Requirement | with Incentives | Requirement ** |
|---|---|---|---|---|---|---|---|
| | - | - | - | - | $0 | $0 | $ - |
| | - | - | - | - | - | - | $ - |
| | - | - | - | - | - | - | $ - |
| | - | - | - | - | - | - | $ - |
| | - | - | - | - | - | - | $ - |
| Project Totals | | | | | | | |

| Year Template w/o Incentives | w/o Incentives | Template with Incentives ** | with Incentives ** | with Incentives ** |
|---|---|---|---|---|
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |
| | $ - | | $ - | $ - |

** This is the total amount that needs to be reported to SPP for billing to all regions.

**** This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for SPP should be incremented by the amount of the incentive revenue calculated for that year on this project.**

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
Worksheet H - Revenue Credits
**COMPANY NAME**

| Line: | | Total Company | Non-Transmission | Transmission |
|---|---|---|---|---|
| 1 | **Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)** | | - | - |
| 2 | **Account 451, Misc. Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)** | | - | |
| | **Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)** | | | |
| | Account 4540001 - Rent from Elect Property-Aff | | - | |
| | Account 4540002 - Rent from Elect Property - Non-Aff | | - | |
| | Account 4540005 - Rent from Elect Property - Pole Attach | | - | |

| | | | | | |
|---|---|---|---|---|---|
| | | Account 4540004 - Rent from Elect Property - ABD - Non-Aff | | | - |
| | | Other 454 Accounts | | | |
| 3 | | Total Rents from Electric Property | - | | - |
| | | **Account 456.0 Other Operating Revenues (FF1 p.300.21.(b); Company Records - Note 1)** | | | |
| | 1 | Account 4560015, Revenues from Associated Business Development | | | - |
| | 2 | All Other 456.0 Revenues | | | - |
| 4 | | Total 456.0 Other Operating Revenues | - | | - |
| | | **Account 456.1, Revenues from Transmission of Electricity of Others (FF1 p.300.22.(b); Company Records - Note 1)** | | | |
| | | **Less:** | | | |
| | | **Transmission Direct Assignment Revenue (if costs not in the ARR)** | | | |
| | | **Sponsored Upgrade Revenue** | | | |
| | | **Credits against Transmission Service Revenue related to Generation Interconnections** | | | |
| | | **Revenue for GFA's (Relative to SPP OATT) Associated with Load Included in the Divisor** | | | |
| | | **Network Service Revenue (SPP Schedule 9) Associated with Load included in the Divisor** | | | |
| | | **Revenue Associated with Transmission Plant Excluded From SPP Tariff** | | | |
| | | **Distribution and Other Non-Transmission Revenue** | | | |
| | | **Revenue from SPP Ancillary Services Provided** | | | |
| | | **Base Plan Revenue (from SPP)** | | | |
| | | **Flow Through of ERCOT Ancillary Charges** | | | |
| | | **Other** | | | |
| 5 | | | **Net 456.1 Transmission Credits** | | - |
| 6 | | **Account 457.1, Regional Control Service Revenues (FF1 p.300.23.(b); Company Records - Note 1)** | | | |
| 7 | | **Account 457.2, Miscellaneous Revenues (FF1p.300.24.(b); Company Records - Note 1)** | | | |
| 8 | | **Total Revenue Credits - Sum lines 1 through 7** | | | - |

Note 1: Data for this worksheet came from the FERC Form 1 and the Company's General Ledger.

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet I** - Supporting Transmission Expense Adjustments
**COMPANY NAME**

Note: This worksheet is used to include any FERC jurisdictional transmission-related (i.e. non-retail) expenses

recorded in Accounts 561 or 565 which are includable in the formula on TCOS line 66, and make any other necessary FERC jursdictional adjustments to Transmission O&M.

| Line Number | (A) Description | | (B) 2XXX |
|---|---|---|---|
| 1 | | | |
| 2 | | | |
| 3 | | | |
| 4 | | | |
| 5 | | | |
| 6 | | | |
| 7 | | | |
| 8 | | | |
| 9 | | | |
| 10 | Total | ( sum of lines 2 through 9 ) | - |

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet J** - Allocation of Specific O&M or A&G Expenses
**COMPANY NAME**

| Line Number | (A) FERC Acct No. | (B) Description | (C) 2XXX Expense | (D) 100% Non-Transmission | (E) 100% Transmission Specific | (F) Explanation of Transmission Specific Items |
|---|---|---|---|---|---|---|
| | | **Account 928** | | | | |
| 1 | | | | | | |
| 2 | | | | | | |
| 3 | | | | | | |
| 4 | | | | | | |
| 5 | | | | | | |
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | |
| 10 | | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | | | | | | |
| 16 | | **Total (FERC Form 1 p.323.189.b)** | - | - | - | |
| | | **Account 930.1** | | | | |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | **Total (FERC Form 1 p.323.191.b)** | - | - | - | |
| | | **Account 930.2** | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | **Total (FERC Form 1 p.323.192.b)** | - | - | - | |

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet K** - Development of Composite State Income Tax Rate
**COMPANY NAME**

**I. DEVELOPMENT OF COMPOSITE STATE INCOME TAX RATES FOR 2XXX**

| | | |
|---|---|---|
| State Income Tax Rate - Oklahoma | Note 1 | |
| Apportionment Factor | | |
| Effective State Income Tax Rate | | - |
| State Income Tax Rate - | | |
| Apportionment Factor | | |

| | | | |
|---|---|---|---|
| | Effective State Income Tax Rate | | - |
| | State Income Tax Rate - Apportionment Factor | | |
| | Effective State Income Tax Rate | | - |
| | State Income Tax Rate - Apportionment Factor | | |
| | Effective State Income Tax Rate | | - |
| | State Income Tax Rate - Apportionment Factor | | |
| | Effective State Income Tax Rate | | - |
| | Total Effective State Income Tax Rate | | - |

Note 1 --- The Oklahoma State Income Tax Rate of 6% is reduced to 5.66% due to the deductibility of Oklahoma State Income Taxes on the Oklahoma State Income Tax Return.

| | | | | | Projected / Actual | |
|---|---|---|---|---|---|---|
| **II.** | **CALCULATION OF TEXAS GROSS MARGIN TAX** | | | | Total Company | Trans. Only |
| Line # | REVENUE REQUIREMENT BEFORE TEXAS GROSS MARGIN TAX (TCOS ln 116) | | | | - | - |
| 1 | Apportionment Factor to Texas (ln12) | | | | - | - |
| 2 | Apportioned Texas Revenues | | | | - | - |
| 3 | Taxable Percentage of Revenue | | | | | |
| 4 | Taxable, Apportioned Margin | | | | - | - |
| 5 | Texas Gross Margin Tax Rate | | | | | |
| 6 | Texas Gross Margin Tax Expense | | | | - | - |
| 7 | Gross-up Required for Texas Gross Margin Expense | ((ln 6 * ln 3 * ln 1)/(1- ln 5) * ln 5) | | | - | - |
| 8 | Total Additional Gross Margin Tax Revenue Requirement | | | | - | - |
| 9 | WHOLESALE LOAD ALLOCATOR (For Use in Gross Margin Tax Allocator) | | | | | |
| 10 | Texas Jurisdictional Load | | - | KW | | |
| 11 | Total Load | | - | KW | | |
| 12 | Allocation Percentage | (ln 10 / ln 11) | - | | | |

AEP West SPP Member Transmission Companies

Actual / Projected 2XXX Rate Year Cost of Service Formula Rate

**Worksheet L** - Taxes Other than Income

**COMPANY NAME**

| **Line No.** | **(A) Account** | **(B) Total Company** | **(C) Property** | **(D) Labor** | **(E) Other** | **(F) Non-Allocable** |
|---|---|---|---|---|---|---|
| 1 | **Revenue Taxes** | | | | | |
| 2 | | | | | | - |
| 3 | | | | | | |
| 4 | **Real Estate and Personal Property Taxes** | | | | | |
| 5 | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6 | | | | | | |
| 7 | | | | | | |
| 8 | | | | | | |
| 9 | | | | | | - |
| 10 | **Payroll Taxes** | | | | | |
| 11 | | | | | | |
| 12 | | | | | | |
| 13 | | | | | | |
| 14 | | | | | | |
| 15 | **Production Taxes** | | | | | |
| 16 | | | | | | - |
| 17 | | | | | | |
| 18 | | | | | | |
| 19 | **Miscellaneous Taxes** | | | | | |
| 20 | | | | | | |
| 21 | | | | | | |
| 22 | | | | | | |
| 23 | | | | | | |
| 24 | | | | | | |
| 25 | | | | | | |
| 26 | | | | | | |
| 27 | | | | | | |
| 28 | | | | | | |
| 29 | | | | | | |
| 30 | | | | | | |
| 31 | | | | | | |
| 32 | | | | | | |
| 33 | | | | | | |
| 34 | | | | | | |
| 35 | Total Taxes by Allocable Basis<br>(Total Company Amount Ties to FFI p.114, Ln 14,(c)) | - | - | - | - | - |

**NOTE: As a check, the difference between the total from Ln 35 above and the total on FF1 p.263 line 41(i) should equal the sum of the 'income' tax line items within FF1 p262.x-263.x**

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet M - Cost of Capital**
**COMPANY NAME**

| | | Average Balance of Common Equity | | | | |
|---|---|---|---|---|---|---|
| Line No | **Month** | **Proprietary Capital** | **Less: Preferred Stock** | **Less Undistributed Sub Earnings (Acct 216.1)** | **Less AOCI (Acct 219.1)** | **Average Balance of Common Equity** |
| | **(a)** **(Note A)** | **(b)** (FF1 112.16) | **(c)** (FF1 250-251) | **(d)** (FF1 112.12) | **(e)** (FF1 112.15) | **(f)=(b)-( c)-(d)-( e)** |
| 1 | December Prior to Rate Year | | | | | - |
| 2 | January | | | | | - |
| 3 | February | | | | | - |
| 4 | March | | | | | - |
| 5 | April | | | | | |

| | | | |
|---|---|---|---|
| 6 | May | | - |
| 7 | June | | - |
| 8 | July | | - |
| 9 | August | | - |
| 10 | September | | - |
| 11 | October | | - |
| 12 | November | | - |
| 13 | December of Rate Year | | - |
| 14 | Average of the 13 Monthly Balances | - - - - | - |

| | | Average Balance of Long Term Debt | | | | | |
|---|---|---|---|---|---|---|---|
| Line No | **Month** | **Acct 221 Bonds** | **Less: Acct 222 Reacquired Bonds** | **Acct 223 LT Advances from Assoc. Companies** | **Acct 224 Senior Unsecured Notes** | **Less: Fair Value Hedges** | **Gross Proceeds Outstanding Long-Term Debt** |
| | **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)=(b)-( c)+(d)+( e)-(f)** |
| | **(Note A)** | (FF1 112.18) | (FF1 112.19) | (FF1 112.20) | (FF1 112.21) | FF1, page 257, Col. (h) - Note 1 | |
| 15 | December Prior to Rate Year | | | | | | - |
| 16 | January | | | | | | - |
| 17 | February | | | | | | - |
| 18 | March | | | | | | - |
| 19 | April | | | | | | - |
| 20 | May | | | | | | - |
| 21 | June | | | | | | - |
| 22 | July | | | | | | - |
| 23 | August | | | | | | - |
| 24 | September | | | | | | - |

| | | | |
|---|---|---|---|
| 25 | October | | - |
| 26 | November | | - |
| 27 | December of Rate Year | | - |
| 28 | Average of the 13 Monthly Balances | - - - - - | - |

NOTE 1: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Page 257 Column H of the FF1)

***Development of Cost of Long Term Debt Based on Average Outstanding Balance***

| Line No | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
|---|---|---|---|---|---|---|---|
| 29 | **Annual Interest Expense for 2XXX** | | | | | | |
| 30 | Interest on Long Term Debt - Accts 221 - 224 (256-257.33.i) | | | | | | |
| 31 | Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 30 and shown in 50 below. | | | - | | | |
| 32 | Plus: Allowed Hedge Recovery From Ln 55 below. | | | - | | | |
| 33 | Amort of Debt Discount & Expense - Acct 428 (117.63.c) | | | | | | |
| 34 | Amort of Loss on Reacquired Debt - Acct 428.1 (117.64.c) | | | | | | |
| 35 | Less: Amort of Premium on Debt - Acct 429 (117.65.c) | | | | | | |
| 36 | Less: Amort of Gain on Reacquired Debt - Acct 429.1 (117.66.c) | | | | | | |
| 37 | **Total Interest Expense (Ln 30 - 31 + 33 + 34 - 35 - 36)** | | | - | | | |

| | | |
|---|---|---|
| 38 | **Average Cost of Debt for 2XXX (Ln 37/ ln 28 (g))** | - |

***CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES***

39 NOTE: The net amount of hedging gains or losses recorded in account 427 to be recovered in this formula rate should be limited to the effective portion of pre-issuance cash flow hedges that are amortized over the life of the underlying debt issuances. The recovery of a net loss or passback of a net gain will be limited to five basis points of the total Capital Structure.
Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the "Excludable" column below.

| | HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1) | Total Hedge (Gain)/Loss for 2XXX | Less Excludable Amounts (See NOTE on Line 39) | Net Includable Hedge Amount | Remaining Unamortized Balance | Amortization Period Beginning | Ending |
|---|---|---|---|---|---|---|---|
| 40 | | | - | - | | | |
| 41 | | | - | - | | | |
| 42 | | | | - | | | |
| 43 | | | | - | | | |
| 44 | | | | - | | | |
| 45 | | | | - | | | |
| 46 | | | | - | | | |
| 47 | | | | - | | | |
| 48 | | | | - | | | |
| 49 | | | | | | | |
| 50 | Total Hedge Amortization | - | - | | - | | |
| 51 | Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 40 to 48) | | | - | | | |
| 52 | Total Average Capital Structure Balance for 2XXX (TCOS, Ln 144) | | | - | | | |
| 53 | Financial Hedge Recovery Limit - Five Basis Points of Total Capital | | | 0.0005 | | | |
| 54 | Limit of Recoverable Amount | | | | | | |

| | | |
|---|---|---|
| 55 | **Recoverable Hedge Amortization (Lesser of Ln 51 or Ln 54)** | - |

***Development of Cost of Preferred Stock***

| | | |
|---|---|---|
| 56 | 13 Month Average Balance of Preferred Stock (Ln 14 Col. (c)) | - |
| 57 | Dividends on Preferred Stock | |
| 58 | Average Cost of Preferred Stock (Ln 57/ Ln 56) | - |

**AEP West SPP Member**

**Transmission Companies**

**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**

**Worksheet N - Schedule 11 True-up With Interest**

**COMPANY NAME**

| True up Revenue Requirement For Year 2XXX Available May, 2XXX+1 Net of Schedule 11 Revenue Credits | | Cash Revenue Collections for True-up Year, Net of Schedule 11 Revenue Credits | | True-up Adjustment - Over (Under) Recovery |
|---|---|---|---|---|
| | - | | = | $0 |

| | |
|---|---|
| True Up Year: | 2XXX |
| Intermediate Year: | 2XXX+1 |
| Rate Year: | 2XXX+2 |

| Month | Refunds/ (Surcharges) | Cumulative Refunds/(Surcharges) - Beginning of Month | Base for Quarterly Compound | Base for Monthly Interest | Monthly Interest Rate | Calculated Interest | Amortization | Cumulative Refunds and Interest |
|---|---|---|---|---|---|---|---|---|

| | | (Without Interest) | Interest | | (Worksheet Q) | | - End of Month |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest** | | | | | | | |
| ***True-Up Year*** | | | | | | | |
| 1/1/2XXX | - | - | - | - | - | - | - |
| 2/1/2XXX | - | - | - | - | - | - | - |
| 3/1/2XXX | - | - | - | - | - | - | - |
| 4/1/2XXX | - | - | - | - | - | - | - |
| 5/1/2XXX | - | - | - | - | - | - | - |
| 6/1/2XXX | - | - | - | - | - | - | - |
| 7/1/2XXX | - | - | - | - | - | - | - |
| 8/1/2XXX | - | - | - | - | - | - | - |
| 9/1/2XXX | - | - | - | - | - | - | - |
| 10/1/2XXX | - | - | - | - | - | - | - |
| 11/1/2XXX | - | - | - | - | - | - | - |
| 12/1/2XXX | - | - | - | - | - | - | - |
| ***Intermediate Year*** | | | | | | | |
| 1/1/2XXX+1 | - | - | - | - | - | - | - |
| 2/1/2XXX+1 | - | - | - | - | - | - | - |
| 3/1/2XXX+1 | - | - | - | - | - | - | - |
| 4/1/2XXX+1 | - | - | - | - | - | - | - |
| 5/1/2XXX+1 | - | - | - | - | - | - | - |
| 6/1/2XXX+1 | - | - | - | - | - | - | - |
| 7/1/2XXX+1 | - | - | - | - | - | - | - |
| 8/1/2XXX+1 | - | - | - | - | - | - | - |
| 9/1/2XXX+1 | - | - | - | - | - | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 10/1/2XXX+1 | - | - | - | - | - | - | | - |
| 11/1/2XXX+1 | - | - | - | - | - | - | | - |
| 12/1/2XXX+1 | - | - | - | - | - | - | | - |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| ***Rate Year*** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 2/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 3/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 4/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 5/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 6/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 7/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 8/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 9/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 10/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 11/1/2XXX+2 | - | - | - | - | - | - | - | - |
| 12/1/2XXX+2 | - | - | - | - | - | - | - | - |

| | |
|---|---|
| True-Up Adjustment with Interest | - |
| Less Over (Under) Recovery | - |
| Total Interest | - |

**Note 1:** The monthly interest rates to be applied to the over recovery or under recovery amounts during the true-up year and the intermediate year will be determined using the monthly FERC interest rates (as determined pursuant to 18 C.F.R. Section 35.19a) posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp. The monthly interest rate to be applied to the over recovery or under recovery amounts each month during the rate year will equal a simple average of the 12 monthly interest rates for the intermediate year.

Note 2: An over or under collection for the Schedule 11 charge will be recovered prorata over the true-up year, held for the intermediate year and returned prorata over the rate year.

**AEP West SPP Member Transmission Companies**
**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**
**Worksheet O - Schedule 9 NITS True-up With Interest**
**COMPANY NAME**

| True up Revenue Requirement For Year 2XXX Available May, 2XXX+1 Net of Schedule 9 Revenue Credits | - | Cash Revenue Collections for True-up Year, Net of Schedule 9 Revenue Credits | = | True-up Adjustment - Over (Under) Recovery |
|---|---|---|---|---|
| | | | | $0 |

True Up Year: 2XXX
Intermediate Year: 2XXX+1
Rate Year: 2XXX+2

| Month | Refunds/ (Surcharges) | Cumulative Refunds/(Surcharges) - Beginning of Month (Without Interest) | Base for Quarterly Compound Interest | Base for Monthly Interest | Monthly Interest Rate (Worksheet Q) | Calculated Interest | Cumulative Refunds and Interest - End of Month |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest** | | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| ***True-Up Year*** | | | | | | |
| 1/1/2XXX | - | - | - | - | - | - |
| 2/1/2XXX | - | - | - | - | - | - |
| 3/1/2XXX | - | - | - | - | - | - |
| 4/1/2XXX | - | - | - | - | - | - |
| 5/1/2XXX | - | - | - | - | - | - |
| 6/1/2XXX | - | - | - | - | - | - |
| 7/1/2XXX | - | - | - | - | - | - |
| 8/1/2XXX | - | - | - | - | - | - |
| 9/1/2XXX | - | - | - | - | - | - |
| 10/1/2XXX | - | - | - | - | - | - |
| 11/1/2XXX | - | - | - | - | - | - |
| 12/1/2XXX | - | - | - | - | - | - |
| ***Intermediate Year*** | | | | | | |
| 1/1/2XXX+1 | - | - | - | - | - | - |
| 2/1/2XXX+1 | - | - | - | - | - | - |
| 3/1/2XXX+1 | - | - | - | - | - | - |
| 4/1/2XXX+1 | - | - | - | - | - | - |
| 5/1/2XXX+1 | - | - | - | - | - | - |
| 6/1/2XXX+1 | - | - | - | - | - | - |

| | |
|---|---|
| True-Up Adjustment with Interest | - |
| Less Over (Under) Recovery | - |
| Total Interest | - |

**Note 1:** The monthly interest rates to be applied to the over recovery or under recovery amounts during the true-up year and the intermediate year will be determined using the monthly FERC interest rates (as determined pursuant to 18 C.F.R. Section 35.19a) posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp.

**Note 2:** An over or under collection for the Schedule 9 charge will be recovered prorata over the true-up year, held through June of the intermediate year and charged/refunded in a lump sum during July of the intermediate year.

**AEP West SPP Member Transmission Companies**
**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**
**Worksheet P - Schedule 1 NITS True-up With Interest**
**COMPANY NAME**

| True up Revenue Requirement For Year 2XXX Available May, 2XXX+1 Net of Schedule 1 Revenue Credits | Cash Revenue Collections for True-up Year, Net of Schedule 1 Revenue Credits | True-up Adjustment - Over (Under) Recovery |
|---|---|---|
| | | |

True Up Year: 2XXX

Intermediate Year: 2XXX+1

| | | | | | |
|---|---|---|---|---|---|
| | - | | = | $0 | Rate Year: 2XXX+2 |

| Month | Refunds/ (Surcharges) | Cumulative Refunds/(Surcharges) - Beginning of Month (Without Interest) | Base for Quarterly Compound Interest | Base for Monthly Interest | Monthly Interest Rate (Worksheet Q) | Calculated Interest | Cumulative Refunds and Interest - End of Month |
|---|---|---|---|---|---|---|---|
| **Calculation of Interest** | | | | | | | |
| ***True-Up Year*** | | | | | | | |
| 1/1/2XXX | - | - | - | - | - | - | |
| 2/1/2XXX | - | - | - | - | - | - | |
| 3/1/2XXX | - | - | - | - | - | - | |
| 4/1/2XXX | - | - | - | - | - | - | |
| 5/1/2XXX | - | - | - | - | - | - | |
| 6/1/2XXX | - | - | - | - | - | - | |
| 7/1/2XXX | - | - | - | - | - | - | |
| 8/1/2XXX | - | - | - | - | - | - | |
| 9/1/2XXX | - | - | - | - | - | - | |
| 10/1/2XXX | - | - | - | - | - | - | |
| 11/1/2XXX | - | - | - | - | - | - | |
| 12/1/2XXX | - | - | - | - | - | - | |
| ***Intermediate Year*** | | | | | | | |
| 1/1/2XXX+1 | - | - | - | - | - | - | |
| 2/1/2XXX+1 | - | - | - | - | - | - | |
| 3/1/2XXX+1 | - | - | - | - | - | - | |
| 4/1/2XXX+1 | - | - | - | - | - | - | |
| 5/1/2XXX+1 | - | - | - | - | - | - | |
| 6/1/2XXX+1 | - | - | - | - | - | - | |

| | |
|---|---|
| True-Up Adjustment with Interest | - |
| Less Over (Under) Recovery | - |
| Total Interest | - |

**Note 1:** The monthly interest rates to be applied to the over recovery or under recovery amounts during the true-up year and the intermediate year will be determined using the monthly FERC interest rates (as determined pursuant to 18 C.F.R. Section 35.19a) posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp.

**Note 2:** An over or under collection for the Schedule 1 charge will be recovered prorata over the true-up year, held through June of the intermediate year and charged/refunded In a lump sum during July of the intermediate year. Schedule 1 Point-to-Point rates are not subject to true-up.

**AEP West SPP Member Transmission Companies**

**Actual / Projected 2XXX Rate Year Cost of Service Formula Rate**

**Worksheet Q - True-up Interest Rates**

**COMPANY NAME**

This Attachment is used to input and compute the interest rates to be applied to each year's revenue requirement true-ups.

| | | |
|---|---|---|
| | Applicable FERC Interest Rate (Note A): | |
| 1 | 1/1/2XXX | |
| 2 | 2/1/2XXX | |
| 3 | 3/1/2XXX | |
| 4 | 4/1/2XXX | |
| 5 | 5/1/2XXX | |
| 6 | 6/1/2XXX | |
| 7 | 7/1/2XXX | |
| 8 | 8/1/2XXX | |
| 9 | 9/1/2XXX | |
| 10 | 10/1/2XXX | |
| 11 | 11/1/2XXX | |
| 12 | 12/1/2XXX | |
| 13 | 1/1/2XXX+1 | |
| 14 | 2/1/2XXX+1 | |
| 15 | 3/1/2XXX+1 | |
| 16 | 4/1/2XXX+1 | |
| 17 | 5/1/2XXX+1 | |
| 18 | 6/1/2XXX+1 | |
| 19 | 7/1/2XXX+1 | |
| 20 | 8/1/2XXX+1 | |
| 21 | 9/1/2XXX+1 | |
| 22 | 10/1/2XXX+1 | |
| 23 | 11/1/2XXX+1 | |
| 24 | 12/1/2XXX+1 | |
| | Schedule 11 Base Plan True Up | |
| 25 | Average Monthly Rate - Lines 13- 24 | - |

Note A - Lines 1-20 are the FERC interest rates under section 35.19a of the regulations for the period shown, as posted at https://www.ferc.gov/enforcement/acct-matts/interest-rates.asp.

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet R** - Unfunded Reserves
**COMPANY NAME**

| Line Number | (A) Description | (B) Account | (C) Formula Expense Account | (D) Balances @ 12/31/2XXX | (E) Balances 12/31/2XXX-1 | (F) Average Balance for 2XXX |
|---|---|---|---|---|---|---|
| 1 | | | | | | - |
| 2 | | | | | | - |
| 3 | | | | | | - |
| 4 | | | | | | - |
| 5 | | | | | | - |
| 6 | Total | | | - | - | - |

Note - The cost of service will make a rate base adjustment to remove unfunded reserves associated with contingent liabilities recorded to Accounts 228.1-228.4 from rate base. Include only contingent liabilities which were expensed through accounts included in formula rate cost of service.

AEP West SPP Member Transmission Companies
Actual / Projected 2XXX Rate Year Cost of Service Formula Rate
**Worksheet S** - Regulatory Assets
**COMPANY NAME**

| (A) | (B) | (C) | (D) | (E) |
|---|---|---|---|---|

| Line | Description | FERC Docket | Source | Amort. / Deferral Account | 2XXX Amortization / (Deferral) |
|---|---|---|---|---|---|
| 1 | **Regulatory Asset Amortizations / (Deferrals) in O&M (Note 1)** | | | | |
| 1a | | | | | |
| 1b | | | | | |
| 1c | | | | | |
| 1d | | | | | |
| 1e | | | | | |
| 2 | Net Amortization / (Deferral) | | | | - |
| 3 | **FERC Approved Regulatory Amortizations / (Deferrals) in O&M (Note 2)** | | | | |
| 3a | | | | | |
| 3b | | | | | |
| 3c | | | | | |
| 3d | | | | | |
| 4 | Net Approved Amortization / (Deferral) | | | | - |
| 5 | **Reg Asset Amortizations / (Deferrals) in A&G (Note 3)** | | | | |
| 5a | | | | | |
| 5b | | | | | |
| 6 | Net Amortization / (Deferral) | | | | - |
| 7 | **FERC Approved Reg Amortizations / (Deferrals) in A&G (Note 4)** | | | | |
| 7a | | | | | |
| 7b | | | | | |
| 8 | Net Approved Amortization / (Deferral) | | | | - |

**Regulatory Assets Included in Rate Base (Note 5)**

| | (A) | | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | Description | FERC Approval Docket | Form 1 Reference | Recovery Start Date | Recovery Period (Months) | Balance @ 12/31/2XXX | Balance @ 12/31/2XXX-1 | Average Balance | Functional Allocator (Note 6) | Functional Allocator Value | Transmission Balance |
| 9a | | | | | | | | - | | | - |
| 9b | | | | | | | | - | | | - |
| 9c | | | | | | | | - | | | - |
| 9d | | | | | | | | - | | | - |
| 9e | | | | | | | | - | | | - |
| 10 | Total | | | | | - | - | - | | | - |

Notes

1 Include all regulatory asset amortizations and deferrals included in accounts in Transmission O&M on FERC Form 1 p. 321, ln 122. Exclude all Distribution and Production-related items.

2 Include only regulatory asset amortizations and deferrals included in accounts in Transmission O&M approved by FERC for inclusion in cost of service.

| | |
|---|---|
| 3 | Include all amortizations and deferrals of regulatory assets included in accounts in A&G expense on FERC Form 1 p. 321, ln 197, except amounts in Account 928, 930.1, and 930.2, which are accounted for on Worksheet J. |
| 4 | Include only regulatory asset amortizations and deferrals included in accounts in A&G expense approved by FERC for inclusion in cost of service. |
| 5 | See referenced FERC docket for details of Regulatory Assets approved for inclusion in rate base. Include only the Transmission functional balance for assets which have both Transmission and Distribution components. |
| 6 | Balances direct assigned to Transmission except for payroll-related balances, which will be allocated using a wages and salaries allocator. |

**Worksheet T** - Depreciation Rates
**AEP OKLAHOMA TRANSMISSION COMPANY, INC.**
**EFFECTIVE AS OF 11/01/2021**

**TRANSMISSION PLANT**

| Acct. No. | Account Title | Total Depr Rates |
|---|---|---|
| 350.1 | Land Rights | 1.18% |
| 352.0 | Structures & Improvements | 1.77% |
| 353.0 | Station Equipment | 1.81% |
| 354.0 | Towers & Fixtures | 2.71% |
| 355.0 | Poles & Fixtures | 4.06% |
| 356.0 | OH Conductor & Devices | 2.55% |
| 358.0 | Underground Conductor | 1.94% |

**GENERAL PLANT**

| Acct. No. | Account Title | Total Depr Rates |
|---|---|---|
| 390.0 | Structures & Improvements | 2.02% |
| 391.0 | Office Furniture | 5.70% |
| 391.11 | Office Equipment - Computers | 31.01% |
| 392.0 | Transportation Equipment | 7.18% |
| 393.0 | Stores Equipment | 3.86% |
| 394.0 | Tools Shop & Garage Equipment | 4.33% |
| 395.0 | Laboratory Equipment | 6.32% |
| 396.0 | Power Operated Equip | 7.93% |
| 397.0 | Communication Equip - Amortized | 6.97% |
| 397.16 | AMI - Communication Equipment | 7.18% |
| 398.0 | Miscellaneous Equipment | 5.65% |
| 399.3 | Alliance Rail | 0.00% |

**INTANGIBLE PLANT**

| Acct. No. | Account Title | Total Depr Rates |
|---|---|---|
| 303.0 | Intangible Plant | 10.00% |

Note 1 - These depreciation and amortization rates will not be changed absent a Section 205 or 206 filing at the Commission.
Note 2 - Oklahoma depreciation rates were approved in Cause No. PUD 202100055, the rates were made effective on November 1, 2021.

## Addendum 12 to Attachment H – Part 2

## THE AEP WEST TRANSMISSION COMPANIES FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template"), and these formula rate implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of AEP Oklahoma Transmission Company, Inc. and AEP Southwestern Transmission Company, Inc. (collectively "AEP West Transcos" or "AEP") for transmission revenue requirement determinations under the Southwest Power Pool ("SPP") Open Access Transmission Tariff ("SPP Tariff"). AEP shall follow the instructions specified in the Formula Rate to calculate annually its net annual transmission revenue requirement, as set forth in the Template ("Net Revenue Requirement"). The Net Revenue Requirement shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Net Revenue Requirement will include revenue requirements and rate calculations for SPP Schedule 1 NITS, Schedule 9 Zonal NITS, and Schedule 11 (Base Plan). The Formula Rate shall become effective for recovery of AEP's Net Revenue Requirement upon the effective date for incorporation into the SPP Tariff through a filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d.

### Section 1. Annual Projection

a. No later than October 31 preceding a Rate Year, and each subsequent Rate Year, AEP shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with the Formula Rate ("Annual Projection"). The Annual Projection shall include the True-Up Adjustment described and defined in Section 2 below, if applicable. Upon determining the Annual Projection, AEP shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format ("PDF") and a data-populated formula rate in native format with all formulae/links intact at a publicly accessible location on SPP's internet website and OASIS, and make a corresponding informational filing at FERC. The date on which the posting occurs shall be that year's "True-Up Publication Date."

b. The posting of the Annual Projection shall:

(i.) Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected Net Revenue Requirement;

(ii.) Include all inputs in sufficient detail to identify the components of AEP's projected Net Revenue Requirement, explanations of the bases for the projections and input data, including workpapers in native software application format, to enable Interested Parties[1] to replicate the calculation of the projected Net Revenue Requirement;

(iii.) With respect to any Accounting Changes (as that term is defined in Section 3.e.iii)

A. Identify any Accounting Changes including:

i. The initial implementation of an accounting standard or policy;

ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the projected Net Revenue Requirement calculation;

iv. The implementation of new estimation methods or policies that change prior estimates; and

v. Changes to income tax elections;

B. Identify items included in the projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

C. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected Net Revenue Requirement; and

D. Provide, for each item identified pursuant to Section 1.b.iii.A - C of these Protocols, a narrative explanation of the individual impact of such changes on the projected Net Revenue Requirement.

(iv.) Include the following information related to affiliate cost allocation:

A. A detailed description of the methodologies used to allocate and directly assign costs between AEP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons for those changes; and

B. The magnitude of such costs that have been allocated or directly assigned between AEP and each affiliate by service category or function.

c. If the date for making the posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day.[2] Within five (5) calendar days of the posting, AEP shall provide notice of such posting via the SPP email subscription ("SPP Exploder List"). Interested Parties can subscribe to the SPP Exploder List on the SPP website.

d. Together with the posting of the Annual Projection, AEP shall cause to be posted on the SPP internet website and OASIS, and distributed to the SPP Exploder List, the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Projection and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Projection ("Annual Projection Meeting"). The Annual Projection Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the posting of the Annual Projection. Notice of the Annual Projection Meeting shall be provided via the SPP Exploder List no less than seven (7) calendar days prior to the meeting. AEP will provide remote access to the Annual Projection Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e. To the extent AEP agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on SPP's internet website and OASIS, and e-mailed to the SPP Exploder List. Changes posted prior to November 30 preceding the Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under SPP's billing practices), shall be reflected in the Annual Projection for the Rate

Year; changes posted after that date will be reflected, as appropriate, in the True-Up Adjustment for the Rate Year.

f. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up, and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

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1 As used in these Protocols, "Interested Parties" shall include but not be limited to: (i) any Eligible Customer under the SPP Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility; and (iv) any party with standing under FPA section 205 or section 206.

2 For the purposes of these Protocols, if any deadline included in these Protocols should fall on a weekend or a holiday recognized by FERC, then the deadline shall be extended to the next business day.

**Section 2. True-Up Adjustment**

AEP will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-Up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-Up Adjustment shall be the sum of the True-Up Adjustment Over/Under Recovery as determined in Section 2(a) and the Interest on the True-Up Adjustment Over/Under Recovery as determined in Section 2(b):

a. AEP's projected Net Revenue Requirement collected during the previous Rate Year[3] will be compared to AEP's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with AEP's Formula Rate and based upon (i) AEP's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to AEP's calculation of its annual revenue requirement, (iii) the books and records of AEP (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the SPP Tariff Governing Documents that apply to the calculation of annual revenue requirements under individual transmission

owner formula rates,[4] to determine any over- or under-recovery ("True-Up Adjustment Over/Under Recovery").

b. Interest on any True-Up Adjustment Over/Under Recovery shall be calculated separately for the SPP Zonal NITS Annual Transmission Revenue Requirement (ATRR), Base Plan ATRR (Base Plan Upgrades) and Schedule 1 Scheduling, System Control, and Dispatch Service (Schedule 1). For the Zonal NITS ATRR and Schedule 1 NITS True-Up Adjustments, monthly interest will be calculated on the Over/Under Recovery during each month of the True-Up Year and for the first six months following the True-Up Year (during the Intermediate Year). The Zonal NITS ATRR and Schedule 1 NITS True-Up adjustments, along with the interest calculated during the eighteen (18) months as described above will be invoiced or refunded to customers all at once during the July billing. For the Base Plan ATRR True-Up Adjustment, monthly interest will be calculated on the Over/Under Recovery during each month of the True-Up Year, during each month of the succeeding year ("Intermediate Year") (12 months-True-up Year plus one), and during each month of the year in which the true-up will be billed and collected ("Projection Year") (True-Up Year plus two). The total true-up adjustment and interest for the 36 months described above will be added to (or deducted from) each Base Plan Project on a pro rata basis for determination of the Base Plan ATRR during the 12 months of the Projection Year.

For example, the 2018 True-Up adjustment will be calculated in 2019 and will be billed or credited to customers during 2020. The True-Up adjustments will include interest calculations over a 36-month period, including the 12 months during the True-Up year (2018), the 12 months during the Intermediate Year (2019) and the 12 months during the Projection Year (2019) in which the True-Up Adjustment is remitted to customers.

c. The rates used to calculate interest for True-Up Adjustments will be sourced directly from the FERC website in accordance with 18 C.F.R. § 35.19a. The monthly interest rate used to calculate interest during each month of the Projection Year will be based on an average of the 12 monthly interest rates during the Intermediate Year. Interest True-up adjustments will be compounded quarterly in accordance

with 18 C.F.R. § 35.19a.

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[3] If the initial use of this Formula Rate covers only part of a calendar year, the initial projected annual Net Revenue Requirement will be divided by 12 to calculate the monthly projected cost of service to be collected each month, or portion thereof, it is effective that first year. Similarly, the actual Net Revenue Requirement will be divided by 12 to calculate the actual cost of service to be collected during those same months of that year. Similar calculations of projected Net Revenue Requirement and actual Net Revenue Requirement will be made for the months prior to the effective date of this Formula Rate using the previous formula rate in effect during those months. The actual Net Revenue Requirements computed under each of the two formula rate periods that initial Rate Year will be added together to obtain the total actual Net Revenue Requirement. The first True-up Adjustment will compare this total actual Net Revenue Requirement to the Net Revenue Requirement collected under the two formulas for that initial Rate Year.

[4] SPP Tariff Governing Documents include the SPP Tariff, Bylaws, Criteria, and Membership Agreements.

**Section 3. Annual Update**

a. On or before May 25 following each Rate Year, AEP shall calculate its actual Net Revenue Requirement and the True-Up Adjustment as described in Section 2 ("Annual Update") for such Rate Year and, together with such other information described in this Section 3, shall cause such Annual Update to be posted, in both a PDF and a data-populated formula rate in native format with all formulae/links intact, at a publicly accessible location on SPP's internet website and OASIS, and make a corresponding informational filing at FERC. Within five (5) calendar days of such posting, SPP shall provide notice of such posting via the SPP Exploder List.

b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c. The date on which the posting occurs shall be that year's "Annual Update Publication Date."

d. Together with the posting of the Annual Update, AEP shall cause to be posted on the SPP website and OASIS the time, date, location, and remote-access information for a stakeholder meeting with Interested Parties in order for AEP to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Annual Update

Meeting"). Notice of the Annual Update Meeting shall be provided via the SPP Exploder List no less than seven (7) calendar days prior to the meeting. The Annual Update Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after the Annual Update Publication Date. AEP will provide remote access to the Annual Update Meeting in order to ease burdens (e.g. travel costs) to ensure all Interested Parties have the opportunity to participate.

e. The Annual Update posting for the Rate Year:

(i.) Shall provide, via the Formula Rate worksheets and associated workpapers in native software application format, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[5]

(ii.) Shall provide sufficient detail and sufficient explanation to enable Interested Parties to replicate the calculation of the Annual Update results from the FERC Form No. 1 and verify that each input to the Template is consistent with the requirements of the Formula Rate;

(iii.) Shall identify:

A. Any change in accounting that affects inputs to the Template or the resulting charges billed under the Formula Rate ("Accounting Change"), including:

i. The initial implementation of an accounting standard or policy;

ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. Correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

iv. The implementation of new estimation methods or policies that change prior estimates; and

v. Changes to income tax elections;

B. Any items included in the Annual Update at an amount other than on a historic cost basis (e.g., fair value adjustments);

C. Any reorganization or merger transaction during the previous year and an explanation of the effect of the accounting for such transaction(s) on inputs to the Annual Update;

D. For each item identified pursuant to Sections 3.e.iii.A - C of these Protocols, the individual impact (in narrative format) of such changes on the Annual Update.

(iv.) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(v.) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vi.) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate (i.e., any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing or initiation of a section 206 investigation).

f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA section 205 or section 206 proceeding: (i) rate of return on common equity ("ROE"); and (ii) the depreciation and/or amortization rates as set forth in Worksheet T included with the Formula Rate template.

g. **Example - Timelines for 2018 Annual Projection and 2019 Annual Update**:

On or before October 31, 2017, AEP will determine the projected Net Revenue Requirement for the 2018 Rate Year. AEP will post the Annual Projection for the 2018 Rate Year in accordance with

Section 1 above. On or before May 25, 2019, AEP will post its Annual Update, consisting of the actual Net Revenue Requirement and True-Up Adjustment for the 2018 Rate Year determined pursuant to Section 2 above. Such True-Up Adjustment for the Zonal NITS ATRR and Schedule 1 NITS will be reflected in July 2019 bill. The Base Plan True-Up will be reflected in the Annual Projection of the Base Plan Project Revenue Requirements for the 2020 Rate Year posted on or before October 31, 2019.

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5 It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

**Section 4. Annual Review Procedures**

Each Annual Update and Annual Projection shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Parties shall have up to the later of two-hundred-ten (210) calendar days after the applicable Publication Date, or thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of AEP or by FERC order) ("Review Period"), to review the calculations and to notify AEP in writing, which may be made electronically, of any specific challenges to the Annual Update or Annual Projection ("Preliminary Challenge"), including challenges related to Accounting Changes. An Interested Party submitting a Preliminary Challenge must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Upon receipt of a Preliminary Challenge, AEP will endeavor to send the Preliminary Challenge to SPP within five (5) business days. AEP shall request that SPP post all Preliminary Challenges at a publicly accessible location on SPP's internet website and OASIS, and that a link to the website will be e-mailed to the SPP Exploder List.

b. In the event of a Preliminary Challenge, AEP will appoint a senior representative to work with the Interested Party (or its representatives) toward a resolution of the dispute.

c. AEP shall respond in writing to a Preliminary Challenge(s) within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which AEP agrees or disagrees with the challenge. If AEP disagrees with the Preliminary Challenge, it will provide the Interested Party with an explanation supporting the challenged inputs, explanations, allocations, calculations, or other information. AEP shall promptly cause to be posted its responses to all Preliminary Challenges at a publicly accessible location on SPP's internet website and OASIS, and a link to the website will be e-mailed to the SPP Exploder List. Provided however, that Preliminary Challenges and responses to Preliminary Challenges that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party.

d. AEP shall respond to all Preliminary Challenges submitted during the Review Period by no later than thirty (30) calendar days after the end of the Review Period.

e. Interested Parties shall have up to one-hundred-fifty (150) calendar days after each annual Publication Date (unless such period is extended with the written consent of AEP or by FERC order) to serve reasonable information requests on AEP ("Discovery Period").

f. Information requests shall be limited to what is necessary to determine: (i) the extent, effect, or impact of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with the Protocols (as provided above in Section 2.a); (iii) the proper application of the Template and procedures in the Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection; (v) the prudence of the actual costs and expenditures, including procurement methods and cost control methodologies; (vi) the effect of any change to the underlying USofA or FERC Form No. 1; and (vii) any other information that may reasonably have substantive effect on the calculation of the charge

pursuant to the Formula Rate. The information requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate in a final order issued by the Commission or by delegation in the context of prior AEP Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6 of these Protocols, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC.

g. AEP shall make a good faith effort to respond to reasonable information requests pertaining to the Annual Update or Annual Projection within fifteen (15) business days of receipt of such requests. AEP shall respond to all reasonable information requests no later than thirty (30) calendar days after the end of the Discovery Period. AEP will cause to be posted on the SPP website and OASIS all information requests from Interested Parties and AEP's response(s) to such requests, and a link to the website will be e-mailed to the SPP Exploder List. Provided however, that information and document requests and responses to information and document requests that include material deemed by AEP to be confidential information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by AEP and the requesting party. Voluminous materials that are unduly burdensome to provide by other means may be made available at a physical AEP site.

h. AEP shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing AEP's Annual Update or Annual Projection.

i. To the extent AEP and any Interested Party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, AEP or the Interested Party may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the

discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

j. Preliminary Challenges or Formal Challenges (as described in Sections 4 and 5) related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update or Annual Projection. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update or Annual Projection shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update or Annual Projection provided that the Interested Party submitted a Preliminary Challenge with respect to one or more other issues. Nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update or Annual Projection to the extent such Accounting Change affects the subsequent Annual Update or Annual Projection.

k. If a change made by AEP to its accounting policies, practices, or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

**Section 5. Resolution of Challenges**

a. Interested Parties shall have up to two-hundred-seventy (270) calendar days following the applicable Publication Date (unless such period is extended with the written consent of AEP or by FERC order), to file a challenge with the FERC ("Formal Challenge"). Such Formal Challenge shall be submitted in the same docket as the AEP informational filing and shall be served on AEP by electronic service on the date of such filing in accordance with Section 385.2010(f)(3) of the Commission's regulations. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all

information and correspondence produced by AEP pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate. This Section 5.a in no way shall affect a party's rights under section 206 of the Federal Power Act as set forth in Section 5.g of these Protocols.

b. Formal Challenges are to be filed pursuant to these Protocols, rather than under rule 206, and shall:

(i.) Clearly identify the action or inaction which is alleged to violate the Formula Rate Template or Protocols;

(ii.) Explain how the action or inaction violates the filed rate Template or Protocols;

(iii.) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including

A. The extent or effect of an Accounting Change;

B. Whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols;

C. The proper application of the Template and procedures in these Protocols;

D. The accuracy of the data and consistency with the Formula Rate of the charges shown in the Annual Update or Annual Projection;

E. The prudence of actual costs and expenditures;

F. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

G. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Template.

(iv.) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(v.) State whether the issues presented are pending in an existing Commission proceeding in which the filing party is a party, or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(vi.) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(vii.) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise reasonably attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(viii.) State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

c. Preliminary and Formal Challenges shall be limited to issues that may be necessary to determine: (i) the extent or effect of an Accounting Change; (ii) whether the Annual Update or Annual Projection fails to include data properly recorded in accordance with these Protocols; (iii) the proper application of the Formula Rate and procedures in these Protocols; (iv) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update and Annual Projection; (v) the prudence of actual costs and expenditures; (vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

d. Failure to raise an issue in a Preliminary Challenge shall not bar an Interested Party from raising that issue in a Formal Challenge, provided the Interested Party submitted a Preliminary Challenge during the Review Period with respect to one or more other issues. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update shall bar pursuit of such issue with respect to that Annual Update, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

e. Any response by AEP to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the SPP Exploder List on the date of such filing.

f. In any Formal Challenge proceeding concerning a given year's Annual Update (including corrections), Annual Projection, or Accounting Change(s), AEP shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating, with respect to the issue being challenged, that it has correctly applied the terms of the Formula Rate consistent with these Protocols and that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

g. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of AEP to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a section 205 filing under these Protocols (including, but not limited to, ROE and depreciation and amortization rates), or the right of any other party or the Commission to seek such changes pursuant to section 206 of the FPA and the regulations thereunder.

h. AEP may, at its discretion and at a time of its choosing, make a limited filing pursuant to section 205 to modify stated values in the Formula Rate (i) for amortization and depreciation rates, or (ii) to correct obvious errors or omissions in the Formula Rate such as would result from changes to the FERC Form No. 1. The sole issue in any such limited section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate or impose upon AEP any burden with respect to such other aspects of the Formula Rate.

**Section 6. Changes to Annual Updates**

If AEP determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, such corrections shall be reflected as adjustments in the Annual Update for the next Rate Year, with interest calculated in accordance with the FERC Interest Rate (as determined pursuant to 18 C.F.R. § 35.19a). This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments.

**Section 7. Joint Meeting of Transmission Owners**

Each year AEP shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members in order to arrange a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

# Addendum 12 to Attachment H – Part 3

Reserved for Future Use

## Addendum 13 to Attachment H

**Grand River Dam Authority**
**Rate Formula Template**
Index of Worksheets

Year: _____


| | Worksheet | Description |
|---|---|---|
| 2 | Calculation | Calculation of Transmission Revenue Requirement |
| 3 | Worksheet A | Operations & Maintenance Expenses |
| 4 | Worksheet B | Taxes Other Than Income Taxes |
| 5 | Worksheet C | Debt Service |
| 6 | Worksheet D | Revenue Credits |
| 7 | Worksheet E | Net Plant in Service |
| 8 | Worksheet F | System Load |
| 9 | Worksheet G | Allocation Factors |
| 10 | Worksheet H | Base Plan Fixed Charge Rate |
| 11 | Worksheet I | Base Plan Rate of Return |
| 12 | Worksheet J | Summary of Base Plan Projects' Revenue Requirement |
| 13 | Worksheet K1 | Base Plan Upgrade Template for Project #1 |
| 14 | Worksheet K2 | Base Plan Upgrade Template for Project #2 |


**Grand River Dam Authority**
**Rate Formula Template**
**Year Ending December 31,**

| Line No | Description | Reference | Total |
|---|---|---|---|
| | **A. Network Service** | | |
| 1 | GRDA Zonal Revenue Requirement | Revenue Req't Calc, L20 | |

| | | |
|---|---|---|
| | **B. Point-To-Point Service** | |
| 2 | DIVISOR | |
| 3 | Transmission Network Load (kW) | Worksheet F, L14 * 1,000 |
| 4 | RATES | |
| 5 | Annual Point-to-Point Cost ($/kW-Yr) | L1 / L3 |
| 6 | Monthly Point-to-Point ($/kW-Month) | L4 / 12 months |
| 7 | Weekly Point-to-Point ($/kW-Week) | L4 / 52 weeks |
| 8 | Daily On-Peak Point-to-Point ($/kW-Day) | L7 / 5 days |
| 9 | Daily Off-Peak Point-to-Point ($/kW-Day) | L7 / 7 days |
| 10 | Hourly On-Peak Point-to-Point ($/MWh) | L8 / 16 hours * 1,000 |
| 11 | Hourly Off-Peak Point-to-Point ($/MWh) | L9 / 24 hours * 1,000 |
| | **C. Base Plan Upgrade** | |
| 12 | Base Plan Revenue Requirement | Worksheet J, L5 |

## Grand River Dam Authority

**Calculation of Revenue Requirement**

**Year Ending December 31,**

| Line No | Description | Reference | Total Company | Allocation Factor | Allocation % | Total Transmission |
|---|---|---|---|---|---|---|
| 1 | Transmission O&M | Worksheet A, L13 | | T-O&M | | |
| 2 | Consumer Accounts | Worksheet A, L24 | | T-Wages | | |
| 3 | Admin & General Expense | Worksheet A, L37 | | T-Wages | | |
| 4 | Total O&M and A&G Expense | SUM(L1…L3) | | | | |
| 5 | | | | | | |
| 6 | Taxes Other Than Income | Worksheet B, L3 | | | | |
| 7 | | | | | | |
| 8 | Transmission Debt Service | Worksheet C, L3 | | T-Net | | |
| 9 | Debt Service Coverage | | | | | |
| 10 | Margin Requirement | | | | | |
| 11 | | | | | | |
| 12 | Subtotal Revenue Requirement | L4 + L6 + L8 + L10 | | | | |

| | | | | |
|---|---|---|---|---|
| 13 | | | | |
| 14 | Revenue Credits | Worksheet D, L1 | Direct | |
| 15 | | | | |
| 16 | Revenue Requirement | L12 - L14 | | |
| 17 | | | | |
| 18 | Base Plan Revenue Requirement | Worksheet J, L5 | | |
| 19 | | | | |
| 20 | Zonal Revenue Requirement | L16 - L18 | | |

## Grand River Dam Authority

**Worksheet A, Operation & Maintenance Expenses**

**Year Ending December 31,**

| Line No | Account Number | Description | Total Company | Allocation Factor | Allocation % | Total Transmission |
|---|---|---|---|---|---|---|
| 1 | | Transmission Operation & Maintenance Expenses | | | | |
| 2 | 560 | Operation Supervision and Engineering | | Direct | | |
| 3 | 561 | Load Dispatching | | Direct | | |
| 4 | 562 | Station Expenses | | Direct | | |
| 5 | 563 | Overhead Line Expenses | | Direct | | |
| 6 | 565 | Transmission of Electricity by Others | | Direct | | |
| 7 | 566 | Miscellanous Transmission Expenses | | Direct | | |
| 8 | 568 | Maint Supervision & Engineering | | Direct | | |
| 9 | 570 | Maint of Station Equipment | | Direct | | |
| 10 | 571 | Maint of Overhead Lines | | Direct | | |
| 11 | 573 | Maint of Misc Transmission Plant | | Direct | | |
| 12 | 575 | Market Facilitiation Monitoring | | Direct | | |
| 13 | | Total Transmission O&M | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 14 | | | | | |
| 15 | | | | | |
| 16 | | Consumer Accounts Expense | | | |
| 17 | 902 | Meter Reading Expense | | T-Wages | |
| 18 | 903 | Customer Records & Collection Expense | | T-Wages | |
| 19 | 904 | A&G Uncollectible Accounts Expense | | T-Wages | |
| 20 | 907 | A&G Customer Service Supervision | | T-Wages | |
| 21 | 908 | A&G Customer Assistance Expense | | T-Wages | |
| 22 | 909 | A&G Informational Advertising Expense | | T-Wages | |
| 23 | 910 | A&G Misc Service & Information Expense | | T-Wages | |
| 24 | | Total Consumer Accounts Expense | | | |
| 25 | | | | | |
| 26 | | Administrative & General Expenses | | | |
| 27 | 920 | A&G Salaries Expense | | T-Wages | |
| 28 | 921 | A&G Office Supplies & Expense | | T-Wages | |
| 29 | 922 | A&G Adm Expense Transferred-Credit | | T-Wages | |
| 30 | 923 | A&G Outside Services Employed | | T-Wages | |
| 31 | 924 | A&G Property Insurance | | T-Wages | |
| 32 | 925 | A&G Injuries & Damages | | T-Wages | |
| 33 | 926 | A&G Employee Pension & Benefits | | T-Wages | |
| | 928 | A&G Regulatory Pension & Benefits | | T- | |

| | | | | | |
|---|---|---|---|---|---|
| 34 | | | | Wages | |
| 35 | 930 | A&G Miscellaneous General Expense | | T-Wages | |
| 36 | 935 | A&G Maintenance of General Plant | | T-Wages | |
| 37 | | Total A&G Expense | | | |
| 38 | | | | | |
| 39 | | Total O&M and A&G Expenses | | | |
| 40 | | | | | |
| 41 | | | | | |

## Grand River Dam Authority

**Worksheet B, Taxes Other Than Income Taxes**

**Year Ending December 31,**

| Line No | Account Number | Description | Total Company | Allocation Factor | Allocation % | Total Transmission |
|---|---|---|---|---|---|---|
| 1 | | Payroll Taxes | | T-Wages | | |
| 2 | | Property Taxes | | T-Plant | | |
| 3 | | Total Taxes Other Than Income Taxes | | | | |

## Grand River Dam Authority

**Worksheet C, Debt Service**

**Year Ending December 31,**

| Line No | Description | Total Company | Allocation Factor | Allocation % | Total Transmission |
|---|---|---|---|---|---|
| 1 | Principal Payments on Debt | | T-Net | | |
| 2 | Interest Payments on Debt | | T-Net | | |
| 3 | Total Debt Service | | | | |

## Grand River Dam Authority

**Worksheet D, Revenue Credits**
**Year Ending December 31,**

| Line No | Account Number | Description | Total Company | Allocation Factor | Allocation % | Total Transmission |
|---|---|---|---|---|---|---|
| 1 | 456-00 | Wheeling Revenues | | Direct | | - |

## Grand River Dam Authority

**Worksheet E, Calculation of Rate Base**
**Year Ending December 31,**

| Line No | Description | Total Company | Allocation Factor | Allocation % | Total Transmission |
|---|---|---|---|---|---|
| 1 | Plant in Service | | | | |
| 2 | Production Plant | | Direct | | |
| 3 | Transmission | | Direct | | |
| 4 | Distribution Plant | | Direct | | |
| 5 | General Plant | | T-Wages | | |
| 6 | Total Plant in Service | | | | |
| 7 | | | | | |
| 8 | Accumulated Depreciation | | | | |
| 9 | Production Plant | | Direct | | |
| 10 | Transmission | | Direct | | |
| 11 | Distribution Plant | | Direct | | |
| 12 | General Plant | | T-Wages | | |

| | | | |
|---|---|---|---|
| 13 | Total Accum Deprec | | |
| 14 | | | |
| 15 | Net Plant in Service | | |
| 16 | Production Plant | | |
| 17 | Transmission | | |
| 18 | Distribution Plant | | |
| 19 | General Plant | | |
| 20 | Net Plant in Service | | |

## Grand River Dam Authority

**Worksheet F, Network Load**
**Year Ending December 31,**

| Line No | Description | Date & Time | Demand (MW) |
|---|---|---|---|
| 1 | January | | |
| 2 | February | | |
| 3 | March | | |
| 4 | April | | |
| 5 | May | | |
| 6 | June | | |
| 7 | July | | |
| 8 | August | | |
| 9 | September | | |
| 10 | October | | |
| 11 | November | | |
| 12 | December | | |
| 13 | Total (MW-Mo) | SUM (L1..L12) | |
| 14 | Average (MW-Mo) | AVERAGE (L1..L12) | |

## Grand River Dam Authority

**Worksheet G, Allocation Factors**
**Year Ending December 31,**

| Line No | Description | Reference | Total |
|---|---|---|---|
| 1 | Production Wages | | |
| 2 | Transmission Wages | | |
| 3 | Distribution Wages | | |
| 4 | Total Wages, excluding A&G | | |
| 5 | **T-Wages Allocation** | | |
| 6 | | | |
| 7 | Total Transmission O&M | Worksheet A | |
| 8 | Allocated to Transmission | | |
| 9 | **T-O&M Allocation** | | |
| 10 | | | |
| 11 | Total Plant in Service | Worksheet E | |
| 12 | Transmission Plant in Service | | |
| 13 | **T-Plant Allocation** | | |
| 14 | | | |
| 15 | Total Net Plant in Service | Worksheet E | |
| 16 | Transmission Net Plant | | |
| 17 | **T-Net Allocation** | | |

## Grand River Dam Authority

**Worksheet H, Base Plan Upgrades Fixed Charge Rate**

**Year Ending December 31,**

| Line No | Description | Reference | Total |
|---|---|---|---|
| 1 | GRDA Transmission Revenue Requirement | Rev Req't Calculation, L16 | |
| 2 | Net Plant in Service - Transmission | Worksheet E, L20 | |
| 3 | BPU Fixed Charge Rate w/o Depreciation (w/o incentives) | L1 / L2 | |
| 4 | | | |
| 5 | Incentive (basis points) | | |

| | | |
|---|---|---|
| 6 | Increased in Rate of Return | Worksheet H, L20 |
| 7 | | |
| 8 | BPU FCR w/o Depreciation (w/ incentives) | L3 + L6 |

## Grand River Dam Authority

**Worksheet I, Incentive Rate of Return**
**Year Ending December 31,**

| Line No | Description | Reference | Total |
|---|---|---|---|
| 1 | Total Debt Service | Worksheet C, L3 | |
| 2 | Minimum DSC | Rev Req't Calculation, L9 | |
| 3 | Total Margin | L1 * (L2 - 1) | |
| 4 | Net Plant in Service | Worksheet E, L20 | |
| 5 | Weighted Cost of Equity | L3 / L4 | |
| 6 | | | |
| 7 | Interest on Long-Term Debt | Worksheet C, L2 | |
| 8 | Total Long-Term Debt | | |
| 9 | Weighted Cost of Debt | L7 / L8 | |
| 10 | | | |
| 11 | Imputed Rate of Return, no incentives | L5 + L9 | |
| 12 | | | |
| 13 | Net Assets | | |
| 14 | Total Capitalization | L8 + L13 | |
| 15 | Imputed Return on Equity | L5 / (L13 / L14) | |
| 16 | 50 Basis Point Adder | | 0.50% |
| 17 | | | |
| 18 | Rate of Return with 50 BP incentive | L16 * L13 / L14 + L9 | |
| 19 | | | |
| 20 | Increase with Incentive | L18 - L11 | |

## Grand River Dam Authority

**Worksheet J, Summary of Base Plan Projects**
**Year Ending December 31,**

| Line No | Description | Reference | w/ Incentives? | Revenue Req't |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | Total | SUM (L1…L4) | | |

## Grand River Dam Authority

**Worksheet K1 -- GRDA**
**Base Plan Upgrade #1**
**Year Ending December 31,**

| Line No | Description | | |
|---|---|---|---|
| 1 | Investment | | Current Year Incentive ROE increase (basis points) |
| 2 | Service Year (yyyy) | | |
| 3 | Service Month (1-12) | | FCR w/o incentives, less depreciation |
| 4 | Useful Life | | FCR w/ incentives, less depreciation |
| 5 | CIAC (Yes or No) | | Annual Depreciation Expense |

| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | BPU Rev Req w/o Incentives | BPU Rev Req w/ incentives |
|---|---|---|---|---|---|---|---|
| 6 | 0 | 1 | | | | | |
| 7 | 1 | 2 | | | | | |
| 8 | 2 | 3 | | | | | |

| | | |
|---|---|---|
| 9 | 3 | 4 |
| 10 | 4 | 5 |
| 11 | 5 | 6 |
| 12 | 6 | 7 |
| 13 | 7 | 8 |
| 14 | 8 | 9 |
| 15 | 9 | 10 |
| 16 | 10 | 11 |
| 17 | 11 | 12 |
| 18 | 12 | 13 |
| 19 | 13 | 14 |
| 20 | 14 | 15 |
| 21 | 15 | 16 |
| 22 | 16 | 17 |
| 23 | 17 | 18 |
| 24 | 18 | 19 |
| 25 | 19 | 20 |
| 26 | 20 | 21 |
| 27 | 21 | 22 |
| 28 | 22 | 23 |
| 29 | 23 | 24 |
| 30 | 24 | 25 |
| 31 | 25 | 26 |
| 32 | 26 | 27 |
| 33 | 27 | 28 |
| 34 | 28 | 29 |
| 35 | 29 | 30 |
| 36 | 30 | 31 |
| 37 | 31 | 32 |
| 38 | 32 | 33 |
| 39 | 33 | 34 |
| 40 | 34 | 35 |
| 41 | 35 | 36 |
| 42 | 36 | 37 |
| 43 | 37 | 38 |
| 44 | 38 | 39 |
| 45 | 39 | 40 |

46 40 41

| |
|---|
| $ - |

**Grand River Dam Authority**
**Worksheet K2 -- GRDA Base Plan Upgrade #2**
**Year Ending December 31,**

| Line No | Description | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Investment | | | | Current Year Incentive ROE increase (basis points) | | |
| 2 | Service Year (yyyy) | | | | | | |
| 3 | Service Month (1-12) | | | | FCR w/o incentives, less depreciation | | |
| 4 | Useful Life | | | | FCR w/ incentives, less depreciation | | |
| 5 | CIAC (Yes or No) | | | | Annual Depreciation Expense | | |
| | Investment Year | Year # | Beginning Balance | Depreciation Expense | Ending Balance | BPU Rev Req w/o Incentives | BPU Rev Req w/ incentives |
| 6 | 0 | 1 | | | | | |
| 7 | 1 | 2 | | | | | |
| 8 | 2 | 3 | | | | | |
| 9 | 3 | 4 | | | | | |
| 10 | 4 | 5 | | | | | |
| 11 | 5 | 6 | | | | | |
| 12 | 6 | 7 | | | | | |

| | | |
|---|---|---|
| 13 | 7 | 8 |
| 14 | 8 | 9 |
| 15 | 9 | 10 |
| 16 | 10 | 11 |
| 17 | 11 | 12 |
| 18 | 12 | 13 |
| 19 | 13 | 14 |
| 20 | 14 | 15 |
| 21 | 15 | 16 |
| 22 | 16 | 17 |
| 23 | 17 | 18 |
| 24 | 18 | 19 |
| 25 | 19 | 20 |
| 26 | 20 | 21 |
| 27 | 21 | 22 |
| 28 | 22 | 23 |
| 29 | 23 | 24 |
| 30 | 24 | 25 |
| 31 | 25 | 26 |
| 32 | 26 | 27 |
| 33 | 27 | 28 |
| 34 | 28 | 29 |
| 35 | 29 | 30 |
| 36 | 30 | 31 |
| 37 | 31 | 32 |
| 38 | 32 | 33 |
| 39 | 33 | 34 |
| 40 | 34 | 35 |
| 41 | 35 | 36 |
| 42 | 36 | 37 |
| 43 | 37 | 38 |
| 44 | 38 | 39 |
| 45 | 39 | 40 |

**Grand River Dam Authority**

**Transmission Formula Rate Protocols**

I. General. The Grand River Dam Authority ("GRDA") transmission formula rate template and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of GRDA, for transmission service in the GRDA zone ("GRDA Zone") of the Southwest Power Pool, Inc. ("SPP") footprint. GRDA will follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point ("PTP") Transmission Service.

II. Annual GRDA Rate Update.

a. Submission of Annual Update to SPP. GRDA will submit to SPP an annual transmission revenue requirement for purposes of Network Integration Transmission Service, Base Plan Upgrades, and for the determination of Point-to-Point rates, which shall be calculated using the Formula Rate Template set forth in Attachment H - Addendum 13 of this Tariff. The Formula Rate shall be applicable to service on and after August 1 of each calendar year through July 31 of the following calendar year ("Rate Year"), beginning with the Annual Update occurring in calendar year 2023, subject to the provisions of these Protocols.

b. Timing and Publication of Rate Update. On or before May 15th of each calendar year, GRDA will:

i. Recalculate the ATRR and the rates for zonal NITS, and zonal PTP service for the new Rate Year in accordance with the Formula Rate ("Annual Update");

ii. Provide its Annual Update to SPP (which may publish the Annual Update on SPP's website);

iii. Post its Annual Update to the GRDA OASIS website; and

iv. If the date for posting the Annual Update falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Posting Date." Any delay in the Posting Date shall result in an equivalent extension of time for the submission of Information Requests discussed in these Protocols.

c. Notice of Rate Update. Concurrent with the Annual Update postings described above, GRDA will provide a notice of such posting via an email distribution list to all interested parties, including SPP Tariff Transmission Customers, state regulatory agencies with rate jurisdiction over a public utility within the SPP footprint, and any consumer advocate agencies authorized by state law to review and contest the rates for any such public utility ("Interested Parties") by:

i. providing a copy of the Annual Update to SPP, and requesting that SPP:

1. post the Annual Update to the SPP OASIS;

2. distribute the Annual Update to the Formula Rate Posting Information Notification List as maintained by SPP of Interested Parties; provided that such Interested Parties request to be added to the Formula

Rate Posting Information Notification List through the "Exploder List" link on the SPP website, https://www.spp.org/stakeholder-center/exploder-lists.

d. Contents of Annual Update. The Annual Update will:

i. include a workable populated rate formula template with fully functional spreadsheets showing the calculation of the Annual Update and underlying workpapers in native format with links and formulas intact, including sufficiently detailed workpapers and supporting documentation for data;

ii. be based on the independently-audited books and records of GRDA for the most recent fiscal year (January 1 through December 31);

iii. provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

iv. identify, with respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate:

1. any accounting changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

2. any items included in the Formula Rate at an amount other than a historic cost basis; and

3. the individual impact of any changes in i. or ii. above on charges billed under the Formula Rate.

v. not seek to modify the Formula Rate.

III. Review of Annual Updates. Within twenty (20) but not less than ten (10) days after the posting of GRDA's Annual Update (or, in the event of a delay, within a reasonable time under the circumstances, with notice to all Interested Parties), GRDA will host a Meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). GRDA will provide notice of this meeting within a reasonable amount of time (on the same business day, if practicable) after GRDA has provided the Formula Rate Update to SPP and posted the Formula Rate Update on GRDA's OASIS website. The notice shall include the date, time and location of the Annual Meeting and shall be provided to the Interested Parties via an email distribution list. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically.

IV. Exchange of Information.

a. Interested Parties may begin submitting information requests immediately following the Posting Date of the Annual Rate Update and will have until sixty (60) days following the date of such posting to serve reasonable information requests on GRDA for information and work papers supporting the Annual Rate Update. Such information requests shall be limited to that what is necessary to determine:

i. the extent or effect of an accounting change;

ii. whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. the proper application of the Formula Rate and procedures in these Protocols;

iv. the prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. the effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable.

b. GRDA shall make a good faith effort to respond to information requests pertaining to the Annual Update within seven (7) business days, or, if an additional response time is required, GRDA will respond as soon as reasonably practicable.

c. GRDA shall post on its website and submit to SPP (for availability on the SPP website) all information requests from Interested Parties and GRDA's response(s) to such requests. If responses to information requests contain

information deemed by GRDA to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and GRDA.

V. Informal Challenge Procedures.

a. Timeline and General Challenge Process. Interested Parties shall have until July 15 (or the first Business Day after July 15 if July 15 falls on a weekend or holiday) to notify GRDA in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. GRDA will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. GRDA, and, if appropriate, SPP, shall appoint internal representatives to work with the Interested Party to resolve the Informal Challenge.

b. Publication of Challenges and Responses. GRDA will post on its website and provide to SPP all Informal Challenges from Interested Parties and GRDA's responses to the Informal Challenges. If responses to information requests contain information deemed by GRDA to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and GRDA.

c. Revisions Secondary to Challenges. If GRDA makes changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by GRDA and resolved prior to the Informational Filing, those changes will be reported in the Informational Filing, and will be reflected in the Annual Rate Update for the following Rate Year.

VI. Formal Challenge Procedures.

a. Filing Formal Challenges. Formal Challenges must be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the Federal Power Act, and must name SPP as the respondent to any such action due to GRDA's jurisdictional status pursuant to section 201(f) of the Federal Power Act. Parties filing a formal challenge may provide service to GRDA by electronic mail in accordance with § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in GRDA's Informational Filing. For the avoidance of doubt, the challenge procedures available under these Protocols are distinct from, and in addition to any applicable remedies that a party may have against SPP pursuant to section 206 of the Federal Power Act.

b. Requirements for Formal Challenges. Formal Challenges must:

i. Name SPP as the respondent to any action initiated under FPA Section 206;

ii. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

iii. Explain how the action or inaction violates the filed Formula Rate or Protocols;

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits;

viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue; and

ix. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

1. the extent or effect of an accounting change;

2. whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

3. the proper application of the Formula Rate and procedures in these Protocols;

4. the prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

5. the effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

6. any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

VII. Modification of Formula Rate.

a. No Modification of Formula Rate via Challenge Procedures. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

b. Section 205 or 206 Filing Directed at SPP. A change to the Formula Rate fixed inputs related to rate of return on equity ("ROE"), depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate SPP filing with FERC pursuant to the Federal Power Act Sections 205 or 206.

c. Correction of Mistakes. If GRDA makes a correction to errors or omissions regarding the values inputted into the Formula Rate template ("Mistake"), such as arithmetic or computational errors in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in

accordance with the SPP Tariff. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

d. Timing of Changes to Formula Rate Inputs. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the SPP Tariff.

VIII. Informational Filing

a. Submission of Informational Filing. By August 1 of each year, GRDA shall submit to the Commission an informational filing ("Informational Filing") regarding GRDA's Annual Update. The Informational Filling will be for administrative and informational purposes only, and will not submit GRDA to the jurisdiction of the Commission under the Federal Power Act. The Informational Filing will include information that is reasonably necessary to determine:

i. that the input data under the Formula Rate is properly recorded in any underlying workpapers;

ii. that GRDA has properly applied the Formula Rate and these procedures;

iii. the accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

iv. the extent of accounting changes that affect Formula Rate inputs.

b. Contents of Informational Filing. The Informational Filing will also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

c. Publication of Informational Filing. Contemporaneous with the making of such Informational Filing (or, if not contemporaneous, without unreasonable delay), GRDA will provide notice of the Informational Filing to Interested Parties in the manner described in Section II(c) above.

IX. Joint SPP Transmission Owners' Meeting. If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, GRDA will participate in that process.

Example GRDA Schedule:

| | Date | Days Since Initial Posting |
|---|---|---|
| Initial Posting | May 15 | |
| Annual Meeting, Interested Parties | May 25 - June 4 | 10-20 |
| Interested Parties Review Period | May 15 – July 14 | 0-60 |
| Final Informal Challenges Due | July 15 | 61 |
| Informational Filing | August 1 | 78 |
| Rate Year | August 1 – July 31 | |

The foregoing schedule is for illustrative purposes only, and is not intended to modify the filing or other dates outlined in these Protocols.

X. Cost Allocation Methodologies Among Affiliates and Following Reorganization or Merger. GRDA is a governmental agency of the State of Oklahoma. Okla. Stat. tit. 82, § 861 *et seq*. According to the Oklahoma Constitution, GRDA cannot "become an owner or stockholder in . . . any company, association, or corporation." Okla. Const. Art. X, § 15(A). As such, GRDA has no affiliates, and does not engage in mergers. Nevertheless, if (upon a future change in Oklahoma law) GRDA engages with affiliates, and/or participates in reorganizations, or mergers, GRDA will allocate costs related to its Formula Rate in a manner that is consistent with the then-current Commission regulations.

**Addendum 14 to Attachment H**

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff*
# *SUMMARY*
## *Test Year 12/31/20XX*

| Line No. | Description | Source | Amount |
|---|---|---|---|
| | **A. Net Revenue Requirement** | | |
| 1 | Base Plan Revenue Requirement | Page 5 (1-Appendix A tab), Ln 118 | #DIV/0! |
| 2 | Balanced Portfolio Revenue Requirement | Page 5 (1-Appendix A tab), Ln 119 | #DIV/0! |
| 3 | | | |
| 4 | Net Zonal Revenue Requirement | Page 5 (1-Appendix A tab), Ln 120 | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 5 | | | | |
| 6 | 12 CP Peak | Page 11 (6-Txn Firm 12 CP tab), Ln14, Col (c) | - | kW |
| 7 | | | | |
| 8 | Network Zonal Service Rate | Page 5 (1-Appendix A tab), Ln 122 | $ - | /kW |
| 9 | | | | |
| 10 | **B. Point-to-Point Service** | | | |
| 11 | Annual ($/kW) | Page 5 ("1-Appendix A" tab), Ln 123 | $ - | $/kW |
| 12 | Monthly ($/kW) - (Annual/12) | Page 5 ("1-Appendix A" tab), Ln 124 | $ - | $/kW |
| 13 | Weekly ($/kW) - (Annual/52) | Page 5 ("1-Appendix A" tab), Ln 125 | $ - | $/kW |
| 14 | Daily ($/kW) - (Weekly/5) | Page 5 ("1-Appendix A" tab), Ln 126 | $ - | $/kW |
| 15 | Hourly ($/MWh) (Daily/16 x 1000) | Page 5 ("1-Appendix A" tab), Ln 127 | $ - | $/MWh |
| 16 | | | | |
| 17 | | | | |
| 18 | **C. Schedule 1 ARR [1]** | | | |
| 19 | Net Schedule 1 Revenue Requirement for Zone | Page 18 ("8 - Sched 1 RevReq" tab), Ln 4 | $ - | |
| 20 | | | | |
| 21 | **Schedule 1 Rate** | | | |
| 22 | Annual Point-to-Point Rate in $/kW - Year | Page 18 ("8 - Sched 1 RevReq" tab), Ln 8 | $ - | $/kW |
| 23 | Monthly Point-to-Point Rate in $/kW - Month | Page 18 ("8 - Sched 1 RevReq" tab), Ln 9 | $ - | $/kW |
| 24 | Weekly Point-to-Point Rate | Page 18 ("8 - Sched 1 | $ | $/k |

| | | | | |
|---|---|---|---|---|
| | in $/kW - Week | RevReq" tab), Ln 10 | - | W |
| | Daily Point-to-Point Rate in | Page 18 ("8 - Sched 1 | $ | $/k |
| 25 | $/kW - Day | RevReq" tab), Ln 11 | - | W |
| | Hourly Point-to-Point Rate in | Page 18 ("8 - Sched 1 | $ | $/M |
| 26 | $/MW - Hour | RevReq" tab), Ln 12 | - | Wh |

[1] Per SA in FERC Docket No. ER17-469, values will be zero until TY2017 filing.

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff*
# *Change Analysis*
## *Test Year 12/31/20XX*

**Per Midwest Energy TFR Protocols, Section 2.A.VI, each Annual Update for the Rate Year shall include a change analysis of the following components below as compared to the corresponding items in the revenue requirement that was calculated for the prior rate year, with an explanation of any material changes (increase over 10 percent and over $100,000 from the previous year for each of the listed revenue requirement components):**

| | TFR REFERENCE | TFR 20XXTY | TFR 20XX-1TY | Difference $ | Difference % | Explanation of Change |
|---|---|---|---|---|---|---|
| **Rate Base** | Page 2, Line 48 | $ - | | $ - | #DIV/0! | |
| **Operating and Maintenance expenses** | Page 3, Line 69 | $ - | | $ - | #DIV/0! | |

| | | | | |
|---|---|---|---|---|
| **Depreciation expense** | Page 3, Line 81 | #DIV/0! | #DIV/0! | #DIV/0! |
| **Taxes** | Page 3, Line 83 | $ - | $ - | #DIV/0! |
| **Return on Rate Base** | Page 4, Line 96 | $ - | $ - | #DIV/0! |
| **Revenue Credits** | Page 5, Line 111 | $ - | $ - | #DIV/0! |

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff*
## *Test Year 12/31/20XX*

| Formula Rate | Notes | FERC Form 1 Page # or Instruction | Year Ending 12/31/20XX |
|---|---|---|---|
| **Shaded cells are input cells** | | | |
| **Allocators** | | | |
| | **Wages & Salary Allocation Factor** | | |
| 1 | Transmission Wages Expense | p354.21.b | |
| 2 | Total Wages Expense | p354.28b | |
| 3 | Less A&G Wages Expense | p354.27b | |
| 4 | Total | (Lines 2 - 3) | 0 |
| 5 | **Wages & Salary Allocator** | (Lines 1 / 4) | **0.0000 %** |

**Plant Allocation Factors**

| | | | | |
|---|---|---|---|---|
| 6 | Electric Plant in Service | (Note B) | Cost Support Sheets | 0 |
| 7 | Common Plant In Service - Electric | | (Line 21) | 0 |
| 8 | Total Plant In Service | | (Sum Lines 6 to 7) | 0 |
| 9 | Accumulated Depreciation (Total Electric Plant) | | p219.29c | |
| 10 | Accumulated Intangible Amortization | (Note A) | p200.21c | |
| 11 | Accumulated Common Amortization - Electric | (Note A) | p356 | |
| 12 | Accumulated Common Plant Depreciation - Electric | (Note A) | p356.1 | |
| 13 | Total Accumulated Depreciation | | (Sum Lines 9 to 12) | 0 |
| 14 | Net Plant | | (Lines 8 - 13) | 0 |
| 15 | Transmission Gross Plant | | (Lines 26 - 25) | 0 |
| 16 | **Gross Plant Allocator** | | (Lines 15 / 8) | **0.0000 %** |
| 17 | Transmission Net Plant | | (Lines 36 - 25) | 0 |
| 18 | **Net Plant Allocator** | | (Lines 17 / 14) | **0.0000 %** |

**Plant Calculations**

| | | | | | |
|---|---|---|---|---|---|
| | **Plant In Service** | | | | |
| 19 | Transmission Plant In Service | (Note B) | p207.58.g | | |
| 20 | General & Intangible | | p205.5.g & p207.99.g | | |
| 21 | Common Plant (Electric Only) | (Notes A & B) | p356 | | |
| 22 | Total General & Common | | (Lines 20 + 21) | 0 | |
| 23 | Wage & Salary Allocation Factor | | (Line 5) | 0.0000 0% | |
| 24 | **General & Common Plant Allocated to Transmission** | | (Lines 22 * 23) | **0** | |
| 25 | **Plant Held for Future Use (Including Land)** | (Note C) | p214 | | |
| 26 | **TOTAL Plant In Service** | | **(Lines 19 + 24 + 25)** | **0** | |
| | **Accumulated Depreciation** | | | | |
| 27 | Transmission Accumulated Depreciation | (Note B) | p219.25.c | | |
| 28 | Accumulated General Depreciation | | p219.28.c | | |
| 29 | Accumulated Intangible Amortization | | (Line 10) | 0 | |
| 30 | Accumulated Common Amortization - Electric | | (Line 11) | 0 | |
| 31 | Common Plant Accumulated Depreciation (Electric Only) | | (Line 12) | 0 | |

| | | | | |
|---|---|---|---|---|
| 32 | Total Accumulated Depreciation | | (Sum Lines 28 to 31) | 0 |
| 33 | Wage & Salary Allocation Factor | | (Line 5) | 0.0000 0% |
| 34 | **General & Common Allocated to Transmission** | | (Lines 32 x 33) | **0** |
| 35 | **TOTAL Accumulated Depreciation** | | **(Lines 27 + 34)** | **0** |
| 36 | **TOTAL Net Property, Plant & Equipment** | | **(Lines 26 - 35)** | **0** |

**Adjustment To Rate Base**

**Prepayments**

| | | | | |
|---|---|---|---|---|
| 37 | Prepayments (Account 165) | (Note A) | p111.57c | |
| 38 | Net Plant Allocation Factor | | (Line 18) | 0.0000 % |
| 39 | **Total Prepayments Allocated to Transmission** | | (Lines 37 x 38) | **0** |

**Materials and Supplies**

| | | | | |
|---|---|---|---|---|
| 40 | Materials and Supplies | (Note A) | Cost Support Sheets | - |
| 41 | Wage & Salary Allocation Factor | | (Line 5) | 0.00% |
| 42 | Total Materials and Supplies Allocated to Transmission | | (Lines 40 x 41) | 0 |

**Cash Working Capital**

| | | | | |
|---|---|---|---|---|
| 43 | Transmission Operation & Maintenance Expense | | (Line 69) | 0 |
| 44 | 1/8th Rule | | x 1/8 | 12.5% |
| 45 | **Total Cash Working Capital Allocated to Transmission** | | (Lines 43 x 44) | **0** |
| | **Construction Work in Progress (CWIP)** | | | |
| 46 | Transmission Construction Work in Progress | | Cost Support Sheets | **0** |
| 47 | **TOTAL Adjustment to Rate Base** | | (Line 39 + 42 + 45 + 46) | **0** |
| 48 | **Rate Base** | | (Lines 36 + 47) | **0** |
| **O&M** | | | | |
| | **Transmission O&M** | | | |
| 49 | Transmission O&M | | p322.112.b | |
| 50 | Less Account 565 | (Note I) | p322.96.b | |
| 51 | Less Schedule 12 payments if specifically recovered elsewhere | (Note I) | MWE Data | |
| 52 | Less Transmission Share of Acc. 454 - Rent from Elec Property | (Note C) | Cost Support Sheets | 0 |
| 53 | Less Acct. 561 Expense Recovered Through Schedule 1 | (Note K) | Sched 1 RevReq Sheet | 0 |
| 54 | Plus Transmission Lease Payments | (Not | Cost Support | |

| | | | | |
|---|---|---|---|---|
| | | e E) | Sheets | |
| 55 | **Transmission O&M** | | (Lines 49 - 50 - 51- 52 - 53 + 54) | **0** |
| | **Allocated General & Common Expenses** | | | |
| 56 | Common Plant O&M | (Note A) | p356 | |
| 57 | Adjusted A&G | | Cost Support Sheets | **0** |
| 58 | **General & Common Expenses** | | (Lines 56 + 57) | 0 |
| 59 | Wage & Salary Allocation Factor | | (Line 5) | 0.0000 % |
| 60 | **General & Common Expenses Allocated to Transmission** | | (Lines 58 x 59) | **0** |
| 61 | **Directly Assigned A&G** | | | |
| 62 | Property Insurance Account 924 | | Cost Support Sheets | 0 |
| 63 | Net Plant Allocation Factor | | (Line 18) | 0.00% |
| 64 | **Transmission Property Insurance** | | (Lines 62 x 63) | **0** |
| 65 | Plus Transmission General Advertising | (Note J) | Cost Support Sheets | **0** |
| 66 | Plus Transmission Regulatory - State | | Cost Support Sheets | **0** |
| 67 | Plus Transmission Regulatory - Federal | | Cost Support Sheets | **0** |
| 68 | Plus Transmission Industry Dues | (Note D) | Cost Support Sheets | **0** |

| | | | | |
|---|---|---|---|---|
| 69 | **Total Transmission O&M** | | **(Lines 55 + 60 + 64 + 65 + 66 + 67 + 68)** | **0** |

**Depreciation & Amortization Expense**

**Depreciation Expense**

| | | | | |
|---|---|---|---|---|
| 70 | Transmission Depreciation Expense | | Depreciation & Amortization Sheets | **0** |
| 71 | General Depreciation | | Depreciation & Amortization Sheets | **0** |
| 72 | Intangible Amortization | (Note A) | Depreciation & Amortization Sheets | **0** |
| 73 | Total | | (Lines 71 + 72) | 0 |
| 74 | Wage & Salary Allocation Factor | | (Line 5) | 0.0000 % |
| 75 | **General Depreciation Allocated to Transmission** | | (Lines 73 x 74) | **0** |
| 76 | Common Depreciation - Electric Only | (Note A) | Depreciation & Amortization Sheets | **#DIV/0!** |
| 77 | Common Amortization - Electric Only | (Not | p356 or | |

| | | | | |
|---|---|---|---|---|
| | | e A) | p336.11.d | |
| 78 | Total | | (Lines 76 + 77) | #DIV/0! |
| 79 | Wage & Salary Allocation Factor | | (Line 5) | 0.0000 % |
| 80 | **Common Depreciation - Electric Only Allocated to Transmission** | | (Lines 78 x 79) | **#DIV/0!** |
| 81 | **Total Transmission Depreciation & Amortization** | | **(Lines 70 + 75 + 80)** | **#DIV/0!** |
| **Taxes Other than Income** | | | | |
| 82 | **Taxes Other than Income** | | Other Taxes Sheets | **0** |
| 83 | **Total Taxes Other than Income** | | **(Line 82)** | **0** |
| **Return / Capitalization Calculations** | | | | |
| | **Long Term Interest** | | | |
| 84 | Long Term Interest (Consolidated) | | p117.62c through 67c | |
| | **Patronage Capital & Other Equity** | | | |

| | | | | | |
|---|---|---|---|---|---|
| 85 | Patronage Capital & Other Equity (Consolidated) | | | p112.16c | |
| | **Capitalization** | | | | |
| 86 | Long Term Debt (Consolidated) | | | p112.18.c through 21.c | |
| 87 | Patronage Cap. | | | (Line 85) | 0 |
| 88 | **Total Capitalization** | | | (Lines 86 + 87) | 0 |
| 89 | Debt % | Total Long Term Debt | | (Lines 86 / 88) | 0.0000 % |
| 90 | Capital % | Patronage Cap. | | (Lines 87 / 88) | 0.0000 % |
| 91 | Debt Cost | Total Long Term Debt | | (Lines 84 / 86) | 0.0000 % |
| 92 | Equity Cost | Patronage Cap. | (Note F) | Fixed | **10.000 0%** |
| 93 | Weighted Cost of Debt | Total Long Term Debt (WCLTD) | | (Lines 89 x 91) | 0.0000 % |
| 94 | Weighted Cost of Capital | Patronage Cap. | | (Lines 90 x 92) | 0.0000 % |
| 95 | **Total Return ( R )** | | | (Lines 93 + 94) | **0.0000 %** |
| 96 | **Investment Return = Rate Base * Rate of Return** | | | **(Lines 48 x 95)** | **0** |

**REVENUE REQUIREMENT**

| | | | | |
|---|---|---|---|---|
| | **Summary** | | | |
| 97 | Net Property, Plant & Equipment | | (Line 36) | 0 |
| 98 | Adjustment to Rate Base | | (Line 47) | 0 |
| 99 | **Rate Base** | | (Line 48) | **0** |
| 100 | O&M | | (Line 69) | 0 |
| 101 | Depreciation & Amortization | | (Line 81) | #DIV/0! |
| 102 | Taxes Other than Income | | (Line 83) | 0 |
| 103 | Investment Return | | (Line 96) | 0 |
| **104** | **Gross Revenue Requirement** | | **(Sum Lines 100 to 103)** | **#DIV/0!** |
| | **Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities** | | | |
| 105 | Transmission Plant In Service | | (Line 19) | 0 |
| 106 | Excluded Transmission Facilities | (Note H) | Cost Support Sheets | 0 |
| 107 | Included Transmission Facilities | | (Lines 105 - 106) | 0 |
| 108 | Inclusion Ratio | | (Lines 107 / 105) | 0.0000 % |
| 109 | Gross Revenue Requirement | | (Lines 104) | #DIV/0! |
| 110 | **Adjusted Gross Revenue Requirement** | | (Lines 108 x 109) | #DIV/0! |
| 111 | Less Account 456 - Other Electric Revenue (transmission- | | Cost Support | 0 |

| | | | |
|---|---|---|---|
| | related activity) | Sheets | |
| **112** | **Net Revenue Requirement** | **(Lines 110 - 111)** | **#DIV/0!** |
| | **Net Plant Carrying Charge without New Investment Incentive** | | |
| 113 | Net Revenue Requirement | (Line 112) | **#DIV/0!** |
| 114 | Net Transmission Plant | (Lines 19 - 27) | **-** |
| 115 | Net Plant Carrying Charge | (Lines 113 / 114) | **0.0000 %** |
| 116 | Net Plant Carrying Charge without Depreciation | ((Line 113 - 70) / Line 114) | **0.0000 %** |
| 117 | **Net Revenue Requirement** | (Line 112) | **#DIV/0!** |
| 118 | Less Base Plan Revenue Requirement | RTO Directed Projects, L13, Col. (k) | #DIV/0! |
| 119 | Less Balanced Portfolio Revenue Requirement | RTO Directed Projects, L17, Col.(k) | #DIV/0! |
| 120 | **Net Zonal Revenue Requirement** | (Line 117 - Line 118 - Line 119) | **#DIV/0!** |
| | **Network Zonal Service Rate** | | |

| | | | |
|---|---|---|---|
| 121 | 12 CP Peak | (Note G) | 12CP Firm Trans Sheet - |
| 122 | Rate ($/KW-Year) | | (Lines 120 / 121) **0.0000** |

| - | **Firm Transmission Service Rates** | | **Non-Firm Transmission Service Rates** | |
|---|---|---|---|---|
| - | | | | |
| 123 | Annual Point-to-Point Firm ($/kW) | 0.0000 | Annual Point-to-Point Non-Firm ($/kW) | n/a |
| 124 | Monthly Firm ($/kW) - (Annual/12) | 0.0000 | Monthly Non-Firm ($/kW) - (Annual/12) | 0.0000 |
| 125 | Weekly Firm ($/kW) - (Annual/52) | 0.0000 | Weekly Non-Firm ($/kW) - (Annual/52) | 0.0000 |
| 126 | Daily Firm ($/kW) - (Weekly/5) | 0.0000 | Daily Non-Firm ($/kW) - (Weekly/5) | 0.0000 |
| 127 | Hourly Firm ($/MWh) | n/a | Hourly Non-Firm ($/MWh) (Daily/16 x 1000) | 0.00 |

## Notes

A Electric portion only

B Exclude Construction Work In Progress.

C Transmission Portion Only

D Removed 100% .

E Transmission lines leased from others. Midwest does not lease transmission lines from other entities.

F The Equity Cost set in Docket No. ER17-469 shall remain fixed and may not change absent FERC approval pursuant to Section 205 or 206 filing. Any change to the total equity cost set in Docket No. ER17-469 and identified on line 92 (e.g. base ROE, incentive adders) cannot occur absent such approval..

G Average aggregated firm demand during each of the 12 calendar-month peak demand hours (i.e., "12 CP") for Network and Point to Point transactions of over one year on the Company's transmission system.

H Amount of transmission plant excluded from rates, includes investment that does not pass the FERC tests for functionalization as transmission plant. Midwest Energy details specific segments of line in Attachment 3.

I Midwest Energy Records assessments by SPP less revenues from SPP in account 555 (i.e. debit and credits) . The amounts offset each other completely. However, SPP also adds its administrative fees thereby making a net expense charged to 555. This administrative fee is recovered through the ECA mechanism and therefore should not be included as part of the TFR.
MWE does not record anything in account 565. ="Account 566 is the account where NERC and FERC assessments are charged and are included in Transmission O&M expense (line 56)."

J Removed 100%.

K PER SA in FERC Docket No. ER17-469: $0 for TY2015 and for TY2016; beginning with the TY2017, this will reflect the account 561 charges to be removed from the Transmission O&M - instead, these charges will be recovered through Schedule 1 ATRR on page 18 (tab "8-Sched 1 RevRe1").

**END**

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - Other Taxes*
## *Test Year 12/31/20XX*

### Taxes Other Than Income Worksheet

| Other Taxes | FERC Form 1 Reference Page 263 Col (i) | Allocator | Allocated Amount |
|---|---|---|---|
| **Plant Related** | | **Gross Plant Allocator** | |
| Property Taxes | Pg 263.14.i (Or Appropriate Line) | | RC Sched 11-1, C4, R1 |

| | | | |
|---|---|---|---|
| | | | |
| **Total Plant Related** | 0 | 0.0000% | 0 |

| | | | |
|---|---|---|---|
| **Labor Related** | | **Wages & Salary Allocator** | |
| | | | |
| **Total Labor Related** | 0 | 0.0000% | 0 |

| | | | |
|---|---|---|---|
| **Other Included** | | **Gross Plant Allocator** | |
| | | | |
| **Total Other Included** | 0 | 0.0000% | 0 |
| **Total Included** | | | 0 |

**Currently Excluded**

| | |
|---|---|
| | |
| Total as reported on p. 263(i) | 0 |

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - Cost Support*
## *Test Year 12/31/20XX*

## Electric / Non-electric Cost Support

| SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Form 1 Amount | Electric Portion | Non-electric Portion | Details |
|---|---|---|---|---|---|---|
| | **Plant Allocation Factors** | | | | | |
| 1 | Accumulated Intangible | (Note A) | | | | |
| 0 | Amortization | | p200.21c | | | |
| 1 | Accumulated Common | (Note A) | | | | |
| 1 | Amortization - Electric | | p356 | | | |
| 1 | Accumulated Common Plant | (Note A) | | | | |
| 2 | Depreciation - Electric | | p356.1 | | | |
| | **Plant In Service** | | | | | |
| 6 | Electric Plant in Service | | p207.104g | | - | - |
| 2 | | (Notes A & B) | | | | |
| 1 | Common Plant (Electric Only) | | p356 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Prepayments** | | | | | |
| 3 7 | Prepayments (Account 165) | (Note A) | p111.57c | | | |
| | **Materials and Supplies** | | | | | |
| 4 0 | Materials and Supplies<br>Reference footnote in Form 1 for split between electric and non-electric portion. | (Note A) | p227.5c & 6c | | - | |
| | **Transmission O&M** | | | | | |
| 5 4 | Plus Transmission Lease Payments | (Note E) | | | - | See WP4 Leased Transmission |
| | **Allocated General & Common Expenses** | | | | | |
| 5 8 | Common Plant O&M | (Note A) | p356 | | | |
| | **Depreciation Expense** | | | | | |
| 7 2 | Intangible Amortization | (Note A) | Depreciation & Amortization Sheets | | | |
| 7 6 | Common Depreciation - Electric Only | (Note A) | Depreciation & Amortization Sheets | | | |
| 7 7 | Common Amortization - Electric Only | (Note A) | p356 or p336.11.d | | | |

## Transmission / Non-transmission Cost Support

| SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Form 1 Amount | Transmission Related | Non-transmission Related | Details |
|---|---|---|---|---|---|---|
| 25 | **Plant Held for Future Use (Including Land)** | (Note C) p214 | | | | Specific identification based on plant records<br>1<br>2<br>3<br>4<br>5<br>6<br>7 |

# CWIP & Expensed Lease Worksheet

| | SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Form 1 Amount | Adjustments | Adjusted CWIP | Details |
|---|---|---|---|---|---|---|---|
| | **Plant Allocation Factors** | | | | | | |
| 6 | Electric Plant in Service | (Note B) | Cost Support Sheets | | | | See Form 1 |
| | **Construction Work in Progress** | | | | | | |
| 4 6 | CWIP Adjustment | | p200.11c | | - | - | Direct amt, see WP 1 |
| | | | | | | 0 | |
| | **Plant In Service** | | | | | | |
| 1 9 | Transmission Plant In Service | (Note B) | p207.58.g | | | | See Form 1 |
| 2 1 | Common Plant (Electric Only) | (Notes A & B) | p356 | | | | See Line 24 |
| | **Accumulated Depreciation** | | | | | | |
| 2 | Transmission Accumulated | (Not | p219.25.c | | | | See Form 1 |

| | | | |
|---|---|---|---|
| 7 | Depreciation | e B) | |

# Administrative and General Cost Support

| SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | Form 1 Amount | Transmission Amount | Removed from Transmission | Calculation Details | Notes |
|---|---|---|---|---|---|---|
| **Allocated General & Common Expenses** | | | | | | |
| Administrative and General Expense | p.324.197b | | | | | |
| Less Property Insurance, Account 924 | p.324.185.b | | | | | |
| Less General Advertising, Account 930.1 | p.324.191.b | | **$0.00** | - | | Removed 100% |
| Less Regulatory- State, Account 928.1 | | | | - | | Prior Year TFR Revenue Requirement divided by GIOR for Prior Year.* |
| Less Regulatory - Federal, Account 928.0 | | | **0** | - | | Direct Assigned if/when applicable |
| Less Industry Dues, Account 930.20.30 | | | **$0.00** | - | | Removed 100% |
| 5 7 Adjusted Administrative & General Expense | | **-** | | | | |

| | | |
|---|---|---|
| | | *The GIOR is the sum of Prior Year TFR revenue requirement, current year Sale for Resale Revenue (Form 1), and TFR-related portion of the Account 456 identified as revenue credit in the Prior Year's TFR. |

# Excluded Plant Cost Support

| SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Excluded Transmission Facilities | Description of the Facilities |
|---|---|---|---|---|
| **Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities** | | | | - |
| 1 0 6 Excluded Transmission Facilities | (Note H) | Cost Support Sheets | $ - | |
| - | | - | | - |
| - | | - | | - |
| - | | - | | - |
| - | | - | | - |
| - | | - | | - |
| - | | - | | - |
| - | | - | | - |

| | | |

| | SPP<br>Attachment Z2<br>Company Total | $<br>- |
|---|---|---|
| January | | $<br>- |
| February | | - |
| March | | - |
| April | | - |
| May | | - |
| June | | - |
| July | | - |
| August | | - |
| September | | - |
| October | | - |
| November | | - |
| December | | - |
| **Period** | | $<br>- |

| | |
|---|---|
| | **Total**<br>See Acct 456 TFR Amt Sheets<br>Note - per SA in FERC Docket No. 17-469, this includes Schedule 1 PTP. Beginning with the TY2017, those revenues will be creditd on Sched 1 RevReq tab, or page 18 of the TFR. |

## Load Cost Support

| SPP Formula Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | | 12 CP Peak | Description & Documentation |
|---|---|---|---|---|---|
| **Network Zonal Service Rate** | | | | | |
| 1 | | | 12CP Firm | | |
| 2 | | (Not | Trans | | |
| 1 | 12 CP Peak | e G) | Sheet | | **Total Transmission System Firm 12 CP Demand** |

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - Acct 456 TFR-related Amount*
# *Test Year 12/31/20XX*

***Revenues for Non-Firm RTO PTP Transmission Service and Revenue Crediting for Upgrades***

**TFR-related Amounts Booked to Acct. 456**

| Month | Schedule 7,8,11 PTP Revenues or any Other PTP Revenue, or Adjustment Revenue Credited to TO by SPP similar to PTP | | | | | | | | | Total [1] |
|---|---|---|---|---|---|---|---|---|---|---|
| | SPP Schedule 7 Revenues | SPP Schedule 8 Revenues | Non-NITS SPP Schedule 11 Revenues | SPP Attachment Z2 Revenue Credits | SPP Schedule 1 Revenues [1] | Other Revenue | | | | |
| January | | | | | | | | | | $0 |
| February | | | | | | | | | | $0 |
| March | | | | | | | | | | $0 |
| April | | | | | | | | | | $0 |
| May | | | | | | | | | | $0 |
| June | | | | | | | | | | $0 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| July | | | | | | | | | | $0 |
| August | | | | | | | | | | $0 |
| September | | | | | | | | | | $0 |
| October | | | | | | | | | | $0 |
| November | | | | | | | | | | $0 |
| December | | | | | | | | | | $0 |
| Total | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |

[1] Per SA in FERC Docket No. ER17-469:

For TY2015 and TY2016, Schedule 1 PTP Revenue paid by SPP is to be included in revenue credits to be applied against Adjusted Gross Revenue Requirement, since

Account 561 charges are still included in the ATRR;

Beginning with TY2017, Schedule 1 PTP revenues will be credited against a Sched 1 RevReq on Page 18, Line 4 ( tab "8 - Schedule 1 Revenue Requirement" tab).

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - 12CP Firm Transmission*
## *Test Year 12/31/20XX*

## Summary of 12 CP Firm Calculation

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Month** | **Year** | **System Firm Peak Load** | **Wholesale Firm PTP Contribution to Peak** | **Wholesale NITS Cont. to Peak Non-MDWE** | **Total MIDW NITS Contribution to Peak** | **WHOLESALE NITS Cont. to Peak MDWE Munis** | **RETAIL NITS Contribution to Peak** |
| 1 | Jan. | | - | - | | | | - |
| 2 | Feb | | - | - | | | | - |
| 3 | Mar | | - | - | | | | - |
| 4 | Apr | | - | - | | | | - |
| 5 | May | | - | - | | | | - |
| 6 | Jun | | - | - | | | | - |
| 7 | Jul | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | - | - | | | | - |
| 8 | Aug | | - | - | | | | - |
| 9 | Sep | | - | - | | | | - |
| 10 | Oct | | - | - | | | | - |
| 11 | Nov | | - | - | | | | - |
| 12 | Dec | | - | - | | | | - |
| 13<br>14 | Average 12 CP | | - | - | #DIV/0! | #DIV/0! | #DIV/0! | - |

PTP = "Point-to-Point"
transmission service.
NITS = "Network Integration Transmission Service" provided under
either Midwest Energy's or the Southwest Power Pool's
Open Access
Transmission Tariff.

**Table 1. Total Transmission System Firm Demand (kW) at Coincident Peak**

| | | | Monthly Coincident Peak Demand (kW) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Month | Date | Hour Ending | Total Transmission System Schedule | Less: Firm PTP Scheduled | Plus: Firm PTP Contract Demand (Table 3) | Less: Non-Firm Demand (Table 4) | Plus: Non-Company Gener | Plus: Non-Con | Total Transmission Syste | Correction for Over- | Corrected Total Transmissio |

| | | | d Peak | Demand (Table 2) | | | ation (Table 5) | trol-Area Demand (Table 6) | m Firm Demand (kW) | Scheduled Firm Demand (Note 1) | n System Firm Demand (kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| January | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| February | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| March | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| April | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| May | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| June | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| July | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| August | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| September | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| October | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| November | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| December | | | | 0 | 0 | 0 | 0 | 0 | 0 | | 0 |
| 12-CP | | | | 0 | 0 | 0 | 0 | 0 | 0 | #DIV/0! | 0 |

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - 12CP Firm Transmission*
## *Test Year 12/31/20XX*

**Table 2. Firm Point-to-Point (PTP) Scheduled Demand (kW) at Coincident Peak**

Data reflect actual scheduled demand under PTP transmission service agreements during monthly coincident peaks.

| Month | Date | Hour Ending | Firm PTP Transmission Customer | | | | | | | | | | | | Firm PTP Scheduled Demand (kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Sunflower GFA | WAPA (OAKLEY) | WAPA (COLBY) | GRDA (STERLING) | GRDA (ELLINWOOD) | GRDA (LARNED) | St. John Firm | Colby Firm | Jetmore Firm | LaCrosse Firm | Seward Firm | Radium Firm | |
| January | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| February | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| March | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| April | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| May | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| June | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| July | 1/0/0 | 0 | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | | | | | | | | | | | | | | |
| August | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| September | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| October | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| November | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| December | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| 12-CP | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0 |

**Table 3. Firm Point-to-Point (PTP) Contract Demand (kW) at Coincident Peak**

Data reflect contract demand reservations under PTP transmission service agreements during monthly coincident peaks.

| Month | Date | Hour Ending | Firm PTP Transmission Customer | | | | | | | | | | | | Firm PTP Contract Demand (kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Sunflower GFA | WAPA (OAKLEY) | WAPA (COLBY) | GRDA (STERLING) | GRDA (ELLINWOOD) | GRDA (LARNED) | St. John Firm | Colby Firm | Jetmore Firm | LaCrosse Firm | Seward Firm | Radium Firm | |
| January | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| February | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| March | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| April | 1/0/00 | 0 | | | | | | | | | | | | | 0 |
| May | 1/0/00 | 0 | | | | | | | | | | | | | 0 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 0 | | | | | | | | | | | | | |
| | 1/0/0 | | | | | | | | | | | | | |
| June | 0 | 0 | | | | | | | | | | | | 0 |
| | 1/0/0 | | | | | | | | | | | | | |
| July | 0 | 0 | | | | | | | | | | | | 0 |
| Augu | 1/0/0 | | | | | | | | | | | | | |
| st | 0 | 0 | | | | | | | | | | | | 0 |
| Sept | | | | | | | | | | | | | | |
| embe | 1/0/0 | | | | | | | | | | | | | |
| r | 0 | 0 | | | | | | | | | | | | 0 |
| Octo | 1/0/0 | | | | | | | | | | | | | |
| ber | 0 | 0 | | | | | | | | | | | | 0 |
| Nove | 1/0/0 | | | | | | | | | | | | | |
| mber | 0 | 0 | | | | | | | | | | | | 0 |
| Dece | 1/0/0 | | | | | | | | | | | | | |
| mber | 0 | 0 | | | | | | | | | | | | 0 |
| 12-CP | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0 |

**Table 4. Non-Firm Sales Demand (kW) at Coincident Peak**

Data reflect scheduled demands under non-firm Point to Point transmission service agreements during monthly coincident peaks.

| Month | Date | Hour Ending | Non-Firm Transmission Customer | | | | | | | | | Non-Firm Sales Demand (kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Colby | Oakley | Jetmore | LaCrosse | Ellinwood | Stafford | Sterling | St. John | Larned | |
| January | 1/0/0 0 | 0 | | | | | | | | | | 0 |
| February | 1/0/0 0 | 0 | | | | | | | | | | 0 |
| March | 1/0/0 | 0 | | | | | | | | | | 0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| h | 0 | | | | | | | | | | |
| | 1/0/0 | | | | | | | | | | |
| April | 0 | 0 | | | | | | | | | 0 |
| | 1/0/0 | | | | | | | | | | |
| May | 0 | 0 | | | | | | | | | 0 |
| | 1/0/0 | | | | | | | | | | |
| June | 0 | 0 | | | | | | | | | 0 |
| | 1/0/0 | | | | | | | | | | |
| July | 0 | 0 | | | | | | | | | 0 |
| Augu | 1/0/0 | | | | | | | | | | |
| st | 0 | 0 | | | | | | | | | 0 |
| Sept | | | | | | | | | | | |
| embe | 1/0/0 | | | | | | | | | | |
| r | 0 | 0 | | | | | | | | | 0 |
| Octo | 1/0/0 | | | | | | | | | | |
| ber | 0 | 0 | | | | | | | | | 0 |
| Nove | 1/0/0 | | | | | | | | | | |
| mber | 0 | 0 | | | | | | | | | 0 |
| Dece | 1/0/0 | | | | | | | | | | |
| mber | 0 | 0 | | | | | | | | | 0 |
| 12-CP | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0 |



# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - 12CP Firm Transmission*
### *Test Year 12/31/20XX*

**Table 5. Non-Company Generation (kW) at Coincident Peak**

Data reflect self-generation covered by grandfathered agreements operating synchronously with the Company's transmission system to serve transmission system demand not accounted for elsewhere.

| Month | Date | Hour Ending | Company Providing Generation on Transmission System | | | | | | | | | Non-Company Gen. Demand |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| January | 1/0/00 | 0 | | | | | | | | | | 0 |
| February | 1/0/00 | 0 | | | | | | | | | | 0 |
| March | 1/0/00 | 0 | | | | | | | | | | 0 |
| April | 1/0/00 | 0 | | | | | | | | | | 0 |
| May | 1/0/00 | 0 | | | | | | | | | | 0 |
| June | 1/0/00 | 0 | | | | | | | | | | 0 |
| July | 1/0/00 | 0 | | | | | | | | | | 0 |
| August | 1/0/00 | 0 | | | | | | | | | | 0 |
| September | 1/0/00 | 0 | | | | | | | | | | 0 |
| October | 1/0/00 | 0 | | | | | | | | | | 0 |
| November | 1/0/00 | 0 | | | | | | | | | | 0 |
| December | 1/0/00 | 0 | | | | | | | | | | 0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 12-CP | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0 |

**Table 6. Non-Control Area Demand (kW) at Coincident Peak**

Data reflect demand on the Company's transmission system that is electronically transferred to other control areas that is not accounted for elsewhere.

| Month | Date | Hour Ending | Customer with Non-Control Area Demand | | | | | | | | | Non-Control-Area Demand (kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| January | 1/0/00 | 0 | | | | | | | | | | 0 |
| February | 1/0/00 | 0 | | | | | | | | | | 0 |
| March | 1/0/00 | 0 | | | | | | | | | | 0 |
| April | 1/0/00 | 0 | | | | | | | | | | 0 |
| May | 1/0/00 | 0 | | | | | | | | | | 0 |
| June | 1/0/00 | 0 | | | | | | | | | | 0 |
| July | 1/0/00 | 0 | | | | | | | | | | 0 |
| August | 1/0/00 | 0 | | | | | | | | | | 0 |
| September | 1/0/00 | 0 | | | | | | | | | | 0 |
| October | 1/0/00 | 0 | | | | | | | | | | 0 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| November | 1/0/00 | 0 | | | | | | | | | | 0 |
| December | 1/0/00 | 0 | | | | | | | | | | 0 |
| 12-CP | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0 |

# *Midwest Energy, Inc.*

# *Transmission Formula Rate*

## *Attachment H to Open Access Transmission Tariff - Depreciation & Amortization Expense Annualization*

### *Test Year 12/31/20XX*

| Line # | Description | [ 1 ] Account Number | [ 2 ] Plant Balance At 12/31/2015 | [ 3 ] Annualized Depreciation Rate[1] | [ 4 ] Pro Forma Annualized Depreciation Expense [ 2 ] * [ 3 ] |
|---|---|---|---|---|---|
| **INTANGIBLE PLANT** | | | | | |
| 1 | Organization | 301 | $ - | | $ - |
| 2 | Franchise & Consent | 302 | $ - | | $ - |
| 3 | Miscellaneous Intangible Plant | 303 | | 0.0500 | $ - |
| 4 | TOTAL INTANGIBLE | Sum L 1 to L 3 | $ - | | $ - |
| **COMMON PLANT - electric only (use same spread by GL as grand total)** | | | | | |
| 5 | Land and land rights | 118-89 | #DIV/0! | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 6 | Structures, Improvements | 118-90 | #DIV/0! | 0.0130 | #DIV/0! |
| 7 | Office furniture and equipment | 118-91-00 | #DIV/0! | 0.0237 | #DIV/0! |
| 8 | Copiers and Remittance Processor | 118-91-10 | #DIV/0! | 0.0297 | #DIV/0! |
| 9 | Other Computer Equipment | 118-91-10 | #DIV/0! | 0.0514 | #DIV/0! |
| 10 | Transportation equipment | | #DIV/0! | - | #DIV/0! |
| 11 | Communications equipment | 118-97 | #DIV/0! | 0.0364 | #DIV/0! |
| 12 | Other | | #DIV/0! | | #DIV/0! |
| 13 | TOTAL COMMON PLANT - Electric (see F1, p.356) | Sum L 5 to L 12 | | | #DIV/0! |

**TRANSMISSION PLANT**

| | | | | | |
|---|---|---|---|---|---|
| 14 | Land and land rights | 350 | | | $ - |
| 15 | Structures, Improvements | 352 | | 0.0218 | $ - |
| 16 | Station Equipment (non-GMEC) | 353 | | 0.0188 | $ - |
| 17 | Station Equipment (GMEC portion) | 353 | | 0.0188 | $ - |
| 18 | Towers and Fixtures | 354 | | | $ - |
| 19 | Poles and Fixtures | 355 | | 0.0216 | $ - |
| 20 | Overhead Conductors and Devices | 356 | | 0.0195 | $ - |
| 21 | Underground Conduit | 357 | | 0.0196 | $ - |
| 22 | Underground Conductor & Devices | 358 | | 0.0198 | $ - |
| 23 | Other Transmission Plant | | | | $ |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | - |
| 24 | TOTAL TRANSMISSION PLANT | Sum L 14 to L 23 | $ - | **#DIV/0!** | $ - |

**GENERAL PLANT**

| | | | | | |
|---|---|---|---|---|---|
| 25 | Land and land rights | 389 | | | $ - |
| 26 | Structures, Improvements | 390 | | 0.0203 | $ - |
| 27 | Office furniture and equipment | 391 | | 0.0830 | $ - |
| 28 | Transportation equipment | 392 | | N/A | $ - |
| 29 | Store equipment | 393 | | 0.0360 | $ - |
| 30 | Tools, shop and garage equipment | 394 | | 0.0373 | $ - |
| 31 | Laboratory equipment | 395 | | 0.0264 | $ - |
| 32 | Power operated equipment | 396 | | 0.0796 | $ - |
| 33 | Electric communications equipment | 397 | | 0.0682 | $ - |
| 34 | Miscellaneous equipment | 398 | | 0.0444 | $ - |
| 35 | Other tangible property | 399 | | | $ - |
| 36 | TOTAL GENERAL | Sum L 25 to L35 | $ - | | $ - |

**DISTRIBUTION PLANT [2]**

| | | | |
|---|---|---|---|
| 37 | Land and land rights | 360 | |
| 38 | Structures, Improvements | 361 | |
| 39 | Station Equipment | 362 | 0.0197 |
| 40 | Poles, Towers and Fixtures | 364 | 0.0268 |
| 41 | Overhead Conductors and Devices | 365 | 0.0258 |
| 42 | Underground Conduit | 366 | 0.0161 |
| 43 | Underground Conductor & Devices | 367 | 0.0211 |
| 44 | Line Transformers | 368 | 0.0249 |
| 45 | Services | 369 | 0.0242 |
| 46 | Meters | 370 | 0.0556 |
| 47 | Installations on Customers' Premises | 371 | 0.0509 |
| 48 | Leased Property On Customers' Premises | 372 | 0.0411 |
| 49 | Street Lighting and Signal Systems | 373 | 0.0383 |

[1] Based on 2017 Depreciation Study. The depreciation and amortization rates are fixed and will not change absent FERC approval.

[2] Distribution Plant depreciation rates are not used in calculating the TFR Depreciation Expense. They are indirectly included in the Net Plant allocator
where denominator contains total net plant, including distribution net plant, which reflects total distribution plant less accumulated depreciation on distribution plant.

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - RTO Directed Transmission Projects Qualified for Regional Funding*
## *Test Year 12/31/20XX*

**I. Summary of Actual RTO Directed Transmission Projects**

| | (a) | (b) | | | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Proj. No.** | **Proj. ID** | **Upgrade ID** | | **Description** | **In Service Date** | **Gross Plant** | **Net Plant** | **Net Plant Carrying Chg. w/o Depr.** | **Gross Revenue Req. w/o Depr.** | **Depreciation Expense** | **KCC/FERC Approved Incentive Adder** | **Total Gross Revenue Requirements** |
| | **A. Base Plan Projects Qualified for Regional Funding (see WP2)** | | | | | | (see below) | (see below) | (see Apx. A, L125) | (f x g) | (see below) | (see WP3 Col h) | (h + i + j) |
| 1 | 1 | 0 | 0 | $0.00 | | 1/0/1900 | $ - | #DIV/0! | 0.00 % | #DIV/0! | #DIV/0! | | #DIV/0! |
| 2 | 2 | 0 | 0 | $0.00 | | 1/0/19 | $ | #DIV/ | 0.00 | #DIV/ | #DIV/0! | | #DIV/ |

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| | | | | | 00 | - | 0! | % | 0! | | | 0! |
| | | | | | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | | | #DIV/ 0! |
| 3 | 3 | 0 | 0 | $0.00 | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 4 | 4 | 0 | 0 | $0.00 | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 5 | 5 | 0 | 0 | $0.00 | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 6 | 6 | 0 | 0 | $0.00 | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 7 | 7 | 0 | 0 | $0.00 | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 8 | 8 | 0 | 0 | $0.00 | 1/0/19 00 | $ - | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 9 | 9 | | | | | | | | | | | |
| 10 | 10 | | | | | | | | | | | |
| 11 | 11 | | | | | | | | | | | |
| 12 | 12 | | | | | | | | | | | |
| 13 | **Total Base Plan Projects** | | | | | $ - | #DIV/ 0! | | #DIV/ 0! | #DIV/0! | $ - | #DIV/ 0! |
| | **B. Balanced Portfolio Projects (see WP2)** | | | | | | | | | | | |
| 14 | 1 | 0 | 0 | $0.00 | 1/0/19 00 | $ 5,268,093 | #DIV/ 0! | 0.00 % | #DIV/ 0! | #DIV/0! | | #DIV/ 0! |
| 15 | 2 | | | | | $ - | $ - | 0.00 % | $ - | #DIV/0! | | #DIV/ 0! |

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|---|---|---|---|---|---|---|---|---|
| 1 6 | 3 | $ - | $ - | 0.00 % | $ - | #DIV/0! | | #DIV/ 0! |
| 1 7 | **Total Balanced Portfolio Projects** | $ 5,268,093 | #DIV/ 0! | | #DIV/ 0! | #DIV/0! | $ - | #DIV/ 0! |

**C. Reserved for Future Use**

| | | |
|---|---|---|
| 1 8 | 1 | |
| 1 9 | 2 | |
| 2 0 | | |
| 2 1 | 3 | |
| 2 2 | **Total - reserved for future category** | |

**II. Calculation of Net Plant and Depreciation Expense for Base Plan Projects:**

| 2 4 | | | |
|---|---|---|---|
| 2 5 | **$0.00** | | |
| 2 6 | **Project SPP Proj. ID** | **1** | **Upgrade ID** |
| 2 7 | **0** | **0** | **0** |

| | | |
|---|---|---|
| **$0.00** | | |
| **Project SPP Proj. ID** | **2** | **Upgrade ID** |
| **0** | **0** | **0** |

| | | |
|---|---|---|
| **$0.00** | | |
| **Project SPP Proj. ID** | **3** | **Upgrade ID** |
| **0** | **0** | **0** |

| | Year | Month | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense |
|---|---|---|---|---|---|
| 28 | #VALUE! | Dec | $ - | | |
| 29 | 20XX | Jan | $ - | #DIV/0! | #DIV/0! |
| 30 | 20XX | Feb | $ - | #DIV/0! | #DIV/0! |
| 31 | 20XX | Mar | $ - | #DIV/0! | #DIV/0! |
| 32 | 20XX | Apr | $ - | #DIV/0! | #DIV/0! |
| 33 | 20XX | May | $ - | #DIV/0! | #DIV/0! |
| 34 | 20XX | Jun | $ - | #DIV/0! | #DIV/0! |
| 35 | 20XX | Jul | $ - | #DIV/0! | #DIV/0! |
| 36 | 20XX | Aug | $ - | #DIV/0! | #DIV/0! |
| 37 | 20XX | Sep | $ - | #DIV/0! | #DIV/0! |
| 38 | 20XX | Oct | $ - | #DIV/0! | #DIV/0! |
| 39 | 20XX | Nov | $ - | #DIV/0! | #DIV/0! |
| 40 | 20XX | Dec | $ - | #DIV/0! | #DIV/0! |
| 41 | | | | Sum | #DIV/0 |

| Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense |
|---|---|---|
| $ - | | |
| $ - | #DIV/0! | #DIV/0! |
| $ - | #DIV/0! | #DIV/0! |
| $ - | #DIV/0! | #DIV/0! |
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| | Sum | #DIV/ |

| Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense |
|---|---|---|
| $ - | | |
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| | lines 29 - 40 ! | | lines 29 - 40 0! | | lines 29 - 40 0! |
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| | | $0.00 | | | | 0 | | | | 0 | | | |
| | | SPP Proj. ID | 0 | Upgrade ID | 0 | SPP Proj. ID | 0 | Upgrade ID | 0 | SPP Proj. ID | 0 | Upgrade ID | 0 |
| | **Year** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** |
| | 2011 | | | | | | | | | | | | |
| | 2012 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | 2013 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | 2014 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | 2015 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | 2016 | | | | | | | | | | | | |
| | 2017 | | | | | | | | | | | | |
| | 2018 | | | | | | | | | | | | |
| | 2019 | | | | | | | | | | | | |
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| 6 | 2021 | | | |
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| 7 | 2022 | | | |
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| 8 | 2023 | | | |
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| 9 | 2024 | | | |
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| 0 | 2025 | | | |
| 6 | | | | |
| 1 | 2026 | | | |
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| 2 | 2027 | | | |
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| 3 | 2028 | | | |
| 6 | | | | |
| 4 | 2029 | | | |
| 6 | | | | |
| 5 | 2030 | | | |



# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - RTO Directed Transmission Projects Qualified for Regional Funding*
## *Test Year 12/31/20XX*

**II. Calculation of Net Plant and Depreciation Expense for Base**

**Plan Projects (Continued):**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | | **$0.00** | | | **$0.00** | | | **$0.00** | | |
| 6 | | | **Project SPP Proj. ID** | **4** | **Upgrade ID** | **Project SPP Proj. ID** | **5** | **Upgrade ID** | **Project SPP Proj. ID** | **6** | **Upgrade ID** |
| 6 | | | | **0** | **0** | | **0** | **0** | | **0** | **0** |
| 6 | **Year** | **Month** | **Plant Balance by Month** | **Monthly Depr. Rate** | **Depreciation Expense** | **Plant Balance by Month** | **Monthly Depr. Rate** | **Depreciation Expense** | **Plant Balance by Month** | **Monthly Depr. Rate** | **Depreciation Expense** |
| | #VALUE! | Dec | $ - | | | $ - | | | $ - | | |
| 7 | 20XX | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 7 | 20XX | Aug | $ | #DIV/0 | #DIV/0 | $ | #DIV/ | #DIV/ | $ | #DIV/0! | #DIV/ |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | X | | - | ! | ! | | - | 0! | 0! | | - | | 0! | |
| 7 | 20X | | $ | #DIV/0 | #DIV/0 | | $ | #DIV/ | #DIV/ | | $ | | #DIV/ | |
| 8 | X | Sep | - | ! | ! | | - | 0! | 0! | | - | #DIV/0! | 0! | |
| 7 | 20X | | $ | #DIV/0 | #DIV/0 | | $ | #DIV/ | #DIV/ | | $ | | #DIV/ | |
| 9 | X | Oct | - | ! | ! | | - | 0! | 0! | | - | #DIV/0! | 0! | |
| 8 | 20X | | $ | #DIV/0 | #DIV/0 | | $ | #DIV/ | #DIV/ | | $ | | #DIV/ | |
| 0 | X | Nov | - | ! | ! | | - | 0! | 0! | | - | #DIV/0! | 0! | |
| 8 | 20X | | $ | #DIV/0 | #DIV/0 | | $ | #DIV/ | #DIV/ | | $ | | #DIV/ | |
| 1 | X | Dec | - | ! | ! | | - | 0! | 0! | | - | #DIV/0! | 0! | |
| | | | | Sum lines | | | | Sum lines | | | | Sum lines | | |
| 8 | | | | 70 - | #DIV/0 | | | 70 - | #DIV/ | | | 70 - | #DIV/ | |
| 2 | | | | 81 | ! | | | 81 | 0! | | | 81 | 0! | |

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| 8 | | | | | | | | | | | | | | |
| 4 | | $0.00 | | | | $0.00 | | | | $0.00 | | | | |
| 8 | | SPP Proj. | | Upgra | | SPP Proj. | | Upgr ade | | SPP | | Upgr ade | |
| 5 | | ID | 0 | de ID | 0 | ID | 0 | ID | 0 | Proj. ID | 0 | ID | 0 |
| 8 | | **Gross** | | | | **Gross** | | | | **Gross** | | **Acc** | |
| 6 | **Year** | **Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Plnt. (EOY)** | **Depr. Exp.** | **Acc m. Depr.** | **Net Plant** | **Plnt. (EOY)** | **Depr. Exp.** | **m. Depr .** | **Net Plant** |
| 8 | | | | | | | | | | | | | |
| 7 | 2011 | | | | | | | | | | | | |
| 8 | | $ | #DIV/0 | #DIV/0 | #DIV/0 | $ | #DIV/ | #DIV/ | #DIV/ | $ | | #DIV/ | #DIV/ |
| 8 | 2012 | - | ! | ! | ! | - | 0! | 0! | 0! | - | #DIV/0! | 0! | 0! |
| 8 | | $ | #DIV/0 | #DIV/0 | #DIV/0 | $ | #DIV/ | #DIV/ | #DIV/ | $ | | #DIV/ | #DIV/ |
| 9 | 2013 | - | ! | ! | ! | - | 0! | 0! | 0! | - | #DIV/0! | 0! | 0! |
| 9 | | $ | #DIV/0 | #DIV/0 | #DIV/0 | $ | #DIV/ | #DIV/ | #DIV/ | $ | | #DIV/ | #DIV/ |
| 0 | 2014 | - | ! | ! | ! | - | 0! | 0! | 0! | - | #DIV/0! | 0! | 0! |
| 9 | 2015 | $ | #DIV/0 | #DIV/0 | #DIV/0 | $ | #DIV/ | #DIV/ | #DIV/ | $ | #DIV/0! | #DIV/ | #DIV/ |

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| 1 | | - ! ! ! | - 0! 0! 0! | - 0! 0! |
| 9 | | | | |
| 2 | 2016 | | | |
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| 3 | 2017 | | | |
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| 4 | 2018 | | | |
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| 5 | 2019 | | | |
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| 6 | 2020 | | | |
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| 7 | 2021 | | | |
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| 4 | 2028 | | | |
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| | | | $0.00 | | | $0.00 | | | | | |
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| | | | Project SPP Proj. ID | 7 | Upgrade ID | Project SPP Proj. ID | 8 | Upgrade ID | Project SPP Proj. ID | 9 | Upgrade ID |
| | | | | 0 | 0 | | 0 | 0 | | | |
| Year | Month | | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense |
| #VALUE! | Dec | | $ - | | | $ - | | | $ - | | |
| 20XX | Jan | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20XX | Feb | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20XX | Mar | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 115 | | | | | | | | | | | | | | |
| 116 | 20XX | Apr | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 117 | 20XX | May | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 118 | 20XX | Jun | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 119 | 20XX | Jul | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 120 | 20XX | Aug | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 121 | 20XX | Sep | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 122 | 20XX | Oct | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 123 | 20XX | Nov | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 124 | 20XX | Dec | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 125 | | | | Sum lines 112 - 123 | #DIV/0! | | | Sum lines 112 - 123 | #DIV/0! | | | Sum lines 112 - 123 | #DIV/0! | |

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| | | $0.00 | | | | $0.00 | | | | | | | |
| | | SPP Proj. ID | 0 | Upgrade ID | 0 | SPP Proj. ID | 0 | Upgrade ID | 0 | SPP Proj. ID | | Upgrade ID | |
| | **Year** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** |
| | 2011 | | | | | | | | | | | | |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | $ - | $ - | $ - |
| | 2015 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | $ - | $ - | $ - |
| | 2016 | | | | | | | | | | | | |
| | 2017 | | | | | | | | | | | | |
| | 2018 | | | | | | | | | | | | |

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| 6 | | | | | |
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| 1 | | | | | |
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| 2030 | | | | |



# *Midwest Energy, Inc.*

# *Transmission Formula Rate*

# *Attachment H to Open Access Transmission Tariff - RTO Directed Transmission Projects Qualified for Regional Funding*

## *Test Year 12/31/20XX*

**II. Calculation of Net Plant and Depreciation Expense for Base Plan Projects (Continued):**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Project SPP Proj. ID | 10 | Upgrade ID | Project SPP Proj. ID | 11 | Upgrade ID | Project SPP Proj. ID | 12 | Upgrade ID |
| Year | Month | | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense | Plant Balance by Month | Monthly Depr. Rate | Depreciation Expense |
| #VA | Dec | $ | | | | $ | | | $ | | |

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| | | SPP Proj. ID | | Upgrade ID | | SPP Proj. ID | | Upgrade ID | | SPP Proj. ID | | Upgrade ID | |
| **Year** | | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** | **Gross Plnt. (EOY)** | **Depr. Exp.** | **Accm. Depr.** | **Net Plant** |
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| 2014 | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |

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| 177 | 2016 | | | | |
| 178 | 2017 | | | | |
| 179 | 2018 | | | | |
| 180 | 2019 | | | | |
| 181 | 2020 | | | | |
| 182 | 2021 | | | | |
| 183 | 2022 | | | | |
| 184 | 2023 | | | | |
| 185 | 2024 | | | | |
| 186 | 2025 | | | | |

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| 2026 | | | |
| 2027 | | | |
| 2028 | | | |
| 2029 | | | |
| 2030 | | | |

**III. Calculation of Net Plant and Depreciation Expense for Balanced Portfolio Projects :**

| | | $0.00 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Project SPP Proj. ID | 1 0 | Upgrade ID 0 | | | | Project SPP Proj. ID | 3 | Upgrade ID |
| Year | Month | Plant Balanc | Monthly | Depre | Plant Balanc | Monthly | Depr | Plant Balanc | Monthly | Depr |

| 7 | | | e by Month | Depr. Rate | ciation Expense | | e by Month | Depr. Rate | eciation Expense | | e by Month | Depr. Rate | eciation Expense |
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| 9 | #VA | | 5,268, | | | | $ | | | | $ | | |
| 8 | LUE! | Dec | 093 | | | | - | | | | - | | |
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| 9 | X | Jan | 093 | ! | ! | | - | 0! | 0! | | - | #DIV/0! | 0! |
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| 0 | X | Feb | 093 | ! | ! | | - | 0! | 0! | | - | #DIV/0! | 0! |
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| 4 | | ID | 0 | de ID | 0 | ID | | ID | | Proj. ID | | ID | | |
| | | **Gross** | | | | **Gross** | | **Acc** | | **Gross** | | **Acc** | | |
| 2 | | **Plnt.** | **Depr.** | **Accm.** | **Net** | **Plnt.** | **Depr.** | **m.** | **Net** | **Plnt.** | **Depr.** | **m. Depr** | **Net** |
| 1 | | **(EOY)** | **Exp.** | **Depr.** | **Plant** | **(EOY)** | **Exp.** | **Depr.** | **Plant** | **(EOY)** | **Exp.** | **.** | **Plant** |
| 5 | **Year** | | | | | | | | | | | | | |
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| 5 | 2020 | | | | | | | | | | | | |
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| 6 | 2021 | | | | | | | | | | | | |
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| 7 | 2022 | | | | | | | | | | | | |
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| 8 | 2023 | | | | | | | | | | | | |
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| 2 | 2024 | | | | | | | | | | | | |

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| 2029 | | | | |
| 2030 | | | | |

# *Midwest Energy, Inc.*
# *Transmission Formula Rate*
# *Attachment H to Open Access Transmission Tariff - Schedule 1*
# *Revenue Requirement*
## *Test Year 12/31/20XX*

| Line No. | Description | (1) FERC Form 1 Page # or Instruction | (2) Amount | (3) Footnote |
|---|---|---|---|---|
| | **Schedule 1** | | | |
| **A.** | **ARR** | | | |
| 1 | Scheduling, System Control and Dispatch Service | p.322.85.b to 88.b | $ - | 1 |
| 2 | Less: PTP Service Credit | Line 30 | $0 | 1 |
| 3 | | | | |
| 4 | Net Schedule 1 Revenue Requirement for Zone | Line 1 - Line 2 | $ - | |
| 5 | | | | |
| 6 | Acct. 561 Expenses Recovered Through Sch. 1 Charges | Line 1 | $ - | |
| **B.** | **Schedule 1 Rate Calculations** | | | |
| 7 | 12-CP. Peak Demand | 12CP Firm Trans Sheet | | |

| | | | |
|---|---|---|---|
| | | | 303,343.3 |
| 8 | Annual Point-to-Point Rate in $/kW - Year | L4 / L7 | $ - |
| 9 | Monthly Point-to-Point Rate in $/kW - Month | L8 / 12 | $ - |
| 10 | Weekly Point-to-Point Rate in $/kW - Week | L8 / 52 | $ - |
| 11 | Daily Point-to-Point Rate in $/kW - Day | L10 / 5 | $ - |
| 12 | Hourly Point-to-Point Rate in $/MW - Hour | (L11 / 16) x 1000 | $ - |
| 13 | | | |
| 14 | | | |

| 15 | Month | SPP Schedule 1 PTP Revenues booked to Account 456 |
|---|---|---|
| 16 | | |
| 17 | | |
| 18 | January | $0 |
| 19 | February | $0 |
| 20 | March | $0 |
| 21 | April | $0 |
| 22 | May | $0 |
| 23 | June | $0 |
| 24 | July | $0 |
| 25 | August | $0 |

| | | |
|---|---|---|
| 26 | September | $0 |
| 27 | October | $0 |
| 28 | November | $0 |
| 29 | December | $0 |
| 30 | Total | $0 |

[1] Per SA in FERC Docket ER17-469, TY2015 and TY2016 Amount is $0. Beginning with the TY2017, these values will be populated as stated in Column (2)

**Midwest Energy Inc.**

**Midwest Energy, Inc. TFR**

**Transmission Formula Rate**

**WP1 - CWIP**

**Test Year 12/31/20XX**

**p1**

**Workpaper 1 - Non-Capitalized Work Order Costs Details**

As of Date: 12/31/XX

**ELE Work Orders**

| Work Order | Job Cost # | Description | Construction Cost | Retirement Cost | Other Cost | Total Cost | In Service Date [1] | In service as of XX/XX/20XX (Yes/No) | Type (Distribution/Transmission) |
|---|---|---|---|---|---|---|---|---|---|

[1] In Service Date is provided for Transmission projects only.

**Midwest Energy, Inc.**
**TFR**
**WP1 - CWIP**
**p2**

| Work Order | Job Cost # | Description | Construction Cost | Retirement Cost | Other Cost | Total Cost | In Service Date | In service as of XX/XX/20XX (Yes/No) | Type (Distribution/Transmission) |
|---|---|---|---|---|---|---|---|---|---|

**Midwest Energy, Inc.**
**TFR**
**WP1 - CWIP**
**p3**

| Work Order | Job Cost # | Description | Construction Cost | Retirement Cost | Other Cost | Total Cost | In Service Date | In service as of XX/XX/20XX (Yes/No) | Type (Distribution/Transmission) |
|---|---|---|---|---|---|---|---|---|---|

**Midwest Energy, Inc.**
**TFR**
**WP1 - CWIP**
**p4**

| Work Order | Job Cost # | Description | Construction Cost | Retirement Cost | Other Cost | Total Cost | In Service Date | In service as of XX/XX/20XX (Yes/No) | Type (Distribution/Transmission) |
|---|---|---|---|---|---|---|---|---|---|

**Midwest Energy, Inc.**
**TFR**
**WP1 - CWIP**
**p5**

| Work Order | Job Cost # | Description | Construction Cost | Retirement Cost | Other Cost | Total Cost | In Service Date | In service as of XX/XX/20XX (Yes/No) | Type (Distribution/Transmission) |
|---|---|---|---|---|---|---|---|---|---|

| | | |
|---|---|---|
| Generation | 0.00 | G |
| Transmission | 0.00 | T |
| Distribution | 0.00 | D |
| EOY Total | 0.00 | |

## Transmission CWIP Included in the TFR[1]

| Test Year | % Inclusion | Description | | Amount | Included Amount |
|---|---|---|---|---|---|
| 2015 | | | | | |
| | 100% | In service as of | 12/31/2016 | $ - | $ - |
| | 50% | Remainder | | $ - | $ - |
| | | Total | | $ - | $ - |
| 2016 | | | | | |
| | 100% | In service | 6/30/2017 | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | | as of | | |
| | | | $ | $ |
| | 50% | Remainder | - | - |
| | | | $ | **$** |
| | | Total | - | **-** |
| 2017 and beyond | | | | |
| | | In service as of | 3/31/FY[2] | $ |
| | 100% | | | - |
| | | | | $ |
| | 50% | Remainder | | - |
| | | | | $ |
| | | Total | | - |

[1] Per SA in FERC Docket No. ER17-469

[2] FY is the Filing Year, which is the year following the Test Year

WP2

# Midwest Energy, Inc.
# Transmission Formula Rate
# Test Year 12/31/20XX
# Workpaper 2 - Midwest Energy RTO-directed Projects

**Source: SPP and/or Midwest Energy .**

| NTC ID | Project ID | Upgrade ID | Owner | Project Name | Upgrade Type | NTC Source Study | In-Service Date | Cost | Upgrade Status | Voltage | New Miles Count | Reconductor/New Conductor Miles Count | Upgrade Description | From Bus Number | From Bus Name | To Bus Number | To Bus Name |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
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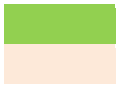
**100% Zonal**



**1/3 Regional, 2/3 Zonal**

**100% Regional**

WP3

# Midwest Energy Inc.

**Transmission Formula Rate**

**Test Year 12/31/20XX**

**Workpaper 3 - Calculation of the FERC- Approved Project Incentive Adder(s) [1]**

| Line - | (a) Proj. No. - From Pg. 15, Ln 1-22, Col a | (b) Proj. ID - From Pg. 15, Ln 1-22, Col b | (c) Project Description - From Pg. 15, Ln 1-22, Col c | (d) FERC Docket Number Authorizing the Incentive - Docket No. | (e) Project's Net Plant - From Pg. 15, Ln 1-22, Col f | (f) Authorized Incentive Return Adder - % in excess of ROE on Pg 1 Ln 97 | (g) Percent Equity - From Pg. 4, Ln 95 | (h) Incentive Return - (e) x (f) x (g) |
|---|---|---|---|---|---|---|---|---|
| 1<br>2<br>3<br>4<br>5 | - | - | - | - | | | | |

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Add lines as necessary

[1] Assumes an ROE adder. If FERC approves a different type of incentive, calculation may need to be modifie accordingly.

WP4

**Midwest Energy Inc.**
**Transmission Formula Rate**
**Test Year 12/31/20XX**
**Workpaper 4 - Transmission Leased From Others [1]**

| | | | |
|---|---|---|---|
| 20XX | TY | Transmission Lease Payments | $0 |

[1] Currently, Midwest does not lease transmission lines from other entities.

WP 5

# Midwest Energy Inc.

## Transmission Formula Rate

## Work Paper 5 - Reconciliation Items, Refunds and Surcharges per Section 5.D of the Midwest Energy's TFR Protocols

## Test Year 12/31/20XX

**ADJUSTMENTS TO GROSS REVENUE REQUIREMENT DUE TO CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| (a) | (b) | (c) | (d | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|
| Line No (A) | ITEM TO BE CORRECTED | Formula Rate Line Reference | Rate Year (B) | Original Amount | Corrected Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest (C) | Total Adjustment to ATRR (D) |
| | | | | | | | | | |
| 1 | | | | | | $ - | | $ - | $ - |
| 2 | | | | | | $ | | $ - | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | - | | | - |
| 3 | | | | | | $ - | | $ - | $ - |
| 4 | | | | | | $ - | | $ - | $ - |
| 5 | | | | | | $ - | | $ - | $ - |

| | | |
|---|---|---|
| 6 | **Total Adjustment to Gross Revenue Requirement:** | $ - |

**ADJUSTMENTS TO RTO DIRECTED PROJECTS' REVENUE REQUIREMENT DUE TO CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| (a) | (b) | (c) | (d | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|
| **Line No (A)** | **ITEM TO BE CORRECTED** | **Formula Reference** | **Rate Year (B)** | **Original Amount** | **Corrected Amount** | **Difference (Cred)/ Chg** | **Impact on ATRR (Cred)/Chg** | **Calculated Interest (C)** | **Total Adjustment to ATRR (D)** |
| | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | $ - | | $ - | $ - |
| 8 | | | | | | $ - | | $ - | $ - |
| 9 | | | | | | $ - | | $ - | $ - |
| 10 | | | | | | $ - | | $ - | $ - |
| 11 | | | | | | $ - | | $ - | $ - |

| | | |
|---|---|---|
| 12 | **RTO Directed Projects' Revenue Requirement:** | $ - |

Base Plan Revenue Requirement
Balanced Portfolio Revenue Requirement

**INTEREST**

**CALCULATION (C):**

| (a) | (b) | | (c) | (d | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| Line No. (A) | Period Start | Period Ending | Year Description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance |
| | | | Rate | | $ | | $ | $ |
| 13 | | | Year | | - | | - | - |
| | | | Rate | $ | $ | | $ | $ |
| 14 | | | Year | - | - | | - | - |
| | | | Rate | $ | $ | | $ | $ |
| 15 | | | Year | - | - | | - | - |
| | | | Rate | $ | $ | | $ | $ |
| 16 | | | Year | - | - | | - | - |
| | Total | | | | | | $ | |
| 17 | | | | | | | - | |

Notes:
A. More lines may be added as needed.
B. Rate Year in which the original amount affected the ATRR and rates paid by customers.

B. Each ATRR adjustment shall include interest calculated pursuant to Section 35.19a of the FERC's Regulations (18 C.F.R.).
C. The interest calculation may need to be modified to recognize the implementation during a partial year.
D. The reconciled value will be incorporated into the “1 – Appendix A” with the appropriate footnote explaining the reconciliation.

# Midwest Energy, Inc.
# Transmission Formula Rate
# Protocols

## Section 1, Definitions

**Annual Publication and Posting Date** shall mean the date on which the event listed in Section 3.A(iii) occurs for each year.

**Annual Transmission Revenue Requirement (ATRR)** means the amount of revenue the Company must recover annually to recover costs associated with its transmission system, as calculated in its Transmission Formula Rate. ATRR is the same as Net Zonal Revenue Requirement.

**Annual Update** shall mean Midwest Energy's re-calculation of its ATRR and Network Service rates pursuant to its Formula Rate and these Protocols for the upcoming Rate Year.

**Business Day** means any day other than a Saturday, Sunday or day on which the FERC is not open for business.

**Company** means Midwest Energy, Inc.

**Customer Meeting** shall mean a meeting convened by Midwest Energy at Midwest Energy corporate headquarters in Hays, KS, for Zonal Transmission Customers as well as any other Interested Party that wishes to attend, as is more fully described in Section3.D(i). Such meeting shall include video conferencing, a webinar, or an internet conference.

**Discovery Period** means a one hundred twenty (120) day period after the Annual Publication and Posting Date for an Interested Party to serve reasonable information requests on Midwest Energy, unless such period is extended with the written consent of Midwest Energy.

**Formal Challenge** shall mean a challenge to the Informational Filing with FERC made by an Interested Party no later than twenty-one (21) days after the submission of the Informational Filing.

**FERC** shall mean the Federal Energy Regulatory Commission or its successor, which is the regulatory entity that has jurisdiction over SPP's Open Access Transmission Tariff (SPP Tariff).

**Formula Rate (or Transmission Formula Rate)** means the mechanism to calculate by formula the ATRR and resulting wholesale rates as directed in the blank Addendum 14 to Attachment H of the SPP Tariff and conducted in the Company's populated Transmission Formula Rate, Sheet 1-20.

**Informational Filing** means the submittal of Midwest Energy's Annual Update to the FERC as described in Section 5 of these Protocols.

**Initial Challenge** shall mean a challenge made by an Interested Party within one hundred fifty (150) days, after the Annual Publication and Posting Date, unless this period is extended by the written consent of the Company. An Initial Challenge shall be made in writing, including via electronic communication, to the Company and shall specify the challenge, including those pertaining to Material Accounting Changes, over how Midwest Energy applied the Formula Rate.

**Interest** means interest computed consistent with the FERC rules in 18 C.F.R. § 35.19a, as in effect from time to time.

**Interested Parties** includes, but is not limited to, (i) customers under the SPP Tariff; (ii) any state utility commission that has jurisdiction over the rates of the customers that are allocated costs of the Company's facilities; (iii) any consumer advocates who represent customers that are allocated costs of the Company's facilities; and (iv) state attorneys general.

**Issue** means a question raised by an Interested Party with respect to an Annual Update. A challenge to the Formula Rate itself is not an Issue.

**KCC** shall mean the State Corporation Commission of the State of Kansas.

**Material Accounting Change** shall mean a material change in Midwest Energy's accounting policies and procedures from those in effect for the calendar year upon which the immediately preceding Annual Update was based.

**Midwest Energy** means Midwest Energy, Inc.

**NERC** means the North American Electric Reliability Corporation.

**NERC Standards** means the reliability and critical infrastructure protection standards promulgated in accordance with Section 1211 of the Energy Policy Act of 2005, Section 215 of the Federal Power Act, 16 U.S.C. 824o, as in effect from time to time.

**Rate Year** means services rendered to the Company's wholesale customers on and after September 1 of a given calendar year through August 31 of the subsequent calendar year.

**Resolution Period** means the twenty-one (21) day period following the Review Period to resolve an Initial Challenge, unless such twenty-one day period is extended by the written consent of the Company.

**Review Period** means the one hundred fifty (150) day period following the Annual Publication and Posting Date, for Interested Parties to review the calculations and notify Midwest Energy of any specific challenges, including those related to Material Accounting Changes, over how Midwest Energy applied the Formula Rate, unless the Company extends the one hundred fifty day period by written consent.

**SPP** means the Southwest Power Pool, Inc., or its successor.

**Zonal Transmission Customers** means any person that is or has applied to become an SPP transmission customer whose service is all or partly in the Midwest Energy Zone.

**Section 2, Annual Update**

A. The Annual Update for the Rate Year:

(i) shall be based upon data included in Midwest Energy's independently-audited, certified FERC Form No. 1 for the most recent calendar year, as specified in the Formula Rate, and Midwest Energy's independently-audited, certified books and records, consistent with FERC accounting policies;

(ii) shall provide supporting documentation for data used in the Formula Rate, but not otherwise available in the FERC Form No. 1, as specified in the Formula Rate;[1]

(iii) shall include an identification of (a) any changes in Midwest Energy accounting policies, practices, and procedures (including changes resulting from revisions to FERC's Uniform System of Accounts and/or Form No. 1 reporting requirements) from those in effect during the calendar year upon which the most recent ATRR was based and that, in Midwest Energy's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next year, and (b) any changes in the SPP Tariff from the provisions of the SPP Tariff in effect during the calendar year upon which the most recent ATRR was based and that, in Midwest Energy's reasonable judgment, could impact the Formula Rate within the next year;

(iv) shall be subject to challenge limited to whether the Formula Rate, including treatment of Material Accounting Changes, has been applied appropriately under its terms and these Protocols;

(v) shall not seek to modify the Formula Rate and shall not be subject to challenge by any party seeking to modify the Formula Rate, including modification of (a) the most recently approved rate of return on equity (b) depreciation and amortization rates, and (c) "Post-Employment Benefits other than Pension" under Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (PBOP) charges;

(vi) shall include a change analysis of, at minimum, revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the revenue requirement that was calculated for the prior rate year with an explanation of any material changes (increase over 10 percent and over $100,000 from the previous year for each of the listed revenue requirement components); and

(vii) to the extent that payment of a fine or penalty for violation or alleged violation of NERC Standards has been made on or after January 1, 2015, and the amount is included in the Formula Rate, shall include a description of the violation, the enforcement proceeding, and the basis for seeking recovery of such violation in rates.

B. Formula Rate inputs for (i) rate of return on patronage capital, (ii) depreciation and amortization rates, and (iii) PBOP under Statement of Financial Accounting Standards No. 106, Employers' Accounting for PBOP charges shall be fixed, stated values to be used in the rate formula until changed under authority of the FERC; provided, however, that despite the previous limitation, periodic updates to the depreciation rates used in the formula, while still subject to the formal review by the FERC and the affected parties in a docketed separate proceeding prior to application, will not cause the re-opening of the entire formula.

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[1] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconciled to the FERC Form No. 1 by the application of clearly identified and supported information. Where any reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate. Worksheets will be clearly labeled to direct the reviewer to the applicable support portion of the worksheet.

**Section 3, Review of Midwest Energy's Annual Update**

A. On or before May 10 of each year, Midwest Energy shall:

(i) Recalculate its ATRR and Network Service Rates, producing the "Annual Update" discussed in Section 2 above for the upcoming Rate Year;

(ii) Prepare for posting an Annual Update. The Annual Update shall include a workable data-populated Formula Rate template with all cell formulas functional, containing the supporting workpapers of the appropriate data to calculate the Annual Update for the upcoming Rate Year.

(iii) Post, or cause to be posted, the Annual Update on SPP's OASIS website; and

(iv) Notify its Zonal Transmission Customers and the KCC's designated staff, via e-mail to the most recent e-mail addresses provided to Midwest Energy, of the website address of the Annual Update posting, and e-mail, phone and street address contact information for corresponding with the appropriate Company representative(s) to answer related questions.

B. If the date for making the Annual Update posting should fall on a weekend, or a FERC-recognized holiday, then the posting and filing shall be due on the next Business Day.

C. Upon written request for a particular year's Annual Update by any Interested Party, Midwest Energy will promptly make available to such entity and/or a consultant designated by it, an Excel file, with all formulas functional, containing that year's Annual Update data.

D. Each Annual Update shall be subject to the following review procedures and timeline (if any of the dates provided for herein do not fall on a Business Day, then the due date shall be the first Business Day thereafter):

(i) Each year, Midwest Energy will, with at least thirty (30) calendar days' notice, convene a Customer Meeting no sooner than ten (10) Business Days after the filing date of the Annual Publication and Posting Date, and no later than June 16 to discuss the Annual Update. Midwest Energy will provide notice on the SPP OASIS website of the time, date, and meeting arrangements. The open meeting will be hosted by Midwest Energy and may be conducted via video conferencing, webinar, internet conferencing, phone conferencing, in person meeting, or other similar options. Midwest Energy shall provide remote access for Interested Parties to participate in the meeting. The Customer Meeting shall (a) permit Midwest Energy to explain and clarify its Annual Update and (b) provide Interested Parties an opportunity to seek information and clarifications from Midwest Energy about the Annual Update.

(ii) Interested Parties shall have a Discovery Period ending one hundred twenty (120) calendar days after the Annual Publication and Posting Date to serve reasonable information requests on Midwest Energy. Information requests shall be limited to what is necessary to determine if Midwest Energy has properly applied the Formula Rate and whether the calculated

rates are just and reasonable. In addition, information requests may only solicit information concerning data inputs to the Formula Rate template. Midwest Energy shall post on the SPP OASIS website all information requests from Interested Parties and Midwest Energy's response(s) to such requests; except, if responses to requests include material deemed by Midwest Energy to be confidential, such responses will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Midwest Energy and requesting party.

(iii) Midwest Energy shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) Business Days of receipt of such requests.

(iv) Interested Parties shall have a Review Period ending one hundred fifty (150) calendar days after the Annual Publication and Posting Date (unless Midwest Energy extends the period under written consent) to review the calculations and to notify Midwest Energy in writing, including via electronic communication, of any specific challenges, including those related to Material Accounting Changes, over how Midwest Energy applied the Formula Rate.

(v) If an Initial Challenge has been made by any Interested Party(ies) during the Review Period, then Midwest Energy and the party(ies) have up to 21 calendar days after the Review Period to resolve the Initial Challenge (Resolution Period) (unless Midwest Energy extends the Resolution Period under written consent).

**Section 4, Contents of Informational Filings at FERC**

A. By November 15 of the year of the posting of the Annual Update on SPP's OASIS and the subsequent Discovery and Review Periods as described in Section 3 of these Protocols, Midwest Energy or the SPP shall submit an Informational Filing to FERC.

B. Midwest Energy shall post, or cause to be posted, the Informational Filing onto SPP's OASIS website. Midwest Energy shall also notify its Zonal Transmission Customers and the KCC's designated Staff, via e-mail to the most recent e-mail addresses provided to Midwest Energy, of the website address of the Informational Filing.

C. The Informational Filing must include the information that is reasonably necessary to determine: (1) the input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that Midwest Energy has properly applied the Formula Rate and these Protocols; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The

Informational Filing must also describe any corrections or adjustments made and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Initial Challenge procedures.

D. Any changes to the data inputs, including but not limited to revisions to Midwest Energy's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of these Protocols, shall detail how the reconciliation is calculated, as well as how associated interest is calculated. The reconciled value will be incorporated into "1-Appendix A" and the charges produced by the Formula Rate, with the appropriate footnote explaining the reconciliation. Interest shall be computed pursuant to 18 C.F.R. § 35.19a. The impact of the change (as well as the associated interest) will be reflected in Midwest Energy's calculated revenue requirement during the next possible Annual Update following the specific change.

**Section 5, Formal Challenges**

A. A Formal Challenge must be filed within 21 days of the filing of the Informational Filing. An Interested Party may not pursue a Formal Challenge if that party did not submit an Initial Challenge on at least one issue. Having submitted an Initial Challenge on at least one issue, an Interested Party may pursue a Formal Challenge on other issues.

B. A Formal Challenge shall:

(i) Clearly identify the action or inaction which is alleged to violate the Formula Rate, explain the alleged violation, and make a good faith effort to quantify the financial impact or burden (if any) on the filing party as a result of the alleged violation;

(ii) State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(iii) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(iv) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(v) State whether the filing party utilized the Initial Challenge procedures above to dispute the alleged violation raised by the Formal Challenge, and, if not, describe why not.

C. The party filing the Formal Challenge must serve a copy of it on Midwest Energy via email simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3).

D. In addition to any challenges brought before the FERC through the Formal Challenge procedures, any challenges to SPP's implementation of Midwest Energy's Formula Rate may be made in a separate Section 206 complaint proceeding before FERC.

E. In any proceeding concerning FERC review of the filing of Midwest Energy's Annual Update, or in response to a Formal Challenge, Midwest Energy shall bear the burden of demonstrating that: (1) SPP's pass-through of Midwest Energy's ATRR in FERC-jurisdictional rates does not result in FERC-jurisdictional rates that are unjust and unreasonable rates; (2) it correctly applied the terms of the Formula Rate consistent with these Protocols; and (3) it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

# Addendum 15 to Attachment H

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

**Prairie Wind Transmission, LLC**



| Line No. | | | (1) | (2) | (3) |
|---|---|---|---|---|---|
| | | | | | Allocated Amount |
| 1 | GROSS REVENUE REQUIREMENT | (line 76) | | 12 months | $ - |

| | REVENUE CREDITS | | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Total Revenue Credits | Attachment 1, line 8 | - | TP | - | - |
| 3 | True-up Adjustment | Attachment 7 | - | DA | 1.00000 | - |
| 4 | NET REVENUE REQUIREMENT | (line 1 & minus line 2 plus line 3) | | | | $ - |

This section is used to develop the net revenue requirement for each "Project" as defined in the Protocols

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | Project Name | Net Plant, CWIP or Abandoned Plant Investment | Carrying Charge | ADIT Charge | Project Specific Revenue Requirement |
| | | | (Line 101) | (Lines 102+) | Col (2) * (Col (3) + (4)) |
| 5 | Project | - | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 6 | | - | - | - | - |
| 7 | | - | - | - | - |
| 8 | | - | - | - | - |

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

Page 2

| | | | | | |
|---|---|---|---|---|---|
| | | | **Prairie Wind Transmission, LLC** | | |
| | (1) | (2) | (3) | (4) | (5) |
| | | **Form No. 1** | | | **Transmission** |
| Line | | **Page, Line, Col.** | **Company Total** | **Allocator** | (Col 3 times Col 4) |
| No | **RATE BASE:** | | | | |

.

| | | | | | | |
|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE | | | | | |
| 9 | Production | (Attachment 3) | - | NA | - | - |
| 10 | Transmission | (Attachment 3) | - | TP | - | - |
| 11 | Distribution | (Attachment 3) | - | NA | - | - |
| 12 | General & Intangible | (Attachment 3) | - | W/S | - | - |
| 13 | TOTAL GROSS PLANT (sum lines 9-12) | (GP=1 if plant =0) | - | GP= | - | - |
| 14 | ACCUMULATED DEPRECIATION & AMORTIZATION | | | | | |
| 15 | Production | (Attachment 3) | - | NA | - | - |
| 16 | Transmission | (Attachment 3) | - | TP | - | - |
| 17 | Distribution | (Attachment 3) | - | NA | - | - |
| 18 | General & Intangible | (Attachment | | W/S | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | 3) | - | | - | - |
| 19 | TOTAL ACCUM. DEPRECIATION (sum lines 15-18) | | - | | | - |
| 20 | NET PLANT IN SERVICE | | | | | |
| 21 | Production | (line 9- line 15) | - | | | - |
| 22 | Transmission | (line 10- line 16) | - | | | - |
| 23 | Distribution | (line 11- line 17) | - | | | - |
| 24 | General & Intangible | (line 12- line 18) | - | | | - |
| 25 | TOTAL NET PLANT (sum lines 21-24) | (NP=1 if plant =0) | - | NP= | - | - |
| 26 | ADJUSTMENTS TO RATE BASE (Note A) | | | | | |
| 27 | Prorated ADIT -not Directly related to Project Depreciation or CWIP | (Attachment 6d, line 83 column (h)) | - | TP | - | - |
| 28 | Account No. 255 (enter negative) (Note F) | (Attachment 3) | - | NP | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 29 | CWIP | (Attachment 3) | - | TP | - | - |
| 30 | Reserves | (Attachment 3) | - | DA | 1.0000 | - |
| 31 | Unamortized Regulatory Asset | (Attachment 3) | - | DA | 1.0000 | - |
| 32 | Unamortized Abandoned Plant | (Attachment 3) (Note K) | 0 | DA | 1.0000 | - |
| 33 | TOTAL ADJUSTMENTS (sum lines 27-32) | | - | | | - |
| 34 | LAND HELD FOR FUTURE USE | (Note L & Attachment 3) | - | TP | - | - |
| 35 | WORKING CAPITAL (Note C) | | | | | |
| 36 | CWC | calculated | - | | | - |
| 37 | Materials & Supplies (Note B) | (Attachment 3) | - | TP | - | - |
| 38 | Prepayments (Account 165 - Note C) | (Attachment 3) | - | GP | - | - |
| 39 | TOTAL WORKING CAPITAL (sum lines 36-38) | | - | | | - |

| | | | |
|---|---|---|---|
| 40 | RATE BASE (sum lines 25, 33, 34, & 39) | - | - |

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

Page 3

**Prairie Wind Transmission, LLC**

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | **Form No. 1** | | | **Transmission** |

| | | **Page, Line, Col.** | **Company Total** | **Allocator** | | (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| 41 | O&M | | | | | |
| 42 | Transmission | 321.112.b | - | TP= | - | - |
| 43 | Less Accounts 565, 561 and 561.1 to 561.8 | 321.96.b | - | TP= | - | - |
| 44 | A&G | 323.197.b | - | W/S | - | - |
| 45 | Less EPRI & Reg. Comm. Exp. & Other Ad. | (Note D & Attach 3) | - | DA | - | - |
| 46 | Plus Transmission Related Reg. Comm. Exp. | (Note D & Attach 3) | - | TP= | - | - |
| 47 | PBOP expense adjustment | (Attachment 3) | - | TP= | - | - |
| 48 | TOTAL O&M (sum lines 42, 44, 46, 47 less lines 43 & 45) | | - | | | - |
| 49 | DEPRECIATION EXPENSE | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 50 | Transmission | 336.7.b & c | - | TP | - | - |
| 51 | General and Intangible | 336.1.d&e + 336.10.b&c | - | W/S | - | - |
| 52 | Amortization of Abandoned Plant | (Attachment 3) (Note K) | - | DA | 1.0000 | - |
| 53 | TOTAL DEPRECIATION (Sum lines 50-52) | | - | | | - |
| 54 | TAXES OTHER THAN INCOME TAXES (Note E) | | | | | |
| 55 | LABOR RELATED | | | | | |
| 56 | Payroll | 263i | - | W/S | - | - |
| 57 | Highway and vehicle | 263i | - | W/S | - | - |
| 58 | PLANT RELATED | | | | | |
| 59 | Property | 263i | - | GP | - | - |
| 60 | Gross Receipts | 263i | - | NA | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 61 | Other | 263i | - | GP | - | - |
| 62 | TOTAL OTHER TAXES (sum lines 56-61) | | - | | | - |
| 63 | Gain or loss on disposition of Land Held for Future Use | (Note L) | - | TP | - | - |
| 64 | INCOME TAXES | (Note F) | | | | |
| 65 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | - | | | |
| 66 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | - | | | |
| 67 | where WCLTD=(line 93) and R= (line 96) | | | | | |
| 68 | and FIT, SIT & p are as given in footnote F. | | | | | |
| 69 | 1 / (1 - T) = (T from line 65) | | - | | | |
| 70 | Amortized Investment Tax Credit (266.8f) (enter | | - | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | negative) | | | | | |
| 70 a | (Excess/)/Deficient Deferred Income Taxes (Note M) | (Att 6c, Total (EDIT)/DDIT col E) | - | | | |
| 71 | Income Tax Calculation = line 66 * line 75 | | - | NA | | - |
| 72 | ITC adjustment (line 69 * line 70) | | - | NP | 1.0000 | - |
| 72 a | (Excess)/Deficient Deferred Income Tax Adjustment | (Line 69 * line 70a) | - | NP | 1.0000 | - |
| 73 | Total Income Taxes | (line 71 plus line 72 plus line 72a) | - | | | - |
| 74 | RETURN | | | | | |
| 75 | [ Rate Base (line 40) * Rate of Return (line 96)] | | - | NA | | - |
| 76 | REV. REQUIREMENT (sum lines 48, 53, 62, 63, | | - | | | - |

73, 75)

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____



**Prairie Wind Transmission, LLC**

**SUPPORTING CALCULATIONS AND NOTES**

7 TRANSMISSION PLANT INCLUDED IN RTO
7 RATES

| | | |
|---|---|---|
| 77 | Total transmission plant (line 10, column 3) | |
| 78 | | - |
| 79 | Less transmission plant excluded from RTO rates (Note H) | - |
| 80 | Less transmission plant included in OATT Ancillary Services (Note H) | - |
| 81 | Transmission plant included in RTO rates (line 78 less lines 79 & 80) | - |
| 82 | Percentage of transmission plant included in RTO Rates (line 81 divided by line 78) [If line 78 equal zero, enter 1) | TP = - |

WAGES & SALARY ALLOCATOR (W&S) (Note I)

| | | | | | |
|---|---|---|---|---|---|
| 84 | | Form 1 Reference | $ | TP | Allocation |
| 85 | Production | 354.20.b | - | | |
| 86 | Transmission | 354.21.b | - | - | - |
| 87 | Distribution | 354.23.b | | | W&S Alloca |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 7 | | | - | | | tor | | |
| 8<br>8 | Other | 354.24,25<br>,26.b | - | | | ($ /<br>Alloca<br>tion) | | |
| 8<br>9 | Total (sum lines 85-88) [TP equals 1 if there are no wages & salaries] | | - | | - | = | = | WS |
| 9<br>0 | RETURN (R) (Note J) | | | | | | | |
| 9<br>1 | | | | | | | | |
| 9<br>2 | | | $ | % | Cost | Weigh<br>ted | | |
| 9<br>3 | Long Term Debt (Note G) | (Attachm<br>ents 3 and<br>5) | - | - | - | - | =<br>W<br>CL<br>TD | |
| 9<br>4 | Preferred Stock | (Attachm<br>ent 3) | - | - | - | - | | |
| 9<br>5 | Common Stock | (Attachm<br>ent 3) | - | - | 12.8<br>0% | - | | |
| 9<br>6 | Total (sum lines 93-95) | | - | | | - | =R | |

CALCULATION OF CARRYING CHARGE AND ADIT CHARGES

| | | | |
|---|---|---|---|
| 97 | NET REVENUE REQUIREMENT | (Line 4) | $ - |
| 98 | Net Transmission Plant in Service | (Line 22) | - |
| 99 | CWIP | (Line 29) | - |
| 100 | Unamortized Abandoned Plant | (Line 32) | - |
| 101 | Carrying Charge | (Line 97 / Sum (Lines 98 - 100) | - |

PROJECT SPECIFIC ADIT CHARGES

| (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|
| Project Name | Project Specific | Return and Income Taxes | ADIT | Net Plant, | ADIT Charge |

| | | | ADIT | | Rev Req | CWIP, Abandoned Investment | |
|---|---|---|---|---|---|---|---|
| | | | Average Attach 6a | (Line 96 * Line 66 + Line 96) | (Col (2) * Col (3)) | | (Col (4) / Col (5)) |
| 102 | Project | | - | - | - | - | - |
| 103 | | | | - | - | | |
| 104 | | | | - | - | | |
| 105 | | | | - | - | | |

**SUPPORTING CALCULATIONS AND NOTES**

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

**Prairie Wind Transmission, LLC**

Page 5

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)

References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter

A The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets

or liabilities related to FASB 106 or 109 and prorated in accordance with IRS regulations. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility

chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission

Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.

D Line 45 removes EPRI Annual Membership Dues listed in Form 1 at 353.f, any EPRI Lobbying expenses included in line 44 and all Regulatory

Commission Expenses itemized at 351.h

Line 45 removes all advertising included in Account 930.1, except safety, education or out-reach related advertising

Line 45 removes EEI and EPRI research, development and demonstration expenses associated with projects in which transmission customers can voluntarily participate

to the extent such expenses exceed a maximum annual aggregate amount of $100,000

Line 46 reflects all Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized at 351.h

E Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

F The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =

"the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a

work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that

elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce

rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)

multiplied by (1/1-T) .

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | | |
| | | - | |
| | SIT= | | (State Income Tax Rate or |
| | | - | Composite SIT from Attachment 3) |
| | p = | | (percent of federal income |
| | | - | tax deductible for state purposes) |

For each Rate Year (including both Annual Projections and True-Up Adjustments) the statutory income tax rates utilized in the Formula Rate shall reflect the weighted average rates

actually in effect during the Rate Year. For example, if the statutory tax rate is 10% from January 1 through June 30, and 5% from July 1 through December 31, such rates would be weighted

181/365 and 184/365, respectively, for a non-leap year.

G The cost of debt is determined using the internal rate of return methodology shown on Attachment 5 until the Actual Capital Structure Date, and is determined using the methodology

in Attachment 3 thereafter. Attachment 5 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Appendix A.

H Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation

step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up

facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

I Enter dollar amounts

J ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

The capital structure will be 50% equity and 50% debt until the earlier of (i) the date that the permanent financing arrangements for the facilities for which FERC approved incentives for Prairie Wind in Docket No. ER09-36-000 ("Project") is in place or (ii) the date that the Project is complete and placed into service ("Actual Capital Structure Date"), after which time the capital structure will be the year-end capital structure. During the year in which the Actual Capital Structure Date occurs, the capital structure will be determined based on the weighted average of the 50/50 capital structure and the actual year-end capital structure, determined as follows: the year-end capital structure will be weighted based on the number of days from the Actual Capital Structure Date until the end of the year, divided by number of day in the year; and the 50/50 capital structure will be weighted based on the number of days in the year prior to the Actual Capital Structure Date divided by the number of days in the year.

For example: Weighted Equity =
[50%*260+60%*(365-260)]/365

After the Actual Capital Structure Date, if the formula produces an equity ratio exceeding 60%, the formulaic value at Line 95

shall be manually set to 60% and the formulaic value at Line 93 shall be manually set to 40% less the percentage shown at Line 94.

K Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Prairie Wind must submit a Section 205 filing to recover the cost of abandoned plant. Any such filing to recover the cost of an abandoned plant item shall be made no later than 730 days after the date that Prairie Wind formally declares such plant item abandoned.

L Land held for future use will be included in rate base in accordance with the instructions to Account 105. The Formula Rate template will include recognition of

gains and losses for disposition of property recorded in Account 105 – See instruction D of Account 105, with reference to amounts recorded in Accounts 411.6/411.7 or 256/187.

Gains are entered as negative numbers and losses entered as positive numbers.

M Includes the amortization of any excess/deficient income taxes resulting from changes to income tax rates (including changes in apportionment) and other actions take by a taxing authority. Excess and deficient deferred income taxes will reduce or increase tax expense by the amount of the excess or deficiency multiplied by (1/1-T).

**Attachment 1 - Revenue Credit Workpaper***

**Prairie Wind Transmission, LLC**

| | | | |
|---|---|---|---|
| | **Account 454 - Rent from Electric Property** | Notes 1 & 4 | |
| 1 | Rent from FERC Form No. 1 | | - |
| | **Account 456 and 456.1** | Notes 1 & 4 | |
| 2 | Other Electric Revenues (Note 2) | | - |
| 3 | Professional Services (Note 3) | | - |
| 4 | Revenues from Directly Assigned Transmission Facility Charges (Note 2) | | - |
| 5 | Rent or Attachment Fees associated with Transmission Facilities (Note 3) | | - |
| 6 | Gross Revenue Credits | Sum lines 2-5 + line 1 | - |
| 7 | Less line 14 | less line 14 | - |

| | | | |
|---|---|---|---|
| 8 | Total Revenue Credits | line 6 + line 7 | - |
| 9 | Total revenues for secondary uses included in lines 1 thru 5 | | - |
| 10 | Income Taxes associated with revenues in line 9 | (line 9 x Appendix A line 66) | - |
| 11 | One half margin (line 9 - line 10)/2 | | - |
| 12 | All expenses (other than income taxes) associated with revenues in line 9 that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue. | | - |
| 13 | Line 11 plus line 12 | | - |
| 14 | Line 9 less line 13 | | - |

Note 1 All revenues booked to Account 454 that are derived from cost items classified as transmission-related will be included as a revenue credit. All revenues booked to Account 456 that are derived from cost items classified as transmission-related, and are not derived from rates under this transmission formula rate will be included as a revenue credit. Work papers will be included to properly classify revenues booked to these accounts to the transmission function. A breakdown of all Account 454 revenues by subaccount will be provided below, and will be used to derive the proper calculation of revenue credits. A breakdown of all Account 456 revenues by subaccount and customer will be provided and tabulated below, and will be used to develop the proper calculation of revenue credits.

Note 2 If the facilities associated with the revenues are not included in the formula, the revenue is shown below, but not included in the total above and explained in the Attachment 3.

Note 3 This ratemaking treatment is for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314; provided, that Company's retention of such revenues is subject to change pursuant to Section II.F of the Settlement Terms. Note: in order to use lines 7 & 9-14, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Note 4 All Account 454 and 456 Revenues must be itemized below

| Line No. | | | | | |
|---|---|---|---|---|---|
| 1 | Account 456 | TOTAL | SPP | Other 1 | Other 2 |
| 1a | Transmission Service | $ | $ | $ | $ |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | - |
| 1x | Trans. Fac. Charge | | | | |
| | | - | - | - | - |
| 2 | Trans Studies | | | | |
| | | - | - | - | - |
| 3 | Total | $ | $ | $ | $ |
| | | - | - | - | - |
| 4 | Less: | | | | |
| 5 | Revenue for Demands in Divisor | | | | |
| | | - | - | - | - |
| 6 | **Sub Total Revenue Credit** | $ | $ | $ | $ |
| | | - | - | - | - |
| 7 | Prior Period Adjustments | | | | |
| | | - | - | - | - |
| 8 | Total | | | | |
| | | | | | |
| 9 | Account 454 | $ | | | |
| 9a | Joint pole attachments - telephone | | | | |
| | | - | | | |
| 9b | Joint pole attachments - cable | | | | |
| | | - | | | |
| 9c | Underground rentals | | | | |

| | | |
|---|---|---|
| | | - |
| 9d | Transmission tower wireless rentals | |
| | | - |
| 9e | Other rentals | |
| | | - |
| 9f | Corporate headquarters sublease | |
| | | - |
| 9g | Misc non-transmission rentals | |
| | | - |
| 9x | xxxx | |
| | | - |
| 10 | Total | |
| | | - |

Note 5 The Formula Rate will provide that, in the event that Prairie Wind receives revenues associated with the secondary use of transmission assets, Prairie Wind may propose to share revenues between customers and shareholders and incorporate such proposal in the Annual Update or True-Up; provided, that Intervenors may challenge Prairie Wind's proposed sharing of revenues at any time either in connection with an Annual Update in which this practice first occurs or pursuant to Section 206. Prairie Wind may oppose Intervenors' challenge. In the event Intervenors present such a challenge, the sharing of such revenues shall be determined in accordance with applicable Commission precedent and regulations, and neither Prairie Wind nor Intervenors may argue that the Formula presumes any particular sharing mechanism is just and reasonable or is not just and reasonable, or that any sharing of certain sources of revenues is appropriate at all.

**Attachment 2 - Calculation of Composite Depreciation Rate**

**Prairie Wind Transmission, LLC**

| | | | |
|---|---|---|---|
| 1 | **Calculation of Composite Depreciation Rate** | | |
| 2 | Transmission Plant @ Beginning of Period | (Attachment 3) | - |
| 3 | Transmission Plant @ End of Period | (Attachment 3) | - |
| 4 | Sum | (sum lines 2 & 3) | - |
| 5 | Average Balance of Transmission Investment | (line 4/2) | - |
| 6 | Depreciation Expense | Appendix A | - |
| 7 | Composite Depreciation Rate | (line 6/ line 5) | - |
| 8 | Depreciable Life for Composite Depreciation Rate | (1/line 7) | - |
| 9 | Round line 8 to nearest whole year | | - |

This attachment is for informational purposes only. This composite rate is made up of the individual account depreciation rates shown in Attachment 9.

**Attachment 3 - Cost Support**

**Prairie Wind Transmission, LLC**

**Plant in Service Worksheet**

Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

| | | | | |
|---|---|---|---|---|
| 1 | **Calculation of Transmission Plant In Service** | Source | Year | Balance |
| 2 | December | p206.58.b | - | - |
| 3 | January | company records | - | - |
| 4 | February | company records | - | - |
| 5 | March | company records | - | - |
| 6 | April | company records | - | - |
| 7 | May | company | | |

| | | | | |
|---|---|---|---|---|
| | | records | - | - |
| 8 | June | company records | - | - |
| 9 | July | company records | - | - |
| 10 | August | company records | - | - |
| 11 | September | company records | - | - |
| 12 | October | company records | - | - |
| 13 | November | company records | - | - |
| 14 | December | p207.58.g | - | - |
| 15 | **Transmission Plant In Service** | (sum lines 2-14) /13 | | - |
| | | | | |
| 16 | **Calculation of Distribution Plant In Service** | Source | | |
| 17 | December | p206.75.b | - | - |
| 18 | January | company | | |

| | | | | |
|---|---|---|---|---|
| 8 | | records | - | - |
| 1 9 | February | company records | - | - |
| 2 0 | March | company records | - | - |
| 2 1 | April | company records | - | - |
| 2 2 | May | company records | - | - |
| 2 3 | June | company records | - | - |
| 2 4 | July | company records | - | - |
| 2 5 | August | company records | - | - |
| 2 6 | September | company records | - | - |
| 2 7 | October | company records | - | - |
| 2 8 | November | company records | - | - |
| 2 9 | December | p207.75.g | - | - |

| | | | | |
|---|---|---|---|---|
| 30 | **Distribution Plant In Service** | (sum lines 17-29) /13 | | - |
| 31 | **Calculation of Intangible Plant In Service** | Source | | |
| 32 | December | p204.5.b | - | - |
| 33 | December | p205.5.g | - | - |
| 34 | **Intangible Plant In Service** | (sum lines 32 & 33) /2 | | - |
| 35 | **Calculation of General Plant In Service** | Source | | |
| 36 | December | p206.99.b | - | - |
| 37 | December | p207.99.g | - | - |
| 38 | **General Plant In Service** | (sum lines 36 & 37) /2 | | - |
| 39 | **Calculation of Production Plant In Service** | Source | | |

| | | | | |
|---|---|---|---|---|
| 40 | December | p204.46b | - | - |
| 41 | January | company records | - | - |
| 42 | February | company records | - | - |
| 43 | March | company records | - | - |
| 44 | April | company records | - | - |
| 45 | May | company records | - | - |
| 46 | June | company records | - | - |
| 47 | July | company records | - | - |
| 48 | August | company records | - | - |
| 49 | September | company records | - | - |
| 50 | October | company records | - | - |
| 51 | November | company | | |

| | | | | |
|---|---|---|---|---|
| 1 | | records | - | - |
| 5 2 | December | p205.46.g | - | - |
| 5 3 | **Production Plant In Service** | (sum lines 40-52) /13 | | - |
| 5 4 | **Total Plant In Service** | (sum lines 15, 30, 34, 38, & 53) | | - |

**Accumulated Depreciation Worksheet**

| Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | | Details |
|---|---|---|---|---|
| 5 5 | **Calculation of Transmission Accumulated Depreciation** | Source | Year | Balance |
| 5 6 | December | Prior year p219.25 | - | - |
| 5 7 | January | company records | - | - |
| 5 8 | February | company records | - | - |

| | | | | |
|---|---|---|---|---|
| 59 | March | company records | - | - |
| 60 | April | company records | - | - |
| 61 | May | company records | - | - |
| 62 | June | company records | - | - |
| 63 | July | company records | - | - |
| 64 | August | company records | - | - |
| 65 | September | company records | - | - |
| 66 | October | company records | - | - |
| 67 | November | company records | - | - |
| 68 | December | p219.25 | - | - |
| 69 | **Transmission Accumulated Depreciation** | (sum lines 56-68) /13 | | - |

| | | | | |
|---|---|---|---|---|
| 70 | **Calculation of Distribution Accumulated Depreciation** | Source | | |
| 71 | December | Prior year p219.26 | - | - |
| 72 | January | company records | - | - |
| 73 | February | company records | - | - |
| 74 | March | company records | - | - |
| 75 | April | company records | - | - |
| 76 | May | company records | - | - |
| 77 | June | company records | - | - |
| 78 | July | company records | - | - |
| 79 | August | company records | - | - |
| 80 | September | company records | - | - |
| 81 | October | company | | |

| | | | | |
|---|---|---|---|---|
| 1 | | records | - | - |
| 8 2 | November | company records | - | - |
| 8 3 | December | p219.26 | - | - |
| 8 4 | **Distribution Accumulated Depreciation** | (sum lines 71-83) /13 | | - |
| | | | | |
| 8 5 | **Calculation of Intangible Accumulated Depreciation** | Source | | |
| 8 6 | December | Prior year p200.21.c | - | - |
| 8 7 | December | p200.21c | - | - |
| 8 8 | **Accumulated Intangible Depreciation** | (sum lines 86 & 87) /2 | | - |
| | | | | |
| 8 9 | **Calculation of General Accumulated Depreciation** | Source | | |
| 9 0 | December | Prior year p219.28 | - | - |
| 9 1 | December | p219.28 | - | - |

| | | | | |
|---|---|---|---|---|
| 92 | **Accumulated General Depreciation** | (sum lines 90 & 91) /2 | | - |
| 93 | **Calculation of Production Accumulated Depreciation** | Source | | |
| 94 | December | Prior year p219 | - | - |
| 95 | January | company records | - | - |
| 96 | February | company records | - | - |
| 97 | March | company records | - | - |
| 98 | April | company records | - | - |
| 99 | May | company records | - | - |
| 100 | June | company records | - | - |
| 101 | July | company records | - | - |

| | | | | |
|---|---|---|---|---|
| 102 | August | company records | - | - |
| 103 | September | company records | - | - |
| 104 | October | company records | - | - |
| 105 | November | company records | - | - |
| 106 | December | p219.20 thru 219.24 | - | - |
| 107 | **Production Accumulated Depreciation** | (sum lines 94-106) /13 | | - |
| 108 | **Total Accumulated Depreciation** | (sum lines 69, 84, 88, 92, & 107) | | - |

**ADJUSTMENTS TO RATE BASE**
**(Note A)**

| | **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | | | | **Details** |
|---|---|---|---|---|---|---|
| | | | Beginning of Year | End of Year | Average Balance | |
| 109 | | | | | | |
| 110 | | | | | | |
| 111 | | | | | | |
| 112 | | | | | | |
| 113 | Account No. 255 (enter negative) | 267.8.h | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 114 | Unamortized Abandoned Plant | Per FERC Order | - | - | - |
| | (recovery of abandoned plant requires a FERC order approving the amount and recovery period) | | | | |
| 115 | Prepayments (Account 165) | 111.57.c | - | - | - |
| | (Prepayments exclude Prepaid Pension Assets) | | | | |

| | | | | |
|---|---|---|---|---|
| 116 | **Calculation of Transmission CWIP** | Source | | |
| 117 | December | 216.b | - | - |
| 118 | January | company records | - | - |

| | | | | |
|---|---|---|---|---|
| 19 | February | company records | - | - |
| 20 | March | company records | - | - |
| 21 | April | company records | - | - |
| 22 | May | company records | - | - |
| 23 | June | company records | - | - |
| 24 | July | company records | - | - |
| 25 | August | company records | - | - |
| 26 | September | company records | - | - |
| 27 | October | company | | |

| | | | | |
|---|---|---|---|---|
| 7 | | records | - | - |
| 1<br>2<br>8 | November | company records | - | - |
| 1<br>2<br>9 | December | 216.b | - | - |
| 1<br>3<br>0 | **Transmission CWIP** | (sum lines 117-129) /13 | | - |

**LAND HELD FOR FUTURE USE**

| **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | | | **Beg of year** | **End of Year** | **Average** | **Details** |
|---|---|---|---|---|---|---|---|
| 1<br>3<br>1 | **LAND HELD FOR FUTURE USE** | | p214 | Total | - | - | - | |
| | | | | Non-transmission | - | - | | |

| | | | | |
|---|---|---|---|---|
| | Related | | | |
| | Transmission Related | - | - | - |

**Reserves**

| 13 2 | List of all reserves: | Amount | Enter 1 if Customer Funded, O if not | Allocation (Plant or Labor Allocator) | Amount Allocated |
|---|---|---|---|---|---|
| | Reserve 1 | - | - | | - |
| | Reserve 2 | - | - | | - |
| | Reserve 3 | - | - | | - |
| | Total | - | | | - |

The Formula Rate shall include a credit to rate base for all funded and unfunded reserves (*i.e.*, those for which the funds collected have not been set aside in escrow and the earnings

thereon included in the reserve fund) that are funded by customers and for which the associated accrued costs are recoverable under the Formula Rate. Prairie Wind will include a spreadsheet

(to be included in the Formula Rate template) each year as part of the Annual Update that lists the reserves and indicates which ones meet the test for crediting to rate base.

**EPRI Dues Cost Support**

| **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | | **Details** |
|---|---|---|---|
| **Allocated General & Common Expenses** | | | |
| | EPRI Dues | EPRI Dues | |
| 133 EPRI Dues | p352-353 | | |

**Regulatory Expense Related to Transmission Cost Support**

| | **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | **Form 1 Amount** | **Transmission Related** | **Non-transmission Related** | **Details*** |
|---|---|---|---|---|---|---|
| | **Directly Assigned A&G** | | | | | |
| 1 | Regulatory Commission Exp | p323.189.b | | | | |
| 3 | Account 928 | | | | - | |
| 4 | | | | | | |
| | | | | | * insert case specific detail and associated assignments here | |

**Multi-state Workpaper**

| **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | **State 1** | **State 2** | **State 3** | **State 4** | **State 5** | **Weighed Averag** |
|---|---|---|---|---|---|---|

| | | | | | | e |
|---|---|---|---|---|---|---|
| | **Income Tax Rates** | | | | | |
| | | | | **Kansas** | | |
| 1 | SIT=State Income Tax Rate or | | | | | 0.0 |
| 3 | Composite | | | - | | 0% |
| 5 | | | | | | |
| | Multiple state rates are weighted based on the state apportionment factors on the state income tax returns | | | | | |

**Safety Related and Education and Out Reach Cost Support**

| | **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | **Form 1 Amount** | **Safety Related, Education, Siting & Outreach Related** | **Other** | **Details** |
|---|---|---|---|---|---|---|
| | **Directly Assigned A&G** | | | | | |
| 1 | General Advertising Exp | p323.191.b | | | | |
| 3 | Account 930.1 | | | | - | |
| 6 | | | | | | |

**Excluded Plant Cost Support**

| | **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | **Excluded Transmission Facilities** | **Description of the Facilities** |
|---|---|---|---|---|
| | **Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities** | | | |
| 1<br>3<br>7 | Excluded Transmission Facilities | | - | **General Description of the Facilities** |
| | Instructions: | | **Enter $** | **None** |
| 1 | Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service. | | - | |
| 2 | If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, | | **Or** | |
| | the following formula will be used: | **Example** | **Enter $** | |
| A | Total investment in substation | 1,000,000 | - | |

| | | | |
|---|---|---|---|
| B | Identifiable investment in Transmission (provide workpapers) | 500,000 | - |
| C | Identifiable investment in Distribution (provide workpapers) | 400,000 | - |
| D | Amount to be excluded (A x (C / (B + C))) | 444,444 | - |

**Add more lines if necessary**

**Materials & Supplies**

| **Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions** | | | **Beg of year** | **End of Year** | **Average** |
|---|---|---|---|---|---|
| 138 | Assigned to O&M | p227.6 | - | - | - |
| 13 | Stores Expense Undistributed | p227.16 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | | | | - | - | - |
| 140 | Undistributed Stores Exp | | | - | - | - |
| 141 | Transmission Materials & Supplies | p227.8 | | - | - | - |

**Regulatory Asset**

**Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions**

| | | | | |
|---|---|---|---|---|
| 142 | Beginning Balance of Regulatory Asset | | - | Uncapitalized costs as of date the rates become effective |
| 143 | Months remaining in Amortization Period | | - | As approved by FERC |
| 144 | Monthly Amortization to Account 566 | (line 142 / line 143) | - | All amortizations of the Regulatory Asset are to be booked to Account 566 |

| | | | | |
|---|---|---|---|---|
| 145 | Months in Year to be amortized | | - | Number of months rates are in effect during the calendar year |
| 146 | Ending Balance of Regulatory Asset | (line 142 - line 144 * 145) | - | |
| 147 | Average Balance of Regulatory Asset | (line 142 + line 146)/2 | - | |

**Capital Structure**

**Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions**

| | | | | | | |
|---|---|---|---|---|---|---|
| 148 | Monthly Balances for Capital Structure | Year | Debt | Preferred Stock | Common Stock | Total Capitalization |
| 149 | December (prior year) | - | - | - | - | - |
| 150 | January | - | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 150 | | | | | | |
| 151 | February | - | - | - | - | - |
| 152 | March | - | - | - | - | - |
| 153 | April | - | - | - | - | - |
| 154 | May | - | - | - | - | - |
| 155 | June | - | - | - | - | - |
| 156 | July | - | - | - | - | - |
| 157 | August | - | - | - | - | - |
| 158 | September | - | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 159 | October | - | - | - | - | - |
| 160 | November | - | - | - | - | - |
| 161 | December | - | - | - | - | - |
| 162 | Average | | - | - | - | - |

Debt is equal to 112.18c less 112.19c plus 112.20c plus 112.21c, recognizing that 112.19c is entered into the Form 1 as a negative number and shall remain negative (i.e., it is not a double minus in the formula that mathematically would lead to adding in line 112.19c) so that Reacquired Bonds (Account 222) are subtracted from other long term debt outstanding and that Line 112.20c may contain both short term and long term indebtedness to affiliates and therefore any short term affiliate debt shall be removed from 112.20c before adding it into the above long term debt balance formula in the formula rate.

Preferred Stock is equal to 112.3c less any Preferred Treasury Stock plus any Preferred Additional Paid-in-Capital, recognizing that if there is any Preferred Treasury Stock or Preferred Additional Paid-in-Capital, then the respective amounts shall be appropriately disclosed in a footnote to the capital structure cost support in the formula rate template.

Common Equity is equal to 112.16c less 112.3c less 112.12c less 112.15c, recognizing that line 112.15c may be a positive or negative number and if it is positive, it shall be subtracted in the formula, and if it is entered as a negative in the Form 1, it shall be added (a double minus sign when subtracting a negative number) in the formula.

The cost of long-term debt for a Rate Year will be the sum of the interest expense and cost of issuances divided by the 13-month average long-term debt balance for the Rate Year. The cost of long-term debt issuances shall include long-term interest expense amounts recorded in the following FERC accounts:

| | | | | Amount |
|---|---|---|---|---|
| 163 | | Account 427 | Interest on Long-Term Debt (limited solely to interest expense for long-term debt reported in Accounts 221-224) (FF1, 117/62/c) | - |
| 164 | plus: | Account 428 | Amortization of Debt Discount and Expense (FF1, 117/63/c) | - |
| 165 | plus: | Account 428.1 | Amortization of Loss on Reacquired Debt (FF1, 117/64/c) | - |
| 166 | less: | Account 429 | Amortization of Premium on Debt (FF1, 117/65/c) | - |
| 167 | less: | Account 429.1 | Amortization of Gain on Reacquired Debt (FF1, 117/66/c) | - |
| 168 | plus**:** | Account 430 | Interest on Debt to Associated Companies but limited solely to the expense associated with long-term debt recorded in Account 223. | - |

| | | |
|---|---|---|
| 169 | Total | - |

Interest expenses not directly related to the long-term bond issuances included in the capital structure will be excluded.

The cost of preferred stock will be preferred stock dividends (booked in FERC Account 437) divided by the average preferred stock balance for the rate year.

| | | |
|---|---|---|
| 170 | Preferred Dividends in Account 437 | - |
| 171 | 13 Month average balance of Preferred Stock | - |
| 172 | Cost of Preferred Stock | - |

**Interest Expense for interest rate computation:**

| Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | Details |
|---|---|---|
| 177 | **Interest Expense for interest** | |

| | | | |
|---|---|---|---|
| 3 | **rate computation:** | | |
| 174 | Interest on Long-Term Debt (as calculated on line 170 above | | - |
| 175 | Net cost (gain) of hedging included in line 174 | | - |
| 176 | Total Capitalization | (line 162) | - |
| 177 | Hedging factor (six basis points) | | 0.0006 |
| 178 | Computed amount of gain or loss | (Line 176 * Line 177) | - |
| 179 | Maximum allowable cost { MIN[Line ABS(Line 175) or Line 178] if Line 175 is net cost; zero if no net gain/cost} | | - |

| | | | |
|---|---|---|---|
| 180 | Maximum allowable (gain) {-MIN[Line ABS(Line 175) or Line 178] if Line 175 is net gain; zero if no net gain/loss} | | - |
| 181 | Allowable amount (Line 179 if net loss, or Line 180 if net gain, zero if no net gain/loss) | | - |
| 182 | Less: net cost(gain) of hedging | (Line 175) | - |
| 183 | Plus: allowable amount | (Line 181) | - |
| 184 | Interest Expense after construction phase | (Line 174 - Line 182 + Line 183) | - |
| 185 | 13 Month average balance of Long-Term Debt | (line 162) | - |
| 186 | Interest rate for Long-Term Debt input to Appendix A line 93 after contruction phase | (Line 184 / Line 185) | - |

Interest Rate Hedging on Long Term Debt – The cost rates for long-term debt for Prairie Wind shall include the annual amortization of gains and losses resulting from interest rate hedging; provided that the net cost

(or cost reduction due to net gains) shall be limited in True Up calculations so as not to exceed 6 basis points in the weighted average cost of capital. To determine the includable hedging costs or gains, Prairie Wind

will multiply the total 3-component capitalization (LTD, PS and CS) by 0.0006, and compare the result to the hedging cost or gain amount amortized in the year.

**PBO**
**Ps**

| Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | Details |
|---|---|---|
| 1<br>8<br>7 | **Calculation of PBOP Expenses** | |
| 1<br>8<br>8 | **AEP Employees** | |
| 1<br>8<br>9 | Total PBOP expenses | $117,25<br>4,159 |
| 1<br>9 | Amount relating to retired personnel | $0 |

| | | |
|---|---|---|
| 190 | | |
| 191 | Amount allocated on Labor | $117,254,159 |
| 192 | Labor dollars | 1,151,954,661 |
| 193 | Cost per labor dollar | $0.102 |
| 194 | labor (labor not capitalized) current year | - |
| 195 | PBOP Expense for current year | - |
| 196 | PBOP Expense in Account 926 for current year | - |
| 197 | PBOP Adjustment for Appendix A, Line 54 | - |
| 198 | Lines 189-193 cannot change absent approval or acceptance by FERC in a separate proceeding. | |

| | | |
|---|---|---|
| 198 | **Westar Employees** | |
| 199 | Total PBOP expenses | $11,664,756 |
| 200 | Amount relating to retired personnel | $0 |
| 201 | Amount allocated on Labor | $11,664,756 |
| 202 | Labor dollars | 164,186,618 |
| 203 | Cost per labor dollar | $0.071 |
| 204 | labor (labor not capitalized) current year | - |
| 205 | PBOP Expense for current year | - |

| | | | |
|---|---|---|---|
| 206 | PBOP Expense in Account 926 for current year | | - |
| 207 | PBOP Adjustment for Appendix A, Line 54 | | - |
| 208 | Lines 199-203 cannot change absent approval or acceptance by FERC in a separate proceeding. | | |
| 209 | PBOP expense adjustment | (sum lines 197 & 207) | - |

**Attachment 4 - Transmission Enhancement Charge Worksheet**

**Prairie Wind Transmission, LLC**

1 New Plant Carrying Charge

| | | |
|---|---|---|
| 2 | Formula Line | Item |
| 3 | 4 | NET REVENUE |

| | | | | | |
|---|---|---|---|---|---|
| | | REQUIREMENT | | - | |
| 4 | 22 | Net Transmission Plant | | - | |
| 5 | 29 | CWIP | | - | |
| 6 | | **Carrying charge (line 3/sum of lines 4 and 5)** | | - | |
| 7 | ADIT Adjustment | | STEP-xxx | STEP-xx2 | STEP-xx3 |
| 8 | ADIT directly related to depreciation or CWIP | | | | |
| 9 | Return and Income Tax Carrying Charge | (Appendix A ln 73+74)/ (ln 4+5) | - | - | - |
| 10 | Rev Req Adjustment | | - | - | - |
| 11 | 13 Month Plant/CWIP balance | | - | - | - |
| 12 | Carrying Charge Adjustment | | - | - | - |
| 13 | Carrying charge | | - | - | - |
| 14 | Adjusted Carrying Charge | | - | - | - |

| | | | | (1) | (2) | (3) | (4) |
|---|---|---|---|---|---|---|---|
| 15 | | **The FCR resulting from Formula in a given year is used for that year only.** | | | | | |
| 16 | | **Therefore actual revenues collected in a year do not change based on cost data for subsequent years** | | | | | |
| | | | | **SPP Upgrade ID:** | | | |
| 17 | | Details | | **STEP-xxx** | **STEP-xx2** | **STEP-xx3** | **Totals** |
| 18 | "Yes" if a project under SPP OATT, otherwise "No" | STEP | (Yes or No) | Yes | Yes | Yes | |
| 19 | | FCR for This Project | | - | - | - | |
| 20 | Forecast – Forecast of average 13 month current year net plant plus 13-mo CWIP balances. Reconciliation – Average of 13 month prior year net plant balances plus prior year 13-mo CWIP balances. | Investment | | - | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 21 | **Revenue Requirement** | - | - | - | - |

**Attachment 5 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology**

Prairie Wind Transmission, LLC

HYPOTHETICAL EXAMPLE

Assumes financing will be a 5 year loan with Origination Fees of $6.6 million and a Commitments Fee of 0.375% on the undrawn principal.

Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of

Return formula below.

Each year, the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount will be updated on this attachment.

The IRR calculation will use the Excel Worksheet Function XIRR.

| | |
|---|---|
| **Total Loan Amount** | **$ 300,000,000** |
| **Internal Rate of Return[1]** | **9.631%** |

**Based on following Financial Formula[2]:**

**NPV = 0 =** $$\sum_{t=1}^{N} C_t/(1+IRR)pwr(t)$$

| | |
|---|---|
| **Origination Fees** | |
| Underwriting Discount | - |
| Arrangement Fee | 2,250,000 |
| Upfront Fee | 2,250,000 |
| Rating Agency Fee | 72,000 |
| Legal Fees | 2,000,000 |
| Total Issuance Expense | **6,572,000** |
| **Annual Rating Agency Fee** | 120,000 |
| **Annual Bank Agency Fee** | 50,000 |
| **Revolving Credit Commitment Fee** | 0.375% |

| | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | |
|---|---|---|---|---|---|---|---|---|
| LIBOR Rate | 4.0000% | 4.2500% | 4.5000% | 4.7500% | 5.0000% | 5.2500% | 5.5000% | |
| Spread | 2.25% | 2.25% | 2.25% | 2.25% | 2.25% | 2.25% | 2.25% | |
| **Interest Rate** | 6.25% | 6.50% | 6.75% | 7.00% | 7.25% | 7.50% | 7.75% | |
| | | | | | | | | |
| (A) | (B) | ( C) | (D) | (E) | (F) | (G) | (H) | (I) |
| **Year** | | **Capital Expenditures ( $000's)** | **Principal Drawn In Quarter ($000's)** | **Principal Drawn To Date ($000's)** | **Interest & Principal ($000's)** | **Origination Fees ($000's)** | **Commitment & Utilization Fee ($000's)** | **Net Cash Flows ($000's)** **(D-F-G-H)** |
| 7/1/2009 | Prior Periods | 6,250 | | | | | | 1 |
| 8/15/2009 | Q3 | 4,000 | 5,125 | 5,125 | | 6,572 | | (1,447) |
| 11/15/2009 | Q4 | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | 5,000 | 2,500 | 7,625 | 81 | 446 | 1,973 |
| 2/15/2010 | Q1 | 6,000 | 3,000 | 10,625 | 120 | 274 | 2,606 |
| 5/15/2010 | Q2 | 5,750 | 2,875 | 13,500 | 173 | 271 | 2,431 |
| 8/15/2010 | Q3 | 13,000 | 6,500 | 20,000 | 219 | 269 | 6,012 |
| 11/15/2010 | Q4 | 16,000 | 8,000 | 28,000 | 325 | 433 | 7,243 |
| 2/15/2011 | Q1 | 48,000 | 24,000 | 52,000 | 455 | 255 | 23,290 |
| 5/15/2011 | Q2 | 53,000 | 26,500 | 78,500 | 878 | 233 | 25,390 |
| 8/15/2011 | Q3 | 62,000 | 31,000 | 109,500 | 1,325 | 208 | 29,468 |
| 11/15/2011 | Q4 | 57,000 | 28,500 | 138,000 | 1,848 | 349 | 26,304 |
| 2/15/2012 | Q1 | 59,000 | 29,500 | 167,500 | 2,329 | 152 | 27,019 |
| 5/14/2012 | Q2 | 59,000 | 29,500 | 197,000 | 2,931 | 166 | 26,403 |
| 8/14/2012 | Q3 | 48,000 | 24,000 | 221,000 | 3,448 | 146 | 20,407 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 11/14/2012 | Q4 | 48,000 | 24,000 | 245,000 | 3,868 | 299 | 19,833 |
| 2/14/2013 | Q1 | 27,000 | 13,500 | 258,500 | 4,288 | 113 | 9,100 |
| 5/14/2013 | Q2 | 27,000 | 13,500 | 272,000 | 4,685 | 104 | 8,711 |
| 8/14/2013 | Q3 | 27,000 | 13,500 | 285,500 | 4,930 | 94 | 8,476 |
| 11/14/2013 | Q4 | 29,000 | 14,500 | 300,000 | 5,175 | 255 | 9,070 |
| 2/14/2014 | Q1 | - | - | 300,000 | 305,438 | 75 | (305,513) |
| 5/14/2014 | Q2 | | | | | | |

1 The IRR is the Debt Cost shown on Line 93 of Appendix A.

[2] The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved

through iterations performed by a computer program (i.e., NPV function with goal seek in a spreadsheet program).

**Prairie Wind Transmission, LLC**

**Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)**

**Beginning of Year**

**Annual Update for the 12 months ending 12/31/20XX**

| Item | Directly Related To Project # Depreciation or CWIP | Directly Related To Project # Depreciation or CWIP | Plant Related | Labor Related | Total Plant & Labor Related |
|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 ADIT- 282 Less | - | - | - | - | | From Acct. 282 total, below |
| 2 ADIT-283 Less | - | - | - | - | | From Acct. 283 total, below |
| 3 ADIT-190 Plus | - | - | - | - | | From Acct. 190 total, below |
| 4 Subtotal | - | - | - | - | | |
| 5 Wages & Salary Allocator | | | | 0.0000% | | |
| 6 TP | | | 0.0000% | | | |
| 7 Beginning of Year | - | - | - | - | - | |
| 8 End of year from Attachment 6b, line 7 | - | - | | | | |
| 9 Average of Beginning of Year and End of Year ((7 +8)/2) | - | - | | | | |

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-G and each separate ADIT item will be listed,

dissimilar items with amounts exceeding $100,000 will be listed separately. For ADIT directly related to project depreciation or CWIP, the balance must shown in a separate column for each project.

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | Total | Gas, Prod | Directly Related | Directly Related | | | |
| ADIT-190 | | Or Other | To Project # | To Project # | Plant | Labor | |
| | | Related | Depreciation or CWIP | Depreciation or CWIP | Related | Related | Justification |

| | | | | | |
|---|---|---|---|---|---|
| Subtotal - p234 | | | | | |
| | - | - | - | - | - |
| Less FASB 109 Above if not separately removed | | | | | |
| Less FASB 106 Above if not separately removed | | | | | |
| Total | | | | | |
| | - | - | - | - | - |

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D and E

3. ADIT items related to Plant and not in Columns C & D & E are included in Column F

4. ADIT items related to labor and not in Columns C & D & E are included in Column G

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Prairie Wind Transmission, LLC**

**Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)**

**Beginning of Year**

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | Total | Gas, Prod | Directly Related | Directly Related | | | |
| ADIT- 282 | | Or Other | To Project # | To Project # | Plant | Labor | |
| | | Related | Depreciation | Depreciation | Related | Related | Justification |

| | | | | | |
|---|---|---|---|---|---|
| | | | or CWIP | or CWIP | |
| Subtotal - p275 | - | - | - | - | - |
| Less FASB 109 Above if not separately removed | | | | - | |

| | | | | | |
|---|---|---|---|---|---|
| Less FASB 106 Above if not separately removed | | | | | |
| Total | - | - | - | - | - |

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D and E

3. ADIT items related to Plant and not in Columns C & D & E are included in Column F

4. ADIT items related to labor and not in Columns C & D & E are included in Column G

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Prairie Wind Transmission, LLC**

## Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)

### Beginning of Year

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | | Gas, Prod | Directly Related | Directly Related | | | |
| ADIT- 283 | | Or Other | To Project # | To Project # | Plant | Labor | |
| | Total | Related | Depreciation or CWIP | Depreciation or CWIP | Related | Related | Justification |

| | | | | | |
|---|---|---|---|---|---|
| Subtotal - p277 | - | - | - | - | - |
| Less FASB 109 Above if not separately removed | - | | | - | |
| Less FASB 106 Above if not separately removed | - | | | | |
| Total | - | - | - | - | - |

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D and E

3. ADIT items related to Plant and not in Columns C & D & E

are included in Column F

4. ADIT items related to labor
and not in Columns C & D & E
are included in Column G

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Prairie Wind Transmission, LLC**

**Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)**

**End of Year**

**Annual Update for the 12 months ending 12/31/20XX**

| A | B | C | D | E | F | G | |
|---|---|---|---|---|---|---|---|
| | | Directly Related | Directly Related | | | | |
| | | To Project | To Project | Plant | Labor | Total | |
| Line | | Depreciation or CWIP | Depreciation or CWIP | Related | Related | Plant & Labor Related | |
| 1 | ADIT- 282 | | | | | | |
| | Less | - | - | - | - | | From Acct. 282 total, below |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2 | ADIT-283 | | | | | | From Acct. 283 |
| | Less | - | - | - | - | | total, below |
| 3 | ADIT-190 | | | | | | From Acct. 190 |
| | Plus | - | - | - | - | | total, below |
| 4 | Subtotal | - | - | - | - | | |
| 5 | Wages & Salary Allocator | | | | - | | |
| 6 | TP | | | - | | | |
| 7 | End of Year | - | - | - | - | - | |

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns C-G and each separate ADIT item will be listed,

dissimilar items with amounts exceeding $100,000 will be listed separately. For ADIT directly related to project depreciation or

CWIP, the balance must be shown in a separate column for each project.

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | Total | Gas, Prod | Directly Related | Directly Related | | | |
| ADIT-190 | | Or Other | To Project | To Project | Plant | Labor | |
| | | Related | Depreciation or CWIP | Depreciation or CWIP | Related | Related | Justification |

| | | | | | |
|---|---|---|---|---|---|
| Subtotal - p234 | - | - | - | - | - |
| Less FASB 109 Above if not separately removed | | | | | |
| Less FASB 106 Above if not separately removed | | | | | |
| Total | - | - | - | - | - |

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D and E

3. ADIT items related to Plant and not in Columns C & D & E are included in Column F

4. ADIT items related to labor and not in Columns C & D & E are included in Column G

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Prairie Wind Transmission, LLC**

**Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)**

**End of Year**

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | Total | Gas, Prod | Directly Related | Directly Related | | | |
| ADIT- 282 | | Or Other | To Project | To Project | Plant | Labor | |
| | | Related | Depreciation or CWIP | Depreciation or CWIP | Related | Related | Justification |

| | | | | | |
|---|---|---|---|---|---|
| Subtotal - p275 | - | - | - | - | - |
| Less FASB 109 Above if not separately removed | | | | - | |
| Less FASB 106 Above if not separately removed | | | | | |
| Total | - | - | - | - | - |

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D and E

3. ADIT items related to Plant and not in Columns
C & D & E are included in Column F

4. ADIT items related to labor and not in Columns
C & D & E are included in Column G

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Prairie Wind Transmission, LLC**

**Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)**

**End of Year**

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| | Total | Gas, Prod or Other Related | Directly Related | Directly Related | Plant | Labor | |
| ADIT- 283 | | | To Project | To Project | | | |
| | | | Depreciation or CWIP | Depreciation or CWIP | | | Justification |

| | | | | | |
|---|---|---|---|---|---|
| Subtotal - p277 | - | - | - | - | - |
| Less FASB 109 Above if not separately removed | - | | | - | |
| Less FASB 106 Above if not separately removed | - | | | | |
| Total | - | - | - | - | - |

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column

C

2. ADIT items related only to Transmission are directly assigned to Column D and E

3. ADIT items related to Plant and not in Columns C & D & E are included in Column F

4. ADIT items related to labor and not in Columns C & D & E are included in Column G

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Prairie Wind Transmission, LLC
Attachment 6c - Accumulated Excess / Deficient Deferred Income Taxes("EDIT)/DDIT")
Annual Update for the 12 months ending 12/31/20XX

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** |
| **190 NON-PLANT and NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | |
| | 190200<br>190300 | | | | | | | |
| | | Total (EDIT)/DDIT – Account 190 | - | - | - | - | - | - |

| (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|
| **Amort Period or Method** | **Explanation** | **Grossed-up EOY amount recorded to Account 182.3** | **Grossed-up EOY amount recorded to Account 254** | **Expense Account Amortization recorded to** |
| **190 NON-PLANT and NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | |
| | | | | |
| | | - | - | |

| No. | | (a) | 12/31/XX (b) | 12/31/XX (c) | 12/31/XX (d) | 20XX (e) | 20XX (f) | 12/31/XX (g) |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** |
| **283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | |
| | 283300 | | | | | | | |
| | | Total (EDIT)/DDIT – Account 283 | - | - | - | - | - | - |

| (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|
| **Amort Period or Method** | **Explanation** | **Grossed-up EOY amount recorded to Account 182.3** | **Grossed-up EOY amount recorded to Account 254** | **Expense Account Amortization recorded to** |
| **283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | |
| | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | - | - | | | | |

| | | | 12/31/XX | 12/31/XX | 12/31/XX | 20XX | 20XX | 12/31/XX |
|---|---|---|---|---|---|---|---|---|
| No. | | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| **Line No.** | **Account** | **Item** | **Beginning Adjusted Balance of Deficient (Excess) ADIT (Note A)** | **BOY Cumulative Amortization** | **BOY Cumulative Other Adjustments (Note B)** | **Current Period Amortization (Expense) Benefit** | **Current Period Other Activity (Note B)** | **EOY Balance (Note C)** |
| **281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | | | | | |
| | 282611 | | | | | | | |
| | | Total Plant(EDIT)/ DDIT | - | - | - | - | - | - |
| | | **Total (EDITExcess)/ DDIT** | - | - | - | - | - | - |

| (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|
| **Amort Period or Method** | **Explanation** | **Grossed-up EOY amount recorded to Account 182.3** | **Grossed-up EOY amount recorded to Account 254** | **Expense Account Amortization recorded to** |
| **281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES** | | | | |
| | | | | |
| | | - | - | |
| | | - | - | |

Notes:

| | |
|---|---|
| A | Amount carried from respective computation worksheet column (h). |
| B | Includes return to accrual adjustments, amended return adjustments, book adjustments and other. |
| C | Excess and Deficient balances exclude income tax gross-ups recorded to accounts 182.3 and 254. |

**Prairie Wind Transmission, LLC**
**Attachment 6d - Prorated Accumulated Deferred Income Taxes (ADIT) Worksheet**
**Annual Update for the 12 months ending 12/31/XXXX**



**Proration Used for Projected Revenue Requirement Calculation**

**Proration Used for True-up Revenue Requirement Calculation**

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **Account 190** | | | | | | | | **Account 190** | | | | | | |
| | | **Days in Period** | | | | **Projection - Proration of Deferred Tax Activity** | | | **True-up Adjustment - Proration of Projected Deferred Tax Activity and Averaging of Other Deferred Tax Activity** | | | | | | |
| 2 | **(a)** Month | **(b)** Days in the Month | **(c )** Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | **(d)** Total Days in Future Portion of Test Period (Line 18, Col B) | **(e)** Proration Amount (Lines 6 to 17, Col c / Col d) | **(f)** Projected Monthly Activity | **(g)** Prorated Projected Monthly Activity (Lines 6 to 17, Col e x Col f) | **(h)** Prorated Projected Balance (Line 5, Col h plus Cumulative Sum of Col g) | **(i)** Actual Monthly Activity ((Line 24 Col n - Line 21 Col n)/12) (See Note 6.) | **(j)** Difference between projected monthly and actual monthly activity (See Note 1.) | **(k)** Preserve proration when actual monthly and projected monthly activity are either both increases or decreases. (See Note 2.) | **(l)** Difference between projected and actual activity when actual and projected activity are either both increases or decreases. (See Note 3.) | **(m)** Actual activity (Col i) when projected activity is an increase while actual activity is a decrease OR projected activity is a decrease while actual activity is an increase. (See Note 4.) | **(n)** Balance reflecting proration or averaging (See Note 5.) | |
| 3 | | | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | | |
| 5 | December 31st | | | | | | | - | - | | | | | | - |
| 6 | January | 31 | 335 | 365 | 91.78% | - | - | - | - | - | - | - | - | - | - |
| 7 | February | 28 | 307 | 365 | 84.11% | - | - | - | - | - | - | - | - | - | - |
| 8 | March | 31 | 276 | 365 | 75.62% | - | - | - | - | - | - | - | - | - | - |
| 9 | April | 30 | 246 | 365 | 67.40% | - | - | - | - | - | - | - | - | - | - |
| 10 | May | 31 | 215 | 365 | 58.90% | - | - | - | - | - | - | - | - | - | - |
| 11 | June | 30 | 185 | 365 | 50.68% | - | - | - | - | - | - | - | - | - | - |
| 12 | July | 31 | 154 | 365 | 42.19% | - | - | - | - | - | - | - | - | - | - |
| 13 | August | 31 | 123 | 365 | 33.70% | - | - | - | - | - | - | - | - | - | - |
| 14 | September | 30 | 93 | 365 | 25.48% | - | - | - | - | - | - | - | - | - | - |
| 15 | October | 31 | 62 | 365 | 16.99% | - | - | - | - | - | - | - | - | - | - |
| 16 | November | 30 | 32 | 365 | 8.77% | - | - | - | - | - | - | - | - | - | - |
| 17 | December | 31 | 1 | 365 | 0.27% | - | - | - | - | - | - | - | - | - | - |
| | | | | | | - | | | | | | | | | |
| 18 | Total (sum of Lines 6 -17) | 365 | | | | - | - | | - | - | - | - | - | | |
| 19 | Beginning Balance-ADIT Total | | | | 20xx Projection Template | | | - | Beginning Balance-ADIT Total | | Worksheet 6a, line 3 column E | | | | - |
| 20 | Beginning Balance-EDIT Total | | | | 20xx Projection Template | | | - | Beginning Balance-EDIT Total | | Worksheet 6c, Total (EDIT)/DDIT-Account 190 columns (b)+(c)+(d) | | | | - |
| 21 | Beginning Balance-Combined ADIT & EDIT | | | | 20xx Projection Template | | | - | Beginning Balance-Combined ADIT & EDIT | | | | | | - |
| 22 | Ending Balance-ADIT Total | | | | 20xx Projection Template | | | - | Ending Balance-ADIT Total | | Worksheet 6b, line 3 column E | | | | - |
| 23 | Ending Balance- EDIT Total | | | | 20xx Projection Template | | | - | Ending Balance- EDIT Total | | Worksheet 6c, Total(EDIT)/DDIT – Account 190 column (g) | | | | - |
| 24 | Ending Balance-Combined ADIT & EDIT | | | | 20xx Projection Template | | | - | Ending Balance-Combined ADIT & EDIT | | | | | | - |
| 25 | | | | | | | | | | | | | | | |
| 26 | Reserved | | | | | | | | Reserved | | | | | | |
| 27 | Prorated ADIT - Account 190 | | | | (Line 17) | | | - | Prorated ADIT - Account 190 | | | (Line 17) | | | - |

| | | Account 282 | | | | | | | | Account 282 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Days in Period | | | | | Projection - Proration of Deferred Tax Activity | | | True-up Adjustment - Proration of Projected Deferred Tax Activity and Averaging of Other Deferred Tax Activity | | | | | |
| | | (a) | (b) | (c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
| | | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period (Line 45, Col B) | Proration Amount (Lines 33 to 44, Col c / Col d) | Projected Monthly Activity | Prorated Projected Monthly Activity (Lines 33 to 44, Col e x Col f) | Prorated Projected Balance (Line 32, Col h plus Cumulative Sum of Col g) | Actual Monthly Activity ((Line 51 Col n - Line 48 Col n)/12) (See Note 6.) | Difference between projected monthly and actual monthly activity (See Note 1.) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases. (See Note 2.) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases. (See Note 3.) | Actual activity (Col i) when projected activity is an increase while actual activity is a decrease OR projected activity is a decrease while actual activity is an increase. (See Note 4.) | Balance reflecting proration or averaging (See Note 5.) |
| 31 | | | | | | | | | | | | | | | |
| 32 | December 31st | | | | | | - | | - | - | | | | | - |
| 33 | January | 31 | 335 | 365 | 91.78% | | - | - | - | - | - | - | - | - | - |
| 34 | February | 28 | 307 | 365 | 84.11% | | - | - | - | - | - | - | - | - | - |
| 35 | March | 31 | 276 | 365 | 75.62% | | - | - | - | - | - | - | - | - | - |
| 36 | April | 30 | 246 | 365 | 67.40% | | - | - | - | - | - | - | - | - | - |
| 37 | May | 31 | 215 | 365 | 58.90% | | - | - | - | - | - | - | - | - | - |
| 38 | June | 30 | 185 | 365 | 50.68% | | - | - | - | - | - | - | - | - | - |
| 39 | July | 31 | 154 | 365 | 42.19% | | - | - | - | - | - | - | - | - | - |
| 40 | August | 31 | 123 | 365 | 33.70% | | - | - | - | - | - | - | - | - | - |
| 41 | September | 30 | 93 | 365 | 25.48% | | - | - | - | - | - | - | - | - | - |
| 42 | October | 31 | 62 | 365 | 16.99% | | - | - | - | - | - | - | - | - | - |
| 43 | November | 30 | 32 | 365 | 8.77% | | - | - | - | - | - | - | - | - | - |
| 44 | December | 31 | 1 | 365 | 0.27% | | - | - | - | - | - | - | - | - | - |
| 45 | Total (sum of lines 33-44) | 365 | | | | | - | - | | - | - | - | - | - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 46 | Beginning Balance-ADIT Total | 20xx Projection Template | | | Balance-ADIT Total | Worksheet 6a, line 1 column E - |
| 47 | Beginning Balance-EDIT Total | 20xx Projection Template | - | | Beginning Balance-EDIT Total | Worksheet 6c, Total Plant (EDIT)/DDIT columns (b)+(c)+(d) - |
| 48 | Beginning Balance-Combined ADIT & EDIT | 20xx Projection Template | - | | Beginning Balance-Combined ADIT & EDIT | - |
| 49 | Ending Balance-ADIT Total | 20xx Projection Template | - | | Ending Balance-ADIT Total | Worksheet 6b, line 1 column E - |
| 50 | Ending Balance- EDIT Total | 20xx Projection Template | - | | Ending Balance- EDIT Total | Worksheet 6c, Total Plant (EDIT)/DDIT column (g) - |
| 51 | Ending Balance-Combined ADIT & EDIT | 20xx Projection Template | - | | Ending Balance-Combined ADIT & EDIT | - |
| 52 | | | | | | |
| 53 | Reserved | | | | Reserved | |
| 54 | Prorated ADIT - Account 282 | (Line 44) | - | | Prorated ADIT - Account 282 | (Line 44) - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 55 | **Account 283** | | | | | | | | **Account 283** | | | | | | | |
| 56 | | **Days in Period** | | | | | **Projection - Proration of Deferred Tax Activity** | | | | **True-up Adjustment - Proration of Projected Deferred Tax Activity and Averaging of Other Deferred Tax Activity** | | | | | |
| | **(a)** | **(b)** | **(c )** | **(d)** | **(e)** | **(f)** | **(g)** | **(h)** | **(i)** | **(j)** | **(k)** | **(l)** | **(m)** | **(n)** | | |
| 57 | Month | Days in the Month | Number of Days Remaining in Year After Month's Accrual of Deferred Taxes | Total Days in Future Portion of Test Period (Line 72, Col B) | Proration Amount (Lines 60 to 71, Col c / Col d) | Projected Monthly Activity | Prorated Projected Monthly Activity (Lines 60 to 71, Col e x Col f) | Prorated Projected Balance (Line 59, Col h plus Cumulative Sum of Col g) | Actual Monthly Activity ((Line 78 Col n - Line 75 Col n)/12) (See Note 6.) | Difference between projected monthly and actual monthly activity (See Note 1.) | Preserve proration when actual monthly and projected monthly activity are either both increases or decreases. (See Note 2.) | Difference between projected and actual activity when actual and projected activity are either both increases or decreases. (See Note 3.) | Actual activity (Col i) when projected activity is an increase while actual activity is a decrease OR projected activity is a decrease while actual activity is an increase. (See Note 4.) | Balance reflecting proration or averaging (See Note 5.) | | |
| 58 | | | | | | | | | | | | | | | | |
| 59 | December 31st | | | | | - | | - | - | | | | | - | | |
| 60 | January | 31 | 335 | 365 | 91.78% | - | - | - | - | - | - | - | - | - | | |
| 61 | February | 28 | 307 | 365 | 84.11% | - | - | - | - | - | - | - | - | - | | |
| 62 | March | 31 | 276 | 365 | 75.62% | - | - | - | - | - | - | - | - | - | | |
| 63 | April | 30 | 246 | 365 | 67.40% | - | - | - | - | - | - | - | - | - | | |
| 64 | May | 31 | 215 | 365 | 58.90% | - | - | - | - | - | - | - | - | - | | |
| 65 | June | 30 | 185 | 365 | 50.68% | - | - | - | - | - | - | - | - | - | | |
| 66 | July | 31 | 154 | 365 | 42.19% | - | - | - | - | - | - | - | - | - | | |
| 67 | August | 31 | 123 | 365 | 33.70% | - | - | - | - | - | - | - | - | - | | |
| 68 | September | 30 | 93 | 365 | 25.48% | - | - | - | - | - | - | - | - | - | | |
| 69 | October | 31 | 62 | 365 | 16.99% | - | - | - | - | - | - | - | - | - | | |
| 70 | November | 30 | 32 | 365 | 8.77% | - | - | - | - | - | - | - | - | - | | |
| 71 | December | 31 | 1 | 365 | 0.27% | - | - | - | - | - | - | - | - | - | | |
| 72 | Total (sum of Lines 60 - | 365 | | | | - | - | | - | - | - | - | - | | | |
| 73 | Beginning Balance-ADIT Total | | | 20xx Projection Template | | | | - | Beginning Balance-ADIT Total | | Worksheet 6a, line 2 column E | | | - | | |
| 74 | Beginning Balance-EDIT Total | | | 20xx Projection Template | | | | - | Beginning Balance-EDIT Total | | Worksheet 6c, Total (EDIT)/DDIT-Account 283 columns (b)+(c)+(d) | | | - | | |
| 75 | Beginning Balance-Combined ADIT & EDIT | | | 20xx Projection Template | | | | - | Beginning Balance-Combined ADIT & EDIT | | | | | - | | |
| 76 | Ending Balance-ADIT Total | | | Projection Template | | | | - | Ending Balance-ADIT Total | | Worksheet 6b, line 2 column E | | | - | | |
| 77 | Ending Balance- EDIT Total | | | 20xx Projection Template | | | | - | Ending Balance- EDIT Total | | Worksheet 6c, Total (EDIT)/DDIT-Account 283 column (g) | | | - | | |
| 78 | Ending Balance-Combined ADIT & EDIT | | | 20xx Projection Template | | | | - | Ending Balance-Combined ADIT & EDIT | | | | | - | | |
| 79 | | | | | | | | | | | | | | | | |
| 80 | Reserved | | | | | | | | Reserved | | | | | | | |
| 81 | Prorated ADIT - Account 283 | | | (Line 71) | | | | - | Prorated ADIT - Account 283 | | | (Line 71) | | - | | |
| 82 | Total Prorated ADIT - Accounts 190, 282 & 283 | | | (Lines 27+54+81) | | | | - | | | | (Lines 27+54+81) | | - | | |
| 53 | Total Rate Base Adjustment to Appendix A | | | | | | | - | | | | | | | | |

NOTES

1) Column J is the difference between projected monthly and actual monthly activity (Column I minus Column F). Specifically, if projected and actual activity are both positive, a negative in Column J represents over-projection (amount of projected activity that did not occur) and a positive in Column J represents under-projection (excess of actual activity over projected activity). If projected and actual activity are both negative, a negative in Column J represents under-projection (excess of actual activity over projected activity) and a positive in Column J represents over-projection (amount of projected activity that did not occur).

2) Column K preserves proration when actual monthly and projected monthly activity are either both increases or decreases. Specifically, if Column J is over-projected, enter Column G x [Column I/Column F]. If Column J is under-projected, enter the amount from Column G and complete Column L). In other situations, enter zero.

3) Column L applies when (1) Column J is under-projected AND (2) actual monthly and projected monthly activity are either both increases or decreases. Enter the amount from Column J. In other situations, enter zero.

4) Column M applies when (1) projected monthly activity is an increase while actual monthly activity is a decrease OR (2) projected monthly activity is a decrease while actual monthly activity is an increase. Enter actual monthly activity (Col I). In other situations, enter zero.

5) Column N is computed by adding the prorated monthly activity, if any, from Column K to 50 percent of the portion of monthly activity, if any, from Column L or M to the balance at the end of the prior month. The activity in columns L and M is multiplied by 50 percent to reflect averaging of rate base to the extent that the proration requirement has not been applied to a portion of the monthly activity.

6) Actual monthly activity is computed based on the annual activity for the period, divided by 12 months.

## Prairie Wind Transmission
## Attachment 6e - Computation of EDIT due to Tax Cut and Jobs Act

| No. | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| Line No. | Account | Description | Temporary Differences Before Rate Change | Prior Tax Rate | Balance Before Tax Rate Change | New Tax Rate | Balance of ADIT after Tax Rate Change | Deficient/ (Excess)ADIT |
| | | 190 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES | | | | | | |
| | 190200 | | | | | | | |
| | | Total (EDIT)/DDIT – Account 190 (Unprotected) | - | | - | | - | - |

| 283 NON-PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES | | | | |
|---|---|---|---|---|
| 283300 | | | | |
| Total (EDIT)/DDIT – Account 283 (Unprotected) | - | - | - | - |
| **Total Non-Plant Unprotected (EDIT)/DDIT** | | | | - |

| 190 NOL (EXCESS) DEFICIENT DEFERRED INCOME TAXES | |
|---|---|
| 190300 | |
| **Total NOL (EDIT)/DDIT – Account 190** | - |

| 281 & 282 PLANT (EXCESS) DEFICIENT DEFERRED INCOME TAXES | | | | |
|---|---|---|---|---|
| 282611 | | | | |
| Total Plant (EDIT)/DDIT | - | - | - | - |
| **Net (Excess)/Deficient Deferred Income Taxes** | | | | - |

**Attachment 7 - Example of True-Up Calculation**

**Prairie Wind Transmission, LLC**

| 2009 | | 2009 | | |
|---|---|---|---|---|
| Actual Revenue Requirement | | Revenue Requirement Forecast | | Over (Under) Recovery |
| $1,794,917 | **Less** | $2,000,000 | **Equals** | $205,083 |

| **Interest Rate on Amount of Refunds or Surcharges** | **Over (Under) Recovery Plus Interest** | **Monthly Interest Rate** | **Months** | **Calculated Interest** | **Amortization** | **Surcharge (Refund) Owed** |
|---|---|---|---|---|---|---|
| | | 0.5500% | | | | |

**An over or under collection will be recovered prorata over year collected, held for one year and returned prorata over nest year**

**Calculation of Interest** **Monthly**

| | | | | | | |
|---|---|---|---|---|---|---|
| January | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 12 | (1,128) | (18,218) |
| February | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 11 | (1,034) | (18,124) |
| March | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 10 | (940) | (18,030) |
| April | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 9 | (846) | (17,936) |
| May | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 8 | (752) | (17,842) |
| June | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 7 | (658) | (17,748) |
| July | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 6 | (564) | (17,654) |
| August | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 5 | (470) | (17,560) |
| September | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 4 | (376) | (17,466) |
| October | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 3 | (282) | (17,372) |
| November | Year | | 0.5500% | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | 2009 | 17,090 | | 2 | (188) | (17,278) |
| December | Year | | 0.5500% | | | |
| | 2009 | 17,090 | | 1 | (94) | (17,184) |
| | | | | | (7,332) | **(212,415)** |

**Annual**

| | | | | | |
|---|---|---|---|---|---|
| January through | Year | | 0.5500% | | |
| December | 2010 | (212,415) | | 12 | (14,019) | **(226,434)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

**Monthly**

| | | | | | | |
|---|---|---|---|---|---|---|
| January | Year | | 0.5500% | | | |
| | 2011 | **226,434** | | | (1,245) | 19,551 | (208,129) |
| February | Year | | 0.5500% | | | |
| | 2011 | 208,129 | | | (1,145) | 19,551 | (189,722) |
| March | Year | | 0.5500% | | | |
| | 2011 | 189,722 | | | (1,043) | 19,551 | (171,215) |
| April | Year | | 0.5500% | | | |
| | 2011 | 171,215 | | | (942) | 19,551 | (152,606) |
| May | Year | | 0.5500% | | | |
| | 2011 | 152,606 | | | (839) | 19,551 | (133,894) |

| | | | | | | |
|---|---|---|---|---|---|---|
| June | Year 2011 | 133,894 | 0.5500% | (736) | 19,551 | (115,080) |
| July | Year 2011 | 115,080 | 0.5500% | (633) | 19,551 | (96,162) |
| August | Year 2011 | 96,162 | 0.5500% | (529) | 19,551 | (77,140) |
| September | Year 2011 | 77,140 | 0.5500% | (424) | 19,551 | (58,013) |
| October | Year 2011 | 58,013 | 0.5500% | (319) | 19,551 | (38,782) |
| November | Year 2011 | 38,782 | 0.5500% | (213) | 19,551 | (19,444) |
| December | Year 2011 | 19,444 | 0.5500% | (107) | 19,551 | (0) |
| | | | | (8,176) | | |

| | |
|---|---|
| Total Amount of True-Up Adjustment | $ (234,611) |
| Less Over (Under) Recovery | $ 205,083 |
| Total Interest | $ (29,528) |

**Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan**

**Prairie Wind Transmission, LLC**

***To be Prepared on 8/15/2015 (hypothetical date)***

**SUMMARY**

| | | | Revenue Requirement | | | | |
|---|---|---|---|---|---|---|---|
| **YEAR** | **Estimated Effective cost of debt used in forecast /true up** | **Final Effective cost of debt for the construction loan:** | **Based on Estimated Effective cost of debt** | **Based on Actual Effective cost of debt** | **Over (Under) Recovery** | **Monthly Interest Rate applicable over the ATRR period** | **Total Amount of Construction Loan Related True-Up included in rates effective Jan 2014 (Refund)/Owe** |

| | | | | | | | d |
|---|---|---|---|---|---|---|---|
| 2009 | 7.18 % | 7.00% | $ 2,500 ,000. 00 | $ 2,400 ,000. 00 | $ 100,0 00.00 | 0.550 % | $ (148,28 8.33) |
| 2010 | 6.8 % | 7.00% | $5,00 0,000 .00 | $5,15 0,000 .00 | $ (150, 000.0 0) | 0.560 % | $ 209,67 0.43 |
| 2011 | 7.2 % | 7.00% | $8,30 0,000 .00 | $8,20 0,000 .00 | $ 100,0 00.00 | 0.540 % | $ (131,10 9.09) |
| 2012 | 7.3 % | 7.00% | $12,3 00,00 0.00 | $12,0 00,00 0.00 | $ 300,0 00.00 | 0.580 % | $ (368,65 6.73) |
| 2013 | 7.1 % | 7.00% | $18,0 00,00 0.00 | $17,9 00,00 0.00 | $ 100,0 00.00 | 0.570 % | $ (114,94 6.28) |
| 2014 | 6.50 % | 7.00% | $25,0 00,00 0.00 | $25,0 00,00 0.00 | $ - | | |

| | | | |
|---|---|---|---|
| 2015 | 6.50 % | 7.00% | $ (553,329.99) |

***Example assumes that the construction loan is retired on Sept 1, 2014***

***Example assumes permanent debt structure is put in place on Sept 1, 2014 with effective rate of 6.5%***

***Example assumes the True-Up period is 2009 - 2014, with the true-up amount included in 2015 forecasted ATRR. Final effective cost of debt for 2015 is computed as follows: ((7%*243 days)+(6.5%*122 days))/365 days***

***Note: The final trued-up interest rate will replace the estimated interest rates beginning on the date the rates become effective***

**Calculation of Applicable Interest Expense for each ATRR period**

| **Interest Rate on Amount of Refunds or Surcharges from 35.19a** | **Over (Under) Recovery Plus Interest** | **Monthly Interest Rate** | **Months** | **Calculated Inter** | **Amortization** | **Surcharge (Refund) Owed** |
|---|---|---|---|---|---|---|

**est**

**Calculation of Interest for 2009 True-Up Period**

| | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| January | 2009 | - | 0.5500% | 12 | - | - |
| February | 2009 | - | 0.5500% | 11 | - | - |
| March | 2009 | 10,000 | 0.5500% | 10 | (550) | (10,550) |
| April | 2009 | 10,000 | 0.5500% | 9 | (495) | (10,495) |
| May | 2009 | 10,000 | 0.5500% | 8 | (440) | (10,440 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | ) |
| June | 2009 | 10,000 | 0.5500% | 7 | (385) | (10,385) |
| July | 2009 | 10,000 | 0.5500% | 6 | (330) | (10,330) |
| August | 2009 | 10,000 | 0.5500% | 5 | (275) | (10,275) |
| September | 2009 | 10,000 | 0.5500% | 4 | (220) | (10,220) |
| October | 2009 | 10,000 | 0.5500% | 3 | (165) | (10,165) |
| November | 2009 | 10,000 | 0.5500% | 2 | (110) | (10,110) |
| December | 2009 | 10,000 | 0.5500% | 1 | (55) | (10,055) |
| | | | | | (3,025) | **(103,025)** |

| | | | | | **Annual** | |
|---|---|---|---|---|---|---|
| January through December | 2010 | (103,025) | 0.5600% | 12 | (6,923) | **(109,948)** |
| January through December | 2011 | (109,948) | 0.5400% | 12 | (7,125) | **(117,073)** |
| January through December | 2012 | (117,073) | 0.5800% | 12 | (8,148) | **(125,221)** |
| January through December | 2013 | (125,221) | 0.5700% | 12 | (8,565) | **(133,786)** |
| January through December | 2014 | (133,786) | 0.5700% | 12 | (9,151) | **(142,937)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

**Mon**

| | | | | **thly** | | |
|---|---|---|---|---|---|---|
| January | 2015 | **142,937** | 0.5700% | (815) | (12,357) | (131,395) |
| February | 2015 | 131,395 | 0.5700% | (749) | (12,357) | (119,786) |
| March | 2015 | 119,786 | 0.5700% | (683) | (12,357) | (108,112) |
| April | 2015 | 108,112 | 0.5700% | (616) | (12,357) | (96,371) |
| May | 2015 | 96,371 | 0.5700% | (549) | (12,357) | (84,563) |
| June | 2015 | 84,563 | 0.5700% | (482) | (12,357) | (72,687) |
| July | 2015 | 72,687 | 0.5700% | (414) | (12,357) | (60,744) |
| August | 2015 | 60,744 | 0.5700% | (346) | (12,357) | (48,733) |

| | | | | | | |
|---|---|---|---|---|---|---|
| September | 2015 | 48,733 | 0.5700% | (278) | (12,357) | (36,653) |
| October | 2015 | 36,653 | 0.5700% | (209) | (12,357) | (24,505) |
| November | 2015 | 24,505 | 0.5700% | (140) | (12,357) | (12,287) |
| December | 2015 | 12,287 | 0.5700% | (70) | (12,357) | 0 |
| | | | | (5,351) | | |

| | |
|---|---|
| Total Amount of True-Up Adjustment for 2008 ATRR | $ (148,288) |
| Less Over (Under) Recovery | $ 100,000 |
| Total Interest | $ (48,288) |

**Calculation of Interest for 2010 True-Up Period**

| | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| January | 2010 | (12,500) | 0.560% | 12 | 840 | 13,340 |
| February | 2010 | (12,500) | 0.560% | 11 | 770 | 13,270 |
| March | 2010 | (12,500) | 0.560% | 10 | 700 | 13,200 |
| April | 2010 | (12,500) | 0.560% | 9 | 630 | 13,130 |
| May | 2010 | (12,500) | 0.560% | 8 | 560 | 13,060 |
| June | 2010 | (12,500) | 0.560% | 7 | 490 | 12,990 |
| July | 2010 | (12,500) | 0.560% | 6 | 420 | 12,920 |
| August | 2010 | (12,500) | 0.560% | 5 | 350 | 12,850 |

| | | | | | | |
|---|---|---|---|---|---|---|
| September | 2010 | (12,500) | 0.5600% | 4 | 280 | 12,780 |
| October | 2010 | (12,500) | 0.5600% | 3 | 210 | 12,710 |
| November | 2010 | (12,500) | 0.5600% | 2 | 140 | 12,640 |
| December | 2010 | (12,500) | 0.5600% | 1 | 70 | 12,570 |
| | | | | | 5,460 | **155,460** |
| | | | | | **Annual** | |
| January through December | 2011 | 155,460 | 0.5400% | 12 | 10,074 | **165,534** |
| January through December | 2012 | 165,534 | 0.5800% | 12 | 11,521 | **177,055** |
| January through December | 2013 | 177,055 | 0.5700% | 12 | 12,11 | **189,16** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | 1 | | **6** |
| January through December | 2014 | 189,166 | 0.5700% | 12 | 12,939 | | **202,104** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | | **Monthly** | | |
|---|---|---|---|---|---|---|---|
| January | 2015 | **(202,104)** | 0.5700% | | 1,152 | 17,473 | 185,784 |
| February | 2015 | (185,784) | 0.5700% | | 1,059 | 17,473 | 169,370 |
| March | 2015 | (169,370) | 0.5700% | | 965 | 17,473 | 152,863 |
| April | 2015 | (152,863) | 0.5700% | | 871 | 17,473 | 136,262 |
| May | 2015 | (136,262) | 0.5700% | | 777 | 17,473 | 119,566 |

| | | | | | | |
|---|---|---|---|---|---|---|
| June | 2015 | (119,566) | 0.5700% | 682 | 17,473 | 102,775 |
| July | 2015 | (102,775) | 0.5700% | 586 | 17,473 | 85,888 |
| August | 2015 | (85,888) | 0.5700% | 490 | 17,473 | 68,905 |
| September | 2015 | (68,905) | 0.5700% | 393 | 17,473 | 51,826 |
| October | 2015 | (51,826) | 0.5700% | 295 | 17,473 | 34,649 |
| November | 2015 | (34,649) | 0.5700% | 197 | 17,473 | 17,374 |
| December | 2015 | (17,374) | 0.5700% | 99 | 17,473 | (0) |
| | | | | 7,566 | | |

Total Amount of True-Up Adjustment for 2009 ATRR $

| | |
|---|---|
| | 209,670 |
| Less Over (Under) Recovery | $ (150,000) |
| Total Interest | $ 59,670 |

**Calculation of Interest for 2011 True-Up Period**

| | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| January | 2011 | 8,333 | 0.5400% | 12 | (540) | (8,873) |
| February | 2011 | 8,333 | 0.5400% | 11 | (495) | (8,828) |
| March | 2011 | 8,333 | 0.5400% | 10 | (450) | (8,783) |
| April | 2011 | 8,333 | 0.5400% | 9 | (405) | (8,738) |
| May | 2011 | | 0.5400 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | 1 | 8,333 | 0% | 8 | (360) | (8,693) |
| June | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 7 | (315) | (8,648) |
| July | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 6 | (270) | (8,603) |
| August | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 5 | (225) | (8,558) |
| September | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 4 | (180) | (8,513) |
| October | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 3 | (135) | (8,468) |
| November | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 2 | (90) | (8,423) |
| December | 2011 | | 0.540 | | | |
| | 1 | 8,333 | 0% | 1 | (45) | (8,378) |
| | | | | | (3,510) | **(103,510)** |
| | | | | | **Annual** | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| January through December | 2012 | (103,510) | 0.5800% | 12 | (7,204) | | **(110,714)** |
| January through December | 2013 | (110,714) | 0.5700% | 12 | (7,573) | | **(118,287)** |
| January through December | 2014 | (118,287) | 0.5700% | 12 | (8,091) | | **(126,378)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | **Monthly** | | |
|---|---|---|---|---|---|---|
| January | 2012 | **126,378** | 0.5700% | (720) | (10,926) | (116,173) |
| February | 2012 | 116,173 | 0.5700% | (662) | (10,926) | (105,909) |
| March | 2012 | 105,909 | 0.5700% | (604) | (10,926) | (95,587) |
| April | 2012 | 95,587 | 0.5700% | (545) | (10,92 | (85,206 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 6) | ) |
| May | 2012 | 85,206 | 0.5700% | (486) | (10,926) | (74,766) |
| June | 2012 | 74,766 | 0.5700% | (426) | (10,926) | (64,266) |
| July | 2012 | 64,266 | 0.5700% | (366) | (10,926) | (53,707) |
| August | 2012 | 53,707 | 0.5700% | (306) | (10,926) | (43,087) |
| September | 2012 | 43,087 | 0.5700% | (246) | (10,926) | (32,407) |
| October | 2012 | 32,407 | 0.5700% | (185) | (10,926) | (21,666) |
| November | 2012 | 21,666 | 0.5700% | (123) | (10,926) | (10,864) |
| December | 2012 | 10,864 | 0.5700% | (62) | (10,926) | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | (4,731) | |
| Total Amount of True-Up Adjustment for 2010 ATRR | | | | | | $ (131,109) |
| Less Over (Under) Recovery | | | | | | $ 100,000 |
| Total Interest | | | | | | $ (31,109) |

**Calculation of Interest for 2012 True-Up Period**

| **An over or under collection will be recovered prorata over 2011, held for 2012, 2013 and returned prorate over 2014** | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| - | | | | | | |
| January | 2012 | 25,000 | 0.5800% | 12 | (1,740) | (26,740) |
| February | 2012 | | 0.5800 | | (1,59 | (26,595 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | 2 | 25,000 | 0% | 11 | 5) | ) |
| March | 2012 | 25,000 | 0.580 0% | 10 | (1,450) | (26,450) |
| April | 2012 | 25,000 | 0.580 0% | 9 | (1,305) | (26,305) |
| May | 2012 | 25,000 | 0.580 0% | 8 | (1,160) | (26,160) |
| June | 2012 | 25,000 | 0.580 0% | 7 | (1,015) | (26,015) |
| July | 2012 | 25,000 | 0.580 0% | 6 | (870) | (25,870) |
| August | 2012 | 25,000 | 0.580 0% | 5 | (725) | (25,725) |
| September | 2012 | 25,000 | 0.580 0% | 4 | (580) | (25,580) |
| October | 2012 | 25,000 | 0.580 0% | 3 | (435) | (25,435) |

| | | | | | | |
|---|---|---|---|---|---|---|
| November | 2012 | 25,000 | 0.5800% | 2 | (290) | (25,290) |
| December | 2012 | 25,000 | 0.5800% | 1 | (145) | (25,145) |
| | | | | | (11,310) | **(311,310)** |
| | | | | | **Annual** | |
| January through December | 2013 | (311,310) | 0.5700% | 12 | (21,294) | **(332,604)** |
| January through December | 2014 | (332,604) | 0.5700% | 12 | (22,750) | **(355,354)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

**Mon**

| | | | | **thly** | | |
|---|---|---|---|---|---|---|
| January | 2013 | **355,354** | 0.5700% | (2,026) | (30,721) | (326,658) |
| February | 2013 | 326,658 | 0.5700% | (1,862) | (30,721) | (297,798) |
| March | 2013 | 297,798 | 0.5700% | (1,697) | (30,721) | (268,774) |
| April | 2013 | 268,774 | 0.5700% | (1,532) | (30,721) | (239,585) |
| May | 2013 | 239,585 | 0.5700% | (1,366) | (30,721) | (210,229) |
| June | 2013 | 210,229 | 0.5700% | (1,198) | (30,721) | (180,706) |
| July | 2013 | 180,706 | 0.5700% | (1,030) | (30,721) | (151,015) |
| August | 2013 | 151,015 | 0.5700% | (861) | (30,721) | (121,154) |

| | | | | | | |
|---|---|---|---|---|---|---|
| September | 2013 | 121,154 | 0.5700% | (691) | (30,721) | (91,123) |
| October | 2013 | 91,123 | 0.5700% | (519) | (30,721) | (60,921) |
| November | 2013 | 60,921 | 0.5700% | (347) | (30,721) | (30,547) |
| December | 2013 | 30,547 | 0.5700% | (174) | (30,721) | 0 |
| | | | | (13,303) | | |

| | |
|---|---|
| Total Amount of True-Up Adjustment for 2011 ATRR | $ (368,657) |
| Less Over (Under) Recovery | $ 300,000 |
| Total Interest | $ (68,657) |

**Calculation of Interest for 2013 True-Up Period**

| | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| January | 2013 | 8,333 | 0.5700% | 12 | (570) | (8,903) |
| February | 2013 | 8,333 | 0.5700% | 11 | (523) | (8,856) |
| March | 2013 | 8,333 | 0.5700% | 10 | (475) | (8,808) |
| April | 2013 | 8,333 | 0.5700% | 9 | (428) | (8,761) |
| May | 2013 | 8,333 | 0.5700% | 8 | (380) | (8,713) |
| June | 2013 | 8,333 | 0.5700% | 7 | (333) | (8,666) |
| July | 2013 | 8,333 | 0.5700% | 6 | (285) | (8,618) |
| August | 2013 | 8,333 | 0.5700% | 5 | (238) | (8,571) |

| | | | | | | |
|---|---|---|---|---|---|---|
| September | 2013 | 8,333 | 0.5700% | 4 | (190) | (8,523) |
| October | 2013 | 8,333 | 0.5700% | 3 | (143) | (8,476) |
| November | 2013 | 8,333 | 0.5700% | 2 | (95) | (8,428) |
| December | 2013 | 8,333 | 0.5700% | 1 | (48) | (8,381) |
| | | | | | (3,705) | **(103,705)** |
| | | | | | **Annual** | |
| January through December | 2014 | (103,705) | 0.5700% | 12 | (7,093) | **(110,798)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

**Mon**

| | | | | **thly** | | |
|---|---|---|---|---|---|---|
| January | 2015 | **110,798** | 0.5700% | (632) | (9,579) | (101,851) |
| February | 2015 | 101,851 | 0.5700% | (581) | (9,579) | (92,853) |
| March | 2015 | 92,853 | 0.5700% | (529) | (9,579) | (83,803) |
| April | 2015 | 83,803 | 0.5700% | (478) | (9,579) | (74,702) |
| May | 2015 | 74,702 | 0.5700% | (426) | (9,579) | (65,549) |
| June | 2015 | 65,549 | 0.5700% | (374) | (9,579) | (56,344) |
| July | 2015 | 56,344 | 0.5700% | (321) | (9,579) | (47,086) |
| August | 2015 | 47,086 | 0.5700% | (268) | (9,579) | (37,776) |

| | | | | | | |
|---|---|---|---|---|---|---|
| September | 2015 | 37,776 | 0.5700% | (215) | (9,579) | (28,412) |
| October | 2015 | 28,412 | 0.5700% | (162) | (9,579) | (18,995) |
| November | 2015 | 18,995 | 0.5700% | (108) | (9,579) | (9,525) |
| December | 2015 | 9,525 | 0.5700% | (54) | (9,579) | 0 |
| | | | | (4,148) | | |

| | |
|---|---|
| Total Amount of True-Up Adjustment for 2012 ATRR | $ (114,946) |
| Less Over (Under) Recovery | $ 100,000 |
| Total Interest | $ (14,946) |

## Attachment 9 - Depreciation and Amortization Rates

## Prairie Wind Transmission, LLC

| | Account Number | FERC Account | Rate (Annual) Percent |
|---|---|---|---|
| | **TRANSMISSION PLANT** | | |
| 1 | 352 | Structures and Improvements | 1.55 |
| 2 | 353 | Station Equipment | 1.95 |
| 3 | 354 | Towers and Fixtures | 1.14 |
| 4 | 355 | Poles and Fixtures | 2.77 |
| 5 | 356 | Overhead Conductor and Devices | 1.01 |

| | | | |
|---|---|---|---|
| 6 | 357 | Underground Conduit | 1.23 |
| 7 | 358 | Underground Conductor and Devices | 3.18 |
| | **GENERAL PLANT** | | |
| 8 | 390 | Structures & Improvements | 2.00 |
| 9 | 391 | Office Furniture & Equipment | 5.00 |
| 10 | | Information Systems | 10.00 |
| 11 | | Data Handling | 10.00 |
| 12 | 392 | Transportation Equipment | |
| 13 | | Other | 5.33 |
| 14 | | Autos | 11.43 |
| 15 | | Light Trucks | 6.96 |
| 16 | | Medium Trucks | 6.96 |
| 17 | | Trailers | 4.44 |
| 18 | | ATV | 5.33 |

| | | | |
|---|---|---|---|
| 19 | 393 | Stores Equipment | 5.00 |
| 20 | 394 | Tools, Shop & Garage Equipment | 5.00 |
| 21 | 395 | Laboratory Equipment | 5.00 |
| 22 | 396 | Power Operated Equipment | 4.17 |
| 23 | 397 | Communication Equipment | 6.67 |
| 24 | 398 | Miscellaneous Equipment | 6.67 |
| | **INTANGIBLE PLANT** | | |
| 25 | 303 | Miscellaneous Intangible Plant | 20.00 |

These depreciation rates will not change absent the appropriate filing at FERC.

# PRAIRIE WIND TRANSMISSION, LLC
# FORMULA RATE IMPLEMENTATION PROTOCOLS

## Section 1. Annual Projection

a. The formula rate template ("Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Prairie Wind Transmission, LLC ("Prairie Wind") for transmission service and revenue requirements determination under the Southwest Power Pool ("SPP") OATT. Prairie Wind shall follow the instructions specified in the Formula Rate to calculate annually its Net Revenue Requirement. The Net Revenue Requirement shall be determined from January 1 to December 31 of a given calendar year (the "Rate Year").

b. No later than September 1 of the current Rate Year, Prairie Wind shall determine its projected Net Revenue Requirement (page 1, line 4 of the Template) for the upcoming Rate Year in accordance with Prairie Wind's Formula Rate, incorporating a True-up Adjustment (as determined in Section 2) for the preceding Rate Year ("Annual Projection"), and shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format and fully-functioning Excel file at a publicly accessible location on SPP's internet website.[1] Such posting shall include (i) all inputs in sufficient detail to identify the components of Prairie Wind's projected Net Revenue Requirement, and (ii) explanations of the bases for the projections and input data. If the date for making such posting should fall on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be made no later than the next business day. Prairie Wind shall electronically serve each Annual Projection upon the Service List.[2]

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1. Since the True-up Adjustment is based on the difference between the actual Net Revenue Requirement less the projected Net Revenue Requirement for the prior Rate Year, the initial True-up Adjustment will be determined in the second Rate Year of this rate schedule with respect to the prior Rate Year, and will be added to the projected Net Revenue Requirement for the third Rate Year of this rate schedule.

2. As used in these protocols, "Service List" shall mean (i) the email list of SPP OATT Transmission Customers maintained by the SPP; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility; and (iv) any signatory to the Settlement Agreement in Docket Nos. ER09-36-000.

c. The Formula Rate shall initially be effective for service and recovery of Prairie Wind's Net Revenue Requirement on and after the effective date specified by the Commission. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

d. Together with the posting of the Annual Projection, Prairie Wind shall cause to be posted on the SPP website the time, date and location for a public meeting with (i) any Eligible Customer under the SPP OATT; (ii) any regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility, or (iv) any party with standing under Federal Power Act ("FPA") Section 205 or 206 (collectively, "Interested Persons") in order for Prairie Wind to explain its Annual Projection and to provide an opportunity to seek information and clarifications regarding the Annual Projection ("Stakeholder Projections Meeting"). The Stakeholder Projections Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after September 1.

e. To the extent Prairie Wind agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted, in a similar manner as the initial Annual Projection for that Rate Year. Changes posted prior to November 15 of the preceding Rate Year, or the next business day if November 15 is not a business day, shall be reflected in the charges for the Rate Year; changes posted after that date will be reflected in the True-up Adjustment for the Rate Year. On such date, Prairie Wind shall provide its zonal ATRR to the SPP for the purpose of SPP preparing any necessary tariff filing by no later than December 1.[3] During the construction phase of the facilities for which FERC approved incentives for Prairie Wind in Docket No. ER09-36-000 ("Project"), when the hypothetical capital structure is used, each Annual Projection and True-Up Adjustment shall use actual data in the FERC Form 1, company records (as applicable) and the most recent data on engineering and procurement construction budgets approved by company management. Prairie Wind shall supply with the Annual Projection a copy of any such budgets that have been provided to lenders during the prior twelve month period.

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3. In the event that the SPP is no longer required to make a tariff filing to reflect Prairie Wind's Zonal ATRR in the SPP OATT, and to the extent consistent with applicable Commission precedent, the November 15 deadline may be delayed or extended, as appropriate, until such later deadline established by the SPP that will facilitate timely billing of the new Zonal ATRR in the subsequent Rate Year.

**Section 2. True-up Adjustment**

The True-up Adjustment shall be the sum of components a and b, determined in the following manner:

a. Prairie Wind's projected Net Revenue Requirement for the previous Rate Year[4] will be compared to Prairie Wind's actual Net Revenue Requirement (page 1, line 4, of the Template) for the previous Rate Year calculated in accordance with Prairie Wind's Formula Rate and based upon (i) Prairie Wind's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to Prairie Wind's calculation of its annual revenue requirement, (iii) the books and records of Prairie Wind (which shall be maintained consistent with the FERC Uniform System of Accounts ("USoA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the SPP OATT that apply to the calculation of annual revenue requirements under individual transmission owner formula rates, to determine any over- or under-recovery ("True-up Adjustment Over/Under Recovery"). Prairie Wind shall cause the True-Up Adjustment Over/Under Recovery and related supporting calculations and explanations to be posted to a publicly accessible location on SPP's internet website and electronically served on the Service List no later than June 1 following the issuance of the FERC Form No. 1 for the previous Rate Year. Prairie Wind also shall cause to be posted simultaneously at such location an explanation of the True-Up Adjustment Over/Under Recovery and information regarding frequently asked questions. Prairie Wind shall also contemporaneously serve such True-Up Adjustment Over/Under Recovery and explanatory information upon the Service List. Further, Prairie Wind shall make a good faith effort to respond to reasonable information requests regarding the True-Up Adjustment Over/Under Recovery as set forth in Section 4 of these Protocols within fifteen (15) business days of receipt of such requests, including posting and serving such responses in a similar manner as the posting and serving of the True-Up Adjustment Over/Under Recovery.

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4. Since the initial year of this rate schedule is a partial year, the initial projected Net Revenue Requirement will be divided by the number of months the rate is in effect to calculate the monthly projected cost of service to be collected each month of the first year. Similarly, the actual Net Revenue Requirement will be divided by the number of months the rate is in effect to calculate the actual cost of service to be collected each month of the first year. The first True-up Adjustment will compare the projected Net Revenue Requirement and the actual Net Revenue Requirement for that initial Rate Year.

b. Interest on any True-Up Adjustment Over/Under Recovery of the actual Net Revenue Requirement shall be based on the Commission's interest rate on refunds (18 C.F.R § 35.19a) and calculated in October following the calculation of the actual Net Revenue Requirement.

The interest payable shall be calculated as follows:

(i) The interest rate to be applied to the True-Up Adjustment Over/Under Recovery of the Net Revenue Requirement will be determined using the average refund rate for the twenty (20) months preceding September of the current Rate Year.

(ii) The Annual Projection to be charged for transmission services for the following Rate Year shall be the sum of the Projected Net Revenue Requirement for such Rate Year and the True-up Adjustment (included on page 1, line 3, of the Template) for the previous Rate Year.

**Example for 2012 Net Revenue Requirement**

In September 2011, Prairie Wind will determine the projected Net Revenue Requirement to be charged for 2012. In May 2013, Prairie Wind's projected Net Revenue Requirement for 2012 will be compared to the actual Net Revenue Requirement for 2012 calculated in accordance with the Template using Prairie Wind's 2012 FERC Form No. 1 and its books and records. The interest rate to be applied to any True-Up Adjustment Over/Under Recovery will be the applicable average monthly FERC refund rate specified in Section 2.b. in effect from January 1, 2012 through August 31, 2013. Prairie Wind will post all information relating to the True-up Adjustment Over/Under Recovery for the 2012 actual Net Revenue Requirement no later than June 1, 2013. The True-up Adjustment will be included on page 1, line 3 of the Template in the 2014 projected Net Revenue Requirement to be charged and that will be made available by September 1, 2013. The new revenue requirement will take effect on January 1, 2014.

**Section 3. <u>Annual Updates</u>**

a. On or before June 1 following each Rate Year, Prairie Wind shall calculate its actual Net Revenue Requirement and the True-Up Adjustment Over/Under Recovery as calculated under Section 2.a. ("Annual Update") for such Rate Year, and shall cause such Annual Update to be posted, in both a Portable Document Format and fully-functioning Excel format, at a publicly accessible location on SPP's internet website, and electronically serve it on the Service List. In addition, Prairie Wind shall contemporaneously submit such Annual Update as an informational filing with the FERC. Prairie Wind.

b. If the date for making the Annual Update posting/filing should fall on a weekend or a holiday recognized by the FERC, then the posting/filing shall be due on the next business day.

c. The date on which the last of the events listed in Section 3.a or 3.b occurs shall be that year's "Publication Date."

d. Upon written request from any Interested Person, Prairie Wind will promptly make available to such entity a "workable" Excel file containing the populated Template for that year's Annual Update.

e. Together with the posting of the Annual Update, Prairie Wind shall cause to be posted on the SPP website the time, date and location for a meeting with Interested Persons in order for Prairie Wind to explain its Annual Update and to provide Interested Persons an opportunity to seek information and clarifications regarding the Annual Update ("Stakeholder Meeting"). The Stakeholder Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after June 1.

f. The Annual Update for the Rate Year:

(i) Shall be calculated in accordance with Prairie Wind's Formula Rate and based upon Prairie Wind's FERC Form No. 1 data for the most recent calendar year, any FERC orders specifically applicable to Prairie Wind's calculation of its annual revenue requirement, the books and records of Prairie Wind (which shall be maintained in accordance with the USoA), any FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and any aspects of the SPP OATT Governing Documents[5] that apply to the calculation of annual revenue requirements under individual transmission owner formula rates.

(ii) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[6]

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5. SPP OATT Governing Documents include the SPP OATT, Bylaws, Articles, Criteria, and Membership/Seams Agreements.

6. It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

(iii) Shall provide notice of changes in Prairie Wind's accounting policies and practices from those in effect for the calendar year upon which the immediately preceding Annual Update was based that affect the Formula Rate or calculation of the Annual Update ("Accounting Change(s)");

(iv) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Person seeking to modify the Formula Rate. *(i.e.,* all modifications to the Formula Rate will require, as applicable, an FPA Section 205 or Section 206 filing or initiation of a Section 206 investigation).

g. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA Section 205 or 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) "Post-Employment Benefits other than Pensions" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges; (iii) extraordinary property losses; (iv) abandoned plant costs; (v) the depreciation and/or amortization rates as set forth in the notes to the Formula Rate template; (vi) capital leases; and (vii) payments in lieu of taxes.

## Section 4. Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Persons shall have up to the latest of one hundred fifty (150) calendar days after the Publication Date, thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of Prairie Wind), or thirty (30) calendar days after resolution of a dispute that does not result in the production of additional information, to review the calculations ("Review Period") and to notify Prairie Wind in writing of any specific challenges, including challenges related to Accounting Changes, to the application of the Formula Rate ("Preliminary Challenge"). Prairie Wind shall promptly cause to be posted all Preliminary Challenges at a publicly accessible location on SPP's internet website.

Prairie Wind shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which Prairie Wind agrees or disagrees with the challenge. If Prairie Wind disagrees with the Preliminary Challenge, its response shall include supporting documentation. Prairie Wind shall promptly cause to be posted responses to all Preliminary Challenges at a publicly accessible location on SPP's internet website.

b. Interested Persons shall have up to one hundred twenty (120) calendar days after each annual Publication Date (unless such period is extended with the written consent of Prairie Wind) to serve reasonable information requests on Prairie Wind. Information requests shall be limited to what is necessary to determine if Prairie Wind has properly calculated the Annual Update under review (including any corrections pursuant to Section 6), whether the costs included in the Annual Update are properly recordable and recorded, prudently incurred, and otherwise consistent with Prairie Wind's accounting policies, practices and procedures consistent with the USoA, whether the input data used in the Annual Update are accurate and correctly used in the Formula Rate, and whether the Formula Rate has been applied according to its terms, including the procedures in these Protocols. In addition, such information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of other Prairie Wind Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, or (ii) are in connection with corrections pursuant to Section 6.

c. Prairie Wind shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receipt of such requests.

To the extent Prairie Wind and any Interested Person(s) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures, Prairie Wind or any Interested Person may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

d. Preliminary or Formal Challenges related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update shall not act as a bar with respect to that Annual Update nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update to the extent such Accounting Change affects the subsequent Annual Update.

e. If a change made by Prairie Wind to its accounting policies, practices or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, and/or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion to restore the operation of the Formula Rate as of the effective date, or as such Formula Rate may be subsequently modified by the FERC or through settlement, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

**Section 5. Resolution of Challenges**

a. If Prairie Wind and any Interested Person(s) have not resolved any Preliminary Challenge to the Annual Update within sixty (60) calendar days after the end of the Review Period (unless such period is extended with the written consent of Prairie Wind to continue efforts to resolve the Preliminary Challenge), such Interested Person may, within thirty (30) calendar days thereafter, file a challenge with the FERC, pursuant to 18 C.F.R. § 385.206 ("Formal Challenge"), which shall be served on Prairie Wind by electronic service on the date of such filing. However, there shall be no need to make a Formal Challenge or to await conclusion of the time periods in Section 4 if the FERC already has initiated a proceeding to consider the Annual Update. Subject to any applicable confidentiality and CEII restrictions, all information and correspondence produced by Prairie Wind pursuant to these Protocols may be included in any Formal Challenge or in any FERC or appellate proceeding relating to the Formula Rate.

b. Any response by Prairie Wind to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal

Challenge, and shall be served on the filing party(ies) and the Service List by electronic service on the date of such filing.

c. In any proceeding concerning a given year's Annual Update (including corrections) or Accounting Change(s), Prairie Wind shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has reasonably and accurately calculated the Annual Update and/or reasonably adopted and applied the Accounting Change.

d. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Prairie Wind to file unilaterally, pursuant to Section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of its inputs requiring a Section 205 filing under these Protocols (including, but not limited to, ROE, extraordinary property losses and abandoned plant costs, depreciation and amortization rates, PBOPs, and Transmission Incentive Mechanisms), or the right of any other party or the Commission to seek such changes pursuant to Section 206 of the FPA and the regulations thereunder.

e. These Protocols in no way limit the rights of Prairie Wind or any Interested Person to initiate a proceeding at the FERC at any time with respect to the Formula Rate or any Annual Update consistent with the party's full rights under the Federal Power Act, including without limitation Sections 205, 206 and 306, and the FERC's regulations.

**Section 6. Changes to Annual Informational Filings**

a. If Prairie Wind determines or concedes that corrections to the Annual Update are required, whether under Sections 2 or 3 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, Prairie Wind shall promptly notify the Service List, file a correction to the Annual Update with the FERC as an amended informational filing, and shall cause such information to be posted at a publicly accessible location on SPP's internet website. Such corrections with interest shall be reflected in the next Annual Projection. Interest on any over- or under-recovery due to corrections for preceding True-Up Adjustment Rate Years shall be calculated monthly on such over- or under-recovery from July 1 of the corrected Rate Year through June 30 of the Rate Year in which such over- or under-recovery is reflected ("Correction Period"). The applicable monthly interest rates for the Correction Period for an over-recovery shall be the annual interest rates for each month pursuant to 18 C.F.R. § 35.19a divided by twelve (12) for each month from the beginning of the Correction Period through August 31 of the Rate Year immediately preceding the Rate Year in which such over-recovery is reflected and the last such monthly rate so determined for each month of the remainder of the Correction Period. The applicable monthly interest rates for the Correction Period for an under-recovery shall be the lower of, on a monthly basis, (i) Prairie Wind's short-term debt

monthly interest rate for each month (provided Prairie Wind has short-term debt outstanding during such month) or (ii) the monthly interest rate determined in accordance 18 C.F.R § 35.19a for each month from the beginning of the Correction Period through August 31 of the Rate Year immediately preceding the Rate Year in which such over-recovery is reflected and the last such monthly rate so determined for each month of the remainder of the Correction Period.

b. A corrected posting shall reset the performance dates under Sections 2 and 3 of the Protocols for Interested Person review, and the revised dates shall run from the posting date(s) for each of the corrections. The scope of review shall be limited to the aspects of the Formula Rate affected by the corrections.

**Section 7. <u>Construction Work in Progress</u>**

a. *Accounting.* For each transmission project for which Prairie Wind has been authorized by a Commission order to include 100 percent of Construction Work in Progress ("CWIP") in transmission rate base, Prairie Wind shall use the following accounting procedures to ensure that it does not recover an Allowance for Funds Used During Construction ("AFUDC") for such project.

(i) Prairie Wind shall assign each authorized incentive transmission project a unique Funding Project Number ("FPN") for internal cost tracking purposes.

(ii) Prairie Wind shall record actual construction costs to each FPN through work orders that are coded to correspond to the FPN for each incentive transmission project. Such work orders shall be segregated from work orders for non-incentive transmission projects for which the Commission has not authorized Prairie Wind to include any portion of CWIP in rate base.

(iii) For each incentive transmission project, Prairie Wind shall prepare monthly work order summaries of costs incurred under the associated FPN. These summaries shall show monthly additions to CWIP and plant in service and shall correspond to amounts recorded in Prairie Wind's FERC Form No. 1. Prairie Wind shall use these summaries as data inputs into the Annual Update calculated pursuant to Section 3. Prairie Wind shall make such work order summaries available upon request under the review procedures of Section 4.

(iv) When an incentive transmission project, or portion thereof, is placed into service, Prairie Wind shall deduct from total CWIP the accumulated charges for work orders under the FPN for that project, or portion thereof. The purpose of this control process is to ensure that expenditures are not double counted as both CWIP and as additions to plant.

(v) For non-incentive transmission projects, Prairie Wind shall record AFUDC to be applied to CWIP and capitalized when the project is placed into service.

b. *Annual Reporting.* For each incentive project for which the Commission has authorized Prairie Wind to include any portion of CWIP in transmission rate base, Prairie Wind shall file a report with the Commission at the time of Prairie Wind's Annual Update that shall include the following information concerning each such project:

(i) the actual amount of CWIP recorded for each project;

(ii) any amounts recorded in related FERC accounts or subaccounts, such as AFUDC and regulatory liability;

(iii) the resulting effect of CWIP on the revenue requirement;

(iv) a statement of the current status of each project; and

(v) the estimated in-service date for each project.

# ADDENDUM 16 TO ATTACHMENT H

## Kansas Power Pool

| | | |
|---|---|---|
| 0<br>**Type Year in Cell B1** | **KPP-Winfield Formula Rate Template Inputs** | **Attachment H Inputs**<br>Page 1 of 3 |

*Note: This tab was included in the GL High Plains Formula Rate Template for illustrative purposes to demonstrate the functionality of the GL High Plains Formula Rate Template with inputs related to the Winfield co-ownership. The GL High Plains template includes assets in addition to those jointly owned with Winfield, and will not include this tab in as-approved form; however, this tab does provide much of the data needed in the Winfield formula and is included as a permanent part of the KPP-Winfield Formula Rate.*

*(Values presented in whole USD)*

| **Key Inputs:** | **Color Key:** |
|---|---|

| | | | | |
|---|---|---|---|---|
| Book Depreciation Rate to Close | 2.4% | Estimated Winfield depreciation rate to determine Net Plant at close | Light Green | GLHP & KPP will coordinate input data that may change in annual updates |
| Book Depreciation Rate Post Close | 2.0% | Estimated GridLiance depreciation rate post close | Aquamarine | Cells that will remain blank or zero except pursuant to a FERC Filing |
| GridLiance Share of Winfield Assets | 65.0% | Share of Winfield assets post close | No Fill | Cells with content that is not to be changed absent a Filing pursuant to the FPA with the FERC. |
| Winfield Share of Winfield Assets | 35.0% | Share of Winfield assets post close | Light Yellow | Cells that each respective Party will populate in annual updates |

## Cost and Plant Value Projection Inputs For 100% of Winfield Assets:

| Capital | Expense |
|---|---|

| Month | Gross Plant in Service | Accumulated Depreciation | Materials & Supplies | Prepayments | Accumulated Deferred Income Taxes | O & M | GLHP G&A | | | GLHP | Wnfld/GLHP |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Total O & M | G & A | Franchise Fees | Total G & A | Property Tax | Depreciation |
| December Prior Year | - | - | - | - | - | | | | | | - |
| January | - | - | - | - | | - | - | - | - | - | - |
| February | - | - | - | - | | - | - | - | - | - | - |
| March | - | - | - | - | | - | - | - | - | - | - |
| April | - | - | - | - | | - | - | - | - | - | - |
| May | - | - | - | - | | - | - | - | - | - | - |
| June | - | - | - | - | | - | - | - | - | - | - |
| July | - | - | - | - | | - | - | - | - | - | - |
| August | - | - | - | - | | - | - | - | - | - | - |
| September | - | - | - | - | | - | - | - | - | - | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| October | - | - | - | - | | - | - | - | - | - | - | |
| November | - | - | - | - | | - | - | - | - | - | - | |
| December | - | - | - | - | - | - | - | - | - | - | - | |
| **13 Month Sum** | - | - | - | - | - | - | - | - | - | - | - | |
| **13 Month Avg** | - | - | - | - | - | **12-Mo. Total** | | | | | | |

**KPP-Winfield Formula Rate Template Inputs**

**Attachment H Inputs**

**Totals of Capital and Expense months must be 13 and 12, respectively except in initial year of the FR**

| Capital | Expense |
|---|---|
| - | - |

## Cost and Plant Value Projection Inputs For 65% of Winfield Assets (GridLiance Share):

| | Capital | | | | | Expense | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Month | Gross Plant in Service | Accumulated Depreciation | Materials & Supplies | Prepayments | Accumulated Deferred Income Taxes | GLHP O&M | GLHP G&A | | | GLHP Property Tax | GLHP Depreciation | Inputs from GLHP Formula Rate | |
| | | | | | | | G&A | Franchise Fees | Total G&A | | | | |
| December | - | - | - | - | - | | | | | | | Long Term | - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Prior Year | | | | | | | | | | | | | | Interest ($) | |
| - | - | January | - | - | - | - | | - | - | - | - | - | - | | | Long Term Debt | - |
| - | - | February | - | - | - | - | | - | - | - | - | - | - | | | Common Stock | - |
| - | - | March | - | - | - | - | | - | - | - | - | - | - | | | Cost of Long Term Debt | 0.0 0% |
| - | - | April | - | - | - | - | | - | - | - | - | - | - | | | Cost of Equity | 10. 30% |
| - | - | May | - | - | - | - | | - | - | - | - | - | - | | | Income Tax Allowance % | 0.0 0% |
| - | - | June | - | - | - | - | | - | - | - | - | - | - | | | Federal Income Tax Rate | 0.0 0% |
| - | - | July | - | - | - | - | | - | - | - | - | - | - | | | State Income Tax Rate | 0.0 0% |
| - | - | August | - | - | - | - | | - | - | - | - | - | - | | | Fed Tax deduct from State | 0.0 0% |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | tax | |
| - | - | September | - | - | - | - | | - | - | - | - | - | - | Zone | Zone 14 |
| - | - | October | - | - | - | - | | - | - | - | - | - | - | Project Name | Kansas Assets |
| - | - | November | - | - | - | - | | - | - | - | - | - | - | | |
| - | - | December | - | - | - | - | - | - | - | - | - | - | - | | |
| - | - | **Total 0 Months** | - | - | - | - | - | - | - | - | - | - | - | | |
| | | **Average 0 Months** | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | | | | | | | | |

**KPP-Winfield Formula Rate Template Inputs**

**Attachment H Inputs**

**Totals of Capital and Expense months must be 13 and 12, respectively except in initial year of the FR**

| Capital | Expense |
|---|---|
| - | - |

## Cost and Plant Value Projection Inputs For 35% of Winfield Assets (Winfield Share):

| | Capital | | | | | Expense | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Month | Gross Plant in Service | Accumulated Depreciation | Materials & Supplies | Prepayments | Accumulated Deferred Income Taxes | WnFld O&M | WnFld G&A From GLHP | WnFld G&A WnFld G&A | WnFld G&A Total G&A | WnFld Property Tax | WnFld Depreciation | See Notes for Item Descriptions |
| December | - | - | - | - | - | | | | | | | Long Term - A |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Prior Year | | | | | | | | | | | | | Interest ($) | | | | |
| - | - | January | - | - | - | - | - | - | - | - | - | - | - | | Long Term Debt | - | A | | |
| - | - | February | - | - | - | - | - | - | - | - | - | - | - | | Common Stock | - | B | | |
| - | - | March | - | - | - | - | - | - | - | - | - | - | - | | Cost of Long Term Debt | #DIV/0! | A | | |
| - | - | April | - | - | - | - | - | - | - | - | - | - | - | | Cost of Equity | 10.30% | C | | |
| - | - | May | - | - | - | - | - | - | - | - | - | - | - | | PILOT Allowance % | 6.90% | D | | |
| - | - | June | - | - | - | - | - | - | - | - | - | - | - | | Federal Income Tax Rate | 0.00% | E | | |
| - | - | July | - | - | - | - | - | - | - | - | - | - | - | | State Income Tax Rate | 0.00% | E | | |
| - | - | August | - | - | - | - | - | - | - | - | - | - | - | | Fed Tax deductible from State | 0.00% | E | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | |
| - | - | September | - | - | - | - | - | - | - | - | - | - | - | - | | | |
| - | - | October | - | - | - | - | - | - | - | - | - | - | - | - | | | |
| - | - | November | - | - | - | - | - | - | - | - | - | - | - | - | | | |
| - | - | December | - | - | - | - | - | - | - | - | - | - | - | - | | | |
| - | - | **Total 0 Months** | - | - | - | **#DIV/0!** | **#DIV/0!** | - | - | - | - | - | - | - | | | |
| | | **Average 0 Months** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | | | | | | | | | | | | |

tax
SPP Zone | Zone 14 | **F**

## Notes:

**A** Value is sourced from "3 - LTD Interest Cost"

**B** Value is assumed equal to LTD outstanding as the Capital Structure is a Hypothetical 50/50 debt/equity construct.

**C** Value is equal to GLHP approved total return on equity

PILOT = Payment in Lieu of Taxes. Winfield is not subject to property or other local taxes, but makes contributions to the Municipal budget, in lieu of taxes, based on a

**D** percentage of gross revenues that is set by City Council,

Winfield is
exempt from
State and
Federal Income

**E** Taxes.

Winfield assets
Revenue Requirement
are included in SPP

**F** Zone 14

**Checke r**

| Excluded Portion | Gross Plant in Service | Accumulated Depreciati | Materials & Supplies | Prepayments | Accumulated Deferred Income | O & M | G&A | | | Property Tax | Depreciation |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | G & A | Franchise Fees | Total G & A | | |

| | | | on | | | | | Taxes | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| December Prior Year | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| January | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| February | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| March | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| April | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| May | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| June | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| July | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| August | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| September | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| October | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| November | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| December | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| **Excluded Sum** | - | | - | | - | | - | - | | - | | - | - | - | | - | - |
| **Total** | | | | | | | #D | #DI | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **GLHP&KPP - Included - Excluded = 0** | - | | - | | - | | IV/0! | | V/0! | | - | | - | - | - | | - | | - | |

Attachment H

**For the 0 months ended 12/31/0**

Formula Rate - Non-Levelized

Kansas Power Pool - Winfield

**Rate Formula Template Utilizing FERC Form 1 Data**

**Kansas Power Pool - Winfield**

| Line No. | (1) | (2) | (3) | | (4) | (5) |
|---|---|---|---|---|---|---|
| | | | | | | Allocated Amount |
| 1 | GROSS REVENUE REQUIREMENT | (page 3, line 47) | | | | #DIV/0! |
| | REVENUE CREDITS | (Note O) | Total | Allocator | | |
| 2 | Account No. 454 | (page 4, line 29) | - | TP | #DIV/0! | #DIV/0! |
| 3 | Account No. 456.1 - P-t-P and Project Revs. | (page 4, line 33) | 816.00 | TP | #DIV/0! | #DIV/0! |
| 4 | Account No. 457.1 Scheduling | Attachment 5, line 36, col e | - | TP | #DIV/0! | #DIV/0! |
| 5 | Revenues from Grandfathered Interzonal Transactions | (Note N) | - | TP | #DIV/0! | #DIV/0! |
| 6 | Revenues from service provided by the ISO at a discount | | - | TP | #DIV/0! | #DIV/0! |
| 7 | TOTAL REVENUE CREDITS | (Sum of Lines 2 through 6) | 816.00 | | | #DIV/0! |
| 8 | NET REVENUE | (line 1 minus line 7) | | | | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | REQUIREMENT | | | | | |
| 9 | True-up Adjustment with Interest | Attachment 3, Col. J | - | DA | 1.00000 | $ - |
| 10 | NET REVENUE REQUIREMENT | (line 8 plus line 9) | | | | **#DIV/0!** |
| 11 | **NET ANNUALIZED REVENUE REQUIREMENT** | **Note A** | | | | **#DIV/0!** |



**For the 0 months ended 12/31/0**

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data Kansas Power Pool - Winfield

| (1) | (2) | (3) | | (4) | (5) |
|---|---|---|---|---|---|
| Line No. | | **Source** | **Company Total** | **Allocator** | | **Transmission** (Col 3 times Col 4) |
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Notes U and R) | | | | | |
| 1 | Production | Attachment 1, Line 14 Col. (b) | #DIV/0! | NA | | - |
| 2 | Transmission | Attachment 1, Line 14 Col. | #DIV/0! | TP | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | (c) | | | | |
| 3 | Distribution | Attachment 1, Line 14 Col. (d) | #DIV/0! | NA | - | - |
| 4 | General & Intangible | Attachment 1, Line 14 Col. (e) | #DIV/0! | NA | #DIV/0! | #DIV/0! |
| 5 | Common | | - | NA | #DIV/0! | #DIV/0! |
| 6 | TOTAL GROSS PLANT | (Sum of Lines 1 through 5) | #DIV/0! | | #DIV/0! | #DIV/0! |
| 7 | ACCUMULATED DEPRECIATION (Notes U and R) | | | | | |
| 8 | Production | Attachment 1, Line 14 Col. (f) | #DIV/0! | NA | | - |
| 9 | Transmission | Attachment 1, Line 14 Col. (g) | #DIV/0! | TP | #DIV/0! | #DIV/0! |
| 10 | Distribution | Attachment 1, Line 14 Col. (h) | #DIV/0! | NA | - | #DIV/0! |
| 11 | General & Intangible | Attachment 1, Line 14 Col. (i) | #DIV/0! | NA | #DIV/0! | #DIV/0! |
| 12 | Common | | - | NA | #DIV/0! | #DIV/0! |
| 13 | TOTAL ACCUM. DEPRECIATION | (Sum of Lines 8 through 12) | #DIV/0! | | | #DIV/0! |
| 14 | NET PLANT IN SERVICE | | | | | |
| 15 | Production | (line 1 - line 8) | #DIV/0! | | | - |
| 16 | Transmission | (Line 2 minus Line 9) | #DIV/0! | | | #DIV/0! |
| 17 | Distribution | (line 3 - line 10) | #DIV/0! | | | #DIV/0! |
| 18 | General & Intangible | (Line 4 minus Line 11) | #DIV/0! | | | #DIV/0! |
| 19 | Common | (line 5 - line 12) | - | | | #DIV/0! |
| 20 | TOTAL NET PLANT | (Sum of Lines 15 through 19) | #DIV/0! | | #DIV/0! | #DIV/0! |
| 21 | ADJUSTMENTS TO RATE BASE (Note R) | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 22 | Account No. 281 (enter negative) | Attachment 1, Line 28 , Col. (g) (Notes B and X) | #DIV/0! | NA | zero | - |
| 23 | Account No. 282 (enter negative) | Attachment 1, Line 28 , Col. (h) (Notes B and X) | #DIV/0! | NA | zero | - |
| 24 | Account No. 283 (enter negative) | Attachment 1, Line 28 , Col. (i) (Notes B and X) | #DIV/0! | NA | zero | - |
| 25 | Account No. 190 | Attachment 1, Line 28 , Col. (j) (Notes B and X) | #DIV/0! | NA | zero | - |
| 26 | Account No. 255 (enter negative) | Attachment 1, Line 28 , Col. (k) (Notes B and X) | #DIV/0! | NA | zero | - |
| 27 | Unfunded Reserves (enter negative) | Attachment 1, Line 28 , Col. (b) (Note G) | #DIV/0! | DA | 1.00000 | #DIV/0! |
| 28 | CWIP | Attachment 1, Line 28 , Col. (c) (Note C) | #DIV/0! | NA | 1.00000 | #DIV/0! |
| 29 | Unamortized Regulatory Asset | Attachment 1, Line 28 , Col. (d) Notes A & E | #DIV/0! | NA | 1.00000 | #DIV/0! |
| 30 | Unamortized Abandoned Plant | Attachment 1, Line 28 , Col. (e) Notes B & F | #DIV/0! | NA | 1.00000 | #DIV/0! |
| 31 | TOTAL ADJUSTMENTS | (Sum of Lines 22 through 29) | #DIV/0! | | | #DIV/0! |
| 32 | LAND HELD FOR FUTURE USE | Attachment 1, Line 28 , Col. (f) | #DIV/0! | DA | #DIV/0! | #DIV/0! |
| 33 | WORKING CAPITAL | (Note D) | | | | |
| 34 | Cash Allowance = 1/8 * O&M excluding KPP Reg. | 1/8*(Page 3, Ln 12 - (Ln 10 + Ln 11) ) | - | | | #DIV/0! |
| 35 | Materials & Supplies - Transmission | Attachment 1, Line 14 , Col. (j) | #DIV/0! | DA | 1.00000 | #DIV/0! |
| 36 | Prepayments (Transmission Account 144 - 165) | Attachment 1, Line 14 , Col. (k) | #DIV/0! | DA | 1.00000 | #DIV/0! |
| 37 | TOTAL WORKING CAPITAL | (Sum of Lines 33 through 35) | #DIV/0! | | | #DIV/0! |
| 38 | **RATE BASE** | **(Sum of Lines 20, 30, 31 & 36)** | **#DIV/0!** | | | **#DIV/0!** |

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data Kansas Power Pool - Winfield

**For the 0 months ended 12/31/0**

| Line No. | (1) | (2) **Source** | (3) **Company Total** | **Allocator** | (4) | (5) **Transmission** (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | O&M | | | | | |
| 1 | Transmission O&M less Gridliance Payments | Attach. 2, Line 13, Col. (a) | - | TP | #DIV/0! | #DIV/0! |
| 2 | Less Account 566 Misc Trans Expense in Line 1 | Attach. 2, Line 13, Col. (b) | - | TP | #DIV/0! | #DIV/0! |
| 3 | Less Account 565 in Line 1 | Attach. 2, Line 13, Col. (c) | - | TP | #DIV/0! | #DIV/0! |
| 4 | WnFld A&G | Attach. 2, Line 13, Col. (d) + Col. (f) | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less A&G Paid by GridLiance | Attach. 2, Line 37, Col (f) | - | DA | #DIV/0! | #DIV/0! |
| 6 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad. In Line 4 | (Note E) Attach. 2, Line 13, Col. (g) | - | W/S | #DIV/0! | #DIV/0! |
| 6a | Less PBOP Expense in Year | Attachment 4, Line 8, Col. (g) | - | W/S | #DIV/0! | #DIV/0! |
| 7 | Plus Transmission Related Reg. Comm. Exp. | (Note E) Attach. 2, Line 13, Col. (h) | - | TP | #DIV/0! | #DIV/0! |
| 7a | Plus PBOP Expense Allowed Amount | Attachment 4, Line 6, Col. (g) | - | W/S | #DIV/0! | #DIV/0! |
| 8 | Plus A&G Expenses form GLHP | Attach. 2 Line 13 (f) | - | DA | 1.00000 | - |
| 9 | Transmission Lease | Attach. 2, Line 13, Col (i) | | DA | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Payments | | - | | 1.00000 | - |
| | Account 566 Miscellaneous Transmission | | | | | |
| 10 | Expense Alloawable | Attach. 2, Line 13, Col (e) | - | DA | 1.00000 | - |
| | Amortization of | (Note T) Attach. 2, Line 13, | | | | |
| 11 | Regulatory Asset | Col. (j) | - | DA | 1.00000 | - |
| 12 | **TOTAL Net O&M and A&G** | **Net of Lines 1 through 11** | - | | | **#DIV/0!** |
| | DEPRECIATION | | | | | |
| 13 | EXPENSE (Note U) | | | | | |
| 14 | Transmission | 336.7.b, d &e Attach. 2, Line 13, Col. (l) | - | TP | #DIV/0! | #DIV/0! |
| 15 | General & Intangible | 336.10.b, d &e, 336.1.b, d &e Attach. 5, Line 26, Col. (a) | - | NA | #DIV/0! | #DIV/0! |
| 16 | Common | 336.11.b, d &e | - | NA | #DIV/0! | #DIV/0! |
| | Amortization of | (Note S) Attach. 2, Line 26, | | | | |
| 17 | Abandoned Plant | Col. (b) | - | NA | 1.0000 | - |
| 18 | TOTAL DEPRECIATION | (Sum of Lines 16 through 19) | - | | | #DIV/0! |
| | TAXES OTHER THAN | | | | | |
| 19 | INCOME TAXES | (Note F) | | | | |
| 20 | LABOR RELATED | | | | | |
| 21 | Payroll | 263.i Attach. 2, Line 26, Col. (c) | - | NA | #DIV/0! | #DIV/0! |
| 22 | Highway and vehicle | 263.i Attach. 2, Line 26, Col. (d) | - | NA | #DIV/0! | #DIV/0! |
| 23 | PLANT RELATED | | | | | |
| 24 | Property | 263.i Attach. 2, Line 26, Co.l (e) | - | NA | #DIV/0! | #DIV/0! |
| 25 | Gross Receipts | 263.i Attach. 2, Line 26, Col. (f) | - | NA | zero | - |
| 26 | Other | 263.i Attach. 2, Line 26, Col. (g) | - | NA | #DIV/0! | #DIV/0! |
| 27 | TOTAL OTHER TAXES | (Sum of Lines 23 through 29) | - | | | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 28 | INCOME TAXES | (Note G) | | | |
| 29 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | WCLTD = Page 4, Line 20 | 0% | | |
| 30 | CIT=(T/1-T) * (1-(WCLTD/R)) = | R = Page 4, Line 23 | #DIV/0! | | |
| 31 | FIT & SIT & P | (Note G) | | | |
| 32 | | | | | |
| 33 | 1 / (1 - T) = (from line 29) | | 1 | | |
| 34 | Amortized Investment Tax Credit | 266.8f (enter negative) Attach. 2, Line 26, Col. (i) | 0 | 0.00000 | $0.00 |
| 35 | Excess Deferred Income Taxes | (enter negative) Attach. 2, Line 26, Col. (j) | 0 | 0.00000 | $0.00 |
| 36 | Tax Effect of Permanent Differences | Attach. 2, Line 26, Col. (k) (Note W) | 0 | 0.00000 | $0.00 |
| 37 | Income Tax Calculation | = ((T/1-T) * (1-(WCLTD/R))) x Rate Base | | | #DIV/0! |
| 38 | ITC adjustment | (Line 35 times Line 36) | | | - |
| 39 | Excess Deferred Income Tax Adjustment | (Line 35 times Line 37) | | | - |
| 40 | Permanent Differences Tax Adjustment | (Line 35 times Line 38) | | | - |
| 41 | Total Income Taxes | (Sum of Lines 39 through 42) | | | #DIV/0! |
| 42 | Total Expenses | | | | #DIV/0! |
| | RETURN | | | | |
| 43 | Rate Base times Return (times No. Months/12) | (Page 2, Line 37 times Page 4, Line 23) * 0 / 12 Months | | | #DIV/0! |
| 44 | Payments (revenue transfer) in lieu of Taxes (PILOT) | Council Authorrized % of Revenue Requirement (Line 48) | | 6.90% | #DIV/0! |
| **45** | **REV. REQUIREMENT** | **(Sum of Lines 14, 20, 30, 44 & 46)** | | | **#DIV/0!** |

**For the 0 months ended 12/31/0**

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data Kansas Power Pool - Winfield

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|

**SUPPORTING CALCULATIONS AND NOTES**

| Line No. | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
|---|---|---|---|---|---|---|
| 1 | Total Transmission plant | (Page 2, Line 2, Column 3) | | | | #DIV/0! |
| 2 | Less Transmission plant excluded from ISO rates | (Note H) | | | | - |
| 3 | Less Transmission plant included in OATT Ancillary Services | (Note I) | | | | - |
| 4 | Transmission plant included in ISO rates | (Line 1 minus Lines 2 & 3) | | | | #DIV/0! |
| 5 | Percentage of Transmission plant included in ISO Rates | (Line 4 divided by Line 1) | | | TP = | #DIV/0! |
| 6 | WAGES & SALARY ALLOCATOR (W&S) | | | | | |
| | | Form 1 Reference | $ | TP | Allocation | |
| 7 | Production | sum of account 402201 subaccounts 511100 + | 530,010 | - | - | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Transmission | 511200 + 511300<br>sum of account 4019201 subaccounts 511100 + 511200 + 511300 | 145,807 | #DIV/0! | | #DIV/0! | | | | | |
| 9 | Distribution | sum of account 402206 subaccounts 511100 +511200 + 511300 | 884,161 | - | | - | | W&S Allocator ($ / Allocation) | | | |
| 10 | Other | sum of account 508801 subaccounts 511100 + 5112 0+ 511300 | - | - | | - | | | | | |
| 11 | Total (W& S Allocator is 1 if lines 7-10 are zero) | (Sum of Lines 7 through 10) | 1,559,978 | | | #DIV/0! | = | #DIV/0! | = | WS | |
| 12 | COMMON PLANT ALLOCATOR (CE) (Note J and X) | | $ | | | % Electric | | W&S Allocator | | | |
| 13 | Electric | 200.3.c | #DIV/0! | | | (line 13 / line 16) | | (line 11) | | CE | |
| 14 | Gas | 201.3.d | - | | | #DIV/0! | * | #DIV/0! | = | #DIV/0! | |
| 15 | Water | 201.3.e | - | | | | | | | | |
| 16 | Total | (Sum of Lines 13 through 15) | #DIV/0! | | | | | | | | |
| 17 | RETURN (R) | (Note V) | | Actual Capital | Capital As | | | $ | | | |
| 18 | | | | | Applied | Cost (Notes K, | | | | | |
| 19 | | | $ | % | % | Q, & R) | | Weighted | | | |
| 20 | Long Term Debt = total G. O Bonds per CAFR | Attachment 3 current year (Notes Q & R) | - | 0% | 40% | #DIV/0! | | #DIV/0! | =WCLTD | | |
| 21 | Preferred Stock (112.3.c) | (Notes Q & R) | - | 0% | 0% | - | | 0.00% | | | |
| 22 | Proprietary Capital = Total Net Position per CAFR | (Notes K, Q & R) | 80,000,000 | 100 % | 60% | 10.30% | | 6.18% | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 23 | Total | (Sum of Lines 20 through 22) | 80,000,000 | 100 % | 100% | #DIV/0! | = R |
| 24 | REVENUE CREDITS | | | | | | |
| 25 | ACCOUNT 447 (SALES FOR RESALE) (Note L) | 310 -311 | | | | | |
| 26 | a. Bundled Non-RQ Sales for Resale | 311.x.h | | | | - | |
| 27 | b. Bundled Sales for Resale | Attach 2, line 36, col (a) | | | | - | |
| 28 | Total of (a)-(b) | | | | | - | |
| 29 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | (Note M) Attach 2, line 36, col (b) | | | | - | |
| 30 | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | 330.x.n | | | | | |
| 31 | a. Transmission Credits for P-t-P transmission transactions | Attach 2, line 36, col (c) | | | | 816 | |
| 32 | b. Transmission Credits associated with Project Rev. Reqs. detailed on 2- Project Rev Req Schedule, Col. 10. | Attach 2, line 36, col (d) | | | | - | |
| 33 | Total of (a)+(b) | | | | | 816 | |

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | Income Taxes | % Ownership that has Actual or Potential Income Tax Liability | [1-Col. (c)] | Total Income Taxes |
| 34 | Ownership | 0.00% | 100.00% | |
| 35 | Return from Page 3, Line 46 times % in Line 34 | #DIV/0! | #DIV/0! | |
| 36 | Income Tax = {CIT=(T/1-T) * (1-(WCLTD/R))] x Line 35 | | | |

-

-



**For the 0 months ended 12/31/0**

Formula Rate - Non-Levelized

Rate Formula Template Utilizing FERC Form 1 Data
Kansas Power Pool - Winfield

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

| Note Letter | |
|---|---|
| A | For 2020, the annualized (Line 11) revenue requirement is 3 times the Line 10 revenue requirement that is based on a 4-month average rate base and expenses for September through December 2020. Annual Updates beginning in 2021 reflect a full-year of costs (13-month average rate base and annual expenses) such that Line 10 and Line 11 are equal. |
| B | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated. |
| C | Identified in Form 1 as being only transmission related. CWIP will remain zero until the Commission approves its inclusion pursuant to an FPA filing. |
| D | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1. |
| E | Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1 found at 323.191.b. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h. |

F Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

G The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes" and TEP = "the tax exempt ownership interest". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 26). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

| Inputs Required: | | | |
|---|---|---|---|
| | FIT = | 0.00% | |
| | SIT= | 0.00% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.00% | (percent of federal income tax deductible for state purposes) |

H Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

I Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

J Enter dollar amounts

K ROE will be equal to that of GridLiance High Planes and no change in ROE may be made absent a filing pursuant to the FPA with the FERC. The fact that the ROE and cap on the equity portion of the capital structure are currently equal to the ROE and equity cap of GridLiance High Plains does not predetermine or limit the Commission’s review of any filing to change the ROE or capital structure in the future.

L Page 4, Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1.

M Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

N Company will not have any grandfathered agreements. Therefore, this line shall remain zero.

O The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. Revenue Credits do not include revenues associated with FERC annual charges, gross receipts taxes,-facilities not included in this template (e.g., direct assignment facilities and GSUs) the costs of which are not recovered under this Rate Formula Template.

P Reserved

Q The KPP-Winfield average cost of LTD will be derived in Attachement 3 based on the total interest cost for the current year and the outstanding LTD computed as the sum of the Principle to be paid during all years from the current year through the final year of the then existing LTD issuances that is scheduled to retire last .

R Calculate using 13 month average balance, except ADIT which is calculated based on the average of the beginning and the end of the year balances.

S Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must receive FERC authorization before recovering the cost of abandoned plant.

| | |
|---|---|
| T | Recovery of Regulatory Assets is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. |
| U | Excludes Asset Retirement Obligation balances |
| V | KPP shall be allowed recovery of Winfield costs related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges. |
| W | The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference |
| X | Calculate using a simple average of beginning of year and end of year balances reconciling to FERC Form No. 1 by Page, Line and Column as shown in Column 2. |

**Attachment 1**
**Rate Base Worksheet**
**Kansas Power Pool - Winfield**
**For the 0 months ended 12/31/0**

| | | Gross Plant In Service | | | | Accumulated Depreciation | | | | Working Capital | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Month | Production | Transmission | Distribution | General & Intangible | Production | Transmission | Distribution | General & Intangible | Transmission M&S | Transmission Prepayments |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| | Attachment H, Page 2, Line No: | 1 | 2 | 3 | 4 | 8 | 9 | 10 | 11 | 35 | 36 |
| | Winfield Account Nos. and Notes | N/A | 401 160550 | N/A | Note I | N/A | 401 161550 | N/A | Note I | 401 141154 | 401 141165 |
| 1 | December Prior Year | - | - | - | - | - | - | - | - | - | - |
| 2 | January | - | - | - | - | - | - | - | - | - | - |
| 3 | February | - | - | - | - | - | - | - | - | - | - |
| 4 | March | - | - | - | - | - | - | - | - | - | - |
| 5 | April | - | - | - | - | - | - | - | - | - | - |
| 6 | May | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | June | - | - | - | - | - | - | - | - | - | - |
| 8 | July | - | - | - | - | - | - | - | - | - | - |
| 9 | August | - | - | - | - | - | - | - | - | - | - |
| 10 | September | - | - | - | - | - | - | - | - | - | - |
| 11 | October | - | - | - | - | - | - | - | - | - | - |
| 12 | November | - | - | - | - | - | - | - | - | - | - |
| 13 | December | - | - | - | - | - | - | - | - | - | - |
| 14 | **Avg. of the Monthly Balances (Note H)** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | | | | | | | | | | | |

## Adjustments to Rate Base

| Line No | Month | Unfunded Reserves (enter negative) | CWIP in Rate Base | Unamortized KPP Regulatory Asset Account 182.3 | Unamortized Abandoned Plant | Land Held for Future Use Transmission | Account No. 281 Accumulated Deferred Income Taxes (Note D) | Account No. 282 Accumulated Deferred Income Taxes (Note D) | Account No. 283 Accumulated Deferred Income Taxes (Note D) | Account No. 190 Accumulated Deferred Income Taxes (Note D) | Account No. 255 Accumulated Deferred Investment Credit |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **(a)** | **(b)** | **(c)** | **(d)** | **(e)** | **(f)** | **(g)** | **(h)** | **(i)** | **(j)** | **(k)** |

| | Attachment H, Page 2, Line No: | 27 | 28 | 29 | 30 | 31 | 22 | 23 | 24 | 25 | 26 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **For the 0 months ended 12/31/0** | **(Note G)** | **(Note C)** | **Notes A & E** | **Notes B & F** | **401 154105** | **N/A** | **N/A** | **N/a** | **N/A** | **N/A** |
| 15 | December Prior Year | | - | - | - | - | - | - | - | - | - |
| 16 | January | | - | - | - | - | | | | | - |
| 17 | February | | - | - | - | - | | | | | - |
| 18 | March | | - | - | - | - | | | | | - |
| 19 | April | | - | - | - | - | | | | | - |
| 20 | May | | - | - | - | - | | | | | - |
| 21 | June | | - | - | - | - | | | | | - |
| 22 | July | | - | - | - | - | | | | | - |
| 23 | August | | - | - | - | - | | | | | - |
| 24 | September | | - | - | - | - | | | | | - |
| 25 | October | | - | - | - | - | | | | | - |
| 26 | November | | - | - | - | - | | | | | - |
| 27 | December | | - | - | - | - | - | - | - | - | - |
| 28 | **Avg. of the Monthly Balances (Note H)** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |

**Attachment 1**
**Rate Base**
**Worksheet**

## KPP Winfield

Unfunded Reserves
(Notes G & H)



| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| 29 | List of all reserves: | | Amount | Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account | Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate | Enter the percentage paid for by customers, 1 less the percent associated with an offsetting liability on the balance sheet | Allocation (Plant or Labor Allocator) | Amount Allocated, col. c x col. d x col. e x col. f x col. g |
| 30a | | Reserve 1 | - | - | | | | - |
| 30b | | Reserve 2 | - | - | | | | - |
| 30 | | Reserve 3 | | | | | | |

| | | | | |
|---|---|---|---|---|
| Reserve 4 | | | | |
| … | | | | |
| … | - | - | - | |
| Total | - | | - | |

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.

B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.

C Includes only CWIP authorized by the Commission for inclusion in rate base. The annual report filed pursuant to Section 7 of the Protocols will include for each project under construction (i) the CWIP balance eligible for inclusion in rate base; (ii) the CWIP balance ineligible for inclusion in rate base; and (iii) a demonstration that AFUDC is only applied to the CWIP balance that is not included in rate base. The annual report will reconcile the project-specific CWIP balances to the total Account 107 CWIP balance reported on p. 216.b of the FERC Form 1.

D ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances.

E Recovery of a Regulatory Asset is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates

F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.

G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account. At the time of filing Winfield does not have such unfunded reserves, but has created account 401132228 to

capture any unfunded reserve relating to transmission service that may occur in the future.

H Calculate monthly average balance for 13 months except year 1 of 7 months, except ADIT which is calculated based on the average of the beginning of the year and the end of the year balances

I Winfield has elected to forego allocation of General, Intangible, and Common Plant to transmission service. When the formula rate was implemented Winfield Electric General plant included no buildings. Winfield does allocate vehicles included in General Plant to transmission construction and O&M based on FEMA rates and reduces O&M for the portion of such charges reimbursed by GridLIance.

J Winfield not subject to income taxes - will remain zero unless income taxes become applicable

**Attachment 2**
**Attachment H, Pages 3 and 4, Worksheet**
**Kansas Power Pool - Winfield**
**For the 0 months ended 12/31/0**

| Line No. | Month | Transmission O&M Expenses, not including Misc. Trans. Exp., Trans. By Others, Reg. Comm. Or EPRI | Misc. Trans. Expense included in Col (a) | Transmission by Others Included in Col (a) | WnFld A&G Expenses | KPP Expenses to Winfield for Transmission Account 566 | A&G Charges from GLHP | EPRI & Reg. Comm. Exp. & Non-safety Ad. Included in Col.a | Transmission Related Reg. Comm. Expense | Transmission Lease Payments | Amortization of Regulatory Asset Account 407.4 | Winfield Miscellaneous Transmission Expense | Depreciation Expense - Transmission |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
| | Attachment H, Page 3, Line No.: | 1 | 2 | 3 | 4 | 4 | 5 | 6 | 7 | 9 | 11 | 12 | 16 |
| | Winfield Account Nos. and Notes | 401 535740 less 401 476200 and 401 476400, Note 1 | NA | NA | Note 1 | 401 548000 | 401 525600 | NA | 401 525500 | 401 529500 | Zero unless auth. By FERC | 401 548000 | 401 389403 |
| 1 | January | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | February | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | March | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | April | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | May | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | June | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | July | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | August | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | September | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | October | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | November | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | December | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | **$** | **$** | **$** | | **$** | | **$** | **$** | **$** | **$** | **$** | **$** |
| **13** | **Total** | - | - | - | - | **$** - | - | | - | - | - | - | - | - |

Note 1 Winfield Transmission O&M expense in Account 401 535740 does not include Misc. Trans. Expense or trans. By other. The amount in Column (a) is reduced for O&M and Stores Overhead charges reimbursed by GridLiance recorded in accounts 401 47620 and 401 476400, respectively. Electric Department A&G Expenses are the sum of account 402210 subaccounts 513500 (City Hall bldg. internal support), 531200 (Mgmt Svcs internal support, 531600 (Engineering internal support), and 531800 (Operations Center bldg. internal support).

| | Depreciation Expense - General & Intangible | Amortization of Abandoned Plant | Payroll Taxes | Highway & Vehicle Taxes | Property Taxes | Gross Receipts Taxes | Other Taxes | Amortized Investment Tax Credit (266.8f) | Excess Deferred Income Taxes | Tax Effect of Permanent Differences |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (i) | (j) | (k) |
| Attachment H, Page 3, Line | 17 | 19 | 23 | 24 | 26 | 27 | 28 | 37 | 38 | 39 |

| | Number | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Winfield Account Nos. and Notes | Note 2 | Note S, Att H | Note 2 | Note 2 | Note 2 | Note 2 | Note 2 | NA | NA | NA |
| 14 | January | - | - | - | - | - | - | - | - | - | - |
| 15 | February | - | - | - | - | - | - | - | - | - | - |
| 16 | March | - | - | - | - | - | - | - | - | - | - |
| 17 | April | - | - | - | - | - | - | - | - | - | - |
| 18 | May | - | - | - | - | - | - | - | - | - | - |
| 19 | June | - | - | - | - | - | - | - | - | - | - |
| 20 | July | - | - | - | - | - | - | - | - | - | - |
| 21 | August | - | - | - | - | - | - | - | - | - | - |
| 22 | September | - | - | - | - | - | - | - | - | - | - |
| 23 | October | - | - | - | - | - | - | - | - | - | - |
| 24 | November | - | - | - | - | - | - | - | - | - | - |
| 25 | December | - | - | - | - | - | - | - | - | - | - |
| | | $ | $ | $ | $ | | $ | $ | $ | $ | $ |
| **26** | **Total** | - | - | - | - | $ - | - | - | - | - | - |



Note 2: Winfield has elected to forego allocation of General Plant to transmission service unless and until it implements separate accounting for General Plant depreciation used for the Electric function and the formula rate is changed pursuant to a filing at the FERC. Winfield has included an allowance for its payments in lieu of taxes (PILOT) to the City Fund and will not include any taxes of the types detailed here unless such is authorized by the FERC pursuant to a filing by

or on behalf of Winfield.

| | | | | **Attachment 2 Attachment H, Pages 3 and 4, Worksheet Kansas Power Pool - Winfield For the 0 months ended 12/31/0** | | |
|---|---|---|---|---|---|---|
| **Bundled Sales for Resale included on page 4 of Attachment H** | **ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)** | **Transmission revenue that SPP allocates to Winfield from PtP transmission transactions** | **Revenue from Projects on Schedule 6 Line 18 Col (17) less incentive Return included from Col (12)** | **Account No. 457.1 Scheduling** | **Winfield A&G Expenses Reimbursed by GridLiance** | **Reserved** |
| (a) | (b) | (c) | (d) | (e) | (f) | (g) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Attachment H, Page &, Line No: | Pg 4 Line 27 | Pg4 Line 29 | 31 | 32 | Pg 1 line 4 | | |
| | Winfield Account Nos. and Notes | (Note L, Att H) NA | 401 462454( Note M) | 401 47700 0 | 401 4770 01 | Zero unless auth. by FERC | 401 476300 | Zero unless auth. by FERC |
| 24 | January | - | - | - | - | | - | |
| 25 | February | - | - | - | - | | - | |
| 26 | March | - | - | - | - | | - | |
| 27 | April | - | - | - | - | | - | |
| 28 | May | - | - | - | - | | - | |
| 29 | June | - | - | - | - | | - | |
| 30 | July | - | - | - | - | | - | |
| 31 | August | - | - | - | - | | - | |
| 32 | September | - | - | - | - | | - | |
| 33 | October | - | - | - | - | | - | |
| 34 | November | - | - | - | - | | - | |
| 35 | December | - | - | - | - | | - | |
| 36 | Total | $ - | $ - | - | $ - | $ | - | |
| 37 | | | | | | | | |
| 38 | RETURN (R) Notes K, Q & R from Attachment H | | | | | | | |

| | | | $ |
|---|---|---|---|
| 39 | | Long Term Interest (117, sum of 62.c through 67.c) | - |
| | | Outstanding LTD | - |
| 40 | | Preferred Dividends (118.29c) (positive number) | - |
| 41 | | Proprietary Capital (112.16.c) | 80,000,000 |
| 42 | | Less Preferred Stock (line 49) | - |
| 43 | | Less Account 216.1 (112.12.c) (enter negative) | - |
| 44 | | Common Stock (sum lines 41-43) | 80,000,000 |

| | | | $ | % | Cost | Weighted | |
|---|---|---|---|---|---|---|---|
| 45 | Long Term Debt | Note A | - | 40.00% | #DIV/0! | #DIV/0! | =WCLTD |
| 46 | Preferred Stock (112.3.c) | Note B | - | 0.00% | - | 0.00% | |
| 47 | Common Stock | Note C | - | 60.00% | 10.30% | 6.18% | |
| 48 | Total | (Sum of Lines | | 100.00% | | #DIV/ | =R |

| | | |
|---|---|---|
| 45-47) | - | 0! |

Not
e:

| | |
|---|---|
| A | Long Term Debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c & d to 21.c & d in the Form No. 1, the cost is calculated by dividing line 39 by the Long Term Debt balance in line 45. |
| B | Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c & d in the Form No. 1 |
| C | Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 3.c & d, 12.c & d, and 16.c & d in the Form No. 1 as shown on lines 41-44 above |

**Attachment 3**

**Attachment H, City of Winfield General Obligation LTD Interest and Principle**
**Kansas Power Pool - Winfield**



**Attachment 3**

**Attachment H, City of Winfield General Obligation LTD Interest and Principle**
**Kansas Power Pool - Winfield**

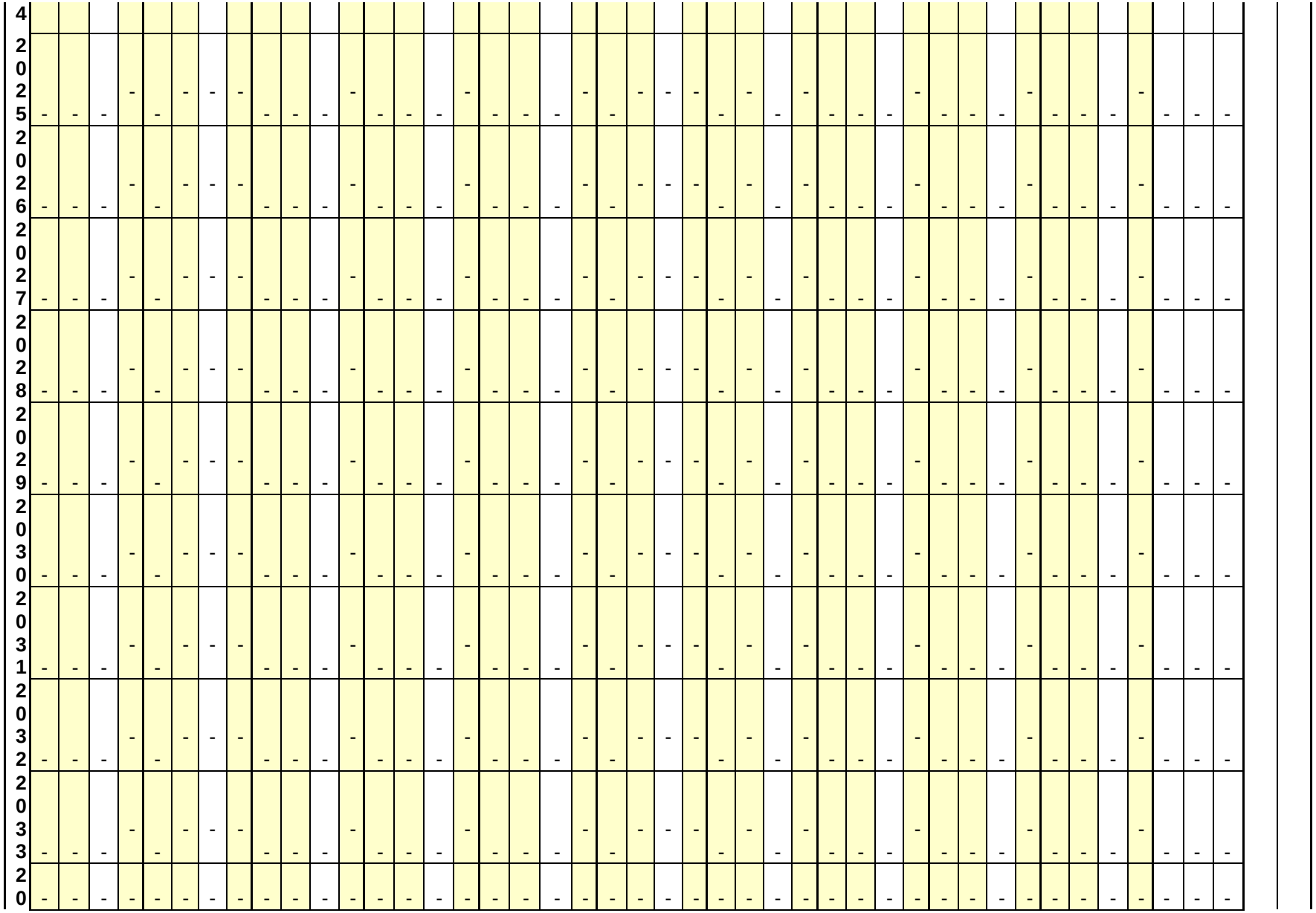


**Attachment 3**

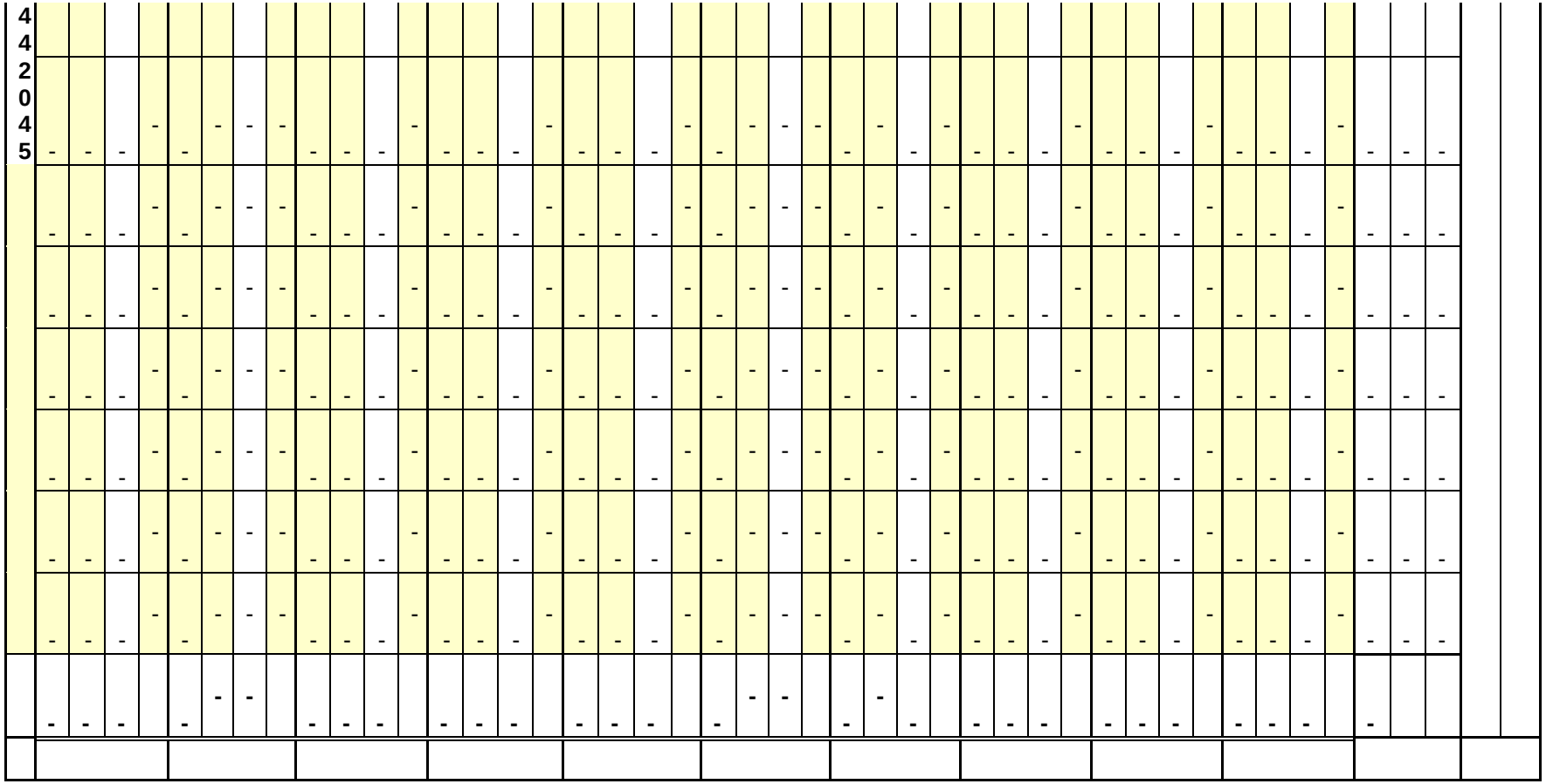
**Attachment H, City of Winfield General Obligation LTD Interest and Principle**
**Kansas Power Pool - Winfield**

| | | | | | | | | | | | Total General Obligation LTD | | | Total LTD & Average Interest Rate | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Issue | | | | | | | | | | | Principalp | Interest Pa | Total LTD | Total Winfie | Year=0 |

| | | |



| | | |



## Attachment 4
## Depreciation Rates
## Kansas Power Pool - Winfield



| FERC ACCOUNT | DESCRIPTION | RATE PERCENT |
|---|---|---|
| **TRANSMISSION** | | |

| | | |
|---|---|---|
| 350 | Land Rights | N/A |
| 352 | Structures and Improvements | 2.1800% |
| 353 | Station Equipment | 2.2000% |
| 354 | Towers and Fixtures | 1.8847% |
| 355 | Poles and Fixtures | 2.0800% |
| 356 | Overhead Conductors & Devices | 2.2700% |
| 357 | Underground Conduit | 1.3665% |
| 358 | Underground Conductors & Devices | 1.8416% |
| 359 | Roads and Trails | 0.0000% |

Note 1:

Transmission Land Rights are amortized

over the life of the land right.

Note 2:

The above depreciation and amortization rates may not be changed absent a section 205 or 206 filing

Attachment 5
Incentive ROE
Kansas Power Pool - Winfield

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | Rate Base | Attachment H, Page 2 line 37, Col.5 | | | | | #DIV/0! |
| 2 | 100 Basis Point Incentive Return | | | | | $ | |
| | | | | % | Cost | Weighted | |
| 3 | Long Term Debt | (Attachment H, Notes Q and R) | | 40.00% | #DIV/0! | #DIV/0! | |
| 4 | Preferred Stock | (Attachment H, Notes Q and R) | | 0.00% | 0.00% | 0.00% | |
| 5 | Common Stock | (Attachment H, Notes K, Q and R) | Cost = Attachment H, Page 4 Line 22, Cost plus .01 | 60.00% | 11.30% | 6.78% | |
| 6 | Total (sum lines 3-5) | | | | | #DIV/0! | |
| 7 | 100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6) | | | | | | #DIV/0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | INCOME TAXES | | | | | | | |
| 9 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | - | | | | | |
| 10 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | #DIV/0! | | | | | |
| 11 | WCLTD = Line 3 | | | | | | | |
| 12 | and FIT, SIT & p are as given in Attachment H footnote G. | | | | | | | |
| 13 | 1 / (1 - T) = (from line 9) | | - | | | | | |
| 14 | Amortized Investment Tax Credit (266.8f) (enter negative) | Attachment H, Page 3, Line 36 | - | | | | | |
| 15 | Excess Deferred Income Taxes (enter negative) | Attachment H, Page 3, Line 37 | - | | | | | |
| 16 | Tax Effect of Permanent Differences (Note B) | Attachment H, Page 3, Line 38 | - | | | | | |
| 17 | Income Tax Calculation = line 10 * line 7 | | | NA | | #DIV/0! | | |
| 18 | ITC adjustment (line 13 * line 14) | | - | NP | - | - | | |
| 19 | Excess Deferred Income Tax Adjustment (line 13 * line 15) | | - | NP | - | - | | |
| 20 | Permanent Differences Tax Adjustment (line 13 * 16) | | - | NP | - | - | | |
| 21 | Total Income Taxes (sum lines 17 - 20) | | - | | | #DIV/0! | #DIV/0! | |
| 22 | Return and Income Taxes with 100 basis point increase in ROE | | | | | | #DIV/0! | |

| | | | | |
|---|---|---|---|---|
| 23 | Return and Income Taxes without 100 basis point increase in ROE | | | #DIV/0! |
| 24 | Incremental Return and Income Taxes = Line 22 - Line 23 | | | #DIV/0! |
| 25 | Incremental Payments in lieu of Taxes (PILOT) | | 6.90% | #DIV/0! |
| 26 | Return, Income Tax & PILOT without 100 basis point increase in ROE | Att. H Pg. 3, Ln. 41 + Ln. 43+ Ln. 44 | | #DIV/0! |
| 27 | Return, Income Tax & PILOT for 100 basis point increase in ROE | Ln. 27 - Ln. 26 | | #DIV/0! |
| 28 | Incremental Return, Income Tax and PILOT for 100 bp ROE increase | Ln. 25 + Ln. 26 + Ln. 27 | | #DIV/0! |
| 29 | Net Transmission Plant (Att. H, Page 2, Line 16) | | | #DIV/0! |
| 30 | Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base | | | #DIV/0! |

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual ROE incentive must be approved by the Commission. For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 1.37 on Attachment 1 column 12.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference

**Attachment 6 Project Revenue Requirement Worksheet Kansas Power Pool - Winfield**



To be completed in conjunction with Attachment H.

| Line No. | (1) | (2) **Attachment H Page, Line, Col.** | (3) **Transmission** | (4) **Allocator** |
|---|---|---|---|---|
| 1 | Gross | Attach H, p 2, line 2 col 5 plus | #DI | |

| | | | | |
|---|---|---|---|---|
| | Transmission Plant - Total | line 27 col 5 (Note A) | V/0! | |
| | Net Transmission Plant - Total | Attach H, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note B) | #DI V/0! | |
| 2 | | | | |
| | **Expense Factors on Gross Plant Basis** | | | |
| | O&M EXPENSE | | | |
| | Total O&M Allocated to Transmission | Attach H, p 3, line 14 col 5 | #DI V/0! | |
| 3 | | | | |
| | Annual Allocation Factor for O&M | (line 3 divided by line 1 col 3) | #DI V/0! | #DI V/0 ! |
| 4 | | | | |
| | GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE | | | |
| | Total G, I & C Depreciation Expense | Attach H, p 3, lines 17 & 18, col 5 (Note H) | #DI V/0! | |
| 5 | | | | |
| | Annual Allocation Factor for G, I & C Depreciation Expense | (line 5 divided by line 1 col 3) | #DI V/0! | #DI V/0 ! |
| 6 | | | | |
| | TAXES OTHER THAN INCOME TAXES | | | |
| | Total Other | Attach | #DI | |
| 7 | | | | |

| | | | | |
|---|---|---|---|---|
| | Taxes | H, p 3, line 30 col 5 | V/0! | |
| 8 | Annual Allocation Factor for Other Taxes | (line 7 divided by line 1 col 3) | #DI V/0! | #DI V/0 ! |
| 9 | Reserved | | - | |
| 10 | Reserved | (line 9 divided by line 1 col 3) | - | 0.00 000 0 |
| **11** | **Annual Allocation Factor for Expense** | **Sum of line 4, 6, 8, and 10** | | **#DIV/0!** |
| | **Income Tax & Return Factors on Net Plant Basis** | | | |
| | INCOME TAXES | | | |
| 12 | Total Income Taxes | Attach H, p 3, line 44 col 5 | #DI V/0! | |
| 13 | Annual Allocation Factor for Income Taxes | (line 12 divided by line 2 col 3) | #DI V/0! | #DI V/0 ! |
| | RETURN | | | |
| 14 | Return on Rate Base | Attach H, p 3, line 46 | #DI V/0! | |

| | | | | |
|---|---|---|---|---|
| | | col 5 | | |
| 15 | Annual Allocation Factor for Return on Rate Base | (line 14 divided by line 2 col 3) | #DIV/0! | #DIV/0! |
| **16** | **Annual Allocation Factor for Inc. Tax & Return** | **Sum of line 13 and 15** | #DIV/0! | **#DIV/0!** |

**Attachment 6 Project Revenue Requirement Worksheet Kansas Power Pool - Winfield**



| | | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No** | | **Project Name (Notes M & N)** | **ITEP Project Number** | **Project Gross Plant** | **Annual Allocation** | **Annual Expense Charge** | **Project Net Plant** | **Annual Allocation** | **Annual Return Ch** | **Project Depreciation/ Amortization** | **Gross Annual Re** | **Revenue Cre** | **Net Revenue** | **Incntive Return in** | **Incntive Return** | **Ceiling R** | **Discount** | **Total Annual Re** | **True-Up Adjustme** | **Net Revr** |

| . | Factor for Expense | | Factor for Return | arge | Expense | venue Requirement | dits - Sch 11 Alloc. To Projs, other to Att. H | Requirement B4 Incentives, Discounts or True-up | basis Points | | ate | | venue Requirement | nt | eq |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (Note C) | (Page 1 line 11) | (Col. 3 * Col. 4) | (Notes D & I) | (Page 1 line 16) | (Col. 6 * Col. 7) | (Notes E & I) | (Cols. 5+8+9) * PILOT Note P | Att. 2-Expenses Pg. 2 Row 16 Cols (c | Col (10) - (11) | (Note K) | (Att 5, Line 30 /100 * Col. (13) * Col (6) | Col. (12) + (14) | (Note J) | Col. (15) - Col. (16) | (Note F) | Col. (14) + (15) (Note G) |

| | | | | | | | | | ) & (d ) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Zone 14** | | | | | | | | | | | | | | | |
| 17 | Attachment H | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | - | #DIV/0! | $0.00 | #DIV/0! |
| 18a | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | $ - | #DIV/0! | $0.00 | #DIV/0! |
| 18b | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | $ - | #DIV/0! | $0.00 | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | $ - | #DIV/0! | $0.00 | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | $ - | #DIV/0! | $0.00 | #DIV/0! |
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| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! | $ - | #DIV/0! | $0.00 | #DIV/0! |
| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! | $ - | #DIV/0! | $0.00 | #DIV/0! |
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| | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! | $ - | #DIV/0! | $0.00 | #DIV/0! |
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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | - | | |
| 18 | Annual Totals Projects | - | #DIV/0! | - | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | 0 | 0 | #DIV/0! | 0 | #DIV/0! | 0 | #DIV/0! |
| 19 | **Annual Total Attachment H and Projects** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **-** | **#DIV/0!** | **#DIV/0!** | **-** | **#DIV/0!** | **-** | **#DIV/0!** |

Note Letter

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H

B Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include Unamortized Abandoned Plant.

D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes any regulatory asset, which are to entered as a separate line item.

E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 16. Project Depreciation Expense includes the amortization of Abandoned Plant

F True-Up Adjustment is calculated on the Project True-up Schedule for the Rate Year

G The Net Rev Req is the value to be used in the SPP's rate calculation under the applicable Schedule under the SPP OATT for each project.

| | |
|---|---|
| H | The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9. |
| I | The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense. |
| J | The discount is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate |
| K | Requires approval by FERC of incentive return applicable to the specified project(s) |
| M | All facilities other than those being recovered under Schedules 7, 8, 9 are to be included in Attachment 1. |
| N | Facilities that provide Wholesale Distribution Service are not to be listed as projects on lines 15, the revenue requirements associated with these facilities are calculated on Attachment 11 |
| O | When an updated projected net revenue requirement is posted due to an asset acquisition as provided for in the Protocols, the difference between the updated net revenue requirement in Col (16) and the revenues collected to date will be recovered over the remaining months of the Rate Year. |
| P | PILOT = Payment in Lieu of Taxes Factor = 1-(PILOT Rate/(1-PILOT Rate)), where PILOT Rate = PILOT Allowance in Formula Rate Inputs page. |



**Attachment 7**
**Project True-Up**
**Kansas Power**

## Pool - Winfield

| 1 | Rate Year being Trued-Up | | Revenue Requirement Projected For Rate Year | | Revenue Received[3] | Actual Revenue Requirement | Annual True-Up Calculation | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | $ - | | | | | |
| | A | B | C | D | E | F | G | H | I | J |
| | Project # Or Other Identifier | Project Name | Projected Net Revenue Requirement[1] | % of Total Revenue Requirement | Revenue Received (E, Line 2 ) x (D) | Actual Net Revenue Requirement[2] | Net Under/(Over) Collection (F)-(E) | Prior Period Adjustment [4] | Interest Income (Expense) [5] | Total True-Up (G) + (H) + (I) |
| 3 | Attachment H | | - | - | - | - | - | - | - | - |
| 3a | | | - | - | - | - | - | - | - | - |
| 3b | | | - | - | - | - | - | - | - | - |
| 3c | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |
| | | | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| | | | - | - | - | - | - | - | - | - | |
| 4 | Total Annual Revenue Requirements (Note A) | | - | - | - | - | - | | - | - | |

| | |
|---|---|
| Monthly Interest Rate | - |
| Interest Income (Expense) | - |

Notes:
1) From Attachment 6, col. 15 for the projection for the Rate Year.
2) From Attachment 6, line 17.ia, col. 14 for that project based on the actual costs for the Rate Year.
3) The "Revenue Received" on line 2, Col. (E), is the total amount of revenue distributed to KPP in the year being trued-up for Winfield transmission, excluding any True-Up revenues.
Column E, lines 3 are the dollar amounts of Revenue Received reflecting the % in Column D. This assigns to each project a percentage of the revenue received based on the percentage of the Projected Net Revenue Requirement in Column C.
4) Prior Period Adjustment from line 5 is pro rata to each project, unless the error was project specific.
5) Interest from Attachment 8.

**Prior Period Adjustment**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | Prior Period Adjustment (Note B) | Amount In Dollars | Interest Note B | Total Col. (b) + Col. (c) |
| 5 | - | - | - | - |

Notes:

A For each project or Attachment H, the utility will populate the formula rate with the inputs for the True-Up Year. The revenue requirements, based on actual operating results for the True-Up Year, associated with the projects and Attachment H will then be entered in Col. (F) above. Column (E) above contains the actual revenues received associated with Attachment H and any Projects paid by SPP to the utility during the True-Up Year. Then in Col. (G), Col. (E) is subtracted from Col. (F) to calculate the True-up Adjustment. The Prior Period Adjustment from Line 5 below is input in Col. (H). Column (I) is the applicable interest rate from Attachment 6. Column (I) adds the interest on the sum of Col.(G) and (H). Col. (J) is the sum of Col. (G), (H), and (I).

B Prior Period Adjustment is the amount of an adjustment to correct an error in a prior period. The FERC Refund interest rate specified in CFR 35.19(a) for the period up to the date the projected rates that are subject to True Up here went into effect.

# Attachment 8
# True-Up Interest Rate
# Kansas Power Pool - Winfield

| | Quarter (Note A) | Interest rate for the Quarter pursuant to Section 35.19(a) |
|---|---|---|
| 1 | 1st Qtr | - |
| 2 | 2nd Qtr | - |
| 3 | 3rd Qtr | - |
| 4 | 4th Qtr | - |
| 5 | 1st Qtr | - |
| 6 | 2nd Qtr | - |
| 7 | 3rd Qtr | - |
| 8 | Avg. Monthly FERC Rate | - |

Note A:
Lines 1-7 are the FERC interest rate under section 35.19(a) of the regulations for the period shown.
Line 8 is the average of lines 1-7.

9 Year
10

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Project # Or Other Identifier | Project Name | (Excess) or Deficient Payments Received | | | | | | | | | | | | Interest Rate (line 8) | Interest (Note B) |
| | | | January | February | March | April | May | June | July | August | September | October | November | December | | |
| 11 | Attachment H | | | | | | | | | | | | | | 0% | - |
| 11 | | | | | | | | | | | | | | | | |
| 1a | | | | | | | | | | | | | | | 0% | - |
| 11 | | | | | | | | | | | | | | | | |
| b | | | | | | | | | | | | | | | 0% | - |
| 11 | | | | | | | | | | | | | | | | |
| 1c | | | | | | | | | | | | | | | 0% | - |
| … | | | | | | | | | | | | | | | 0% | - |
| | | | | | | | | | | | | | | | 0% | - |
| | | | | | | | | | | | | | | | 0% | - |
| | | | | | | | | | | | | | | | 0% | - |
| | | | | | | | | | | | | | | | 0% | - |

| | | | | |
|---|---|---|---|---|
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |
| | | | 0% | - |

Note B
Interest is calculated by taking the interest rate in line 8 and applying it monthly to the balances in Column C-N (i.e., for January 12/12* Column O, February 11/12* Column O, etc.)
plus the interest rate in line 8 times 1.5 times the sum of the balances for January through December.

Attachment 9



PBOPs

Kansas Power Pool - Winfield

**Calculation of PBOP Expenses**

| | (a) | (b) |
|---|---|---|
| 1 | | **Winfield** |
| 2 | Total PBOP expenses (Note A) | - |
| 3 | Labor dollars (total labor from budget) | - |
| 4 | Cost per labor dollar (line2 / line3) | - |
| 5 | labor expensed (labor not capitalized) by SCMCN in current year, 354.28.b. | - |
| 6 | PBOP Expense for current year | - |
| 7 | Lines 2-3 cannot change absent approval or acceptance by FERC in a separate proceeding. | |
| 8 | PBOP amount included in Company's O&M and A&G expenses included in FERC Account Nos. 500-935 | |

| Note Letter | |
|---|---|
| A | There will be zero PBOP expenses in the KPP-Winfield rates until KPP files for recovery of its PBOP expenses. |

**Kansas Power Pool ("KPP")**

**Attachment A – KPP**

**ANNUAL TRUE-UP, INFORMATION EXCHANGE,**

**AND CHALLENGE PROCEDURES**

## Section I. Applicability

The following procedures shall apply to KPP's calculation of its actual net revenue requirement, True-Up Adjustment, and projected net revenue requirement. The project-specific annual revenue requirements, if any, determined under the KPP formula are "up to" rates, i.e., ceiling rates, and permit KPP to discount the revenue requirement to the extent necessary to reflect the result of any cost commitment to SPP. In the Formula Rate Template, the effect of any such discount is removed from the projected revenue requirement and the actual revenue requirement, which ensures that customers receive the benefits of any discount.

## Section II. Annual True-Up and Projected Net Revenue Requirement

A. Beginning on or before September 1 of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent September 1, KPP shall determine the Annual True-Up under this Attachment H - KPP and Section VII of these protocols, to derive a True-Up Adjustment to be included in KPP's projected net revenue requirement for the subsequent calendar year (the "Rate Year").

B. On or before September 1 of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent September 1, KPP shall provide the Annual True-Up, actual net revenue requirement, and True-Up Adjustment to SPP and cause such information to be posted on the SPP website. Within ten (10) days of such posting, KPP shall provide notice of such posting via the email exploder list. Interested Parties shall contact KPP at the following email address to be placed on the exploder list: regulatorynotices@kpp.agency.

C. On or before October 1, of the year following FERC's acceptance of these protocols in the SPP Tariff, and on or before each subsequent October 1, KPP shall provide the projected net revenue requirement to SPP and cause such information to be posted on the SPP website. Within ten (10) days of posting of the projected net revenue requirement, KPP shall provide notice of such posting to the email exploder list.

D. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the projected net revenue requirement will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols and for challenge procedures discussed in Section IV of these protocols.

E. The Annual True-Up shall:

1. Include a workable populated Formula Rate Template and underlying workpapers in native format with fully functional spreadsheets showing the calculation of the net revenue requirement;

2. Have components that are based on Winfield's Comprehensive Annual Financial Reports, specifically the Electric Utility sections ("Winfield Financials"), and Gridliance High Plains, LLC's ("GLHP") FERC Form No. 1 reports for the prior calendar year;

3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in the Winfield Financials and GLHP FERC Form No. 1 reports;[1]

4. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the Annual True-Up results from the Winfield Financials and GLHP FERC Form No. 1 reports;

5. Identify any changes in the formula references (page and line numbers) to the Winfield Financials and GLHP FERC Form No. 1 reports;

6. Identify all material adjustments made to the Winfield Financials and GLHP FERC Form No. 1 report data in determining formula inputs, including relevant footnotes to the GLHP FERC Form No. 1 reports and any adjustments not shown in the GLHP FERC Form No. 1 reports;

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[1] It is the intent of the formula rate, including the supporting explanations and allocations described therein, that each input to the formula rate will be either taken directly from the Winfield Comprehensive Annual Financial Reports, including the Electric Utility Sections, and GLHP FERC Form No. 1 or reconcilable to the Winfield Comprehensive Annual Financial Reports, including the Electric Utility Sections or FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall

be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form(s) is (are) discontinued, equivalent information as that provided in the discontinued form(s) shall be utilized.

7. Provide underlying data for formula rate inputs that provide greater granularity than is required for the Winfield Financials and GLHP FERC Form No. 1 reports;

8. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

   a. Identify any Accounting Changes, including:

      i. the initial implementation of an accounting standard or policy;

      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

      iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation; and

      iv. the implementation of new estimation methods or policies that change prior estimates;

   b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

   c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up;

   d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

F. The projected net revenue requirement shall:

1. Include a workable populated Formula Rate Template and underlying workpapers in native format with fully functional spreadsheets showing the calculation of the net revenue requirement;
2. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement;
3. Provide sufficient information to enable Interested Parties (as that term is defined in Section II.G of these protocols) to replicate the calculation of the projected net revenue requirement;
4. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):
    a. Identify any Accounting Changes, including:
        i. the initial implementation of an accounting standard or policy;
        ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
        iii. correction of errors and prior period adjustments that impact the projected net revenue requirement calculation; and
        iv. the implementation of new estimation methods or policies that change prior estimates;
    b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement; and

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

G. KPP shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") with remote access in conjunction with KPP's Annual Projected Rate Meeting since the date of the Annual True-Up posting and Annual Projected Rate posting are so close together in time[2]. This meeting will be held jointly with GLHP. No less than seven (7) days prior to such Annual True-Up Meeting, KPP shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual True-Up Meeting and

KPP shall provide notice of such meeting to the email exploder list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and

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[2] Due to time constraints regarding the timing of the completion of the audited financial reports of the various governmental and business type subdivisions necessary for completion and issuance of the City of Winfield Comprehensive Annual Financial Report, the Annual True-Up will not be completed and available until September 1. As some of the information in KPP's formula rate is derived from GLHP information, GLHP has agreed to coordinate its Annual Projected Rate Meeting with KPP's Annual Projected Rate Meeting and will participate in both meetings.

state attorneys general. The Annual True-Up Meeting shall (i) permit KPP to explain and clarify its Annual True-Up and True-Up Adjustment and (ii) provide Interested Parties an opportunity to seek information and clarifications from KPP about the Annual True-Up and True-Up Adjustment.

H. KPP shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") with remote access between the date that the projected net revenue requirement is posted to the SPP website (as described in Section II.C of these protocols) and October 31. This meeting will be held in conjunction with the Annual True-Up meeting and will be held jointly with GLHP. No less than seven (7) days prior to such Annual Projected Rate Meeting, KPP shall cause notice to be provided on SPP's internet website of the time, date, and location of the Annual Projected Rate Meeting and KPP shall provide notice of such meeting to the email exploder list. The Annual Projected Rate Meeting shall (i) permit KPP to explain and clarify its projected net revenue requirement and (ii) provide Interested Parties an opportunity to seek information and clarifications from KPP about the projected net revenue requirement.

I. Each year KPP shall endeavor to coordinate with other Transmission Owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost-sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

**Section III. Information Exchange Procedures**

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until February 1 following the Publication Date (unless such period is extended with the written consent of KPP or by FERC order) to serve reasonable information and document requests on KPP ("Information Exchange Period"). If February 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) the extent or effect of an Accounting Change;

(2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(3) the proper application of the formula rate and procedures in these protocols;

(4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;

(5) the prudence of actual costs and expenditures;

(6) the effect of any change to the underlying Uniform System of Accounts, Winfield's Financials, or the FERC Form No. 1 reports of GLHP; or

(7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. KPP shall make a good faith effort to respond to information and document requests within ten (10) business days of receipt of such requests. KPP shall respond to all information and document requests by no later than February 10 following the Publication Date, unless the Information Exchange Period is extended by KPP or FERC.

C. KPP will cause to be posted on the SPP website all information requests from Interested Parties and KPP's response(s) to such requests; except, however, if responses to information and document requests include material deemed by KPP to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by KPP and the requesting party.

D. KPP shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing KPP's Annual True-Up or projected net revenue requirement.

**Section IV. Challenge Procedures**

A. Interested Parties shall have until February 28 following the Publication Date (unless such period is extended with the written consent of KPP or by FERC order) to review the inputs, supporting explanations, allocations, and calculations and to notify

KPP in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or projected net revenue requirement. The period of time from the Publication Date until February 28 shall be referred to as the Review Period. If February 28 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that Annual True-Up or projected net revenue requirement, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement.

B. A party submitting an Informal Challenge to KPP must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. KPP shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. KPP, and where applicable, the Transmission Provider, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge[3]. If KPP disagrees with such challenge, KPP will provide the Interested

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[3] It may be appropriate and necessary for GLHP to participate in such Information Challenge process if the challenge relates to information derived from the GLHP Formula Rate.

Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after February 28, and KPP must respond to all Informal Challenges by no later than March 31, unless the Review Period is extended by KPP or FERC.

C. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.

(1) A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

(b) Explain how the action or inaction violates the filed rate formula or protocols;

(c) Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

(i) the extent or effect of an Accounting Change;

(ii) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

(iii) the proper application of the formula rate and procedures in these protocols;

(iv) the accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;

(v) the prudence of actual costs and expenditures;

(vi) the effect of any change to the underlying Uniform System of Accounts, Winfield Financials, or FERC Form 1 of GLHP; or

(vii) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula;

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(2) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on KPP. Service to KPP must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in

accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on KPP's Informational Filing required under Section VI of these protocols.

D. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts, Winfield Financials, or the GLHP FERC Form No. 1 reports; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

E. KPP will cause to be posted on the SPP website all Informal Challenges from Interested Parties and KPP's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by KPP to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by KPP and the requesting party.

F. Any changes or adjustments to the True-Up Adjustment or projected net revenue requirement resulting from the Information Exchange and Informal Challenge processes that are agreed to by KPP will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by KPP on or before December 1 will

be reflected in the projected net revenue requirement for the upcoming Rate Year. Any changes or adjustments agreed to by KPP after December 1 will be reflected in the following year's Annual True-Up, as discussed in Section V of these protocols.

G. An Interested Party shall have until May 15 following the Review Period (unless such date is extended with the written consent of KPP to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on KPP on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as KPP's Informational Filing discussed in Section VI of these protocols. KPP shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

H. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, KPP shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in this Attachment H - KPP. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

I. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of KPP to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a

stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

J. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual True-Up or projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

K. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts, Winfield Financials, or GLHP FERC Form No. 1, shall first raise the matter with KPP in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to True-Up Adjustment or Projected Net Revenue Requirement**

Except as provided in Section IV.F of these protocols, any changes to the data inputs, including, but not limited to, revisions to Winfield's Financials or GLHP's FERC Form No. 1 reports, or as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.

**Section VI. Informational Filings**

A. By April 15 of each year, KPP shall submit to FERC an informational filing ("Informational Filing") of their projected net revenue requirement for the Rate Year, including their Annual True-Up and True-Up Adjustment. This Informational Filing must:

(1) Include the information that is reasonably necessary to determine: (i) that input data under the formula rate are properly recorded in any underlying workpapers; (ii) that KPP has properly applied the formula rate and these procedures; (iii) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement under review; (iv) the extent of accounting changes that affect formula rate inputs; and (v) the reasonableness of projected costs.

(2) If there have been any changes to GLHP's affiliate cost allocation that impacts KPP's formula rate, include for the applicable Rate Year the following information from GLHP related to affiliate cost allocation: (i) a detailed description of the methodologies used to allocate and directly assign costs between GLHP and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (ii) the magnitude of such costs that have been allocated or directly assigned between GLHP and each affiliate by service category or function; and

(3) Describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, KPP shall provide notice of the Informational Filing via the email exploder list and shall cause SPP to post the docket number assigned to KPP's Informational Filing on the SPP website.

B. Any challenges to the implementation of the Attachment H - KPP formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

**Section VII. Calculation of True-Up Adjustment**

The True-Up Adjustment is developed on Attachment 7 and will be determined in the following manner:

(1) Actual transmission revenues for the previous year will be compared to Net Revenue Requirement not including any prior year True-Up Adjustment calculated in accordance with KPP's Attachment H of this Tariff for the previous year using Winfield's Financials and GLHP's FERC Form No. 1 for that same year to determine any over or under recovery, as well as any other appropriate documentation from KPP ("True-Up Adjustment"). KPP shall cause the True-Up Adjustment and related calculations to be posted to the SPP website no later than September 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day.

(2) Interest on any over recovery or under recovery of the net revenue requirement shall be determined on Attachment 8 of the formula rate. The interest rate to be applied to the over or under recovery amounts will be determined using the average interest rate for the twenty-one (21) months preceding October of the current year. In either case, the interest payable shall be calculated by applying the average interest rate to the over or under recovery in the revenue requirement or volume changes for the twenty-four (24) month period. The interest amount will be included in the projected costs made available on October 1 in accordance with Section II.C above.

(3) The Net Revenue Requirement for transmission services for the following Year shall be the sum of the projected revenue requirement for the following year, plus or minus the True-Up Adjustment from the previous year, if any, including interest, as explained above.

(4) KPP may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

# ADDENDUM 17 TO ATTACHMENT H

City Utilities of Springfield, MO

**NOTE: All Entries on this page are subject to change to provide a summary of changes and other comments by City Utilities related to the TFR.**

## Index of Worksheets

| Line No. | Worksheet | Description |
|---|---|---|
| 1 | Rate | Rate Formula Template for the 12 months ended 9/30/2021 |
| 2 | ATRR | Calculation of Gross Annual Transmission Revenue Requirement (ATRR) |
| 3 | Worksheet A | Average of 12 Coincident Peaks |
| 4 | Worksheet B | Return (R ) Calculation and Net Plant Carrying Charge Calculation |
| 5 | Worksheet C | Adjusted Transmission O&M Expense and Transmission Depreciation Expense, per book |
| 6 | Worksheet D | Transmission Related Ratebase Calculation and Depreciation Summary |
| 7 | Worksheet E | Transmission Plant Summary |
| 8 | Worksheet F | Analysis of Account 566 |
| 9 | Worksheet G | Account 448000, Revenue from Telecommunications Pole Rental |
| 10 | Worksheet H | Allocation of Administrative & General costs |
| 11 | Worksheet I | Upgrade Revenue Requirements Determination |
| 12 | Worksheet J | Sponsored Upgrade Revenue Requirements Determination |

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## Rate Formula Template for the 12 months ended 9/30/2021

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G | |
|---|---|---|---|---|---|---|---|
| Line No. | Account | | Description | Notes | | Transmission Amount | |
| | **A. Zonal Net ATRR** | | | | | | |
| 1 | | | Gross ATRR | Worksheet ATRR, Line 14, Col. I | | #DIV/0! | |
| | | | Revenue Credits | | | | |
| 2 | 456 | | Less: Revenue from SPP | Note A | | | |
| 3 | 412 | | Less: Other Transmission Revenue | Note B | | | |
| 4 | 448, 454 | | Less: Transmission Related Rents | Worksheet G, Line 13, Col. H | - | | |
| 5 | | | Total Transmission Revenue Credits | Line 2 + Line 3 + Line 4 | | 0 | |
| 6 | | | Subtotal | Line 1 + Line 5 | | #DIV/0! | |
| 7 | | | Less: Net Upgrade Revenue Requirements Determination | Worksheet I, Line 9, Col. J | | #DIV/0! | |
| 7A | | | Zonal Net ATRR | Line 6 + Line 7 | | #DIV/0! | |
| 7B | | | Less: Net Sponsored Upgrade Revenue Requirements Determination | Worksheet J, Line 9, Col. H | | $ - | |
| 8 | | | **Zonal Net ATRR for SPP Open Access Transmission Tariff (OATT) Attachment H** | Line 7A + Line 7B | | **#DIV/0!** | |
| | **B. Point-to-Point Transmission Service Rates** | | | | | | |
| | | | **Divisor** | | | | |
| 9 | | | Network - Average of 12 Coincident Peaks | Worksheet A, Line 13, Col. C | | #DIV/0! | MW |
| | **Rates for SPP OATT Attachment T** | | | | | | |
| 10 | | | Point-to-Point Firm & Non-Firm ($/Kilowatt (kW) /Year) | Line 8 / Line 9 / 1000 | | **#DIV/0!** | |
| 11 | | | Point-to-Point Firm & Non-Firm ($/kW/Month) | Line 10 / 12 months | | **#DIV/0!** | |
| 12 | | | Point-to-Point Firm & Non-Firm ($/kW/Week) | Line 10 / 52 weeks | | **#DIV/0!** | |
| 13 | | | Point-to-Point Firm ($/kW/Day) | Line 12 / 5 days | | **#DIV/0!** | |
| 14 | | | Non-firm Point-to-Point ($/kW/Day) | Line 12 / 5 days | | **#DIV/0!** | |

| | | | | | |
|---|---|---|---|---|---|
| 15 | | Non-firm Point-to-Point ($/kW/Hour) | Line 14 / 16 hours | **#DIV/0!** | |
| | **C. Schedule 1 Annual Revenue Requirements** | | | | |
| 16 | | Load Dispatching & Scheduling | Worksheet C, Line 5, Col. F | $ - | |
| 17 | | Less: PTP Service Credit | Note C | | |
| 18 | | Subtotal | Line 16 - Line 17 | - | |
| 19 | | Payment in Lieu of Taxes | Line 18 / .97 * .03 | - | |
| 20 | | Net Schedule 1 Revenue Requirements for Zone | Line 18 + Line 19 | **$ -** | |
| | **D. Schedule 1 Rate Calculations** | | | | |
| 21 | | Network - Average of 12 Coincident Peaks | Worksheet A, Line 13, Col. C | #DIV/0! | MW |
| 22 | | Point-to-Point Firm & Non-Firm ($/Kilowatt (kW) /Year) | Line 20 / Line 21 / 1000 | **#DIV/0!** | |
| 23 | | Point-to-Point Firm & Non-Firm ($/kW/Month) | Line 22 / 12 months | **#DIV/0!** | |
| 24 | | Point-to-Point Firm & Non-Firm ($/kW/Week) | Line 22 / 52 weeks | **#DIV/0!** | |
| 25 | | Point-to-Point Firm ($/kW/Day) | Line 24 / 5 days | **#DIV/0!** | |

26 Note A These are revenues received from SPP for Schedules 7, 8 and 11 Point-to-Point services, and the MISO payments, as booked in the fiscal year.

27 Note B City Utilities receives $11,000 per month related to an interconnection agreement. $9,500 is related to power generation, with approximately $1,500 booked to Transmission as a Facilities Fee revenue (account 412004), Adjusted for imputed interest.

28

29 Note C Schedule 1 PTP Revenue Credit



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## Calculation of Gross Annual Transmission Revenue Requirement (ATRR)

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G | Col. H | Col. I |
|---|---|---|---|---|---|---|---|---|

| Line No. | Account | Description | Source | Allocation Basis | Total Company | Allocation Pct. | Transmission Amount |
|---|---|---|---|---|---|---|---|
| | | **Operating & Maintenance (O&M)** | | | | | |
| 1 | 560-575 | Transmission | Worksheet C, Line 20, Col. F | Direct to Transmission | $ - | 100% | $ - |
| 2 | 561000 | Less: Load Dispatch (Account 561000) | Worksheet C, Line 5, Col. F | Direct to Transmission | 0 | 100% | 0 |
| 3 | | Subtotal | Line 1 + Line 2 | | | | 0 |
| | | **Administrative & General (A&G)** | | | | | |
| 4 | 920-932 | Direct A&G Charges | Worksheet H, Line 14, Col. F | Direct to Transmission | (105,204) | 100% | (105,204) |
| 5 | 920-932 | Common A&G Charges | Worksheet H, Line 29, Col. D * Worksheet H, Line 29, Col E | Prorata based on Test Year Actual Expenses, excluding fuels | 0 | #DIV/0! | #DIV/0! |
| 6 | | Total A&G | Line 4 + Line 5 | | | | #DIV/0! |
| 7 | | Total O&M and A&G | Line 3 + Line 6 | | | | #DIV/0! |
| | | **Depreciation & Amortization Expense** | | | | | |
| 8 | 352-359 | Transmission | Worksheet C, Line 33, Col. F | Direct to Transmission | 0 | 100% | 0 |
| 9 | 389-397 & 301-303 | General & Intangible | Worksheet D, Line 43, Col. M | Allocation methods noted on Worksheet D | | | 0 |
| 10 | | Total Depreciation & Amortization | Line 8 + Line 9 | | | | 0 |
| 11 | | **Return on Ratebase** | Worksheet D, Line 48, Col. I * Worksheet B, Line 3, Col. F | | 0 | 9.90% | 0 |
| 12 | | **Subto** | Line 7 + Line 10 + Line 11 | | | | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | **tal** | | | | |
| 13 | 408.1-409.1 | **Payments in Lieu of Taxes** | Line 12 / 0.97 * 0.03 | 3% of gross revenues | #DIV/0! | |
| 14 | | **Gross ATRR** | Line 12 + Line 13 | ` | **#DIV/0!** | Carry forward to Worksheet Rate, Line 1, Col. G |



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## Worksheet A - Average of 12 Coincident Peaks

| **Col. A** | **Col. B** | **Col. C** | **Col. D** |
|---|---|---|---|
| Line No. | Month | System Max Peak Load | |
| | **MONTHLY COINCIDENT PEAK DEMAND (kW)** | | |
| 1 | OCT | | |
| 2 | NOV | | |
| 3 | DEC | | |
| 4 | JAN | | |
| 5 | FEB | | |
| 6 | MAR | | |
| 7 | APR | | |
| 8 | MAY | | |
| 9 | JUN | | |
| 10 | JUL | | |
| 11 | AUG | | |
| 12 | SEP | | |

| | | | |
|---|---|---|---|
| 13 | Average | #DIV/0! | Carry forward to Worksheet Rate, Line 9 and Line 21 |



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## Worksheet B - Return (R ) and Net Plant Carrying Charge Calculation

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G |
|---|---|---|---|---|---|---|
| Line No. | Description | Amount | Percentage | Cost | Weighted | |
| | **Step 1. Calculate Rate of Return (R )** | | | | | |
| | **Transmission Related Capital Structure** | | | | | |
| 1 | Long-term debt | $ - | #DIV/0! | 0% | #DIV/0! | Note A |
| 2 | Equity (Line 3 - Line 1) | - | #DIV/0! | 9.9% | #DIV/0! | Note B |
| 3 | Total Transmission Related Capital (Set Equal to Rate base, Worksheet D, Line 48, Col. I) | $ - | | | **9.9%** | **=R** Carry forward to Worksheet ATRR, Line 11, Col. I |
| 4 | Note A: Long-term debt financings are associated with specific assets. | | | | | |
| 5 | Note B: Equity cost is fixed until refiled at FERC. Transmission Equity will equal Transmission Rate Base less Transmission long-term debt, if any. | | | | | |
| | **Step 2. Calculate Net Plant Carrying Charge Rate (NPCC)** | | | | | |
| | **Determine NPCC** | | | | | |
| 6 | Net Transmission Plant (Worksheet D, Line 4, Col. I) | $ - | | | | |
| 7 | Gross Revenue Requirement | #DIV/0! | | | | |

| | | | |
|---|---|---|---|
| | (Worksheet ATRR, Line 14) | | |
| 8 | Less: Depreciation Expense (Worksheet ATRR, Line 8) | - | |
| 9 | Revenue Requirement net of depreciation | #DIV/0! | |
| 10 | **NPCC (Line 9 / Line 6) less depreciation** | **#DIV/0!** | Carry forward to Worksheet I and Worksheet J |



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## Worksheet C - Adjusted Transmission O&M Expense and Transmission Depreciation Expense

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G |
|---|---|---|---|---|---|---|
| Line No. | Account | Account Description | Actual | Adjustments | Adjusted Total | |
| 1 | | OPERATING EXPENSES | | | | |
| 2 | | Transmission Expense | | | | |
| 3 | | Operation | | | | |
| 4 | E560 | Supervision & Engineering | | | $ - | |
| 5 | E561 | Load Dispatching | | | - | Carry forward to Worksheet Rate, Line 16, Col. G and Worksheet ATRR, Line 2, Col. G; |
| 6 | E561.5 | Transm Reliability Planning | | | - | Note A |
| 7 | E562 | Station Expenses | | | - | |
| 8 | E563 | Overhead Lines | | | - | |
| 9 | E564 | Underground Lines | | | - | |
| 10 | E565 | Transmission By Others | | | - | Note B |
| 11 | E566 | Misc. Transmission Expenses | | 0 | - | Note C |
| 12 | E567 | Rent | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | - | |
| 13 | | Maintenance | | | | |
| 14 | E568 | Supervision & Engineering | | | - | |
| 15 | E569 | Structures | | | - | |
| 16 | E570 | Station Equipment | | | - | Note D |
| 17 | E571 | Overhead Lines | | | - | |
| 18 | E572 | Underground Lines | | | - | |
| 19 | E573 | Misc. Transmission Plant | | | - | |
| 20 | | Total Operation and Maintenance | $ - | $ - | $ - | sum of Lines 4-19 - Carry forward to Worksheet ATRR, Line 1, Col. G |
| 21 | | Payments in Lieu of Taxes | | | - | Note E |
| 22 | | DEPRECIATION EXPENSES | | | | |
| 23 | | Transmission Plant | | | | |
| 24 | E350 | Land & Land Rights | | | - | |
| 25 | E352 | Structures & Improvements | | | - | |
| 26 | E353 | Station Equipment | | | - | |
| 27 | E354 | Towers & Fixtures | | | - | |
| 28 | E355 | Poles & Fixtures | | | - | |
| 29 | E356 | Overhead Conductors | | | - | |
| 30 | E357 | Underground Conduit | | | - | |
| 31 | E358 | Underground Conductors | | | - | |
| 32 | E359 | Roads & Trails | | | - | |
| 33 | | Total Depreciation Expense | $ - | $ - | $ - | sum of Lines 24-32 - Carry forward to Worksheet ATRR, Line 8, Col. G |

| | | |
|---|---|---|
| 34 | Note A | Adjustment to remove charges associated with power generation or distribution function. |
| 35 | Note B | Adjustment to remove charges for transmission by others. |
| 36 | Note C | See Worksheet F, exclusion of LSE expenses and other adjustments. |
| 37 | Note D | Adjustment to remove Station Equipment charged to distribution function. |

| | | |
|---|---|---|
| 38 | Note E | Adjustment to remove payments in lieu of taxes. Payments in Lieu of Taxes are recovered through grossing up revenue requirements, as shown on schedule ATRR, line 13, and Rate line 19. |

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## Worksheet D - Transmission Ratebase Calculation and Depreciation Summary

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G | Col. H | Col. I | Col. K | Col. L | Col. M | Col. N |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Rate Base | Reference | | | Company Total | Allocator Ref. | Allocator Pct. | Transmission | Annual Depreciation | Allocator Pct. | Transmission Depreciation | |
| 1 | Net Transmission Plant | | | | | | | | | | | |
| 2 | Gross Plant in Service | Worksheet E, Line 12, Col. F | | | $ - | A | | $ - | $ - | 0 % | $ - | Annual Depreciation from Worksheet C, Line 33, Col. F |
| 3 | Accumulated Depreciation | Worksheet E, Line 24, Col. F | | | 0 | A | | 0 | | | | |
| 4 | **Net Transmission Plant in Service** | Line 2 - Line 3 - Line 3A | | | $ - | | | $ - | $ - | | $ - | |
| 5 | General Plant in Service | | Gross Plant in Service | Less: Acc | Net Plant | | | | | | | |

| | | | | um Depreciation | in Service | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | Assets shared equally between transmission and distribution (EGEN1) | Per Book | | | $ - | B | | $ - | | 0.00% | $ - |
| 7 | Assets shared between transmission and distribution (EGEN2) | Per Book | | | - | C | | - | | 0.000% | - |
| 8 | Assets shared equally between metering and distribution (EGEN3) | Per Book | | | - | D | | - | | 0.000% | - |
| 9 | Assets shared equally between SurgePro and distribution (EGEN4) | Per Book | | | - | E | | - | | 0.000% | - |
| 10 | Assets shared between transmission, distribution & metering (EGEN5) | Per Book | | | - | F | | - | | 0.000% | - |
| 11 | Assets shared between power generation, transmission & distribution (EGEN6) | Per Book | | | - | G | | - | | 0.000% | - |
| 12 | Assets labeled EGEN with product 120000 (EGEN) | Per Book | | | - | A | | - | | 0.000% | - |
| 13 | Assets shared between Telecommunications and IT (TCGN1) | Per Book | | | - | CC | | - | | 0.000% | - |
| 14 | **General Plant in Service** | sum of Lines 6-13 | | $ - | $ - | $ - | | | $ - | $ - | | $ - |
| 15 | Common Plant | | | | | | | | | | | |
| 16 | Common structures, | Per Book | | | $ - | H | | $ - | | 0.00 | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | including Main Office (CGN01) | | | | | | | 0 | % | 0. |
| 17 | Class reserved for future use (CGN02) | Per Book | | - | I | - | | 0 | 0% | - |
| 18 | TecHouse plant (CGN03) | Per Book | | - | J | - | | 0 | 0% | - |
| 19 | Vehicle Maintenance plant (CGN04) | Per Book | | - | K | - | | 0 | 0% | - |
| 20 | Infrared Thermography plant (CGN05) | Per Book | | - | L | - | | 0 | 0% | - |
| 21 | Natural Gas and Water Common plant (CGN06) | Per Book | | - | M | - | | 0 | 0% | - |
| 22 | Meter and Service Center (CGN07) | Per Book | | - | N | - | | 0 | 0% | - |
| 23 | Carpenter Shop (CGN08) | Per Book | | - | O | - | | 0 | 0% | - |
| 24 | Mainframe computer equipment (CGN09) | Per Book | | - | P | - | | 0 | 0% | - |
| 25 | Information Technology equipment (CGN10) | Per Book | | - | Q | - | | 0 | 0% | - |
| 26 | Childcare facility (CGN11) | Per Book | | - | R | - | | 0 | 0% | - |
| 27 | Lake Springfield plant (CGN12) | Per Book | | - | S | - | | 0 | 0% | - |
| 28 | Fellows Lake plant (CGN13) | Per Book | | - | T | - | | 0 | 0% | - |
| 29 | Dispatch Center plant (CGN14) | Per Book | | - | U | - | | 0 | 0% | - |
| 30 | Operations Technology - | Per Book | | - | V | - | | 0 | 0 | - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Common Distribution (CGN15) | | | | | | | | | 0% | | | |
| | Operations Technology - Toughbooks | | | | | | | | | 0.00% | | | |
| 131 | (CGN16) | Per Book | | | - | W | | - | | | - | | |
| | Operations Technology - Electric | | | | | | | | | 0.00% | | | |
| 132 | Distribution plant (CGN17) | Per Book | | | - | X | | - | | | - | | |
| | Operations Technology - | | | | | | | | | 0.00% | | | |
| 133 | Natural Gas plant (CGN18) | Per Book | | | - | Y | | - | | | - | | |
| | Operations Technology - | | | | | | | | | 0.00% | | | |
| 134 | Water plant (CGN19) | Per Book | | | - | Z | | - | | | - | | |
| | Job Order | | | | | | | | | 0.00% | | | |
| 135 | Tracking System (CGN20) | Per Book | | | - | AA | | - | | | - | | |
| | | | | | | | | | | 0.00% | | | |
| 136 | Land & Land Rights (CGENL) | Per Book | | | - | H | | - | | | - | | |
| | Transportation | | | | | | | | | 0.00% | | | |
| 137 | Equipment (CGENV) | Per Book | | | - | K | | - | | | - | | |
| 138 | …. | Per Book | | | | | | | | | | | |
| 139 | …. | Per Book | | | | | | | | | | | |
| 140 | **Common Plant in Service** | sum of Lines 16-39 | | $ - | $ - | $ - | | | $ - | $ - | | $ - | |
| | Intangible Asset - AECI | | | | | | 0.00% | | | | 0.00% | | |
| 141 | Interconnection Agreement | Account 186052 | | | | A | 0% | - | | 23,352 | 0% | 0 | |
| 142 | Materials and Supplies | | | | | | | | | | | | |
| 143 | Electric Storerooms (#1) | Account 154001 | | | | C | 0.00% | $ - | | Total | Line 14 + Line 4 | 0 | Carry forward to Worksheet ATRR, |
| 144 | Vehicle Maintenance | Account 154004 | | | | K | 0.0 | - | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Storeroom (#4) | | | 0 % | | 0 + Line 9 | |
| 4 5 | Materials and Supplies | sum of Lines 43 + 44 | $ - | | $ - | 0 + Line 41 | |
| 4 6 | Prepayments | Account 165000 | | B B | $ - | | |
| 4 7 | Cash and Working Capital | Total O&M/A&G expenses - Worksheet ATRR, Line 7 | #Div /0! | | - | | |
| 4 8 | Rate Base | line 4 + Line 14 + Line 40 + Line 41+ sum (Lines 45-47) | | | **$ -** | Carry forward to Worksheet ATRR, Line 11, Col. G | |

Note: General and Common plant are assigned to asset categories based on the appropriate allocation of future depreciation when placed in service. Electric general plant are assets that benefit more than one function within the electric system (i.e. Generation, Transmission, Distribution, and Metering). Common plant are assets that benefit more than one business unit of the Utility. The allocator explanations column, below, lists the different allocations methods that are currently setup. During the process of placing assets in service, each asset is analyzed to determine which allocator method is most appropriate for this asset. Any additions to lines 38, 39, or 83 of Worksheet D will require a Section 205 filing at FERC.

Allocator Explanations (may be updated Annually)

A - Transmission-only assets.

B - Assets shared equally between transmission and distribution.

C - Assets shared between transmission and distribution

D - Assets shared equally between

metering and distribution.
E - Assets shared equally between SurgePro and distribution.
F - Assets shared between transmission & distribution & metering & SpringNet
G - Assets shared between power generation, transmission , distribution
H - Allocated on the basis of direct labor charges to each business unit component.
I - This class is not currently used.
J - Allocated based on number of customers by business unit - attributed to distribution
K - The class is allocated on the basis of number of vehicles used in each business unit component.
L - Infrared Thermography assets
M - Allocated between Natural Gas & Water Operations.
N - Allocated to the metering departments (Meter & Service Center).
O - Allocated on the basis of Land & Structures Plant by business unit component.
P - Mainframe Computer assets
Q - Allocated on the basis of number of PCs in use by business unit component.
R - Allocated on the basis of City Utilities Operating Income

S - Allocated to the Water Source of Supply business unit component, associated with Lake Springfield.
T - Allocated to the Water Source of Supply business unit component, associated with Fellows Lake.
U - Allocated based on dispatch center usage
V - Operations Technology costs are allocated on the basis of labor dollars for business unit components benefiting from these projects.
W - Operations Technology costs are allocated by the number of laptops in service by business unit component.
X - Operations Technology costs are allocated to the electric distribution department.
Y - Operations Technology costs are allocated to the natural gas distribution department.
Z - Operations Technology costs are allocated to the water distribution department.
AA -Allocted based on number of work orders created by product in Job Order Tracking System.
BB - Allocated on the basis of total property insurance values, by business unit component.
CC - Assets shared between Telcom system and IT. IT portion is allocated to all business units based on allocator H (direct labor charges).

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## Worksheet E - Transmission Plant Summary

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G |
|---|---|---|---|---|---|---|
| Line No. | Rate Base | Reference | Company Total | Allocator Pct. | Transmission Amount | |
| 1 | Gross Plant in Service: | | | | | |
| 2 | Transmission Plant | | | | | |
| 3 | Land & Land Rights | E350 | | | $ - | |
| 4 | Structures & Improvements | E352 | | | - | |
| 5 | Station Equipment | E353 | | | - | |
| 6 | Towers & Fixtures | E354 | | | - | |
| 7 | Poles & Fixtures | E355 | | | - | |
| 8 | Overhead Conductors & Devices | E356 | | | - | |
| 9 | Underground Conduit | E357 | | | - | |
| 10 | Underground Conductors & Devices | E358 | | | - | |
| 11 | Roads & Trails | E359 | | | - | |
| 12 | Total Transmission Gross Plant in Service | sum of Lines 3-11 | **$ -** | | **$ -** | Carry forward to Worksheet D, Line 2, Col. F |
| 13 | Accumulated Depreciation: | | | | | |
| 14 | Transmission Plant | | | | | |
| 15 | Land & Land Rights | E350 | | | $ - | |
| 16 | Structures & Improvements | E352 | | | - | |
| 17 | Station Equipment | E353 | | | - | |
| 18 | Towers & Fixtures | E354 | | | - | |
| 19 | Poles & Fixtures | E355 | | | - | |
| 20 | Overhead Conductors & Devices | E356 | | | - | |

| | | | | | |
|---|---|---|---|---|---|
| 21 | Underground Conduit | E357 | | - | |
| 22 | Underground Conductors & Devices | E358 | | - | |
| 23 | Roads & Trails | E359 | | - | |
| 24 | Total Transmission Accumulated Depreciation | sum of Lines 15-23 | **$ -** | **$ -** | Carry forward to Worksheet D, Line 3, Col. F |

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## Worksheet F - Analysis of Account 566

| Line No. | Col. B Account | Col. C | Col. D | Col. E | Col. F | Col. G | Col. H |
|---|---|---|---|---|---|---|---|
| | | Description | | | | Transmission Amount | |
| 1 | | Less: LSE Expenses: | | | | | |
| 2 | 5660 03 | SPP Administrative Expenses | | | | | |
| 3 | 5660 04 | SPP Power Pool Billing | | | | | |
| 4 | 5660 05 | FERC Schedule 12 Fees | | | | | |
| 5 | 5660 06 | FERC Schedule 11 Charges | | | | | |
| 6 | 5660 07 | Ancillary Transmission Service | | | | | |
| 7 | 5660 10 | Other Exclusions | | | | | |
| 8 | 5660 11 | Schedule 11 Base Zonal Charges | | | | | |
| 9 | 5660 12 | Schedule 11 Base Regional Charges | | | | | |
| 10 | 5660 13 | Schedule 12 FERC Assessment Charges | | | | | |
| 11 | 5660 14 | Schedule 7 Charges | | | | | |
| 12 | 5660 15 | Schedule 2 Charges | | | | | |
| 13 | **Subtotal** | | | sum of Lines 2-12 | | - | Carry forward to Worksheet C, Line 11, Col. E |

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## Worksheet G - Account 448000 - SJE 207001 (Telecommunications Pole Rental)

| | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G | Col. H | | Col. J | Col. K |
|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Journal | Account | Product | Dept | Project | Activity | Amount | Stat Amount | Date | Journal Line Description |
| 1 | | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | | | | | | | | | | |
| 4 | | | | | | | | | | |
| 5 | | | | | | | | | | |
| 6 | | | | | | | | | | |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 10 | | | | | | | | | | |
| 11 | | | | | | | | | | |
| 12 | | | | | | | | | | |
| 13 | | | **Total** | | sum of lines 1-12 | | **$ -** | | | Carry forward to Worksheet Rate, Line 4 |

| | | |
|---|---|---|
| **0** | | Page 1 of 1 |
| **0** | | |
| **0** | | |

## Worksheet H - Allocation of Administrative & General costs

| Line No. | Account | Description | Col. B | Col. C | Col. D | Col. E<br>Generation | Col. F<br>Transmission | Col. G<br>Distribution | Col. H<br>Metering | Col. I<br>Billing & Collection | Col. J<br>Total Electric | Col. K<br>All Other Direct Charges | Col. L<br>Total Direct A&G Charges | Col. M<br>Common A&G Charges | Col. N<br>Total A&G Charges |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | ***Step 1 - Direct A&G charges to specific cost center.*** | | | | | | | | | | | | | | |
| | | | | | | E | F | G | H | I | J= Sum(E:J) | K | L= J+K | M | N= L+M |
| 1 | 920000 | Administrative & General (A&G) Salaries | | | | | | | | | $ - | | $ - | | $ - |
| 2 | 921000 | Office Supplies & Other Expenses | | | | | | | | | - | | - | | - |
| 3 | 923000 | Outside Services - Employed - A&G | | | | | | | | | - | | - | | - |
| 4 | 924000 | Liability & Other Insurance | | | | | | | | | - | | - | | - |
| 5 | 924100 | Property Insurance | | | | | | | | | - | | - | | - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 925000 | Injuries & Damages - A&G | | | | | | - | | - | | - | |
| 7 | 926000 | Employee Pensions & Benefits - A&G | | | | | | - | | - | | - | |
| 8 | 930100 | General Advertising | | | | | | - | | - | | - | |
| 9 | 930200 | Misc. General Expenses - A&G | | | | | | - | | - | | - | |
| 10 | 931000 | Rents - A&G | | | | | | - | | - | | - | |
| 11 | 932000 | Maintenance of General Plant - A&G | | | | | | - | | - | | - | |
| 12 | | **A&G Charges** | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | |
| 13 | | Less: Excluded Corporate Dues | | (105,204) | | | | | | | | | |
| 14 | | **Net A&G Charges** | | $ (105,204) | Carry forward to Worksheet ATRR, Line 4, Col. G | | | | | | | | |

***Step 2- Common A&G charges collected in pool***

| | | |
|---|---|---|
| 15 | Common A&G Charges (Line 12, Col. M) | $ - |
| 16 | Less: Corporate Dues and Advertising | |
| 17 | Each capital project expenditure has A&G added to capital asset; reduces common A&G pool | |
| 18 | Total Common A&G | $ - |

| | | | | |
|---|---|---|---|---|
| | Charges, Expensed | | | |

| | ***Step 3 - Calculate Actual Operating costs excluding Depreciation & Fuels*** | **120 000 TRANSMISSION** | **TOTAL City Utilities** |
|---|---|---|---|
| 19 | Other Production | | |
| 20 | Distribution And Transmission | | |
| 21 | Bus And Garage Operations | | |
| 22 | Customer Accounting | | |
| 23 | Customer Informational | | |
| 24 | Customer Selling | | |
| 25 | Maintenance | | |
| 26 | Other Services | | |
| 27 | Total Operating Expenses excl Fuels, A&G, Depreciation and PILOT | $ - | $ - |
| 28 | *Percent based on current year (Line 27, Col. E/Col F)* | ***#DIV/0!*** | |

| | ***Step 4 - Allocate Common A&G to individual functions.*** | Total Company | Allocator | Transmission |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 29 | Total Company Common A&G Charges | $ - | #DIV/0! | **#DIV/0!** |
| 30 | (Line 18 X Line 28) | | | Carry forward to Worksheet ATRR, Line 5, Cols G & H |

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**Worksheet I - Upgrade Revenue Requirements Determination**
**This Worksheet is used to calculate the ATRR amounts for Base Plan Upgrades, Transmission Service Upgrades and Economic Upgrades authorized by SPP.**

| Col. A Line No. | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G | Col. H | Col. I | Col. J |
|---|---|---|---|---|---|---|---|---|---|
| | **I. Project Summary** | | | | | | | | |
| 1 | | | | | | | | | |
| 2 | **A. ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY** | | | | | | | | |
| 3 | **Project Description Summary** | | **Upgrade Type** | **In-Service** | **NPCC** | **Net Plant** | **Rev. Req.** | **PTP Rev.** | **NETATRR** |
| 4 | | | | | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | | | | | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | | | | | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | | | | | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | | | | | | | | | |
| 9 | **TOTALS** | | | | | **$ -** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |

Carry forward to Workshe

et Rate , Line 7, Col. G

| | |
|---|---|
| 10 | **PTP Schedule 11 Revenue Calculation** |
| 11 | |

| | | |
|---|---|---|
| 12 | **NPCC (Worksheet B, Line 10, Col. C)** | #DIV/0! |

13 Note: Schedule 11 Point-to-point revenues are allocated based on previous year's ATRR.

## II Net Plant and Depreciation Calculations



14 **A. Facilities.**

| | | | | | |
|---|---|---|---|---|---|
| 15 | | | | | |
| 16 | **Project 1:** | | | | |
| 17 | | | | | |
| 18 | **Col. A** | **Col. B** | **Col. C** | **Col. D** | **Col. E** | **Col. F** |
| 19 | | Details | | | | |
| 20 | | Investment Service | $ - | Current Year | | |
| 21 | | Fiscal Year (yyyy) | 0 | | | |
| 22 | | Service Fiscal Month (1-12) | 2 | | | |
| 23 | | Useful Life | | Annual Depreciation Expense | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 24 | SPP Project ID | | (Investment / Useful Life) | | |
| 25 | SPP Upgrade ID | | | | |
| 26 | **Investment** | **Plant Balance** | **Depreciation Expense** | **Ending** | |
| 27 | **Year** | | | **Balance** | |
| | | $ | $ | $ | |
| 28 | 0 | - | - | - | |
| 29 | 1 | - | - | - | |
| 30 | 2 | - | - | - | |
| 31 | 3 | - | - | - | |
| 32 | 4 | - | - | - | |
| 33 | 5 | - | - | - | |
| 34 | 6 | - | - | - | |
| 35 | 7 | - | - | - | |
| 36 | 8 | - | - | - | |
| 37 | 9 | - | - | - | |
| 38 | 10 | - | - | - | |
| 39 | 11 | - | - | - | |
| 40 | 12 | - | - | - | |
| 41 | 13 | - | - | - | |
| 42 | 14 | - | - | - | |
| 43 | 15 | - | - | - | |
| 44 | 16 | - | - | - | |
| 45 | 17 | - | - | - | |
| 46 | 18 | - | - | - | |
| 47 | 19 | - | - | - | |
| 48 | 20 | - | - | - | |
| 49 | 21 | - | - | - | |

| | | | | |
|---|---|---|---|---|
| 50 | 22 | - | - | - |
| 51 | 23 | - | - | - |
| 52 | 24 | - | - | - |
| 53 | 25 | - | - | - |
| 54 | 26 | - | - | - |
| 55 | 27 | - | - | - |
| 56 | 28 | - | - | - |
| 57 | 29 | - | - | - |
| 58 | 30 | - | - | - |
| 59 | 31 | - | - | - |
| 60 | 32 | - | - | - |
| 61 | 33 | - | - | - |
| 62 | 34 | - | - | - |
| 63 | 35 | - | - | - |
| 64 | 36 | - | - | - |
| 65 | 37 | - | - | - |
| 66 | 38 | - | - | - |
| 67 | 39 | - | - | - |
| 68 | 40 | - | - | - |
| 69 | 41 | - | - | - |
| 70 | 42 | - | - | - |
| 71 | 43 | - | - | - |
| 72 | 44 | - | - | - |
| 73 | 45 | - | - | - |
| 74 | 46 | - | - | - |
| 75 | 47 | - | - | - |
| 76 | 48 | - | - | - |
| 77 | 49 | - | - | - |

| | | | | |
|---|---|---|---|---|
| 78 | 2061 | - | - | - |



**Project 2:**

| | | | | |
|---|---|---|---|---|
| 82 | Details | | | |
| 83 | Investment Service Fiscal Year (yyyy) | $ - | Current Year | 0 |
| 84 | Service Fiscal Month (1-12) | 0 | | |
| 85 | Useful Life | | Annual Depreciation Expense (Investment / Useful Life) | $ - |
| 86 | SPP Project ID | | | |
| 87 | SPP Upgrade ID | | | |

| | Investment Year | Plant Balance | Depreciation Expense | Ending Balance |
|---|---|---|---|---|
| 88 | | | | |
| 89 | | | | |
| | | $ | $ | $ |
| 90 | 0 | - | - | - |
| 91 | 1 | - | - | - |
| 92 | 2 | - | - | - |
| 93 | 3 | - | - | - |
| 94 | 4 | - | - | - |
| 95 | 5 | - | - | - |
| 96 | 6 | - | - | - |
| 97 | 7 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | |
| 98 | 8 | - | - | - | |
| 99 | 9 | - | - | - | |
| 100 | 10 | - | - | - | |
| 101 | 11 | - | - | - | |
| 102 | 12 | - | - | - | |
| 103 | 13 | - | - | - | |
| 104 | 14 | - | - | - | |
| 105 | 15 | - | - | - | |
| 106 | 16 | - | - | - | |
| 107 | 17 | - | - | - | |
| 108 | 18 | - | - | - | |
| 109 | 19 | - | - | - | |
| 110 | 20 | - | - | - | |
| 111 | 21 | - | - | - | |
| 112 | 22 | - | - | - | |
| 113 | 23 | - | - | - | |
| 114 | 24 | - | - | - | |
| 115 | 25 | - | - | - | |
| 116 | 26 | - | - | - | |
| 117 | 27 | - | - | - | |
| 118 | 28 | - | - | - | |
| 119 | 29 | - | - | - | |
| 120 | 30 | - | - | - | |
| 121 | 31 | - | - | - | |
| 122 | 32 | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 123 | 33 | - | - | - | |
| 124 | 34 | - | - | - | |
| 125 | 35 | - | - | - | |
| 126 | 36 | - | - | - | |
| 127 | 37 | - | - | - | |
| 128 | 38 | - | - | - | |
| 129 | 39 | - | - | - | |
| 130 | 40 | - | - | - | |
| 131 | 41 | - | - | - | |
| 132 | 42 | - | - | - | |
| 133 | 43 | - | - | - | |
| 134 | 44 | - | - | - | |
| 135 | 45 | - | - | - | |
| 136 | 46 | - | - | - | |
| 137 | 47 | - | - | - | |
| 138 | 48 | - | - | - | |
| 139 | 49 | - | - | - | |
| 140 | 50 | - | - | - | |
| 141 | | | | | |



142 **Project 3:**

143

144

| | | | | | |
|---|---|---|---|---|---|
| 145 | Details | | | | |
| 146 | Investment Service Fiscal Year (yyyy) | $ - | Current Year | **0** | |
| 147 | Service Fiscal Month (1-12) | 0 | | | |
| 148 | Useful Life | - | Annual Depreciation Expense (Investment / Useful Life) | $ - | |
| 149 | SPP Project ID | - | | | |
| 150 | SPP Upgrade ID | - | | | |
| 151 | **Investment Year** | **Plant Balance** | **Depreciation Expense** | **Ending Balance** | |
| 152 | | $ | $ | $ | |
| 153 | 0 | - | - | - | |
| 154 | 1 | - | - | - | |
| 155 | 2 | - | - | - | |
| 156 | 3 | - | - | - | |
| 157 | 4 | - | - | - | |
| 158 | 5 | - | - | - | |
| 159 | 6 | - | - | - | |
| 160 | 7 | - | - | - | |
| 161 | 8 | - | - | - | |
| 162 | 9 | - | - | - | |
| 163 | 10 | - | - | - | |
| 164 | 11 | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 4 | | - | - | - | |
| 16 | | | | | |
| 5 | 12 | - | - | - | |
| 16 | | | | | |
| 6 | 13 | - | - | - | |
| 16 | | | | | |
| 7 | 14 | - | - | - | |
| 16 | | | | | |
| 8 | 15 | - | - | - | |
| 16 | | | | | |
| 9 | 16 | - | - | - | |
| 17 | | | | | |
| 0 | 17 | - | - | - | |
| 17 | | | | | |
| 1 | 18 | - | - | - | |
| 17 | | | | | |
| 2 | 19 | - | - | - | |
| 17 | | | | | |
| 3 | 20 | - | - | - | |
| 17 | | | | | |
| 4 | 21 | - | - | - | |
| 17 | | | | | |
| 5 | 22 | - | - | - | |
| 17 | | | | | |
| 6 | 23 | - | - | - | |
| 17 | | | | | |
| 7 | 24 | - | - | - | |
| 17 | | | | | |
| 8 | 25 | - | - | - | |
| 17 | | | | | |
| 9 | 26 | - | - | - | |
| 18 | | | | | |
| 0 | 27 | - | - | - | |
| 18 | | | | | |
| 1 | 28 | - | - | - | |
| 18 | | | | | |
| 2 | 29 | - | - | - | |
| 18 | | | | | |
| 3 | 30 | - | - | - | |
| 18 | | | | | |
| 4 | 31 | - | - | - | |
| 18 | | | | | |
| 5 | 32 | - | - | - | |
| 18 | | | | | |
| 6 | 33 | - | - | - | |
| 18 | | | | | |
| 7 | 34 | - | - | - | |
| 18 | | | | | |
| 8 | 35 | - | - | - | |
| 18 | | | | | |
| 9 | 36 | - | - | - | |

| | | | | |
|---|---|---|---|---|
| 37 | - | - | - | |
| 38 | - | - | - | |
| 39 | - | - | - | |
| 40 | - | - | - | |
| 41 | - | - | - | |
| 42 | - | - | - | |
| 43 | - | - | - | |
| 44 | - | - | - | |
| 45 | - | - | - | |
| 46 | - | - | - | |
| 47 | - | - | - | |
| 48 | - | - | - | |
| 49 | - | - | - | |



**Project 4:**

| Details | | | |
|---|---|---|---|
| Investment Service Fiscal Year | $ - 0 | Current Year | **0** |

| | | | | |
|---|---|---|---|---|
| 210 | (yyyy) Service | | | |
| | Fiscal Month (1-12) | - | | |
| 211 | | | Annual Depreciation | $ |
| | Useful Life | - | Expense | - |
| 212 | SPP Project ID | | (Investment / Useful Life) | |
| 213 | SPP Upgrade ID | | | |

| 214 | **Investment** | **Plant** | **Depreciation** | **Ending** | |
|---|---|---|---|---|---|
| 215 | **Year** | **Balance** | **Expense** | **Balance** | |
| 216 | | $ | $ | $ | |
| | 0 | - | - | - | |
| 217 | 1 | - | - | - | |
| 218 | 2 | - | - | - | |
| 219 | 3 | - | - | - | |
| 220 | 4 | - | - | - | |
| 221 | 5 | - | - | - | |
| 222 | 6 | - | - | - | |
| 223 | 7 | - | - | - | |
| 224 | 8 | - | - | - | |
| 225 | 9 | - | - | - | |
| 226 | 10 | - | - | - | |
| 227 | 11 | - | - | - | |
| 228 | 12 | - | - | - | |
| 229 | 13 | - | - | - | |
| 230 | 14 | - | - | - | |
| 231 | 15 | - | - | - | |
| 232 | 16 | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 2 | | - | - | - | |
| 23 | | | | | |
| 3 | 17 | - | - | - | |
| 23 | | | | | |
| 4 | 18 | - | - | - | |
| 23 | | | | | |
| 5 | 19 | - | - | - | |
| 23 | | | | | |
| 6 | 20 | - | - | - | |
| 23 | | | | | |
| 7 | 21 | - | - | - | |
| 23 | | | | | |
| 8 | 22 | - | - | - | |
| 23 | | | | | |
| 9 | 23 | - | - | - | |
| 24 | | | | | |
| 0 | 24 | - | - | - | |
| 24 | | | | | |
| 1 | 25 | - | - | - | |
| 24 | | | | | |
| 2 | 26 | - | - | - | |
| 24 | | | | | |
| 3 | 27 | - | - | - | |
| 24 | | | | | |
| 4 | 28 | - | - | - | |
| 24 | | | | | |
| 5 | 29 | - | - | - | |
| 24 | | | | | |
| 6 | 30 | - | - | - | |
| 24 | | | | | |
| 7 | 31 | - | - | - | |
| 24 | | | | | |
| 8 | 32 | - | - | - | |
| 24 | | | | | |
| 9 | 33 | - | - | - | |
| 25 | | | | | |
| 0 | 34 | - | - | - | |
| 25 | | | | | |
| 1 | 35 | - | - | - | |
| 25 | | | | | |
| 2 | 36 | - | - | - | |
| 25 | | | | | |
| 3 | 37 | - | - | - | |
| 25 | | | | | |
| 4 | 38 | - | - | - | |
| 25 | | | | | |
| 5 | 39 | - | - | - | |
| 25 | | | | | |
| 6 | 40 | - | - | - | |
| 25 | | | | | |
| 7 | 41 | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 258 | 42 | - | - | - | |
| 259 | 43 | - | - | - | |
| 260 | 44 | - | - | - | |
| 261 | 45 | - | - | - | |
| 262 | 46 | - | - | - | |
| 263 | 47 | - | - | - | |
| 264 | 48 | - | - | - | |
| 265 | 49 | - | - | - | |
| 266 | | | | | |

**Project 5:**



| Details | | | |
|---|---|---|---|
| | $ | Current | |
| Investment | - | Year | **0** |
| Service Fiscal Year (yyyy) | 0 | | |
| Service Fiscal Month (1-12) | - | | |
| | | Annual Depreciation | $ |
| Useful Life | - | Expense | - |
| | | | |
| SPP Project ID | | (Investment / Useful Life) | |
| SPP Upgrade ID | | | |

| Investment Year | Plant Balance | Depreciation Expense | Ending Balance |
|---|---|---|---|
| | $ | $ | $ |
| 0 | - | - | - |
| 1 | - | - | - |
| 2 | - | - | - |
| 3 | - | - | - |
| 4 | - | - | - |
| 5 | - | - | - |
| 6 | - | - | - |
| 7 | - | - | - |
| 8 | - | - | - |
| 9 | - | - | - |
| 10 | - | - | - |
| 11 | - | - | - |
| 12 | - | - | - |
| 13 | - | - | - |

| | | | | |
|---|---|---|---|---|
| 29 | | | | |
| 32 | 14 | - | - | - |
| 29 | | | | |
| 42 | 15 | - | - | - |
| 29 | | | | |
| 52 | 16 | - | - | - |
| 29 | | | | |
| 62 | 17 | - | - | - |
| 29 | | | | |
| 72 | 18 | - | - | - |
| 29 | | | | |
| 82 | 19 | - | - | - |
| 29 | | | | |
| 93 | 20 | - | - | - |
| 00 | | | | |
| 03 | 21 | - | - | - |
| 01 | | | | |
| 13 | 22 | - | - | - |
| 02 | | | | |
| 23 | 23 | - | - | - |
| 03 | | | | |
| 33 | 24 | - | - | - |
| 04 | | | | |
| 43 | 25 | - | - | - |
| 05 | | | | |
| 53 | 26 | - | - | - |
| 06 | | | | |
| 63 | 27 | - | - | - |
| 07 | | | | |
| 30 | 28 | - | - | - |
| 08 | | | | |
| 30 | 29 | - | - | - |
| 09 | | | | |
| | 30 | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 31 | 31 | - | - | - | |
| 32 | 32 | - | - | - | |
| 33 | 33 | - | - | - | |
| 34 | 34 | - | - | - | |
| 35 | 35 | - | - | - | |
| 36 | 36 | - | - | - | |
| 37 | 37 | - | - | - | |
| 38 | 38 | - | - | - | |
| 39 | 39 | - | - | - | |
| 40 | 40 | - | - | - | |
| 41 | 41 | - | - | - | |
| 42 | 42 | - | - | - | |
| 43 | 43 | - | - | - | |
| 44 | 44 | - | - | - | |
| 45 | 45 | - | - | - | |
| 46 | 46 | - | - | - | |
| 47 | 47 | - | - | - | |

| | | | | |
|---|---|---|---|---|
| 327 | 48 | - | - | - |
| 328 | 49 | - | - | - |
| 329 | 50 | - | - | - |

**0**
**0**
**0**

## Worksheet J - Sponsored Upgrades
## Revenue Requirements Determination

| Col. A Line No. | Col. B | Col. C | Col. D | Col. E | Col. F | Col. G | Col. H |
|---|---|---|---|---|---|---|---|
| 1 | **I. Project Summary** | | | | | | |
| 2 | **A. ANNUAL TRANSMISSION REVENUE REQUIREMENT SUMMARY** | | | | | | |
| 3 | **Project Description Summary** | | **In-Service** | **Gross Plant** | **NPCC( see note)** | **Net Plant** | **Rev. Req.** |
| 4 | | | | $ - | | $ - | $ - |
| 5 | | | | $ - | | $ - | $ - |
| 6 | | | | $ - | | $ - | $ - |
| 7 | | | | $ - | | $ - | $ - |
| 8 | | | | | | | |
| 9 | **TOTALS** | | | **$ -** | | **$ -** | **$ -** |

Note A: NPCC for each Sponsored Upgrade
10 is set at the time the contract is approved.
Note B: No PTP Revenues are allocated to Sponsored Projects since they do not make
11 up any ATRR billed by SPP nor are they used to allocate PTP Revenes by SPP.

## II Net Plant and Depreciation Calculations



12

### A. Facilities. Net Plant and Depreciation Calculations

13

**Sponsored Upgrade 1**

| Col. A | Col. B | Col. C | Col. D | Col. E | Col. F |
|---|---|---|---|---|---|
| 17 | Details | | | | |
| 18 | Investment Service Fiscal Year (yyyy) | $ - | Current Year | | |
| 19 | Service Fiscal Month (1-12) | 0 | | | |
| 20 | Useful Life | | Annual Depreciation Expense (Investment / Useful Life) | $ - | |
| 21 | SPP Project ID | | | | |
| 22 | SPP Upgrade ID | | | | |
| 23 | | | | | |
| 24 | **Investment Year** | **Plant Balance** | **Depreciation Expense** | **Ending Balance** | |
| 25 | | $ | $ | $ | |
| 26 | 0 | - | - | - | |
| 27 | 1 | - | - | - | |
| 28 | 2 | - | - | - | |
| 29 | 3 | - | - | - | |
| 30 | 4 | - | - | - | |
| 31 | 5 | - | - | - | |
| 32 | 6 | - | - | - | |
| 33 | 7 | - | - | - | |
| 34 | 8 | - | - | - | |
| 35 | 9 | - | - | - | |
| 36 | 10 | - | - | - | |
| 37 | 11 | - | - | - | |
| 38 | 12 | - | - | - | |
| 39 | 13 | - | - | - | |
| 40 | 14 | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | |
| 41 | 15 | - | - | - | |
| 42 | 16 | - | - | - | |
| 43 | 17 | - | - | - | |
| 44 | 18 | - | - | - | |
| 45 | 19 | - | - | - | |
| 46 | 20 | - | | - | |
| 47 | 21 | - | - | - | |
| 48 | 22 | - | - | - | |
| 49 | 23 | - | - | - | |
| 50 | 24 | - | - | - | |
| 51 | 25 | - | - | - | |
| 52 | 26 | - | - | - | |
| 53 | 27 | - | - | - | |
| 54 | 28 | - | - | - | |
| 55 | 29 | - | - | - | |
| 56 | 30 | - | - | - | |
| 57 | 31 | - | - | - | |
| 58 | 32 | - | - | - | |
| 59 | 33 | - | - | - | |
| 60 | 34 | - | - | - | |
| 61 | 35 | - | - | - | |
| 62 | 36 | - | - | - | |
| 63 | 37 | - | - | - | |
| 64 | 38 | - | - | - | |
| 65 | 39 | - | - | - | |
| 66 | 40 | - | - | - | |
| 67 | 41 | - | - | - | |

| | | | | |
|---|---|---|---|---|
| 68 | 42 | - | - | - |
| 69 | 43 | - | - | - |
| 70 | 44 | - | - | - |
| 71 | 45 | - | - | - |
| 72 | 46 | - | - | - |
| 73 | 47 | - | - | - |
| 74 | 48 | - | - | - |
| 75 | 49 | - | - | - |
| 76 | 2061 | - | - | - |



**Sponsored Upgrade 2**

| | | | | |
|---|---|---|---|---|
| 80 | Details | | | |
| 81 | Investment | $ - | Current Year | 0 |
| 82 | Service Fiscal Year (yyyy) | 0 | | |
| 83 | Service Fiscal Month (1-12) | - | | |
| 84 | Useful Life | - | Annual Depreciation Expense (Investment / Useful Life) | $ - |
| | SPP Project ID | | | |
| 85 | SPP Upgrade ID | | | |

| | Investment Year | Plant Balance | Depreciation Expense | Ending Balance |
|---|---|---|---|---|
| 86 | | | | |
| 87 | | | | |
| | | $ | $ | $ |
| 88 | 0 | - | - | - |
| 89 | 1 | - | - | - |
| 90 | 2 | - | - | - |
| 91 | 3 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | |
| 92 | 4 | - | - | - | |
| 93 | 5 | - | - | - | |
| 94 | 6 | - | - | - | |
| 95 | 7 | - | - | - | |
| 96 | 8 | - | - | - | |
| 97 | 9 | - | - | - | |
| 98 | 10 | - | - | - | |
| 99 | 11 | - | - | - | |
| 100 | 12 | - | - | - | |
| 101 | 13 | - | - | - | |
| 102 | 14 | - | - | - | |
| 103 | 15 | - | - | - | |
| 104 | 16 | - | - | - | |
| 105 | 17 | - | - | - | |
| 106 | 18 | - | - | - | |
| 107 | 19 | - | - | - | |
| 108 | 20 | - | - | - | |
| 109 | 21 | - | - | - | |
| 110 | 22 | - | - | - | |
| 111 | 23 | - | - | - | |
| 112 | 24 | - | - | - | |
| 113 | 25 | - | - | - | |
| 114 | 26 | - | - | - | |
| 115 | 27 | - | - | - | |
| 116 | 28 | - | - | - | |
| 117 | 29 | - | - | - | |
| 118 | 30 | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 119 | 31 | - | - | - | |
| 120 | 32 | - | - | - | |
| 121 | 33 | - | - | - | |
| 122 | 34 | - | - | - | |
| 123 | 35 | - | - | - | |
| 124 | 36 | - | - | - | |
| 125 | 37 | - | - | - | |
| 126 | 38 | - | - | - | |
| 127 | 39 | - | - | - | |
| 128 | 40 | - | - | - | |
| 129 | 41 | - | - | - | |
| 130 | 42 | - | - | - | |
| 131 | 43 | - | - | - | |
| 132 | 44 | - | - | - | |
| 133 | 45 | - | - | - | |
| 134 | 46 | - | - | - | |
| 135 | 47 | - | - | - | |
| 136 | 48 | - | - | - | |
| 137 | 49 | - | - | - | |
| 138 | 50 | - | - | - | |
| 139 | | | | | |



| | | |
|---|---|---|
| 140 | **Sponsored Upgrade 3** | |
| 141 | | |
| 142 | | |

| | | | | |
|---|---|---|---|---|
| 143 | Details | | | |
| 144 | Investment | $ | Curren | |

| | | | | | |
|---|---|---|---|---|---|
| | | - | t Year | | |
| 145 | Service Fiscal Year (yyyy) | 0 | | | |
| 146 | Service Fiscal Month (1-12) | | | | |
| 147 | Useful Life | | Annual Depreciation Expense | $ - | |
| 148 | SPP Project ID<br>SPP Upgrade ID | | (Investment / Useful Life) | | |
| 149 | **Investment** | **Plant Balance** | **Depreciation Expense** | **Ending** | |
| 150 | **Year** | | | **Balance** | |
| | | $ | $ | $ | |
| 151 | 0 | - | - | - | |
| 152 | 1 | - | - | - | |
| 153 | 2 | - | - | - | |
| 154 | 3 | - | - | - | |
| 155 | 4 | - | - | - | |
| 156 | 5 | - | - | - | |
| 157 | 6 | - | - | - | |
| 158 | 7 | - | - | - | |
| 159 | 8 | - | - | - | |
| 160 | 9 | - | - | - | |
| 161 | 10 | - | - | - | |
| 162 | 11 | - | - | - | |
| 163 | 12 | - | - | - | |
| 164 | 13 | - | - | - | |
| 165 | 14 | - | - | - | |
| 166 | 15 | - | - | - | |
| 167 | 16 | - | - | - | |
| 168 | 17 | - | - | - | |
| 169 | 18 | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 170 | 19 | - | - | - | |
| 171 | 20 | - | - | - | |
| 172 | 21 | - | - | - | |
| 173 | 22 | - | - | - | |
| 174 | 23 | - | - | - | |
| 175 | 24 | - | - | - | |
| 176 | 25 | - | - | - | |
| 177 | 26 | - | - | - | |
| 178 | 27 | - | - | - | |
| 179 | 28 | - | - | - | |
| 180 | 29 | - | - | - | |
| 181 | 30 | - | - | - | |
| 182 | 31 | - | - | - | |
| 183 | 32 | - | - | - | |
| 184 | 33 | - | - | - | |
| 185 | 34 | - | - | - | |
| 186 | 35 | - | - | - | |
| 187 | 36 | - | - | - | |
| 188 | 37 | - | - | - | |
| 189 | 38 | - | - | - | |
| 190 | 39 | - | - | - | |
| 191 | 40 | - | - | - | |
| 192 | 41 | - | - | - | |
| 193 | 42 | - | - | - | |
| 194 | 43 | - | - | - | |
| 195 | 44 | - | - | - | |
| 196 | 45 | - | - | - | |
| 197 | 46 | - | - | - | |

| | | | | |
|---|---|---|---|---|
| 198 | 47 | - | - | - |
| 199 | 48 | - | - | - |
| 200 | 49 | - | - | - |
| 201 | 50 | - | - | - |
| 202 | | | | |



**Sponsored Upgrade 4**

| | | | | |
|---|---|---|---|---|
| 206 | Details | | | |
| 207 | Investment Service Fiscal Year (yyyy) | $ - | Current Year | |
| 208 | Service Fiscal Month (1-12) | 0 | | |
| 209 | Useful Life | | Annual Depreciation Expense | $ - |
| 210 | SPP Project ID | | | |
| 211 | SPP Upgrade ID | | (Investment / Useful Life) | |
| 212 | | | | |
| 213 | **Investment Year** | **Plant Balance** | **Depreciation Expense** | **Ending Balance** |
| 214 | | $ | $ | $ |
| 215 | 0 | - | - | - |
| 216 | 1 | - | - | - |
| 217 | 2 | - | - | - |
| 218 | 3 | - | - | - |
| 219 | 4 | - | - | - |
| 220 | 5 | - | - | - |
| 221 | 6 | - | - | - |
| 222 | 7 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | |
| 223 | 8 | - | - | - | |
| 224 | 9 | - | - | - | |
| 225 | 10 | - | - | - | |
| 226 | 11 | - | - | - | |
| 227 | 12 | - | - | - | |
| 228 | 13 | - | - | - | |
| 229 | 14 | - | - | - | |
| 230 | 15 | - | - | - | |
| 231 | 16 | - | - | - | |
| 232 | 17 | - | - | - | |
| 233 | 18 | - | - | - | |
| 234 | 19 | - | - | - | |
| 235 | 20 | - | - | - | |
| 236 | 21 | - | - | - | |
| 237 | 22 | - | - | - | |
| 238 | 23 | - | - | - | |
| 239 | 24 | - | - | - | |
| 240 | 25 | - | - | - | |
| 241 | 26 | - | - | - | |
| 242 | 27 | - | - | - | |
| 243 | 28 | - | - | - | |
| 244 | 29 | - | - | - | |
| 245 | 30 | - | - | - | |
| 246 | 31 | - | - | - | |
| 247 | 32 | - | - | - | |
| 248 | 33 | - | - | - | |
| 249 | 34 | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 250 | 35 | - | - | - | |
| 251 | 36 | - | - | - | |
| 252 | 37 | - | - | - | |
| 253 | 38 | - | - | - | |
| 254 | 39 | - | - | - | |
| 255 | 40 | - | - | - | |
| 256 | 41 | - | - | - | |
| 257 | 42 | - | - | - | |
| 258 | 43 | - | - | - | |
| 259 | 44 | - | - | - | |
| 260 | 45 | - | - | - | |
| 261 | 46 | - | - | - | |
| 262 | 47 | - | - | - | |
| 263 | 48 | - | - | - | |
| 264 | 49 | - | - | - | |
| 265 | 50 | - | - | - | |

## Transmission Formula Rate Implementation Protocols

## I. ANNUAL UPDATE

1. The transmission formula rate template of City Utilities of Springfield Missouri ("City Utilities") and these Transmission Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of City Utilities for transmission service in the City Utilities zone of the Southwest Power Pool, Inc. ("SPP") footprint. City Utilities must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service ("NITS") and Point-to-Point ("PTP") Transmission Service, as well as rates for Scheduling, System Control and Dispatch Service ("Schedule 1 Service") in the City Utilities zone of the SPP footprint.

2. The Formula Rate shall be applicable to service on and after April 1 of each calendar year through March 31 of the following calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before February 1 of each calendar year, City Utilities shall:

   (a) Recalculate the ATRR and the rates for zonal NITS, zonal PTP and Schedule 1 service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

   (b) Provide its Annual Update to SPP and cause such information to be accessible on SPP's website; and

   (c) Post its Annual Update to the City Utilities website; and

   (d) If the date for posting the Annual Update falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission (FERC), then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Posting Date." Any delay in the Posting Date shall result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these Protocols.

4. Concurrent with the Annual Update postings, City Utilities shall provide a notice of such posting via an email distribution list to all Interested Parties.

   (a) Interested Parties shall include:

      i. Customers under the SPP Tariff;

ii. the Missouri Public Service Commission;

iii. the Kansas Corporation Commission;

iv. Missouri Consumer Advocacy Agencies;

v. Missouri Attorney General; and

vi. any person or entity who communicates to City Utilities an interest in participating in the Annual Update process.

5. The Annual Update shall:

(a) Include a workable populated rate formula template with fully functional spreadsheets showing the calculation of the Annual Update and underlying workpapers in native format with links and formulas intact, including sufficiently detailed workpapers and supporting documentation for data;

(b) Be based on the independently-audited books and records of City Utilities for the most recent fiscal year (October 1 through September 30);

(c) Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

(d) With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, City Utilities shall identify:

i. Any accounting changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

ii. Any items included in the Formula Rate at an amount other than a historic cost basis; and

iii. The individual impact of any changes in i. or ii. above on charges billed under the Formula Rate; and

(e) Not seek to modify the Formula Rate.

## II. Review of Annual Update

Within twenty (20) but not less than 10 days after the posting of City Utilities' Annual Update, City Utilities will host a Meeting for Interested Parties to discuss the Annual Update ("Annual Meeting"). City Utilities shall provide notice of this meeting concurrent with the posting of the Formula Rate Update accessible on SPP's website and City Utilities' website. The notice shall include the date, time and location of the Annual Meeting and shall be provided via email distribution list of Interested Parties identified in Section I.4.(a) above. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically.

**III. Information Exchange**

1. Interested Parties may begin submitting information requests immediately following the Posting Date of the Annual Rate Update and will have until sixty (60) days of the date of the posting to serve reasonable information requests on City Utilities for information and work papers supporting the Annual Rate Update. Such information requests shall be limited to that what is necessary to determine:

   (a) The extent or effect of an accounting change;

   (b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

   (c) The proper application of the Formula Rate and procedures in these Protocols;

   (d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

   (e) The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

   (f) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable.

2. City Utilities shall make a good faith effort to respond to information requests pertaining to the Annual Update within seven (7) business days.

3. City Utilities shall post on its website and cause to be accessible on the SPP Website all

information requests from Interested Parties and City Utilities' response(s) to such requests. If responses to information requests contain information deemed by City Utilities to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and City Utilities.

## IV. Informal Challenge Procedures

1. Interested Parties shall have until April 15 (or the first Business Day after April 15 if April 15 falls on a weekend or holiday) to notify City Utilities in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. City Utilities will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. City Utilities, and, if appropriate, SPP, shall appoint representatives to work with the Interested Party to resolve the Informal Challenge.

2. City Utilities will post on its website and cause to be accessible on the SPP Website all Informal Challenges from Interested Parties and City Utilities' responses to the Informal Challenges. If responses to information requests contain information deemed by City Utilities to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and City Utilities.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by City Utilities and resolved prior to the Informational Filing shall be reported in the Informational Filing made with FERC and will be reflected in the Annual Rate Update for the following Rate Year.

## V. Formal Challenges

1.A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the Federal Power Act, and shall be served upon City Utilities contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), by facsimile, express delivery or messenger to the individual listed as the contact person in City Utilities' Informational Filing.

## VI. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of return on equity ("ROE"), depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the Federal Power Act Sections 205 or 206.

3. If City Utilities makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the SPP Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the SPP Tariff.

## VII. Informational Filing

1. By June 1 of each year, City Utilities shall submit to FERC an informational filing ("Informational Filing") of its Annual Update.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   (a) That input data under the Formula Rate is properly recorded in any underlying workpapers;

   (b) That City Utilities has properly applied the Formula Rate and these procedures;

   (c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   (d) The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, City Utilities shall provide notice of the Informational Filing via the mail distribution list and by posting the docket number assigned to the Informational filing on City Utilities website and accessible on SPP's website.

## VIII. Joint SPP Transmission Owners' Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, City Utilities will participate in that process.

# ADDENDUM 18 TO ATTACHMENT H

## The Empire District Electric Company

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**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**


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|---|---|
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| ATTACHMENT 2 - TAXES OTHER THAN INCOME | 12 |
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## ADDENDUM 18 TO ATTACHMENT H - Page 2 of 47

### The Empire District Electric Company
### Formula Rate Template Inputs
**(For Rate Year Beginning July 1, 20 , Based on 20__ Data)**

**Data Entered Directly From FERC Form No. 1 ("FF1"):**

| Line No | Account/Description/Classification | Inputs From 20 FF1 | FF1 Page Location | Template Sheet of the Link |
|---|---|---|---|---|
| 1 | Prepayments (165) | - | 111.57c | ATT 5 - Cost Support, Ln. 37 |
| 2 | Preferred Stock Issued (204) - End of Year | - | 112.3c | ATT 8 - Pref Stock, Ln. 2, Col. A |
| 3 | Preferred Stock Issued (204) - Beg of Year | - | 112.3d | ATT 8 - Pref Stock, Ln. 1, Col. A |
| 4 | Unappropriated Undistrib Subsid Earnings (216.1) - End of Yr | - | 112.12c | ATT 11 - Reconciliation, Ln. 6, Col. C |
| 5 | Unappropriated Undistrib Subsid Earnings (216.1) - Beg of Yr | - | 112.12d | ATT 11 - Reconciliation, Ln. 5, Col. C |
| 6 | Accum Other Comp Income (219) - End of Year | - | 112.15c | ATT 7 - Com Stock, Ln. 2, Col. F |
| 7 | Accum Other Comp Income (219) - Beginning of Year | - | 112.15d | ATT 7 - Com Stock, Ln. 1, Col. F |
| 8 | Total Proprietary Capital - End of Year | - | 112.16c | ATT 7 - Com Stock, Ln. 2, Col. A |
| 9 | Total Proprietary Capital - Beginning of Year | - | 112.16d | ATT 7 - Com Stock, Ln. 1, Col. A |
| 10 | Bonds (221) - End of Year | - | 112.18c | ATT 11- Reconciliation, Ln. 4, Col. C |
| 11 | Bonds (221) - Beginning of Year | - | 112.18d | ATT 11 - Reconciliation, Ln. 3, Col. C |
| 12 | (Less) Reacquired Bonds (222) - End of Year | - | 112.19c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. C |
| 13 | (Less) Reacquired Bonds (222) - Beginning of Year | - | 112.19d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. C |
| 14 | Advances from Assoc Companies (223) - End of Year | - | 112.20c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. A |
| 15 | Advances from Assoc Companies (223) - Beginning of Year | - | 112.20d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. A |
| 16 | Other Long Term Debt (224) - End of Year | - | 112.21c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. D |
| 17 | Other Long Term Debt (224) - Beginning of Year | - | 112.21d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. D |
| 18 | Unamortized Premium on Long Term Debt - End of Year | - | 112.22c | ATT 9 - LTD, Pg. 1, Ln. 5 |
| 19 | Unamortized Premium on Long Term Debt - Beginning of Year | - | 112.22d | ATT 9 - LTD, Pg. 1, Ln. 4 |
| 20 | (Less) Unamortized Disc. on Long-Term Debt (Debit) - End of Yr | - | 112.23c | ATT 9 - LTD, Pg. 1, Ln. 8 |
| 21 | (Less) Unamortized Disc. on Long-Term Debt (Debit) - Beg of Yr | - | 112.23d | ATT 9 - LTD, Pg. 1, Ln. 7 |
| 22 | Accumulated Provision for Injuries and Damages (228.2) | - | 112.28c | ATT 4 - Non-Escowed Funds, Ln. 4 |
| 23 | Elec - Taxes Other than Income Taxes (408.1) | - | 115.14g | ATT-2, Other Taxes, Ln. 30 |
| 23a | Elec - Deficient Deferred Taxes Regulatory Asset (182.3) | - | 111 | Appendix A - Pg. 1, Ln. 36a |
| 23b | Elec - Excess Deferred Taxes Regulatory Liability (254) | - | Attachment 14, Summary of Excess Deferred Income Tax Amoritazations, Line 3, Column D from the prior year's TFR Update. | Appendix A - Pg. 1, Ln. 36b |
| 23c | Elec - Amortized Deficient Deferred Taxes (410.1) | - | 114 | Appendix A - Pg. 3, Ln 103a |
| 23d | Elec - Amortized Excess Deferred Taxes (411.1) | - | Attachment 14 Summary of Excess Deferred Income Tax Amortizations, Line 3, Column F from the current year's TFR Update. | Appendix A - Pg. 3, Ln 103b |
| 24 | Interest on LTD (427) | - | 117.62c | ATT 11 - Reconciliation, Ln. 2, Col. C |
| 25 | Amort of Debt Disc & Expenses (428) | - | 117.63c | ATT 9 - LTD, Pg. 2, Ln. 2 |
| 26 | Amort of Loss on Reacquired Debt (428.1) | - | 117.64c | ATT 9 - LTD, Pg. 2, Ln. 3 |
| 27 | (less) Amort of Premium on Debt-Credit (429) | - | 117.65c | ATT 9, Pg. 2, Ln. 4 |
| 28 | (less) Amort of Gain on Reacquired Debt-Credit (429.1) | - | 117.66c | ATT 9, Pg. 2, Ln. 5 |
| 29 | Total Dividends Declared Pref Stock (437) | - | 118.29c | ATT 11 - Reconciliation, Ln. 1, Col. C |
| 30 | Electric - Amort of Oth Utility Plant | - | 200.21c | Appendix A - Ln. 8 & ATT 10A, Ln. 42 |
| 31 | Total Intangible Plant | - | 205.5g | Appendix A - Ln. 22 & ATT 10A, Ln. 40 |
| 32 | Total Electric Plant in Service | - | 207.104g | Appendix A - Ln. 6 |
| 33 | Trn - Total Transmission Plant | - | 207.58g | Appendix A - Ln. 20 |
| 34 | Transmission Materials & Supplies | - | 227.8.c | Appendix A - Ln. 41 |
| 35 | Stores Expense Undistributed (Account 163) | - | 227.16.c | Appendix A - Ln. 38 |
| 36 | TOTAL (Acct 190) | - | 234.18c | ATT 1 - ADIT, Pg. 1, Ln. 23 |
| 37 | TOTAL (Acct 281) | - | 273.17k | ATT 1 - ADIT, Pg. 2, Ln. 13 |
| 38 | TOTAL (Acct 282) | - | 275.9k | ATT 1 - ADIT, Pg. 2, Ln. 13 |
| 39 | TOTAL (Acct 283) | - | 277.19k | ATT 1 - ADIT, Pg. 3, Ln. 23 |
| 40 | (561) Load Dispatching | - | 321.84b | ATT 5 - Cost Support, Ln. 50 |
| 41 | (561.1) Load Dispatch Reliability | - | 321.85b | ATT 5 - Cost Support, Ln. 50 |
| 42 | (561.2) Load Dispatch - Monitor and Operate Transm System | - | 321.86b | ATT 5 - Cost Support, Ln. 50 |
| 43 | (561.3) Load Dispatch - Transm Dispatch and Scheduling | - | 321.87b | ATT 5 - Cost Support, Ln. 50 |
| 44 | (561.4) Scheduling, System Control and Dispatch Services | - | 321.88b | ATT 5 - Cost Support, Ln. 50 |
| 45 | Interest on Debt to Assoc. Companies | - | 117.67c | ATT 9 - LTD, Pg. 2, Ln. 5a |
| 46 | Gen - Total General Plant | - | 207.99g | Appendix A - Ln. 21 |
| 47 | Transmission Accum. Depreciation | - | 219.25c | Appendix A - Ln. 28 |
| 48 | General Accum. Depreciation | - | 219.28c | Appendix A - Ln. 29 |
| 49 | Total Accum Depr Utility Plant | - | 219.29.c | ATT 11 - Reconciliation, Ln. 7, Col. C |
| 50 | Amortized Investment Tax Credit | - | 266.8f | ATT 5 - Cost Support, Ln. 103 |
| 51 | Trn Oper Transmission of Elec by Others | - | 321.96b | ATT 5 - Cost Support, Ln. 50 |
| 52 | Total Transmission Expenses | - | 321.112b | ATT 5 - Cost Support, Ln. 49 |
| 53 | A&G Oper Regulatory Commission Expenses | - | 323.189b | Appendix A - Ln. 58 & ATT - 5, Ln. 63 |
| 54 | A&G Oper General Advertising Expenses | - | 323.191b | Appendix A - Ln. 59 |
| 55 | Total Admin & General Expenses | - | 323.197b | Appendix A - Ln. 54 |

| | | | | |
|---|---|---|---|---|
| 56 | Depreciation Exp (403) - Intangible Plant | - | 336.1b | Appendix A - Ln.69 |
| 57 | Depr Exp Asset Retire (403.1) - Intangible Plant | - | 336.1c | Appendix A - Ln. 69 |
| 58 | Amort Lim Term (404) - Intangible Plant | - | 336.1d | Appendix A - Ln. 69 & ATT 10, Ln. 41 |
| 59 | Amort of Other Intangible Electric Plant (405) | - | 336.1e | Appendix A - Ln. 69 |
| 60 | Depreciation Exp (403) - Transmission Plant | - | 336.7b | Appendix A - Ln. 67 |
| 61 | Depr Exp Asset Retire (403.1) - Transmission Plant | - | 336.7c | Appendix A - Ln. 67 |
| 62 | Amort Lim Term (404) - Transmission Plant | - | 336.7d | Appendix A - Ln. 67 |
| 63 | Depreciation Exp (403) - General Plant | - | 336.10b | Appendix A - Ln. 68 |
| 64 | Depr Exp Asset Retire (403.1) - General Plant | - | 336.10c | Appendix A - Ln. 68 |

| | | | | |
|---|---|---|---|---|
| 65 | Amort Lim Term (404)- General Plant | - | 336.10d | Appendix A - Ln. 68 |

Inputs
Page 1 of 3

**ADDENDUM 18 TO ATTACHMENT H - Page 3 of 47**

# The Empire District Electric Company
## Formula Rate Template Inputs
(For Rate Year Beginning July 1, 20 , Based on 20 Data)

**Data Entered Directly From FF1 (continued):**

| Line No | Account/Description/Classification | Inputs From 20 FF1 | FF1 Page Location | Template Sheet of the Link |
|---|---|---|---|---|
| 66 | Tot Elec O & M Transmission Direct Payroll | - | 354.21b | Appendix A - Ln. 1 |
| 67 | Tot Elec O & M Admin & General Direct Payroll | - | 354.27b | Appendix A - Ln. 3 |
| 68 | Total Elec O & M Direct Payroll | - | 354.28b | Appendix A - Ln. 2 |
| 69 | Transmission Towers and Fixtures | - | 206.51.b | Appendix A - Ln. 16 |
| 70 | Transmission Poles And Fixtures | - | 206.52.b | Appendix A - Ln. 16 |
| 71 | Distribution Poles, Towers, and Fixtures | - | 206.64.b | Appendix A - Ln. 15 |
| 72 | Rent from Electric Property | - | 300.19.b | ATT 3 - Revenue Credits, Ln. 1 |
| 73 | Kansas Real & Personal Property Taxes | - | 263.23i | ATT 2 - Other Taxes, Ln. 1 |
| 74 | Missouri Real & Personal Property Taxes | - | 263.37i | ATT 2 - Other Taxes, Ln. 1 |
| 75 | Arkansas Real & Personal Property Taxes | - | 263.1.12i | ATT 2 - Other Taxes, Ln. 1 |
| 76 | Kansas Real & Personal Property Taxes - Local | - | 263.1.18i | ATT 2 - Other Taxes, Ln. 1 |
| 77 | Missouri Real & Personal Property Taxes - Local | - | 263.1.24i | ATT 2 - Other Taxes, Ln. 1 |
| 78 | Oklahoma Real & Personal Property Taxes - Local | - | 263.1.31i | ATT 2 - Other Taxes, Ln. 1 |
| 79 | Federal OAB | - | 263.5i | ATT 2 - Other Taxes, Ln. 8 |
| 80 | Federal Unemployment | - | 263.7i | ATT 2 - Other Taxes, Ln. 9 |
| 81 | Arkansas Unemployment | - | 263.14i | ATT 2 - Other Taxes, Ln. 10 |
| 82 | Kansas Unemployment | - | 263.25i | ATT 2 - Other Taxes, Ln. 10 |
| 83 | Missouri Unemployment | - | 263.32i | ATT 2 - Other Taxes, Ln. 10 |
| 84 | Oklahoma Unemployment | - | 263.1.4i | ATT 2 - Other Taxes, Ln. 10 |
| 85 | Arkansas Corp Franchise | - | 263.16i | ATT 2 - Other Taxes, Ln. 21 |
| 86 | Kansas Corp Franchise | - | 263.21i | ATT 2 - Other Taxes, Ln. 21 |
| 87 | Missouri Corp Franchise | - | 263.35i | ATT 2 - Other Taxes, Ln. 21 |
| 88 | Oklahoma Corp Franchise | - | 263.1.6i | ATT 2 - Other Taxes, Ln. 21 |
| 89 | Arkansas Franchise | - | 263.1.14i | ATT 2 - Other Taxes, Ln. 21 |
| 90 | Kansas Franchise | - | 263.1.20i | ATT 2 - Other Taxes, Ln. 21 |
| 91 | Missouri Franchise | - | 263.1.26i | ATT 2 - Other Taxes, Ln. 21 |
| 92 | Oklahoma Franchise | - | 263.1.33i | ATT 2 - Other Taxes, Ln. 21 |

# ADDENDUM 18 TO ATTACHMENT H - Page 4 of 47
## The Empire District Electric Company
## Formula Rate Template Inputs
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**Data Input from Company Records and/or Verification Required (Manual Input)**

| Line No | Account/Description/Classification | Inputs From End of Year | Source of Data | Template Sheet of the Link |
|---|---|---|---|---|
| 1 | Federal Income Tax Rate | -% | From Tax Department | Appendix A - Ln. 98 |
| 2 | Missouri State Income Tax Rate | -% | From Tax Department | ATT 5 - Cost Support, Ln. 99 & Appendix A - Ln. 99 |
| 3 | Percent of Federal Tax Eligible for Deduction by Missouri | -% | From Tax Department | Appendix A - Ln. 100 |
| 4 | Kansas State Income Tax Rate | -% | From Tax Department | ATT 5 - Cost Support, Ln. 99 |
| 5 | Oklahoma State Income Tax Rate | -% | From Tax Department | ATT 5 - Cost Support, Ln. 99 |
| 6 | Arkansas State Income Tax Rate | -% | From Tax Department | ATT 5 - Cost Support, Ln. 99 |
| 7 | Safety/Peak Alert Advtzg - Acct 909, Product codes ADAS, ADCS, ADPA (Adult Safety, Child Safety, Peak Alert) | -%<br>-%<br>-% | From General Ledger, Manager of General Accounting | ATT 5 - Cost Support, Ln. 64 |
| 8 | EPRI Annual Membership Dues | - | FF1, Pgs. 352 & 353 & Co. Records | For informational purposes only. Empire currently is not a member of EPRI. |
| 9 | Plant Held for Future Use (Account 105) - Total | - | FF1, 214.47.d & Co. Records | ATT 5 - Cost Support, Ln. 26 |
| 10 | Plant Held for Future Use (Account 105) - Non-Transmission | - | FF1, 214.47.d & Co. Records | ATT 5 - Cost Support, Ln. 26 |
| 11 | Transmission Related Regulatory Expenses | - | FF1, 350.41-44.d | ATT 5 - Cost Support, Ln. 63 |
| 12 | Plant Held for Future Use (Non-Land) - Transmission Only | - | Company Records from Mgr of Property Acctg | ATT 5 - Cost Support, Ln. 26 |
| 13 | Actual PBOP Expense - Electric Portion Only | - | Company Records- From Controller (Acct 926.328) | ATT 5 - Cost Support, Ln. 56 |
| 14 | Fixed PBOP Expense (Based on 2011 Data) - Electric Portion Only | | Electric Portion of 2011 Actuarial Study and Report. | ATT 5 - Cost Support, Ln 55 |
| 15 | Revenues from Directly Assigned Transmission Facilities (ATT 3, Note 2) | - | No DA Transmission Lines as of 12/31/11. Need to verify annually with Director of Transmission Policy and/or Director of Supply Management. To: ATT 5 - Cost Support, Ln. 117 | |
| 16 | Charges billed to Transmission Owner for system integration and transmission costs paid to others that benefit transmission customers and are recorded in Account 565. | - | Verify amount annually with Director of Transmission Policy, Director of Supply Management, Manager of Fuel-Revenue Accounting, and/or Controller. | |
| 17 | Zonal Transmission Network 12 CP Average (Trans. 12 CP Avg) | - | Data to be supplied by Director of Supply Management, based on SPP information. | |
| 18 | Other Electric Revenues - Transmission for Others (Schedules 7 & 8) | - | From Manager of General Accounting (Acct 457.137 & Acct 457.138). To: ATT-3, Line 4. Also see ATT 3, Notes 1 & 4 | |
| 19 | Net revenues associated with Transmission Service Requests, Sponsored Upgrades, and Generation Interconnections for which the load is not included in the divisor. | - | Need to verify during each annual update with Director of Supply Management if there are any such TSR revenues (including TSR revenue from SPP customers not in EDE zone) for load that is NOT included in Empire's divisor. From Energy Supply Services derived from respective Transmission Statement (Recorded in Acct 457.160. To: ATT-3, Line 5) | |
| 20 | Other Electric Revenues - Transmission for Others (Schedule 1 P-T-P Revenue | -0 | | |
| 21 | Pre-OATT grandfathered Non-Firm Point to Point Service bundled deman revenues for which the load is not included in the divisor received by Transmission owner and for which the revenues are divided between production and transmission functions. Revenues are collected directly by Empire under mid-180-s agreements. | | This represents "Point-To-Point" demand revenue margins derived from the "grandfathered" BPU & Kaw Valley agreements (the BPU contract terminated effective 5/31/12, and data input associated with this contract will no longer be includedafter the 2013 Annual Update. The non-RQ "Demand Revenues" found in FF1, Pg.3, Col. H (and page 311 extensions) for these two customers should be reduced by the sum of the Demand Charges (costs) found in FF1, Pg. 3 27,col.j (and page 327 extensions for these two customers. | |

**The Worksheets listed below require Input of Data directly into the Worksheets themselves:**

| Line | Sheet |
|---|---|
| 22 | ATT 1 - ADIT |
| 23 | ATT 2 - Other Taxes |
| 24 | ATT 4 - Non-Escrowed Funds |
| 25 | ATT 5 - Cost Support |
| 26 | ATT 8 - Pref Stock |
| 27 | ATT 10 - Depreciation Rates |
| 28 | ATT 10A - Intangible Plant Detail |
| 29 | ATT 11 - Reconciliation |
| 30 | ATT 12 - Regional Projects |

| | | Description/Source | | | |
|---|---|---|---|---|---|
| | | Accumulated Def Inc Taxes - Verify with Controller and Tax Department. | | | |
| | | From FF1 - Out of period Property taxes (included in Appendix A) and Corporate Franchise Taxes (excluded from Appendix A). | | | |
| | | Non-Escrowed Funds - Verify with Controller. | | | |
| | | Provide Description of Direct Assigned Transmission Facilities (See Line 15, above). Pref Stock & Accts 204, 207,208, 210, 211, 213 - Verify with Director of Finance and Controller Depreciation Rates from FF1 will remain fixed absent a Section 205 or 206 filing. | | | |
| | | Enter Description, Amortization Amounts, and Plant Balances for Intangible Plant. Adjustments to FF1 data - Verify with Director of Finance and Controller | | | |
| | | Enter Specific SPP Regional Project/Upgrade Information from Property Accounting Records of the Company. | | | |
| | | | | | |
| | | | | | |
| | |

Inputs

# ADDENDUM 18 TO ATTACHMENT H - Page 5 of 47
## The Empire District Electric Company
## APPENDIX A
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**Shaded cells are input cells**

| | | | Notes | FF1 Page # or Instruction | |
|---|---|---|---|---|---|
| | **Allocators** | | | | |
| | **Wages & Salary Allocation Factor** | | | | |
| 1 | Transmission Wages Expense | p354.21.b [From Inputs, Pg. 2, Ln. 66] | | | - |
| 2 | Total Wages Expense | p354.28.b [From Inputs, Pg. 2, Ln. 68] | | | - |
| 3 | Less A&G Wages Expense | p354.27.b [From Inputs, Pg. 2, Ln. 67] | | | - |
| 4 | Total Wages Less A&G Wages Expense | (Line 2 - Line 3) | | | - |
| 5 | **Wages & Salary Allocator** | | | (Line 1 / Line 4) | **-** |
| | **Plant Allocation Factors** | | | | |
| 6 | Electric Plant in Service | | | p207.104.g [From Inputs, Pg. 1, Ln. 32] | - |
| 7 | Accumulated Depreciation (Total Electric Plant) | | (Notes B & L) | p219.29.c [As adjusted on ATT-11, Ln. 6, Col. E] | - |
| 8 | Accumulated Intangible Amortization (Other Utility Plant) | | (Notes A & B) | p200.21.c [From Inputs, Pg. 1, Ln. 30] | - |
| 9 | Total Accumulated Depreciation | | | (Line 7 + 8) | - |
| 10 | Net Plant | | | (Line 6 - Line 9) | - |
| 11 | Transmission Gross Plant (excluding Land Held for Future Use) | | | (Line 27 - Line 26) | - |
| 12 | **Gross Plant Allocator** | | | (Line 11 / Line 6) | **-** |
| 13 | Transmission Net Plant (excluding Land Held for Future Use) | | | (Line 35 - Line 26) | - |
| 14 | **Net Plant Allocator** | | | (Line 13 / Line 10) | **-** |
| | **T/D Pole Allocation Factor** | | | | |
| 15 | Gross Distribution Pole/Structure Investment (Acct 364) | | | p206.64.b [From Inputs, Pg. 2, Ln. 71] | - |
| 16 | Gross Transmission Pole/Structure Investment (Accts 354 + 355) | | | p206.51.b + p206.52.b [From Inputs, Pg. 2, Lns. 69 & 70] | - |
| 17 | Total Pole/Tower Gross Plant | | | (Line 15 + Line 16) | - |
| 19 | **T/D Revenue Allocation Factor (For Pole Attachment Revenue)** | | | (Line 16 / Line 17) | **-** |
| | **Plant Calculations** | | | | |
| | **Plant In Service** | | | | |
| 20 | **Transmission Plant In Service** | | | p207.58.g [From Inputs, Pg. 1, Ln. 33] | **-** |
| 21 | General | | | p207.99.g [From Inputs, Pg. 1, Ln. 46] | - |
| 22 | Intangible | | | p205.5.g [From Inputs, Pg. 1, Ln. 31] | - |
| 23 | Total General and Intangible Plant | | | (Line 21 + Line 22) | - |
| 24 | Wage & Salary Allocator | | | (Line 5) | - |
| 25 | **Total General and Intangible Functionalized to Transmission** | | | (Line 23 * Line 24) | **-** |
| 26 | **Land Held for Future Use** | | (Note C) | [From ATT-5, Ln. 26] | **-** |
| 27 | **Total Plant In Rate Base** | | | **(Line 20 + Line 25 + Line 26)** | **-** |
| | **Accumulated Depreciation** | | | | |
| 28 | Transmission Accumulated Depreciation | | (Note B) | p219.25.c [From Inputs, Pg. 1, Ln. 47] | **-** |
| 29 | General Plant Accumulated Depreciation | | (Note B) | p219.28.c [From Inputs, Pg. 1, Ln. 48] | - |
| 30 | Accumulated Intangible Amortization (Other Utility Plant) | | | (Line 8) | - |
| 31 | Total Accumulated Depreciation | | | (Line 29 + 30) | - |
| 32 | Wage & Salary Allocator | | | (Line 5) | - |
| 33 | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission | | | (Line 31 * Line 32) | - |
| 34 | **Total Accumulated Depreciation** | | | **(Sum Lines 28 + 33)** | **-** |
| 35 | | | | | |
| | **Adjustment To Rate Base** | | | | |
| | **Accumulated Deferred Income Taxes** | | | | |
| 36 | **ADIT** | | | [From ATT 1, Pg. 3, Ln. 26] | **-** |
| | **Regulatory Assets and Liabilities** | | | | |
| 36a | Deficient Deferred Taxes Regulatory Asset (Account 182.3) | | (Note N) | [From Inputs, Pg. 1, Ln. 23a ; see also ATT-14, Ln. 2] | **0** |
| 36b | Excess Deferred Taxes Regulatory Liability (Account 254) | | (Note N) | [From Inputs, Pg. 1, Ln. 23b ; see also ATT-14, Ln. 1] | **0** |
| 36c | **Deficient/Excess Deferred Taxes Regulatory Assets and Liabilities Allocated to Transmission** | | | (Line 36a + Line 36b) | **0** |

| | | | | |
|---|---|---|---|---|
| | **Prepayments** | | | |
| 37 | Prepayments | (Note A) | [From ATT-5, Ln. 37] | - |
| | **Materials and Supplies** | | | |
| 38 | Undistributed Stores Expense | (Note A) | p227.16.c [From Inputs, Pg. 1, Ln. 35] | - |
| 39 | Wage & Salary Allocator | | (Line 5) | - |
| 40 | Total Undistributed Stores Expense Allocated to Transmission | | (Line 38 * Line 39) | - |
| 41 | Transmission Materials & Supplies | | p227.8.c [From Inputs, Pg. 1, Ln. 34] | - |
| 42 | **Total Materials & Supplies Allocated to Transmission** | | (Line 40 + Line 41) | - |

| | | | | |
|---|---|---|---|---|
| | **Cash Working Capital** | | | |
| 43 | ~~Operation & Maintenance Expense~~ | ~~(Line 88)~~ | ~~-~~ | |
| 44 | ~~1/8th Rule~~ | ~~1/8~~ | | ~~12.5%~~ |
| 45 | **Total Cash Working Capital Allocated to Transmission** | (Line 43 * Line 44) | **-** | |
| 46 | **Non-Escrowed Funds** | [From ATT-4, Line 3, Col. C] | **-** | |
| 47 | **Total Adjustment to Rate Base** | (Lines 36 + 37 + 42 + 45 - 46) | **-** | |
| 48 | **Rate Base** | | | |

# ADDENDUM 18 TO ATTACHMENT H - Page 6 of 47
# The Empire District Electric Company
# APPENDIX A
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

Operations & Maintenance Expense

| | | | | | |
|---|---|---|---|---|---|
| **Transmission O&M** | | | | | |
| 49 | Transmission O&M | | | [From ATT-5, Ln. 49] | - |
| 50 | Less Account 565 | | | [From ATT-5, Ln. 50] | - |
| 51 | Less Expenses Associated with Schedule 1 Rate | | | [From ATT-5, Ln. 51] | - |
| 52 | Plus Charges billed to Transmission Owner and booked to Account 565 | (Note J) | | [From ATT-5, Ln. 52] | - |
| 53 | **Transmission O&M** | | | (Lines 49 - 50 - 51 + 52) | **-** |
| **Allocated Administrative & General Expenses** | | | | | |
| 54 | Total A&G | | | 323.197b [From Inputs, Pg. 1, Ln. 55] | - |
| 55 | Plus: **Fixed** PBOP expense | (Note M) | | [From ATT-5, Ln. 55] | |
| 56 | Less: Actual PBOP expense | | | [From ATT-5, Ln. 56] | - |
| 57 | | | | | |
| 58 | Less Regulatory Commission Exp Account 928 | (Note D) | | p323.189.b [From Inputs, Pg. 1, Ln. 53] | - |
| 59 | Less General Advertising Exp Account 930.1 | | | p323.191.b [From Inputs, Pg. 1, Ln. 54] | - |
| 60 | Administrative & General Expenses | | | Sum (Lines 54 to 55) - Sum (Lines 56 to 59) | - |
| 61 | Wage & Salary Allocator | | | (Line 5) | - |
| 62 | **Administrative & General Expenses Allocated to Transmission** | | | (Line 60 * Line 61) | **-** |
| **Directly Assigned A&G** | | | | | |
| 63 | Regulatory Commission Exp Account 928 | | (Note F) | [From ATT-5, Ln. 63] | - |
| 64 | Safety/Peak Alert Advertising Expense (Acct 909) | | (Note E) | [From ATT-5, Ln. 64] | - |
| 65 | **Subtotal - Accounts 909 and 928 - Transmission Related** | | | (Line 63 + Line 64) | **-** |
| 66 | **Total Transmission O&M** | | | **(Lines 53 + 62 + 65)** | **-** |

Depreciation & Amortization Expense

| | | | | |
|---|---|---|---|---|
| **Depreciation Expense** | | | | |
| 67 | Transmission Depreciation Expense Including Amortization of Limited Term Plant | (Note B) | p336.7.b&c&d [From Inputs, Pg. 1, Lns. 60, 61, & 62] | **-** |
| 68 | General Depreciation Expense Including Amortization of Limited Term Plant | (Note B) | p336.10.b&c&d [From Inputs, Pg. 1, Lns. 63, 64, & 65] | - |
| 69 | Intangible Amortization | (Notes A & B) | p336.1.b&c&d&e [From Inputs, Lns. 56, 57, 58, & 59] | - |
| 70 | Total | | (Line 68 + Line 69) | - |
| 71 | Wage & Salary Allocator | | (Line 5) | - |
| 72 | **General Depreciation & Intangible Amortization Allocated to Transmission** | | (Line 70 * Line 71) | **-** |
| 73 | **Total Transmission Depreciation & Amortization** | | **(Lines 67 + 72)** | **-** |

Taxes Other than Income Taxes

| | | | | |
|---|---|---|---|---|
| 74 | **Taxes Other than Income Taxes** | [From ATT-2, Pg. 1, Ln. 14] | | **-** |
| 75 | **Total Taxes Other than Income Taxes** | **(Line 74)** | | **-** |

Return \ Capitalization Calculations

| | | | | | |
|---|---|---|---|---|---|
| **Long Term Interest** | | | | | |
| 76 | **Long Term Interest & Hedging Costs** | | | [From ATT-9, Pg. 2, Ln. 6] | **-** |
| 77 | **Preferred Dividends** | | | [From ATT-8, Pg. 1, Ln. 4] | **-** |
| | **Common Stock** | | | | |
| 78 | Proprietary Capital | | | [From ATT-7, Pg. 1, Ln. 3, Col. A] | - |
| 79 | Less Accumulated Other Comprehensive Income Account 219 | | | [From ATT-7, Pg. 1, Ln. 3, Col. F] | - |
| 80 | Less Preferred Stock | | | [From ATT-8, Pg. 1, Ln. 3, Col. F] | - |
| 81 | Less Account 216.1 | | | [From ATT-7, Pg. 1, Ln. 3, Col. G] | - |
| 82 | **Common Stock** | | | (Line 78 - 79 - 80 - 81) | **-** |
| | **Capitalization** | | | | |
| 83 | Total Long Term Debt | | | [From ATT-6, Pg. 1, Ln. 1, Col A] | - |
| 84 | Preferred Stock | | | [From ATT-6, Pg. 1, Ln. 2, Col A] | - |
| 85 | Common Stock | | | [From ATT-6, Pg. 1, Ln. 3, Col A] | - |
| 86 | **Total Capitalization** | | | (Sum Lines 83 to 85) | **-** |
| 87 | Debt % | Total Long Term Debt | | (Line 83 / Line 86) | - |
| 88 | Preferred % | Preferred Stock | | (Line 84 / Line 86) | - |
| 89 | Common % | Common Stock | | (Line 85 / Line 86) | - |
| 90 | Debt Cost | Total Long Term Debt | | [From ATT-6, Pg. 1, Ln. 1, Col C] | - |
| 91 | Preferred Cost | Preferred Stock | | [From ATT-6, Pg. 1, Ln. 2, Col C] | - |
| 92 | Common Cost | Common Stock | (Note H) | **Fixed** | **10.00%** |
| 93 | Weighted Cost of Debt | Total Long Term Debt (WCLTD) | | (Line 87 * Line 90) | - |
| 94 | Weighted Cost of Preferred | Preferred Stock | | (Line 88 * Line 91) | - |
| 95 | Weighted Cost of Common | Common Stock | | (Line 89 * Line 92) | - |
| 96 | **Rate of Return on Rate Base ( ROR )** | | | (Sum Lines 93 to 95) | **-** |
| 97 | **Investment Return = Rate Base * Rate of Return** | | | **(Line 48 * Line 96)** | **-** |

[redacted]

# ADDENDUM 18 TO ATTACHMENT H - Page 7 of 47
## The Empire District Electric Company
## APPENDIX A
**(For Rate Year Beginning July 1, 20 ___, Based on 20___Data)**

Composite Income Taxes

| | | | | | |
|---|---|---|---|---|---|
| **Income Tax Rates** | | | | | |
| 98 | FIT=Federal Income Tax Rate | | (Note G) | [From Inputs, Pg. 3, Ln. 1] | -% |
| 99 | SIT=State Income Tax Rate or Composite | | (Note G) | [From Inputs, Pg. 3, Ln. 2; see also ATT-5, Ln. 99] | -% |
| 100 | p | (% of fed inc tax deductible for state purposes) | (Note G) | [From Inputs, Pg. 3, Ln. 3; see also ATT-5, Ln. 99] | -% |
| 101 | T | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | - |
| 102 | T / (1-T) | Tax Gross-Up | | | - |
| **ITC Adjustment** | | | | | |
| 103 | Amortized Investment Tax Credit - Transmission Related | | | [From ATT-5, Ln. 103] | - |
| Excess Deferred Taxes Amortization | | | | | |
| 103a | Amortized Deficient Deferred Taxes (Account 410.1) | | (Note N) | [From Inputs, Pg. 1, Ln. 23c] | 0 |
| 103b | Amortized Excess Deferred Taxes (Account 411.1) | | (Note N) | [From Inputs, Pg. 1, Ln. 23d] | 0 |
| 103c | Total | | | | 0 |
| 103d | Tax Gross Up | | | Revenue Requirement Impact Worksheet | |
| 103e | Deficient/Excess Deferred Taxes Allocated to Transmission | | | (Line 103c * Line 103d) | 0 |
| 104 | **ITC Adjust. Allocated to Trans. - Grossed Up** | ITC Adjustment x 1 / (1-T) | | (Line 103 * (1 / (1-Line 101)) | **-** |
| 105 | **Income Tax Component =** | (T/1-T) * Investment Return * (1-(WCLTD/ROR)) = | | [Line 102 * Line 97 * (1- (Line 93 / Line 96))] | **-** |
| 106 | **Total Income Taxes** | | | **(Line 105 - Line 104-Line 103e)** | **-** |

Revenue Requirement

| | | | | |
|---|---|---|---|---|
| **Summary** | | | | |
| 107 | Net Property, Plant & Equipment | | (Line 35) | - |
| 108 | Total Adjustment to Rate Base | | (Line 47) | - |
| 109 | Rate Base | | (Line 48) | - |
| 110 | Total Transmission O&M | | (Line 66) | - |
| 111 | Total Transmission Depreciation & Amortization | | (Line 73) | - |
| 112 | Taxes Other than Income | | (Line 75) | - |
| 113 | Investment Return | | (Line 97) | - |
| 114 | Income Taxes | | (Line 106) | - |
| **115** | **Gross Revenue Requirement** | | **(Sum Lines 110 to 114)** | **-** |
| **Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities** | | | | |
| 116 | Transmission Plant In Service | | (Line 20) | - |
| 117 | Revenues from Direct Assigned Transmission Facilities | (Note I) | [From ATT-5, Ln. 117] | - |
| 118 | Included Transmission Facilities | | (Line 116 - Line 117) | - |
| 119 | Inclusion Ratio | | (Line 118 / Line 116) | - |
| 120 | Gross Revenue Requirement | | (Line 115) | - |
| 121 | **Adjusted Gross Revenue Requirement** | | (Line 119 * Line 120) | **-** |
| **Revenue Credits & Adjustments** | | | | |
| 122 | Revenue Credits | | [From ATT-3, Ln. 10] | - |
| 122a | Refunds and Surcharges (Adjustments to Gross ATRR) | | [From ATT-11, Pg. 2, Ln. 6] | - |
| 122b | **Total Revenue Credits and Adjustments** | | (Line 122 + Line 122a) | **-** |
| **123** | **Annual Total Net Revenue Requirement** | | **(Line 121 - Line 122b)** | **-** |
| 124 | Rev. Rqmt. (w/o incentives) from SPP Regional Upgrades | | [From ATT-12, Page 2, Ln. 41, ATRR w/o Incentives] | - |
| 124a | Incentive Rev. Rqmt from SPP Regional Upgrades | | [From ATT-12, Page 2, Ln. 41, Incentive ATRR] | - |
| 124b | Refunds and Surcharges (Adjustments to SPP Regional Projects' ATRR) | | [From ATT-11, Pg. 2, Ln. 12] | - |
| **124c** | **TOTAL Rev Rqmt Collected by SPP under SPP OATT for Regional Upgrades** | | **[Line 124 + Line 124a + Line 124b]** | **-** |
| **125** | **Annual Total Zonal Revenue Requirement (Attachment H)** | | **[Line 123 - Line 124]** | **-** |
| **Network Zonal Service Rate** | | | | |
| 126 | Zonal Transmission Network 12 CP Average | (Note K) | [From ATT-5, Ln. 126] | - |
| 127 | Rate ($/MW-Year) | | (Line 125 / 126) | - |
| **128** | **Network Service Rate ($/MW/Year)** | | **(Line 127)** | **-** |
| **Schedule 1 Rate Calculations** | | | | |
| 129 | Account 561 Expenses Associated with Schedule 1 Rate | | (Line 51) | - |
| 130 | Zonal Transmission Network 12 CP Average | (Note K) | (Line 126) | - |
| 131 | Rate ($/MW-Year) | | (Line 129 / Line 130) | - |
| **132** | **Schedule 1 Annual Rate ($/MW/Year)** | | **(Line 131)** | **-** |
| 133 | Schedule 1 Rate ($/MW/Month) | | (Line 132 / 12 months) | - |
| 134 | Schedule 1 Rate ($/MW/Week) | | (Line 132 / 52 weeks) | - |
| 135 | Schedule 1 Rate ($/MW/Day) | | (Line 132 / 365 days) | - |

| | | | |
|---|---|---|---|
| 136 | Schedule 1 Rate ($/MW/Hour) | (Line 132 / 8760 hours) | - |
| **137** | **Schedule 7 Annual Firm Point-to-Point Rate ($/MW/Yr) = Annual Network Service Rate ($/MW/Yr)** | **(Line 128)** | **-** |
| 138 | Schedule 7 Rate ($/MW/Month) | (Line 137 / 12 months) | - |
| 139 | Schedule 7 Rate ($/MW/Week) | (Line 137 / 52 weeks) | - |
| 140 | Schedule 7 Rate ($/MW/Day, On-Peak) | (Line 139 / 5 days) | - |
| 141 | Schedule 7 Rate ($/MW/Day, Off-Peak) | (Line 139 / 7 days) | - |
| 142 | Schedule 7 Rate ($/MWHour, On-Peak) | (Line 140 / 16 hours) | - |

| | | | |
|---|---|---|---|
| **144** | **Schedule 8 Non-Firm Annual Point-To-Point Rate ($/MW/Yr)=Annual Network Service Rate ($/MW/Yr)** | **(Line 128)** | **-** |
| 145 | Schedule 8 Rate ($/MW/Month) | (Line 144 / 12 months) | - |
| 146 | Schedule 8 Rate ($/MW/Week) | (Line 144 / 52 weeks) | - |
| 147 | Schedule 8 Rate ($/MW/Day, On-Peak) | (Line 146 / 5 days) | - |
| 148 | Schedule 8 Rate ($/MW/Day, Off-Peak) | (Line 146 / 7 days) | - |
| 149 | Schedule 8 Rate ($/MW/Hour, On-Peak) | (Line 147 / 16 hours) | - |
| 150 | Schedule 8 Rate ($/MW/Hour, Off-Peak) | (Line 148 / 24 hours) | - |

## ADDENDUM 18 TO ATTACHMENT H - Page 8 of 47
## The Empire District Electric Company
## APPENDIX A
**(For Rate Year Beginning July 1, 20 ___, Based on 20___Data)**

**Notes:**

A Electric portion only.

B Depreciation rates are displayed in ATT 10 and will not change absent a Federal Power Act Section 205 or 206 filing. Amortization periods are displayed in ATT 10A and will not change absent a Federal Power Act Section 205 or 206 filing.

C Includes Transmission portion only.

D Includes all Regulatory Commission Expenses for all Electric jurisdictions.

E Includes safety-related and load/grid congestion management advertising expense included in Account 909 (Product codes ADAS, ADCS, ADPA).

F Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting; as itemized on ATT-5, Ln. 63. G The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the Missouri income tax rate, and p = the percentage of federal income tax deductible for Missouri state income taxes. See details on ATT 5, Ln. 99.

H ROE will be fixed at 10.00% and will not change absent a Federal Power Act Section 205 or 206 filing at FERC.

I There are no direct assigned transmission facilities on EDE's system as of 12/31/2011. Annual verification/updates will be documented on ATT 5. J Includes only charges incurred for system integration and transmission costs paid to others that benefit transmission customers.

K Represents the average of Empire's 12 Monthly Coincident Peaks of Empire Zonal Transmission load (includes all firm wholesale NITS & Pt-Pt loads during the FF1 year).

L Total Electric Accumulated Depreciation has been adjusted to reflect Missouri Regulatory Plan Amortization, as shown on ATT 11, Line 6.

M PBOP expense is fixed at 2011 levels until changed as a result of a Federal Power Act Section 205 or 206 filing at FERC.

N Unamortized Excess/Deficient Deferred Tax Regulatory Liabilities/Assests and the Amortization of those Regulatory Liablities/Assets arising from future tax changes may only be included after receiving Commission approval.

**ADDENDUM 18 TO ATTACHMENT H - Page 9 of 47**
**The Empire District Electric Company**

## Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNT 190

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| Line | Account * Identification | *(A)* YE Balance | *(B)* 100% Non-Transmission Related | *(C)* 100% Transmission Related | *(D)* Plant Related | *(E)* Total Labor Related | *(F)* Added to Ratebase | *(G)* Description |
|---|---|---|---|---|---|---|---|---|
| 1 | 190.117 | | | | | | | |
| 2 | 190.122 Deferred FIT - Accrued Rate Relief - Arkansas | | | | | | | Adjusts deferred tax back to 1970's ADR - Non- Generation |
| 3 | 190.123 Deferred FIT - Hedge Transaction Gains | | | | | | | Interest hedge gains amortized per books vs current recognition for tax |
| 4 | 190.124 Deferred Federal Tax Asset - Miscellaneous | | | | | | | Relates to injuries and damages, bad debts, rate case expense and other |
| Adj5 | 190.125 FAS 123 Deferred Tax Asset | | | | | | | Relates to compensation |
| 6 | 190.114 Def Tax Asset - Reg Plan Amort (See Note 1) | | | | | | | Recognizes Mo Reg Plan Amortization. |
| 7 | 190.211 Deferred Income Tax - Disallowed Plant | | | | | | | Relates to book deduction of disallowed plant - tax depreciable. (State Line CC partially disallowed in 2001 by Mo PSC; Energy Center |

| | | |
|---|---|---|
| | | partially disallowed in 2006 by Mo PSC.). |
| 8 | 190.230 Def Tax - Net Operating Loss | NOL Due to Bonus Depreciation |

| | |
|---|---|
| 9 190.260 Deferred FIT - Officers & Directors Deferred Comp. | Deferred compensation, tax deductible when paid |
| 10 190.310 Deferred FIT - Contribution - Aid Construction | Distribution plant related - adds to current tax - tax depreciable |
| 11 190.320 Deferred FIT - Deferred Tax Asset - FAS 109 | Excess deferred tax and ITC amortization revenue effect |
| 12 190.330 Deferred FIT - PBOP Costs - Missouri | PBOP costs - tax deductible when paid |
| 13 190.331 Deferred FIT - Post Retirement Benefits - Pension | Relates to pensions - tax funding vs book accrual |
| 14 190.340 Accum. Deferred FIT - Interest Capitalized | Relates to tax capitalized interest over booked AFUDC debt |
| 15 190.112 Ozark Beach Lost Generation | Relates to Dmgs rec'd for future generation impairments. |
| 16 190.113 Deferred ITC Cr - Advanced Coal Credit | Iatan II Def Tax Recognition of ITC not currently available. |
| 17 190.356 Deferred Tax - FAS 158 | Recognition of deferred tax related to future pension PBOP costs |
| 18 190.350 Accum. Def. Inc. Tax - Alternative Min. Tax | Relates to AMT incurred that creates a credit for future years. |

| | | |
|---|---|---|
| 19 | 190.995 Current Deferred Income Tax - Other Comp. e | Comprehensive income |

| | | | |
|---|---|---|---|
| 20 | to Generation | Ozark Beach Lost | Relates to Dmgs rec'd for future generation impairments. |
| 21 | 190.999 | Current Deferred Tax Asset - ITC | S-T Deferred Tax - ITC |
| 21a | 190.989 | Long-Term Def Tax Asset | Reclassified to S-T DTA |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| - | | - | - | - | - | - | - | - | - | - |
| - | **Total** | | - | - | 0 | - | | | - | |
| - | **Conform - [FF1, pg. 234, ln. 18, col. c]** | - | | | | | | | | |
| - | **Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]** | | % | 0.0000% | 100.0000% | #DIV/ | #DIV/0! | | | |
| - | **Total Transmission** | | | 0 | 0 | -#DIV/0! | #DIV/0!! | #DIV/0! | | - |

* Source: General Ledger

Note 1: Deferred taxes related to the MO Regulatory Plan Amortization were included in Account 282.100 in 2011. At the end of 2012, the deferred taxes related to the MO Regulatory Plan Amortization were reclassified to Account 190.114 and identified as "100% Non-Transmission". Going forward, the deferred taxes related to the MO Regulatory Plan Amortization will be included in the Account 190 deferred tax asset schedule as "100% Non-Transmission".

**ADDENDUM 18 TO ATTACHMENT H - Page 10 of 47**
**The Empire District Electric Company**

## Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNTS 281 & 282

(For Rate Year Beginning July 1, 20 , Based on 20 Data)

| Line | Account * Identification | (A) YE Balance | (B) 100% Non-Transmission Related | (C) 100% Transmission Related | (D) Plant Related |
|---|---|---|---|---|---|
| 1 | 281.000 Accum Def FIT - Accel Amort. | | | | |
| 2 | 282.100 Accum Def FIT - LD Electric | | | | |
| 3 | 282.120 Accum Def FIT - LD KS Jurisdiction | | | | |
| 4 | 282.130 Accum Def FIT - LD NonUT DR | | | | |
| 5 | 282.135 Accum Def FIT - LD Nonutility | | | | |
| 6 | 282.140 Accum Def FIT - LD Oklahoma Jurisdiction | | | | |
| 7 | 282.150 Accum Def FIT - LD FERC Jurisdiction | | | | |
| 8 | 282.200 Accum Def FIT - LD Water | | | | |
| 9 | 282.300 | | | | |
| 10 | | | | | |
| 11 | | | | | |
| 12 | **Total** | | | | |
| 13 | - **Conform - [FF1, pg. 273, ln.17 col. k] + -** | | | | |

| | | | (E) Total Labor Related | (F) Added to Ratebase | (G) Description |
|---|---|---|---|---|---|
| | | | | | normalize Kansas Non-Utility |
| | | | | | Should be reclassified to non-reg Plant |
| | | | | | celerated depreciation and amortization - normalized Oklahoma |
| | | | | | Plant accelerated depreciation and amortization - normalized FERC |
| | | | | | Plant accelerated depreciation and amortization - water |
| | | | | | Accelerated Amortization of Polution Control Facilities |
| | | | | | Plant accelerated depreciation and amortization - electric. |
| | | | | | Plant accelerated depreciation and amortization - electric - to ac |
| | | [FF1, pg. 275, ln. 9, col. k] | | | |
| 14 | | **Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]** | 0.0000% | 100.0000%1 | #DIV/0! #DIV/0! |
| 15 | | **Total Transmission** | - | 100.0000%- | #DIC/0! #DIV/0! #DIV/0! |

* Source: General Ledger

**ADDENDUM 18 TO ATTACHMENT H - Page 11 of 47**
**The Empire District Electric Company**

**Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNT 283**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| Line | Account * | Identification | *(A) YE Balance* | *(B) 100% Non-Transmission Related* | *(C) 100% Transmission Related* | *(D) Plant Related* | *Description* |
|---|---|---|---|---|---|---|---|
| | | ***Ratebase*** | | | | | |
| 1 | 283.100 | Accum Def FIT - 5 Yr. Maintenance | - | - | | | |
| 2 | 283.116 | Def Tax Liability - Iatan 1 Deferred Charges | - | - | - | - | - |
| 3 | 283.123 | Deferred FIT - Hedge Transaction Loss | | | | | |
| 4 | 283.126 | | | | | | |
| 5 | 283.139 | Deferred Tax Liability - Fuel Costs | | | | | |
| 6 | 283.251 | | | | | | |
| 7 | 283.355 | | | | | | |
| 8 | 283.366 | Def Tax - ITC Tax Basis Reduction - Iatan 2 | | | | | |
| 9 | 283.400 | Accum Def FIT - Licensed Software | | | | | |
| 10 | 283.900 | Accum Def Fit - Loss on Reacquired Debt | | | | | |
| 11 | 283.914 | Deferred Income Tax - FAS 158 | | | | | |
| 12 | 283.915 | Deferred Income Tax - FAS 109 | | | | | |
| 13 | 283.916 | | | | | | |

| (E) Total Labor Related to | (F) Added | (G) |
|---|---|---|
| | | |
| | | |
| | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 14 | 283.917 | Deferred Tax Liability - Equity AFUDC | | | | | | | |
| 15 | 283.921 | Deferred FIT - Ice Storm Expense | | | | | | | |
| 16 | 283.924 | | | | | | | | |
| 17 | 283.990 | Accum Def FIT - Other Comprehensive Income | | | | | | | |
| 18 | 283.995 | Current Def FIT - Other Comprehensive Income | | | | | | | |
| 19 | 283.103 | Accumulated Def Tax - Repair Allowance | | | | | | | [redacted] Tax Expensing of Distr Trans & Gen Book Additions. |
| 20 | 283.989 | Long-term Def Tax Liability (Note 2) | | | | | | | Reclassifie[redacted] |
| 21 | | | | | | | | | |
| | | **Total** | - | - | - | - | - | | |
| | | **Conform - [FF1, pg. 277, ln. 19, col. k]** | - | | | | | | |
| | | **Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]** | | **0.0000**-% | 100.0000-% | #DIV/0!% | #DIV/0! | | |
| | | **Total Transmission** | - | | - | #DIV/0!- | -#DIV/0! | -#DIV/0! | |
| | | **Total ADIT (Pg. 1, Ln. 25 + Pg. 2, Ln. 15 + Pg. 3, Ln 25)** | | | | | | #DIV/0! | To Appendix A, Line 36 |

* Source: General Ledger

[1] ITC is not an adjustment from Plant in Service. EDE is an "Option2" company. Balance, by law, is not allowed to be decreased from rate base. Annual amortization reduces income tax expense.

# ADDENDUM 18 TO ATTACHMENT H - Page 12 of 47
# The Empire District Electric Company

## Attachment 2 - Taxes Other Than Income
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | Column A | Column B | Column C |
|---|---|---|---|
| **OTHER TAXES:** | **Pg. 263 & 263.1 Col (i)** | **Allocator** | **Allocated Amount** |
| **Currently Included on Appendix A** | | | |
| **Plant Related:** | | **Gross Plant Allocator** | |
| 1 Real and Personal Property (State, Municipal or Local) -Current FF1 Year [FF1, Pg. 263, Lns. 23i & 37i; Pg. 263.1, Lns. 12i, 18i, 24i & 31i][From Inputs, Pg. 2, Lns. 73-78] | - | | |
| 2 Real and Personal Property (State, Municipal or Local) -From Prev Years | - | | |
| 3 | | | |
| 4 | | | |
| 5 | | | |
| 6 | | | |
| 7 **Total Plant Related [GP Allocator from Appendix A, Ln. 12]** | - | - | - |
| **Labor Related:** | | **Wages & Salary Allocator** | |
| 8 Social Security (FICA/OAB) [FF1, Pg. 263, Ln.5i] [From Inputs, Pg. 2, Ln. 79] | - | | |
| 9 Federal Unemployment Comp. [FF1, Pg. 263, Ln. 7i] [From Inputs, Pg.2, Ln. 80 ] | - | | |
| 10 State Unemployment Comp. [From Inputs, Pg. 2, Lines 81, 82, 83, & 84] | - | | |
| 10a Missouri Unemployment - From Prev Years | - | | |
| 11 | | | |
| 12 | | | |
| 13 **Total Labor Related [Wages & Sal. Alloc. from Appendix A, Ln.5]** | - | - | - |
| 14 **Total Included (Column C, Lines 7 + 13)** [To Appendix A, Line 74] | | | - |
| **Currently Excluded from Appendix A** | | | |
| 21 Corporate Franchise-Retail [Current Year] [From Inputs, Pg. 2, Lns. 85-92] [FF1, Pg. 263, Col. i, Lns. 16, 21, & 35; Pg. 263.1, Col. i, Lns. 6, 14, 20, 26, & 33] | - | | |
| 22 Corporate Franchise-Retail [From Prev Years] | - | | |
| 23 | | | |
| 24 | | | |
| 27 | | | |
| 28 **Subtotal, Excluded [Ln. 21 + Ln. 22]** | - | | |
| 29 **Total, Included and Excluded (Column A, Lines 7 + 13 + 28)** | - | The Total shown on Line 29 (Included and Excluded taxes) should reconcile with the Total shown on Line 30 (which is derived from the FF1). | |
| 30 **Total Other Taxes [FF1, pg. 115.14.g] [From Inputs, Pg. 1, Ln. 23]** | - | | |
| 31 Difference (Line 29 - Line 30) | - | | |

Criteria for Allocation:
A Other Taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Gross Plant Allocator. If the taxes are 100% recovered at retail, they shall not be included.
B Other Taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail, they shall not be included.
C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.
D Other taxes, except as provided for in A, B and C above, which are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service, will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated, as described in footnote B above.

## ADDENDUM 18 TO ATTACHMENT H - Page 13 of 47
## The Empire District Electric Company

### Attachment 3 - Revenue Credits
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**Account 454 - Rent from Electric Property**

| | | |
|---|---|---|
| 1 | Rent from Electric Property [FF1, Pg. 300, Ln. 19, Col. b] [From Inputs, Pg. 2, Ln. 72] | - |
| 2 | T/D Revenue Allocation Factor [From Appendix A, Ln. 19] | - |
| 3 | Rent from Electric Transmission Property [Line 1 x Line 2] | - |

**Other Electric Revenues (Note 1)**

| | | |
|---|---|---|
| 4 | SPP Schedule 7 & 8 Transmission Revenues (Note 1 & Note 4) [From Inputs, Pg. 3, Ln. 18] | - |
| 5 | Schedule 1 P-T-P Revenue | - |
| 6 | This Line Not used | |
| 7 | Non-Firm Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4) [From Inputs, Pg. 3, Ln. 20] | - |
| 8 | Direct Assigned Facilities Revenues (Note 2) [From Inputs, Pg. 3, Ln. 15] | - |
| 9 | Other Revenues Associated with Loads Outside of Empire's Zone [From Inputs, Pg. 3, Ln. 19] | - |
| 10 | Gross Revenue Credits (sum Lines 3 thru 9) [To Appendix A, Line 122] | - |

**Note 1**: All Schedule 7 & 8 revenues derived as a Transmission Owner from SPP for loads not included in the system peak and for which the cost of the service is recovered under this formula will be included in this revenue credit. These revenues are booked in Accounts 457.137 (Firm Point-to- Point) and 457.138 (Non-Firm Point-to-Point). All current NITS customers in the Empire zone are included in the Load Divisor.

**Note 2**: If the costs associated with Directly Assigned Transmission Facility Charges are included in this TFR, the associated revenues will be included in this TFR. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in this TFR, the associated revenues will not be included in this TFR.

**Note 3**: Schedule 1A charges are assessed by SPP directly to the transmission customers and are retained by SPP. Schedule 12 revenues associated with Transmission Service are collected by SPP and remitted to FERC by SPP. Any Schedule 1a or Schedule 12 revenues collected by Empire on behalf of Zonal customers are not retained by Empire, but are simply passed through to SPP.

**Note 4**: The portion of Point-to-Point revenues collected by SPP and assigned to Empire are included on ATT 3, Ln. 4. Any demand revenue margins collected directly by Empire for "grandfathered" bundled contracts will be included on ATT 3, Ln. 8. See note on "Inputs" worksheet, Pg. 3, Ln. 20 regarding remaining pre-OATT contracts.

**ADDENDUM 18 TO ATTACHMENT H - Page 14 of 47**

**The Empire District Electric Company**

**Attachment 4, NON-ESCROWED FUNDS**

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

The purpose of this worksheet is to individually document the value(s) of the non- escrowed reserve funds that will be credited against working capital. All inputs are derived from the Company's Books and Records, as described.

| FERC Reserve Acct | | FERC Expense Acct [3] | Balance | Allocator NP | Working Capital Adjustment (Col. C = Col. A x Col. B) |
|---|---|---|---|---|---|
| COL. A | | | | COL. B | COL. C |
| **Description of Reserve:** | | | | | |
| Line | | | | | |
| 1. Accum Prov for Inj/Damgs - Public Liability [1] (NP Allocator) | 228.210 | 925 | - | - | - |
| 2. Accum Prov Inj/Damgs - Workman's Comp [2] (NP Allocator) | 228.220 | 925 | - | - | - |
| 3. **Total** (Ln. 1 + Ln. 2) [Appendix A, Pg. 1, Ln. 46] | | | - | | - |
| 4. Conformation [FF1, Pg. 112, Ln. 28, Col. c] [From Inputs, Pg. 1, Ln. 22] | | | - | | |

[1] Serves as the reserve for injuries and damages to the public for which we have open litigation.

[2] Serves as the reserve for future costs of worker's compensation claims and long-term disability claims.

[3] Account 925 is the FERC expense account which includes the cost of insurance, the cost of claims not covered by insurance, the re-imbursement from insurance companies, and amounts credited to account 228.2 as an Accumulation Provision for Injuries and Damages.

# ADDENDUM 18 TO ATTACHMENT H - Page 15 of 47
# The Empire District Electric Company
# Attachment 5 - Cost Support
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ITC Adjustment:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | FF1 Amount | GP Allocator | Transmission Related | Details |
|---|---|---|---|---|---|---|
| 103 **Amortized Investment Tax Credit** | | 266.8.f [From Inputs, Pg.1, Ln. 50] | - | - | - | |

**Transmission / Non-transmission Cost Support:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | Plant Held for Future Use | Less Non-Transmission Related | Less Non-Land Items | Plant Held for Future Use (land only-transmission) | Details |
|---|---|---|---|---|---|---|---|
| 26 **Land Held for Future Use** | (Note C) | [From Inputs, Pg. 3, Lns. 9, 10, & 12] | - | - | - | - | |

**Adjustments to A & G Expense:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | Total | Details |
|---|---|---|---|---|
| **Allocated Administrative & General Expenses** | | | | |
| 55 Fixed PBOP expense (Based on 2011 Data - Electric portion only) | | [From Inputs, Pg. 3, Ln. 14] | | 2011 Fixed PBOP Expense (Will not change absent Section 205 or 206 Filing) Current year actual |
| 56 Actual Current Year PBOP expense - Electric portion only | | [From Inputs, Pg. 3, Ln. 13] | - | PBOP expense - Electric portion only |

**Regulatory Expense Related to Transmission Cost Support:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | FF1 Amount | Transmission Related | Non-transmission Related | Details |
|---|---|---|---|---|---|---|
| **Directly Assigned A&G** | | | | | | |
| 63 Regulatory Commission Exp Account 928 | (Note F) | 323.189.b [From Inputs, Pg. 1, Ln. 53] & 350.41.d thru 350.44.d [From Inputs, Pg. 3, Ln. 11] | - | - | | |
| | | | | - | | |

**State Income Tax Rates:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | Missouri | Kansas | Oklahoma | Arkansas | Details |
|---|---|---|---|---|---|---|---|
| **Income Tax Rates** | | | In lieu of using a blended state tax rate, Empire will use the Missouri state income tax rate (and 50% Federal Deduction); which yields the lowest rate for the four states. The vast majority of Empire's transmission system is located in Missouri. | | | | |
| 99 SIT=State Income Tax Rate or Composite | (Note G) | [From Inputs, Pg. 3, Lns. 2, 4, 5 & 6] | -% | -% | -% | -% | |

**Education and Out Reach Cost Support:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | Total Amount | T/D Allocator |
|---|---|---|---|---|
| **Directly Assigned Advertizing Expenses** | | | | |
| 64 Safety & Peak Alert Advertizing/Informational Expense | | | | |

(Note E) [From Input Sheet, Pg. 3, Ln. 7] - - **Allocated Amount** **Details**

-

Attachment 5
Page 1 of 2

**ADDENDUM 18 TO ATTACHMENT H - Page 16 of 47**

# The Empire District Electric Company
## Attachment 5 - Cost Support
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**Excluded Plant Cost Support:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | Revenues from Direct Assigned Transmission Facilities | General Description of the Direct Assigned Transmission Facilities |
|---|---|---|---|---|
| **Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities** | | | | |
| 117 Revenues from Direct Assigned Transmission Facilities | (Note I) | [From Inputs, Pg. 3, Ln. 15] | - | |

**Prepayments:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | FF1 Amount | Gross Plant Allocator | Functionalized to TX |
|---|---|---|---|---|---|
| **37 Prepayments** | | | | | |
| Prepayments | (Note A) | 111.57.c [From Inputs, Pg. 1, Ln. 1] | - | - | - |

**Adjustments to Transmission O&M:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions | | | Total |
|---|---|---|---|
| 49 Transmission O&M | | 321.112.b [From Inputs, Pg. 1, Ln. 52] | - |
| 50 Less Account 565 | | 321.96.b [From Inputs, Pg. 1, Ln. 51] | - |
| Less Ancillary Services Associated with Schedule 1: | | | |
| (561) Load Dispatching | | 321.84.b [From Inputs, Pg. 1, Ln. 40] (561.1) Load | - |
| Dispatch-Reliability | | 321.85.b [From Inputs, Pg. 1, Ln. 41] (561.2) Load Dispatch- | - |
| Monitor and Operate Transmission System | | 321.86.b [From Inputs, Pg. 1, Ln. 42] (561.3) Load Dispatch-Transmission | - |
| Service and Scheduling | | 321.87.b [From Inputs, Pg. 1, Ln. 43] (561.4) Scheduling, System Control and Dispatch | - |
| Services | | 321.88.b [From Inputs, Pg. 1, Ln. 44] | - |
| 51 Total Load Dispatching, Scheduling, and Control (Sum Accts 561 through 561.4, above) | | | - |
| 52 Plus Charges billed to Transmission Owner and booked to Account 565 | | [From Inputs, Pg. 3, Ln. 16] | - |

**EDE Zonal Load:**

| Appendix A Line #s, Descriptions, Notes, FF1 Page #s and Instructions<br>Network Zonal Service Rate | | | Transmission Network 12 CP | Description & SPP Documentation |
|---|---|---|---|---|
| 126 Zonal Transmission Network 12 CP Average | (Note K) | [From Inputs, Pg. 3, Ln. 17] | - | Includes Firm EDE Native Retail Load plus Firm SPP NITS loads delivered to service points located within EDE's transmission system. |

**ADDENDUM 18 TO ATTACHMENT H - Page 17 of 47**

**The Empire District Electric Company**

**Attachment 6, WEIGHTED AVERAGE COST OF CAPITAL**

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| Type of Capital | Total Company Average Capitalization ($) | | Weighted Cost Ratios* | Cost of Capital | | Weighted Cost of Capital |
|---|---|---|---|---|---|---|
| Balance<br>Col B = Col A/Col A Total | | Source | (%) | (%) | Source | (%)<br>Col D = Col B x Col C |
| Line | Col A | | Col B | Col C | | Col D |
| 1. Long Term Debt | - | [Note (1)] | - | - | [Note (4)] | - |
| 2. Preferred Stock | - | [Note (2)] | - | - | [Note (5)] | - |
| 3. Common Stock | - | [Note (3)] | - | **10.00%** | [Note (6)] | - |
| 4. Totals | - | | - | | | |
| 5. **Weighted Average Cost of Capital ("R")** | | | | | | - |

* The Equity Ratio will be capped at 55.00 %. If the actual Equity Ratio (Ln. 3 Col A/Ln.4, ColA) exceeds 55.00%, the formula in Ln. 3, Col B will set the Common Stock Ratio to 55% and the formula in Ln. 1, Col B will set the Long Term Debt ratio to 45.00% less the percentage shown on Ln. 2, Col B.

Note(1): From ATT 9, Pg. 1, Ln. 3.

Note (2): From ATT 8, Pg. 1, Ln. 3.

Note (3): From ATT 7, Pg. 1, Ln. 4.

Note(4): From ATT 9, Page 2, Ln. 8.

Note (5): From ATT 8, Pg. 1, Ln. 5.

Note (6): Return on Equity shall be set at 10.00% and cannot be changed absent a filing under Section 205/206 of the Federal Power Act.

# ADDENDUM 18 TO ATTACHMENT H -
## Page 18 of 47
## The Empire District Electric Company
## Attachment 7, COMMON STOCK
(For Rate Year Beginning July 1, 20 , Based on 20 Data)

| Line | Date | Total Proprietary Capital* Balance | Source | Preferred Stock: Outstanding Balance Acct 204 | Source | Preferred Stock: Premium (Discount) Acct 207, 213-Pfd | Source | Gains/(Losses) on Reacq'd Preferred Stock Acct 210 | Source | Other Paid-In Capital (Preferred Stock) Accts 208 - 211 | Source | Acc Other Comp Income Acct 219 | Source | Unappropriated Undistributed Subsidiary Earnings Acct 216.1 | Source | Common Equity Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col A | | Col B | | Col C | | Col D | | Col E | | Col F | | Col G | | Col H (H=A-B-C-D-E-F-G) |
| 1. | 1/0/1900 | - | [Note (1)] | - | [Note (3)] | - | [Note (5)] | - | [Note (7)] | - | [Note (9)] | - | [Note (11)] | - | [Note (13)] | - |
| 2. | 1/0/1900 | - | [Note (2)] | - | [Note(4)] | - | [Note (6)] | - | [Note (8)] | - | [Note (10)] | - | [Note (12)] | - | [Note (14)] | - |
| 3. | | - | | - | | - | | - | | - | | - | | - | | |

4. **Common Equity Balance** [Average of Beg of Yr & End of Yr CE Balance]: -

[To ATT-6, Page 1, Line 3, Col A]

* Includes both Common and Preferred Stock accounts.

[Note (1)]: FF1, Pg. 112, Ln. 16, Col. d. [From Inputs, Pg. 1, Ln. 9]

[Note (2)]: FF1, Pg. 112, Ln. 16, Col. c. [From Inputs, Pg. 1, Ln. 8]

[Note (3)]: From ATT 8, Ln. 1, Col. A.

[Note (4)]: From ATT 8, Ln. 2, Col. A.

[Note (5)]: From ATT 8, Ln. 1; Col. B + Col. C.

[Note (6)]: From ATT 8, Ln. 2; Col. B + Col. C.

[Note (7)]: From ATT 8, Ln. 1, Col. D.

[Note (8)]: From ATT 8, Ln. 2, Col. D.

[Note (9)]: From ATT 8, Ln. 1, Col. E.

[Note (10)]: From ATT 8, Ln. 2, Col. E.

[Note (11)]: FF1, Pg. 112, Ln. 15, Col. d. [From Inputs, Pg. 1, Ln. 7]

[Note (12)]: FF1, Pg. 112, Ln. 15, Col. c. [From Inputs, Pg. 1, Ln. 6]

[Note (13)]: FF1, Pg. 112, Ln. 12, Col. d; as adjusted on ATT 11, Pg. 1, Ln. 4, Col. E

[Note (14)]: FF1, Pg. 112, Ln. 12, Col. c; as adjusted on ATT 11, Pg. 1, Ln. 5, Col. E

# ADDENDUM 18 TO ATTACHMENT H -
## Page 19 of 47
## The Empire District Electric Company
## Attachment 8, PREFERRED STOCK

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| Line | Date | Preferred Stock Acct 204 | Data Source | Premium on Preferred Stock Acct 207 | Data Source | Discount on Preferred Stock Acct 213 | Data Source | Gain/(Loss) On Reaq'd Pref Stock Acct 210 | Data Source | Other Paid-In Capital - Preferred Accts 208 - 211 | Data Source | Total Outstanding Col F = Cols A+B-C+D+E |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col A | | Col B | | Col C | | Col D | | Col E | | COL F |
| **1.** | | - | [Note (1)] | - | [Note (3)] | - | [Note (5)] | - | [Note (7)] | - | [Note (9)] | - |
| **2.** | 1/0/1900 | - | [Note (2)] | - | [Note (4)] | - | [Note (6)] | - | [Note (8)] | - | [Note (10)] | - |
| **3.** | | | | **Avg of B of Yr and E of Yr Pref Stock** [To ATT 6, Pg. 1, Col. A, Ln. 2]: | | | | | | | | - |
| **4.** | | | | | | **Preferred Dividends** [Note 11]: | | | | | | - |
| **5.** | | | | **Average Cost Rate** [Ln 4 / Ln 3] [To ATT 6, Pg. 1, Col. C, Ln. 2]: | | | | | | | | |

Note (1): FF1, Pg. 112, Ln. 3, Col d. [From Inputs, Pg. 1, Ln. 3]

Note (2): FF1, Pg. 112, Ln. 3, Col c. [From Inputs, Pg. 1, Ln. 2]

Note (3): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. d that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records. Note (4): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. c that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records. Note (5): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. d that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records. Note (6): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. c that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

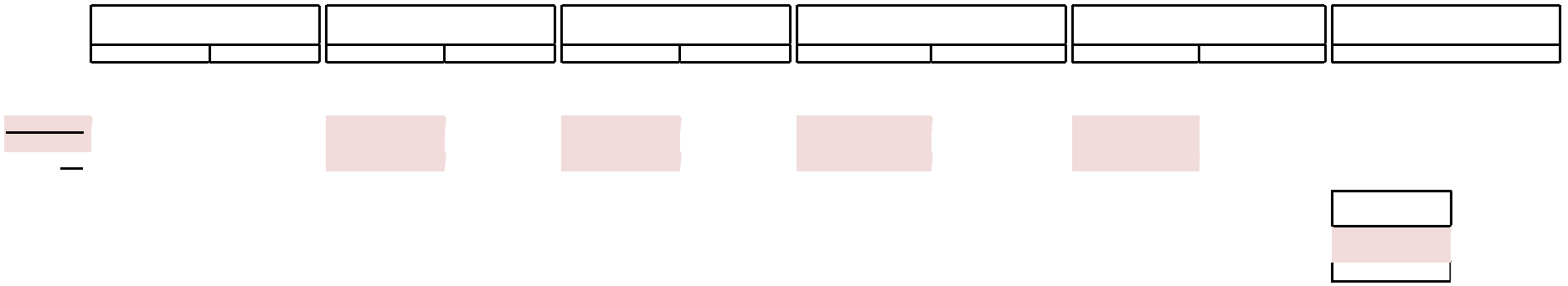
Note (7): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (8): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (9): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. d that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (10): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. c that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (11): FF1, Pg. 118, Ln. 29, Col. c. (Enter as a positive number).



**ADDENDUM 18 TO ATTACHMENT H - Page 20 of 47**
**The Empire District Electric Company**
**Attachment 9, LONG-TERM DEBT**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

## GROSS PROCEEDS - LTD OUTSTANDING

| | | Advances from Associated Company LTD | | Bonds | | Reacquired Bonds | | Other Long Term Debt | | Total Long Term Debt Outstanding |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Acct 223 | Source | Acct 221 | Source | Acct 222 | Source | Acct 224 | Source | Col E= Cols A+B+C+D |
| Line | Date | Col A | | Col B | | Col C | | Col D | | Col E |
| **1.** | 1/0/1900 | - | [Note (1)] | - | [Note (3)] | - | [Note (5)] | - | [Note (7)] | - |
| **2.** | 1/0/1900 | - | [Note (2)] | - | [Note (4)] | - | [Note (6)] | - | [Note (8)] | - |
| **3.** | | **GROSS PROCEEDS** (Avg of Beg of Yr and End of Yr LTD Gross Outstanding Balances in Col E) [To ATT 6, Pg.1, Ln. 1, Col. A]: | | | | | | | | - |

Note (1): FF1, Pg. 112, Line 20, Col d. [From Inputs, Pg. 1, Ln. 15]
Note (2): FF1, Pg. 112, Line 20, Col c. [From Inputs, Pg. 1, Ln. 14]
Note (3): FF1, Pg. 112, Ln 18, Col. d; as adjusted on ATT 11, Pg. 1, Ln. 2.
Note (4): FF1, Pg. 112, Ln 18, Col. c; as adjusted on ATT 11, Pg. 1, Ln. 3.
Note (5): FF1, Pg. 112, Ln 19, Col. d. [From Inputs, Pg. 1, Ln. 13]
Note (6): FF1, Pg. 112, Ln 19, Col. c. [From Inputs, Pg. 1, Ln. 12]
Note (7): FF1, Pg. 112, Ln 21, Col. d. [From Inputs, Pg. 1, Ln. 17]
Note (8): FF1, Pg. 112, Ln 21, Col. c. [From Inputs, Pg. 1, Ln. 16]

## NET PROCEEDS

| Line | Date | | |
|---|---|---|---|
| **4.** | 1/0/1900 | Unamortized balance Premiums (Beg of Yr) [Form 1, Pg. 112, Ln. 22, Col. d] [From Inputs, Pg. 1, Ln. 19] | - |
| **5.** | 1/0/1900 | Unamortized balance Premiums (End of Yr) [Form 1, Pg. 112, Ln. 22, Col. c] [From Inputs, Pg. 1, Ln. 18] | - |
| **6.** | | **Avg of Beg & End of Yr Premiums** | - |
| **7.** | 1/0/1900 | Unamortized balance Discounts (Beg of Yr) [Form 1, Pg. 112, Ln. 23, Col. d] [From Inputs, Pg. 1, Ln. 21] | - |
| **8.** | 1/0/1900 | Unamortized balance Discounts (End of Yr) [Form 1, Pg. 112, Ln. 23, Col. c] [From Inputs, Pg. 1, Ln. 20] | - |
| **9.** | | **Avg of Beg & End of Yr Discounts** | - |
| **10.** | | Gross Proceeds [From Line 3, above] | - |
| **11.** | | Plus: Unamortized balance Premiums [From Line 6, above] | - |
| **12.** | | Less: Unamortized balance Discounts [From Line 9, above] | - |

**13.** **NET PROCEEDS** (Avg of Beg of Yr and End of Yr LTD): -

General Note: Net long-term average debt balance is used as the divisor to determine LTD debt cost rate. Gross long-term average debt balance is used in the capital structure.

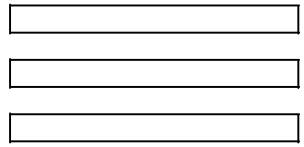
Attachment 9
Page 1 of 2

**ADDENDUM 18 TO ATTACHMENT H -**
**Page 21 of 47**
**The Empire District Electric Company**
**Attachment 9, LONG-TERM DEBT**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

## LTD COSTS AND EXPENSES (Actual)

| Line | | |
|---|---|---|
| **1.** | LTD Interest Expense [FF1, Pg. 117, Ln. 62, Col. c]; as adj. on ATT 11, Pg. 1, Ln. 1. | - |
| **2.** | Amortization Debt Discount and Expense (Acct 428) [FF1, Pg. 117, Ln. 63, Col. c] [From Inputs, Pg. 1, Ln. 25] * | - |
| **3.** | Amortization of Loss on Reacquired Debt (Acct 428.1) [FF1, Pg. 117, Ln. 64, Col. c] [From Inputs, Pg. 1, Ln. 26] | - |
| **4.** | Less: Amort Premium on Debt Credit (Acct 429) [FF1, Pg. 117, Ln. 65, Col. c] [From Inputs, Pg.1, Ln. 27] | - |
| **5.** | Less: Amort Gain on Debt Credit (Acct 429.1) [FF1, Pg. 117, Ln. 66, Col. c] [From Inputs, Pg. 1, Ln. 28] | - |
| **5a.** | Plus: Interest on Debt to Associated Companies (Acct 430) [FF1, Pg. 117, Ln. 67, Col. c] [From Inputs, Pg. 1, Ln. 45] | - |
| **6.** | **TOTAL LTD Interest Amount** | - |
| **7.** | Total Long Term Debt Balance (Net Proceeds) [From Pg. 1, Ln. 13, above] | - |
| **8.** | **Embedded Cost of Long Term Debt [Line 6/Line 7]** [To ATT 6, Pg. 1, Ln. 1, Col. C] | **-** |

* Includes Debt Hedging Cost.



**ADDENDUM 18 TO ATTACHMENT H - 22 of 47**
**The Empire District Electric Company**
**Attachment 10, DEPRECIATION RATES**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| Line | FERC Account Number | Description | 2011 FERC Depreciation Rates (%)[1] | 2012 FERC Depreciation Rates (%)[2] |
|---|---|---|---|---|
| | | **Transmission Depreciation Rates** | | |
| 1. | 352 | Transmission Structures and Improvements | | |
| 2. | 353 | Transmission Station Equipment | | |
| 3. | 354 | Transmission Towers and Fixtures | | |
| 4. | 355 | Transmission Poles and Fixtures | | |
| 5. | 356 | Transmission Overhead Conductors and Devices | | |
| | | **General Plant Depreciation Rates** | | |
| 6. | 390 | Structures and Improvements | | |
| 7. | 391 | Office Furnishings - Except Computers | | |
| 8. | 391C | Office Furnishings - Computers | | |
| 9. | 392 | Transportation Equipment | | |
| 10. | 393 | Stores Equipment | | |
| 11. | 394 | Tools, Shop, and Garage Equipment | | |
| 12. | 395 | Laboratory Equipment | | |
| 13. | 396 | Power Operated Equipment | | |
| 14. | 397 | Communication Equipment | | |
| 15. | 398 | Miscellaneous Equipment | | |

[1] These FERC depreciation rates are found in the 2011 FF1, Pages 337 and 337.1, and will be used for the Annual Update of the Rate Year beginning July 1, 2012 only. These depreciation rates will not change absent a filing under Section 205 or 206 of the Federal Power Act.

[2] These FERC depreciation rates are found in the 2012 FF1, Pages 337 and 337.1, and will be used for the Annual Update of the Rate Year beginning July 1, 2013, and each subsequent Annual Update, unless and until changed via a filing under Section 205 or 206 of the Federal Power Act.

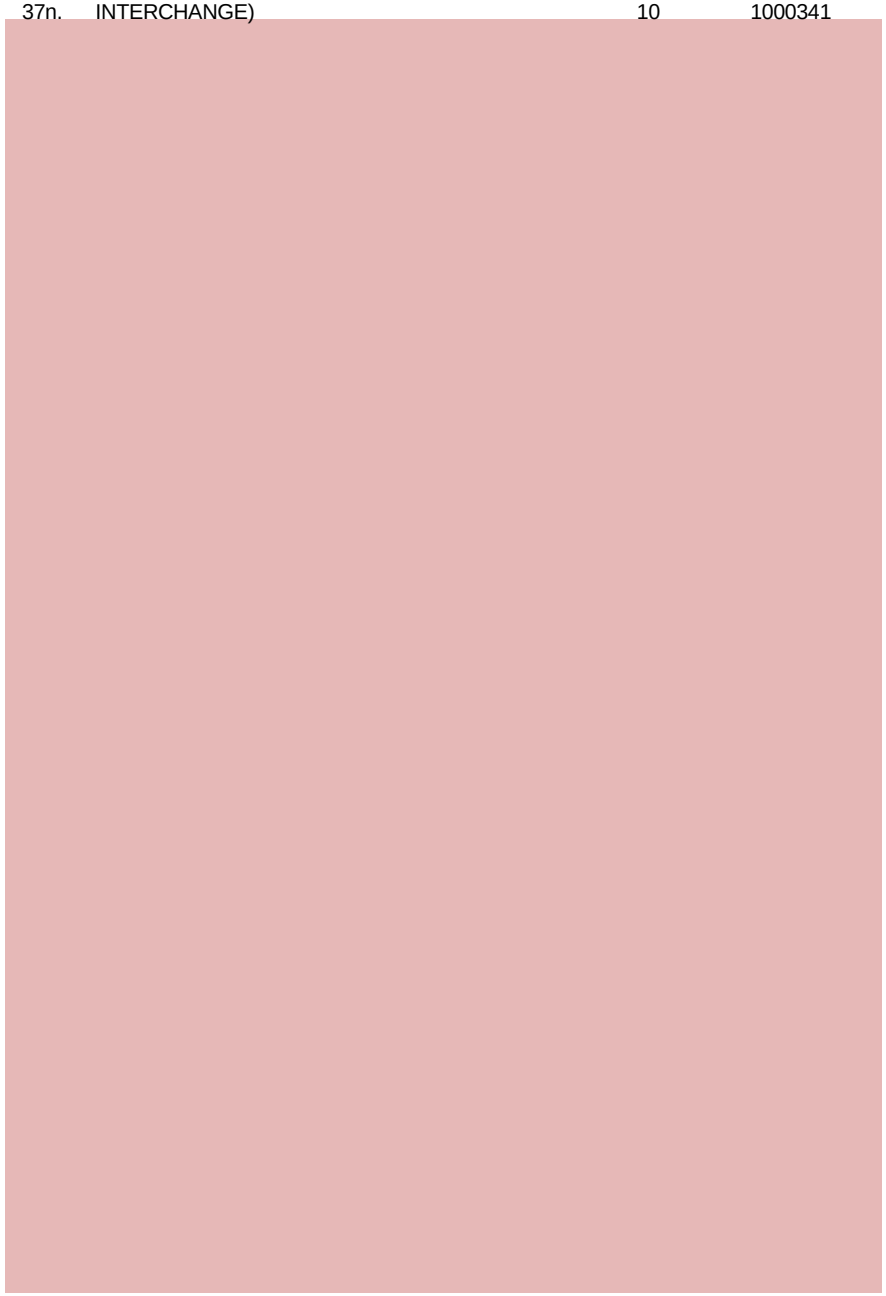
**ADDENDUM 18 TO ATTACHMENT H - Page 23 of 47**
**The Empire District Electric Company**
**Attachment 10A, INTANGIBLE PLANT DETAIL**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| Line | | Amort Period | Job # | Identification | Accumulated Amortization 12/31/20 | Beginning Bal. | Current Year | Current Year | Current Year | Ending Balance |
|---|---|---|---|---|---|---|---|---|---|---|
| | 21. | | | | FACILITIES STOCKTON DAM 161 KV CIRCUIT | | | SOFTWARE IATAN CRITICAL PIPING | | |
| | 21a. | | | | SPP SOFTWARE | | | SOFTWARE - IATAN CYBER SECURITY | | |
| | 22. | | | | POWERPLANT TAX SOFTWARE | | | SOFTWARE - CUSTOMER INFO SYSTEM | | |
| | 23. | | | | MAXIMO WORK MANAGEMENT | | | PROOFPOINT SECURITY SOFTWARE | | |
| 1. | | | | | ENOSERV RELAY SOFTWARE | | | SOFTWARE, STATELINE 1 DCS CONTROL | | |
| 2. | | | | | LICENSED PROGRAM - LOADSTAR | | | SOFTWARE - CENTURION | | |
| 3. | | | | | RESEARCH SOFTWARE - 2000 EMS UPGRADE | | | | | |
| 3a. | | | | | GIS AM/FM SYSTEM | | | | | |
| 3b. | | | | | SOFTWARE - FUTRAK | | | | | |
| 4. | | | | | SOFTWARE - FINANCIAL FORECASTING SOFTWARE - SOX | | | | | |
| 5. | | | | | SOFTWARE SLCC DCS CTRL SYSTEM COMP SFTWR-IATAN | | | | | |
| 6. | | | | | CMMS | | | | | |
| 7. | | | | | COMP SOFTWARE - CHECWORKS | | | | | |
| 8. | | | | | COMP SOFTWARE - PASTA / IATAN | | | | | |
| 9. | | | | | | | | | | |
| 10. | | | | | | | | | | |
| 11. | | | | | | | | | | |
| 12. | | | | | | | | | | |
| 13. | | | | | | | | | | |
| 14. | | | | | | | | | | |
| 15. | | | | | | | | | | |
| 15a. | | | | | | | | | | |
| 16. | | | | | | | | | | |
| 17. | | | | | | | | | | |
| 18. | | | | | | | | | | |
| 19. | | | | | | | | | | |
| 20. | | | | | | | | | | |

| (Years) [1] | | | Plant Balance (a) | Account 111 (b) | Retirements (d) | Amortization [2] (c) | Adjustment (e) | Account 111 (f = b + c + d + e) |
|---|---|---|---|---|---|---|---|---|
| N/A | 5 | MG7505C | | | | | | |
| | 5 | MG9382C | | | | | | |
| | 7 | MG9675C | | | | | | |
| | 7 | MS13869C | | | | | | |
| KP00 | 5 | MI3136C | | | | | | |
| 42C | 5 | MI9234C | | | | | | |
| 30 | 5 | MI93093C | | | | | | |
| MO19 | 5 | MI93000C | | | | | | |
| 11C | 5 | 1000263 | | | | | | |
| 30 | 5 | MO2849C | | | | | | |
| AP39 | 5 | 1002566 | | | | | | |
| 36C | 3 | MS15683C | | | | | | |
| 30 | 10 | MO5816C | | | | | | |
| AP39 | | | | | | | | |
| 36C | | | | | | | | |
| 7 | | | | | | | | |
| M983 | | | | | | | | |
| 1C | | | | | | | | |
| 30 | | | | | | | | |
| AP40 | | | | | | | | |
| 90C | | | | | | | | |
| N/A | | | | | | | | |
| M983 | | | | | | | | |
| 1C | | | | | | | | |
| 5 | | | | | | | | |
| MG102 | | | | | | | | |
| 10C | | | | | | | | |
| 7 | | | | | | | | |
| MG114 | | | | | | | | |
| 03C | | | | | | | | |
| 8 | | | | | | | | |
| MG124 | | | | | | | | |
| 23C | | | | | | | | |
| 10 | | | | | | | | |
| MG132 | | | | | | | | |
| 43C | | | | | | | | |
| 5 | | | | | | | | |
| MG25 | | | | | | | | |
| 98C | | | | | | | | |
| 10 | | | | | | | | |
| MG54 | | | | | | | | |
| 75C | | | | | | | | |
| 8 | | | | | | | | |
| MG71 | | | | | | | | |
| 84C | | | | | | | | |

| | | | |
|---|---|---|---|
| 24. | MERCURY MONITORING SOFTWARE, ASBURY | 7 | MP10954C |
| 25. | DCS UPGRADE, ASBURY | 10 | MP6358C |
| 26. | SOFTWARE - STATE LINE COMB CYCLE | 8 | MS5912C |
| 27. | SOFTWARE-MAXIMO | 8 | MS12344C |
| 28. | CITY UTILITIES SUB #170 | 30 | MT10571C |
| 29. | NETWORK UPGRADE SPA | 30 | MT10983C |
| 30. | KAMO SUB AND LAND | 30 | MT12318C |
| 31. | SOFTWARE - PLANNING & PROTECTION | 5 | MT4418C |
| 32. | KAMO SUB #221, 262 (CHESAPEAKE & ALBATROSS) | 30 | MT8584C |
| 33. | SOFTWARE PCI DAY AHEAD MARKET | 10 | MG14851C |
| 34. | SOFTWARE PCI | 10 | MG15176C |
| 35. | COMP SFTWR-IATAN EQUIP MONITORING | 5 | MI93004C |
| 36. | SOFTWARE INTERGRAPH OMS | 10 | MG15702C |
| 36a | SOFTWARE INTERGRAPH GIS | 10 | MG15183C |
| 36b | POWERPLANT UPGRADE - PA PORTION | 10 | 1002537 |
| 37. | GATEWAY SECURITY NGFW | 5 | 1002610 |
| 37a. | POWERPLANT UPGRADE - TAX PORTION | 10 | 1002536 |
| 37b. | PURCHASE MAXIMO UTILITY LICENCES | 10 | 1002895 |
| 37c. | SERVICE DESK IMPLEMENTATION | 5 | 1002530 |
| 37d. | PEOPLESOFT 9.2 UPGRADE 2015 | 10 | MO14859C |
| 37e. | PEOPLE SOFT HCM UPGRADE 2015 | 10 | MO14859C |
| 37f. | PEOPLE SOFT FINANCE PROJECT OVERHAUL | 10 | MO14859C |
| 37g. | PEOPLESOFT HCM PROJECT OVERHAUL | 10 | MO14859C |
| 37h. | SOFTWARE MAXIMO PROJ OVERHAUL | 10 | MO14923C |
| 37i. | SOFTWARE POWER PLANT PROJ OVERHAUL | 10 | MO14931C |
| 37j. | SOFTWARE SHAREPOINT PROJ OVERHAUL | 10 | MO14933C |
| 37k. | SOFTWARE PUR/IN DAY AHEAD MARKET SYSTEM | 10 | MG17107C |
| 37l. | SOFTWARE EMS | 10 | MG16312C |
| 37m. | SOFTWARE TEAMMATE AUDIT MGMT | 10 | 1000292 |

| | | | |
|---|---|---|---|
| 37n. | SOFTWARE EDI (ELECTRONIC DATA INTERCHANGE) | 10 | 1000341 |



| | | | |
|---|---|---|---|
| 38. | SOFTWARE MONARCH REMOTE USER SERVER | 10 | 1001050 |
| 38a. | SOFTWARE TALEO LEARNING MANAGEMENT SYSTEM | 10 | 1001219 |
| 38b. | SOFTWARE EMS OSI/MONARCH | 10 | 1001357 |
| 38c. | SOFTWARE, ASBURY DCS UPGRADE 2014 | 7 | 4000301 |
| 38d. | SOFTWARE DELL KASE 1000, SVC DESK | 5 | 1002530 |
| 38e. | SOFTWARE, CERIDIAN PAYROLL | 10 | 1003062 |
| 38f. | SOFTWARE, CUSTOMER WATCH UPGRADE 3.3 | 5 | 1001447 |
| 38g. | SOFTWARE, CW UPGRADE NET METERING | 10 | 1002974 |
| 38h. | SOFTWARE, HMI UPGRADE, RIV 10, 11 | 10 | 4003229 |
| 38i. | SOFTWARE, MAXIMO MOBILE | 10 | 1002821 |
| 38j. | SOFTWARE, MICROSOFT ENTERPRISE LICENSE | 3 | 1003000 |
| 38k. | SOFTWARE, OSI SECURITY PROFILER | 5 | 1002841 |
| 38l. | SOFTWARE, PCI 2017 UPGRADES | 5 | 1002973 |
| 38m. | PLUM POINT TURBINE CONTROLL | 5 | 1002883 |
| 38n. | SOFTWARE, SO/PD II TEST BATTERY | 5 | 1002914 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
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| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Total | | | | - | - | - | - | - | - |
| Column (a) Conformation [FF1, Pg. 205, Ln. 5, Col. g] [From Inputs, Pg. 1, Ln. 31] | | | | - | | | | | |
| Column (c) Conformation [FF1, Pg. 336, Ln. 1, Col. f] [From Inputs, Pg.1, Ln. 58] | | | | | | - | | | |
| Column (f) Conformation [FF1, Pg. 200, Ln. 21, Col. c] [From Inputs, Pg. 1, Ln. 30] | | | | | | | | | - |

[1] Amortization periods for each Intangible item will not change absent a filing under Section 205 or 206 of the Federal Power Act.

[2] Amortization amounts shall cease once the amount is fully amortized.

## ADDENDUM 18 TO ATTACHMENT H - Page 24 of 47
## The Empire District Electric Company

## Attachment 11, RECONCILIATION ITEMS, REFUNDS, & SURCHARGES

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**RECONCILIATION ITEMS TO FF1:**

| Line | TFR Reference COLUMN A | Description & FF1 Reference COLUMN B | FF1 COLUMN C | Adjustment COLUMN D | Total COLUMN E |
|---|---|---|---|---|---|
| 1. | ATT-9, Pg. 2, Ln. 1 | Interest on Long-Term Debt [1] [FF1, Pg. 117, Ln. 62, Col. c] [From Inputs, Pg. 1, Ln. 24] | - | - | - |
| 2. | ATT-9, Pg. 1, Ln. 1, Col. B | Beg. of Year 1st Mortgage Bond Balance [2] [FF1, Pg. 112, Ln. 18, Col. d] [From Inputs, Pg. 1, Ln. 11] | - | - | - |
| 3. | ATT-9, Pg. 1, Ln. 2, Col. B | End of Year 1st Mortgage Bond Balance [3] [FF1, Pg. 112, Ln. 18, Col. c] [From Inputs, Pg. 1, Ln. 10] | - | - | - |
| 4. | ATT-7, Pg. 1, Ln. 1, Col. G | Beg of Year Unapprop. Undistrib. Subsidiary Earnings [4] [FF1, Pg. 112, Ln. 12, Col. d] [From Inputs, Pg. 1, Ln. 5] | - | - | - |
| 5. | ATT-7, Pg. 1, Ln. 2, Col. G | End of Year Unapprop. Undistrib. Subsidiary Earnings [5] [FF1, Pg. 112, Ln. 12, Col. c] [From Inputs, Pg. 1, Ln. 4] | - | - | - |
| 6. | Appendix A, Ln. 7 | Total Electric Accumulated Depreciation [6] [FF1, Pg. 219, Ln. 29, Col. c] [From Inputs, Pg. 1, Ln. 49] | - | - | - |

[1] The bond interest paid [FF1, Pg. 117, Ln. 62, Col. c] does not include the interest paid on the EDG bond. This adjustment adds the EDG bond interest into LTD interest costs to reflect the consolidated capital structure used by Empire. See FF1, Pg. 256, EDG Bond Footnote.

[2] The beginning of year 1st mortgage bond balance [FF1, Pg. 112, Ln. 18, Col. d] does not include the EDG bond principal. This adjustment adds the EDG bond principal to the bond balance to reflect the consolidated capital structure used by Empire. See FF1, Pg. 256, EDG Bond Footnote.

[3] The end of year 1st mortgage balance [FF1, Pg. 112, Ln. 18, Col. c] does not include the EDG bond principal; which is added in to reflect the consolidated capital structure used by Empire. See FF1, Pg. 256, EDG Bond Footnote.

[4] The unappropriated undistributed subsidiary earnings [FF1, Pg. 112, Ln. 12, Col. d] includes interest paid [$ ] on the bonds held by an LDC gas subsidiary of Empire (EDG) for previous FF1 year (20___). This adjustment reflects the exclusion of the EDG interest payments from the "end of year" unappropriated undistributed subsidiary earnings. This adjustment is necessary because these items were reclassed to interest expense.

[5] This adjustment is described as follows: The unappropriated undistributed subsidiary earnings [FF1, Pg. 112, Ln. 12, Col. c] includes the interest paid [$ ] on the bonds held by an LDC gas subsidiary of Empire (EDG) for the 20___FF1 year. This adjustment reflects the exclusion of this interest payment from the "end of year" unappropriated undistributed subsidiary earnings. This adjustment is necessary because this item was reclassed to interest expense.

[6] The accumulated depreciation is adjusted to reflect the Missouri Regulatory Plan [as described in footnote to FF1, Pg. 219, Ln. 20, Col. c]. The Total Electric Accumulated Depreciation on Line 6, above, will be reduced by the amounts displayed in the tables below, for each respective Annual Update. After the 2071 Annual Update, the adjustment amount will be "zero". The adjustment amounts in the tables below will not change absent a Federal Power Act Section 205 or 206 filing.

| Annual Update Year | Mo Reg Plan Amt | Annual Update Year | Mo Reg Plan Amt | Annual Update Year | Mo Reg Plan Amt | Annual Update Year | Mo Reg Plan Amt |
|---|---|---|---|---|---|---|---|
| 2012 | 3 | 2027 | | 2042 | | 2057 | |
| 2013 | | 2028 | | 2043 | | 2058 | |
| 2014 | | 2029 | | 2044 | | 2059 | |
| 2015 | | 2030 | | 2045 | | 2060 | |
| 2016 | | 2031 | | 2046 | | 2061 | |
| 2017 | | 2032 | | 2047 | | 2062 | |
| 2018 | | 2033 | | 2048 | | 2063 | |
| 2019 | | 2034 | | 2049 | | 2064 | |
| 2020 | | 2035 | | 2050 | | 2065 | |
| 2021 | | 2036 | | 2051 | | 2066 | |
| 2022 | | 2037 | | 2052 | | 2067 | |
| 2023 | | 2038 | | 2053 | | 2068 | |

2024 2039 2054 2069
2025 2040 2055 2070
2026 2041 2056 2071

## ADDENDUM 18 TO ATTACHMENT H - Page 25 of 47
## The Empire District Electric Company

## Attachment 11, RECONCILIATION ITEMS, REFUNDS, & SURCHARGES

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ADJUSTMENTS TO GROSS ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| Line | ERROR IDENTIFICATION | Formula Reference | Contract Year [1] | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest [2] | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| | Column A | Column B | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| | | | | | | | | | Col. I = Col. G + Col. H |
| 1. | - | - - | - | | - | - | - | - | - |
| 2. | - | - | - | - | - | - | - | - | - |
| 3. | - | - | - | - | - | - | - | - | - |
| 4. | - | - | - | - | - | - | - | - | - |
| 5. | - | - | - | - | - | - | - | - | - |

6. **Total Adjustment to Gross ATRR (Sum of Lines 1 through 5) [To Appendix, Line 122a]:** -

**ADJUSTMENTS TO SPP REGIONAL PROJECTS' ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| Line | ERROR IDENTIFICATION | Formula Reference | Contract Year [1] | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest [2] | Total Adjustment to |
|---|---|---|---|---|---|---|---|---|---|
| | Column A | Column B | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| | | | | | | | | | Col. I = Col. G + Col. H |
| 7. | - | - | - | - | - | - | - | - | - |
| 8. | - | - | - | - | - | - | - | - | - |
| 9. | - | - | - | - | - | - | - | - | - |
| 10. | - | - | - | - | - | - | - | - | - |
| 11. | - | - | - | - | - | - | - | - | - |

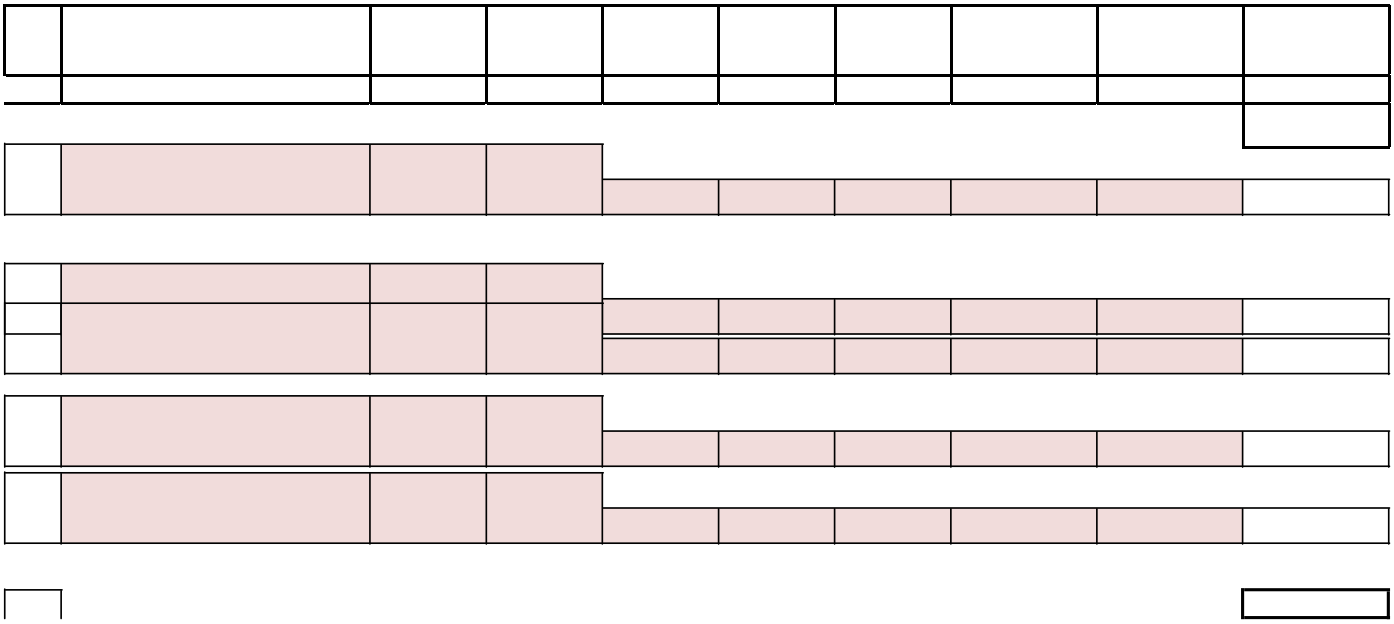
12. **Total Adjustment to SPP Regional Projects' ATRR (Sum of Lines 7 through 11) [To Appendix, Line 124b]:** -

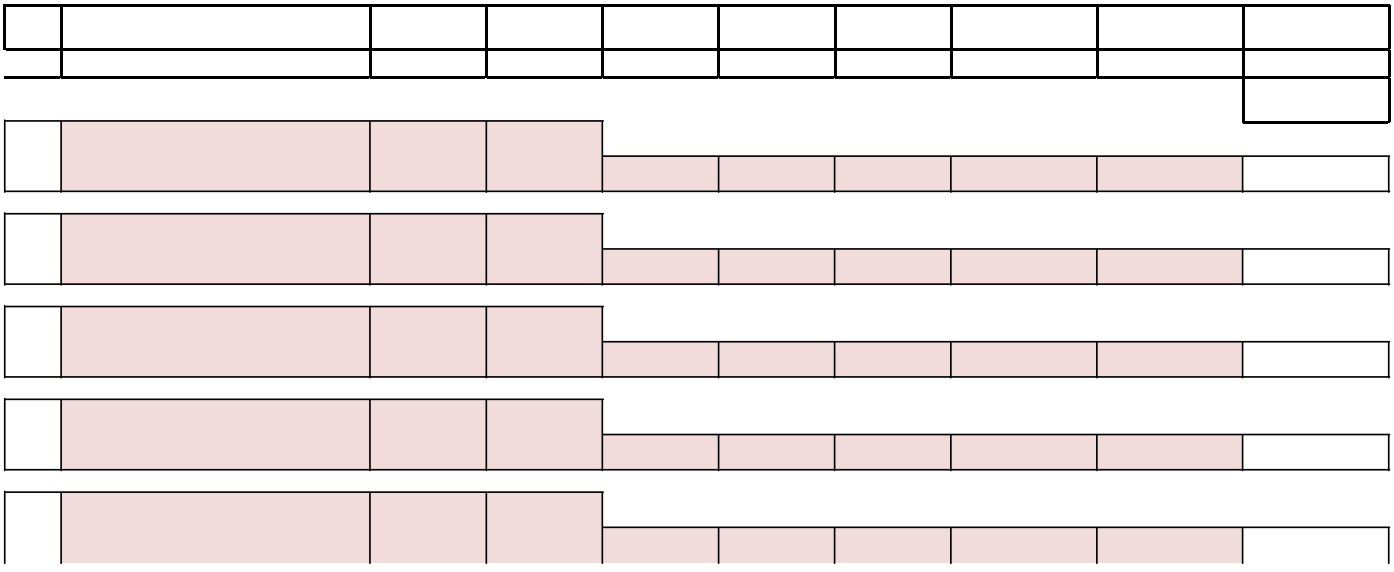
Notes:

[1] Contract Year in which the error occurred and affected the ATRR and rates paid by customers.

[2] Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.







## ADDENDUM 18 TO ATTACHMENT H - Page 26 of 47
## The Empire District Electric Company

### Attachment 12, SPP Regional Projects

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**SPP REGIONAL UPGRADE SUMMARY LISTS:**

**As of Year End:**

**BASE PLAN and"PARTIAL" BASE PLAN FUNDED (RELIABILITY) UPGRADES**

| Ln | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Gross Plant Date | |
|---|---|---|---|---|---|
| 1 | - | | - | | |
| 2 | - | - | - | | |
| 3 | - | - | - | | |
| 4 | - | - | - | - | - |
| 5 | - | - | - | - | - |
| 6 | - | - | - | - | - |
| 7 | - | - | - | - | - |
| 8 | - | - | - | - | - |
| 9 | - | - | - | - | - |
| 10 | - | - | - | - | - |
| 11 | - | - | - | - | - |
| 12 | - | - | - | - | - |
| 13 | - | - | - | - | - |
| 14 | - | - | - | - | - |
| 15 | - | - | - | - | - |
| 16 | - | - | - | - | - |
| 17 | - | - | - | - | - |
| 18 | - | - | - | - | - |
| 19 | - | - | - | - | - |
| 20 | - | - | - | - | - |
| 21 | - | - | - | - | - |
| 22 | - | - | - | - | - |
| 23 | - | - | - | - | - |
| 24 | - | - | - | - | - |
| 25 | - | - | - | - | - |
| 26 | - | - | - | - | - |
| 27 | - | - | - | - | - |
| 28 | - | - | - | - | - |
| 29 | - | - | - | - | - |
| 30 | - | - | - | - | - |
| 31 | - | - | - | - | - |
| 32 | - | - | - | - | - |
| 33 | - | - | - | - | - |
| 34 | - | - | - | - | - |
| 35 | - | - | - | - | - |
| 36 | - | - | - | - | - |
| 37 | - | - | - | - | - |
| 38 | - | - | - | - | - |
| 39 | - | - | - | - | - |
| 40 | - | - | - | - | - |
| 41 | - | - | - | - | - |
| 42 | - | - | - | - | - |
| 43 | - | - | - | - | - |
| 44 | - | - | - | - | - |
| 45 | - | - | - | - | - |
| 46 | - | - | - | - | - |
| 47 | - | - | - | - | - |
| 48 | - | - | - | - | - |
| 49 | - | - | - | - | - |
| 50 | - | - | - | - | - |
| 51 | - | - | - | - | - |
| 52 | - | - | - | - | - |

1/0/1900

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | ATRR w/o Incentives | | Incentive ATRR | |
| #DIV/0! | | | | | | | |
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| 54 | **Reliability and "Partial" Base Plan Funded Upgrade Totals** | | | | - | - | - |

## ADDENDUM 18 TO ATTACHMENT H - Page 27 of 47
## The Empire District Electric Company

### Attachment 12, SPP Regional Projects
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**SPP REGIONAL UPGRADE SUMMARY LISTS (Continued):**

**ECONOMIC UPGRADES**

| Ln | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | Gross Plant | ATRR w/o Incentives | Incentive ATRR |
|---|---|---|---|---|---|---|---|
| 1 | - | - | - | - | - | - | - |
| 2 | - | - | - | - | - | - | - |
| 3 | - | - | - | - | - | - | - |
| 4 | - | - | - | - | - | - | - |
| 5 | - | - | - | - | - | - | - |
| 6 | - | - | - | - | - | - | - |
| 7 | - | - | - | - | - | - | - |
| 8 | - | - | - | - | - | - | - |
| 9 | - | - | - | - | - | - | - |
| 10 | **Economic Upgrade Totals** | | | | - | - | - |

**BALANCED PORTFOLIO UPGRADES**

| | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | Gross Plant | ATRR w/o Incentives | Incentive ATRR |
|---|---|---|---|---|---|---|---|
| 11 | - | - | - | - | - | - | - |
| 12 | - | - | - | - | - | - | - |
| 13 | - | - | - | - | - | - | - |
| 14 | - | - | - | - | - | - | - |
| 15 | - | - | - | - | - | - | - |
| 16 | - | - | - | - | - | - | - |
| 17 | - | - | - | - | - | - | - |
| 18 | - | - | - | - | - | - | - |
| 19 | - | - | - | - | - | - | - |
| 20 | **Balanced Portfolio Upgrade Totals** | | | | - | - | - |

**INTEGRATED TRANSMISSION PLANNING UPGRADES**

| | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | Gross Plant | ATRR w/o Incentives | Incentive ATRR |
|---|---|---|---|---|---|---|---|
| 21 | - | - | - | - | - | - | - |
| 22 | - | - | - | - | - | - | - |
| 23 | - | - | - | - | - | - | - |
| 24 | - | - | - | - | - | - | - |
| 25 | - | - | - | - | - | - | - |
| 26 | - | - | - | - | - | - | - |
| 27 | - | - | - | - | - | - | - |
| 28 | - | - | - | - | - | - | - |
| 29 | - | - | - | - | - | - | - |
| 30 | - | - | - | - | - | - | - |
| 31 | - | - | - | - | - | - | - |
| 32 | - | - | - | - | - | - | - |
| 33 | - | - | - | - | - | - | - |
| 34 | - | - | - | - | - | - | - |
| 35 | - | - | - | - | - | - | - |
| 36 | - | - | - | - | - | - | - |
| 37 | - | - | - | - | - | - | - |
| 38 | - | - | - | - | - | - | - |
| 39 | - | - | - | - | - | - | - |
| 40 | **Integrated Transmission Planning Upgrade Totals** | | | | - | - | - |

41 **TOTAL** (Gross Plant, ATRR w/o Incentives, Incentive ATRR) for SPP Regional Upgrades

[Sum Line 54 (Page 1) , Line 10 (Page 2), Line 20 (Page 2), & Line 40 (Page 2)] - - -

**ADDENDUM 18 TO ATTACHMENT H - Page 28 of 47**

| | | | | | | |
|---|---|---|---|---|---|---|
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| | | | | | | |

## The Empire District Electric Company - Page 28 of 47.

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

## Attachment 12, SPP Regional Projects

**SPP REGIONAL UPGRADE DETAILS:**

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Line

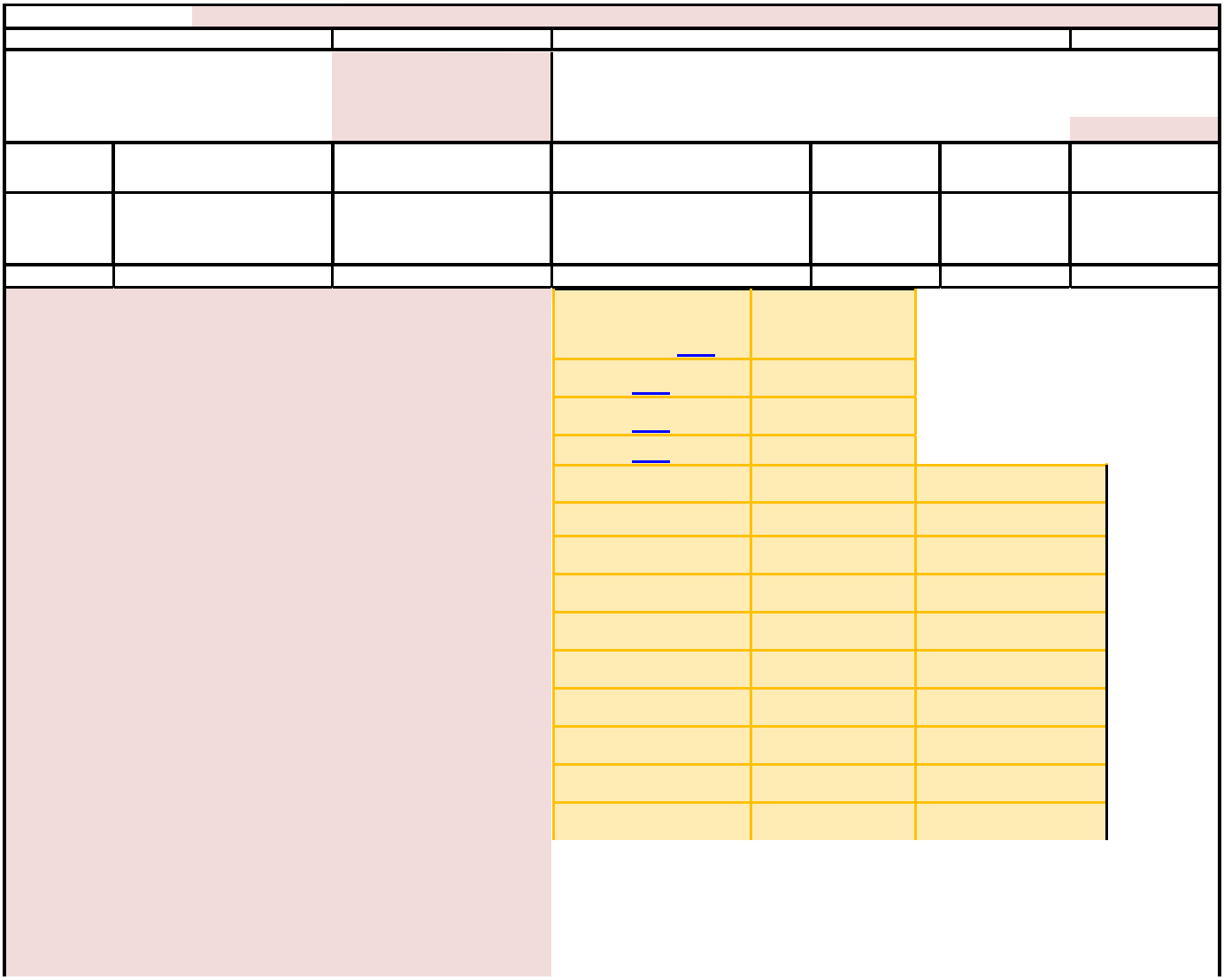
| | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 7. | Upgrade Description: | - | | |
| | | Column A | | Column B |
| 8. | SPP UID # : | - | NTPCC w/o Incentives: #DIV/0! | Incentive ROE (See Note 1, below): ROE |
| 9. | SPP NTC Approval Letter Date: | - | Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |
| 10. | Upgrade Status: | - | | |
| 11. | Upgrade In-Service Date: | - | BPF Funding Percentage: | - |

| | Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|---|
| | | | | Col F = Col D minus Col E | Col G = Col F x Ln 8, Col B x Ln 11, Col B | Col H = Col F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
| | | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| 12. | | - | - | - | - | - | | |
| 13. | | - | - | - | | - | | |
| 14. | | - | - | - | | -N/A | #DIV/0! | |
| 15. | | - | - | - | | | | |
| 16. | | - | - | - | | N/A | #DIV/0! | |
| 17. | | - | - | - | | N/A | #DIV/0! | |
| 18. | | - | - | - | | | | |
| 19. | | - | - | - | | N/A | #DIV/0! | |
| 20. | | - | - | - | | | #DIV/0! | #DIV/0! |
| 21. | | - | - | - | | | | |
| 22. | | - | - | - | | | #DIV/0! | #DIV/0! |
| 23. | | - | - | - | | | #DIV/0! | #DIV/0! |
| 24. | | - | - | - | | | | |
| 25. | | - | - | - | | | #DIV/0! | #DIV/0! |
| 26. | | - | - | - | | | | |
| 27. | | - | - | - | | | #DIV/0! | #DIV/0! |
| 28. | | - | - | - | | | #DIV/0! | #DIV/0! |
| 29. | | - | - | - | | | | |
| 30. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 31. | | - | - | - | | | | |
| 32. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 33. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 34. | | - | - | - | | | | |
| 35. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 36. | | - | - | - | | | | |
| 37. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 38. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 39. | | - | - | - | | | | |
| 40. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |
| 41. | | - | - | - | #DIV/0! | | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

## Attachment 12, SPP Regional Projects



(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

## SPP REGIONAL UPGRADE DETAILS:

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| Line | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |
| 7. | Upgrade Description: | |

| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

11.

Upgrade In-Service Date:

BPF Funding Percentage:

| Year | Year-End Gross | Year-End Accumulat | ATRR w/o | Incentive ATRR | ATRR to be |
|---|---|---|---|---|---|

| | Plant Investment | ed Depreciation | Year-End Net Plant | Incentive ROE | collected by SPP |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |

| | Column C | Column D | Column E | Col F = Col D minus Col E Column F | Col G = Col F x Ln 8, Col B x Ln 11, Col B Column G | Col H = Col F x Ln 10, Col B x Ln 11, Col B Column H | Col I = Col G + Col H Column I |
|---|---|---|---|---|---|---|---|
| 12. | | | | - | N/A | #DIV/0! | N/A |
| 13. | | | | - | N/A | #DIV/0! | N/A |
| 14. | | | | - | N/A | #DIV/0! | N/A |
| 15. | | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | | - | | #DIV/0! | #DIV/0! |
| 18. | | | | - | | #DIV/0! | #DIV/0! |
| 19. | | | | - | | #DIV/0! | #DIV/0! |
| 20. | | | | - | | #DIV/0! | #DIV/0! |
| 21. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

## Attachment 12, SPP Regional Projects

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

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Line

| | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |
| 7. | Upgrade Description: | |

| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

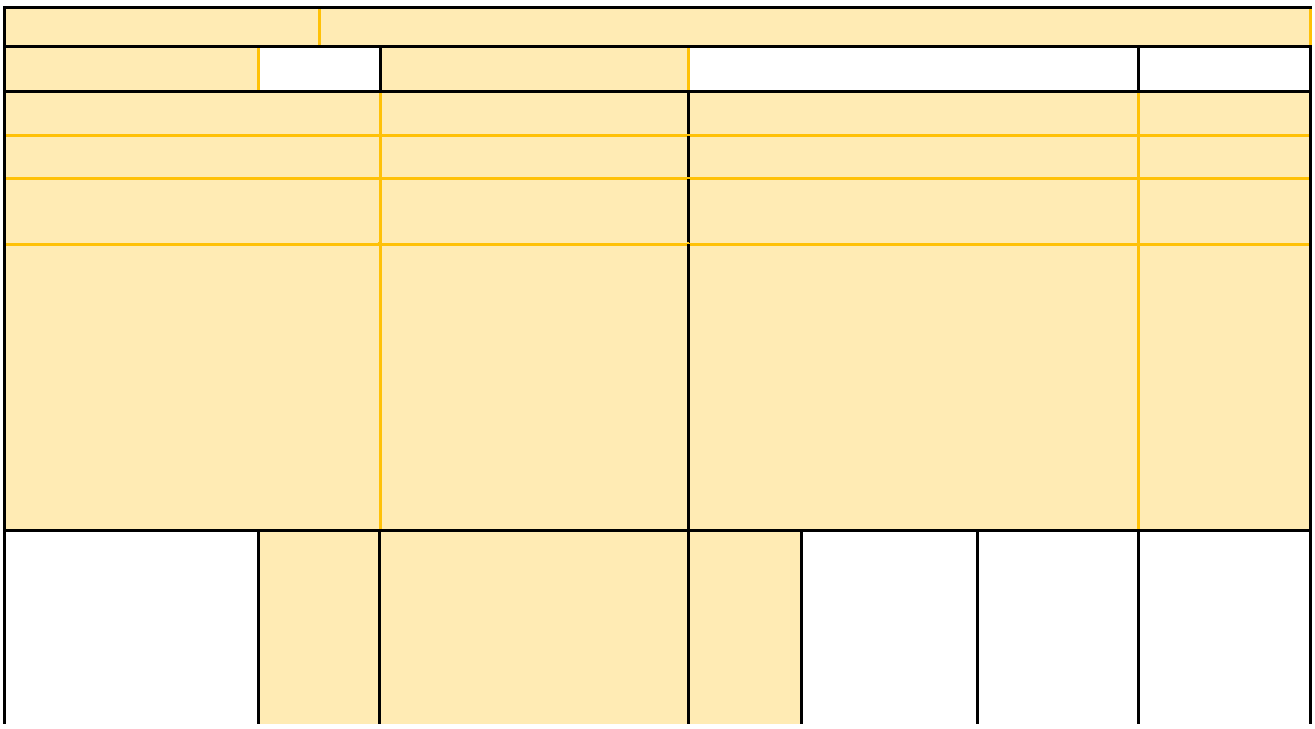
11.

Upgrade In-Service Date:

BPF Funding Percentage:

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant Col F = | ATRR w/o Incentive ROE | Incentive ATRR Col H = Col | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|

| Col D minus Col E | Col G = Col F x Ln 8, Col B x Ln 11, Col B | F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
|---|---|---|---|



| | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
|---|---|---|---|---|---|---|---|
| 12. | | | | - | N/A | #DIV/0! | N/A |
| 13. | | | | - | N/A | #DIV/0! | N/A |
| 14. | | | | - | | #DIV/0! | #DIV/0! |
| 15. | | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | | - | | #DIV/0! | #DIV/0! |
| 18. | | | | - | | #DIV/0! | #DIV/0! |
| 19. | | | | - | | #DIV/0! | #DIV/0! |
| 20. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 21. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

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Line

| | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |
| 7. | Upgrade Description: | |

| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

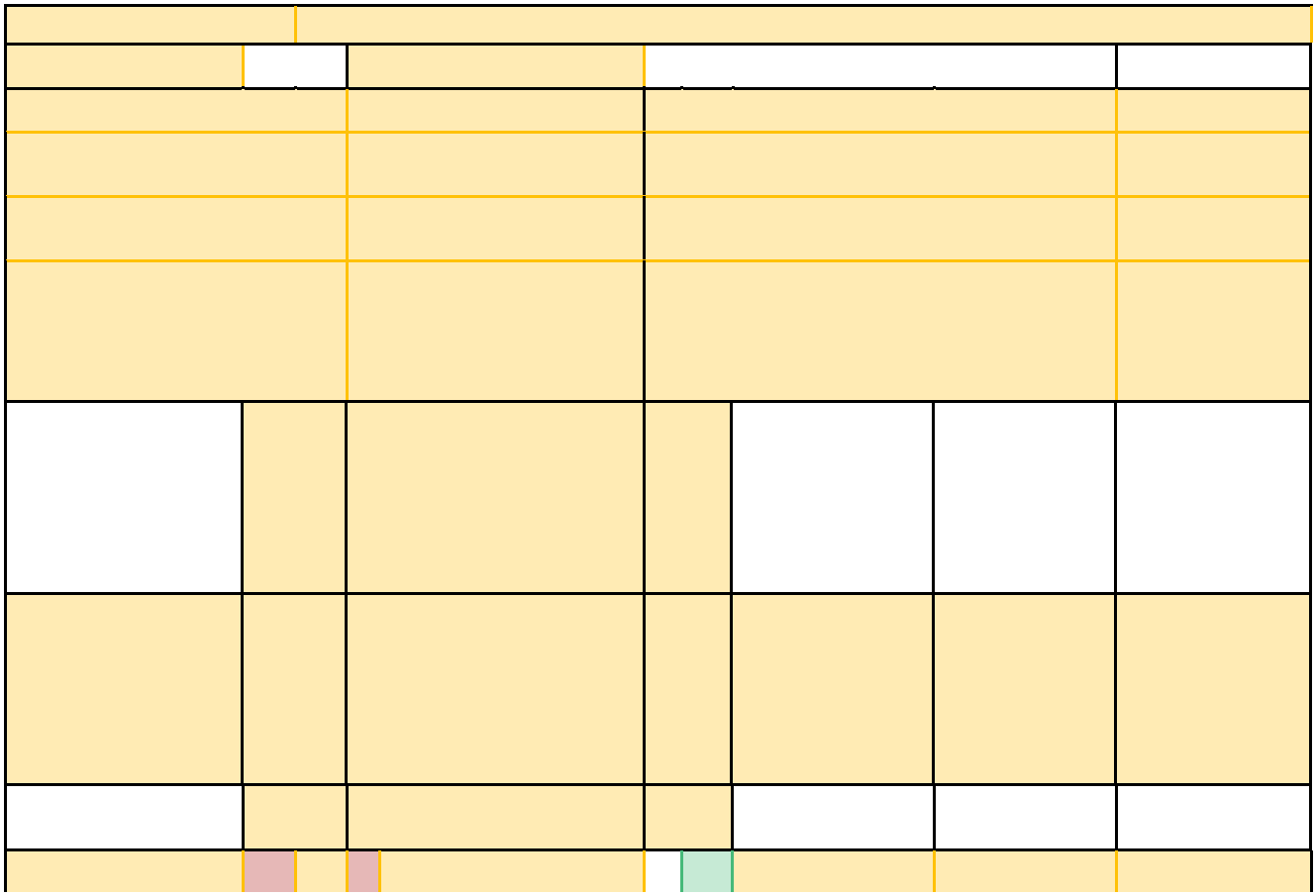
11.

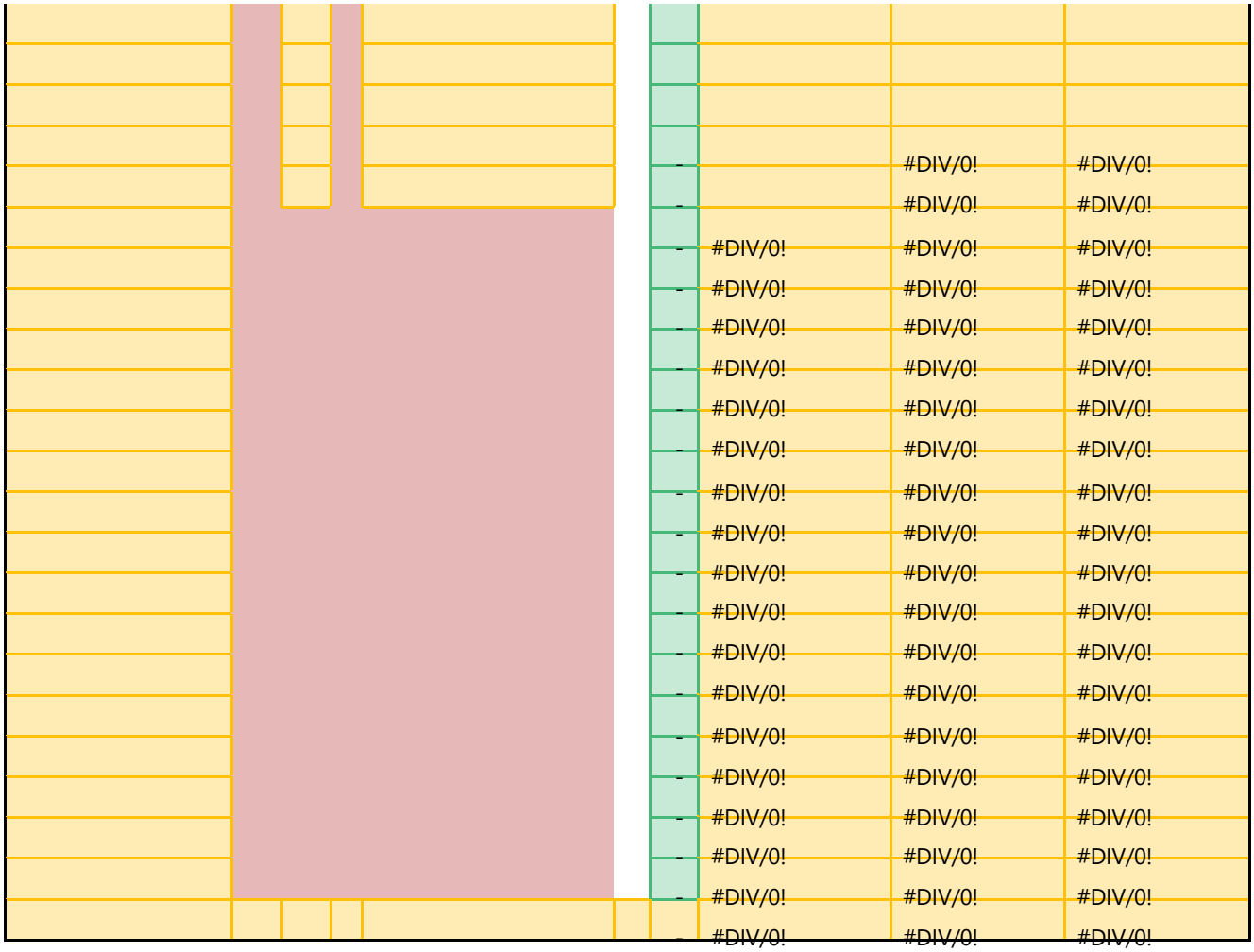
Upgrade In-Service Date:

BPF Funding Percentage:

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant Col F = Col D minus Col E | ATRR w/o Incentive ROE Col G = Col F x Ln 8, Col B x Ln 11, Col B | Incentive ATRR Col H = Col F x Ln 10, Col B x Ln 11, Col B | ATRR to be collected by SPP Col I = Col G + Col H |
|---|---|---|---|---|---|---|
| Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| 12. | | | - | N/A | #DIV/0! | N/A |
| 13. | | | - | N/A | #DIV/0! | N/A |
| 14. | | | - | N/A | #DIV/0! | N/A |
| 15. | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | - | | #DIV/0! | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 17. | | - | #DIV/0! | #DIV/0! |
| 18. | | - | #DIV/0! | #DIV/0! |





| | | | | |
|---|---|---|---|---|
| 19. | - | | #DIV/0! | #DIV/0! |
| 20. | - | | #DIV/0! | #DIV/0! |
| 21. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

## Attachment 12, SPP Regional Projects

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

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| Line | |
|---|---|
| 1. | 2. |

| | |
|---|---|
| Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! Total Net Transmiss |
| 13] | #DIV/0! |

| | | |
|---|---|---|
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |

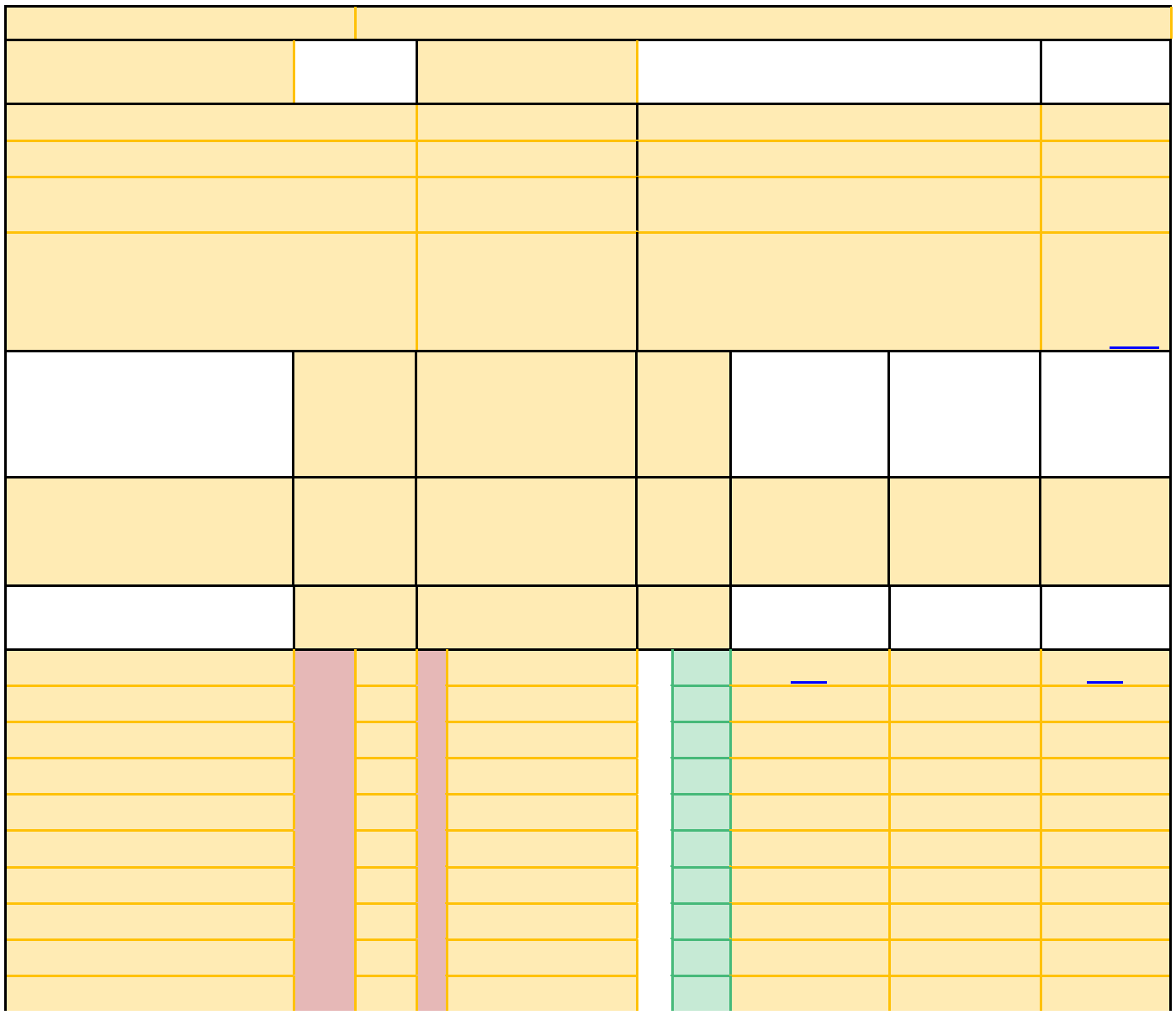
7. Upgrade Description:

| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

11. Upgrade In-Service Date: BPF Funding Percentage: 100%

| | Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|---|
| | | | | Col F = Col D minus Col E | Col G = Col F x Ln 8, Col B x Ln 11, Col B | Col H = Col F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
| | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| 12. | | | | - | N/A | #DIV/0! | N/A |
| 13. | | | | - | | #DIV/0! | #DIV/0! |
| 14. | | | | - | | #DIV/0! | #DIV/0! |
| 15. | | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | | - | | #DIV/0! | #DIV/0! |
| 18. | | | | - | | #DIV/0! | #DIV/0! |
| 19. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 20. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 21. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 26. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | | - | #DIV/0! | #DIV/0! | #DIV/0! |



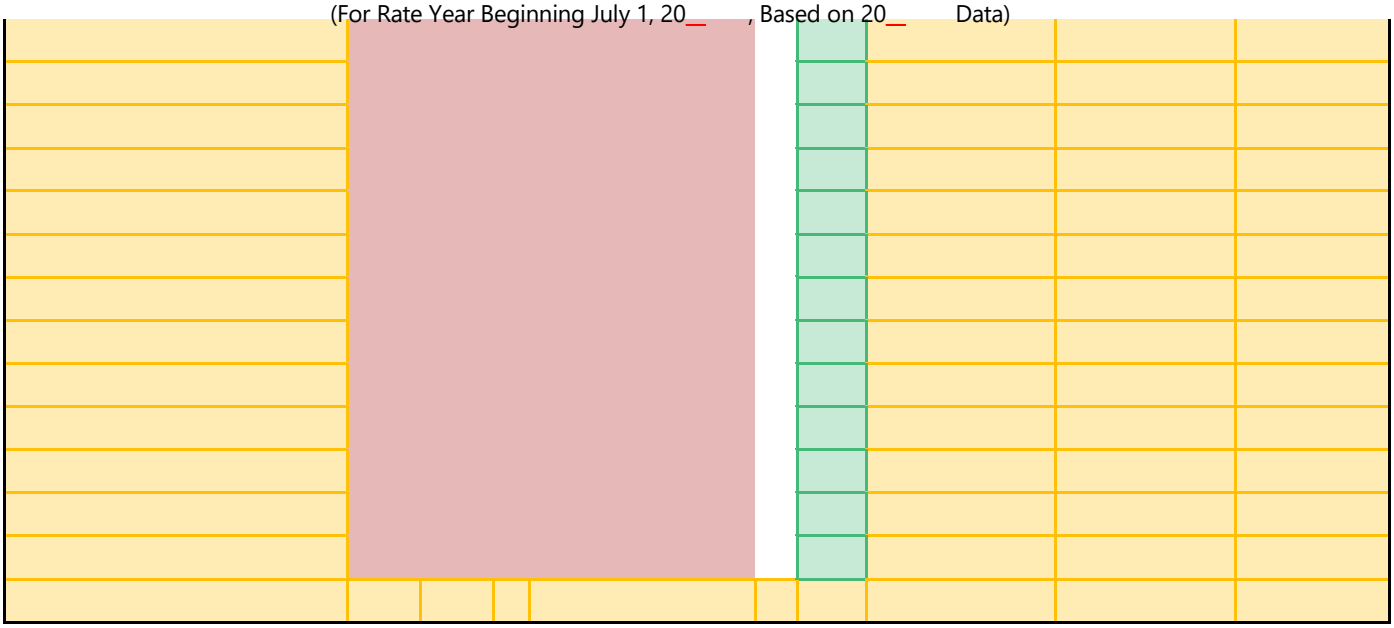
| | | | | |
|---|---|---|---|---|
| 28. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment
12

Pg. __ of __

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)



**SPP REGIONAL UPGRADE DETAILS:**

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| Line | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |
| 7. | Upgrade Description: | |

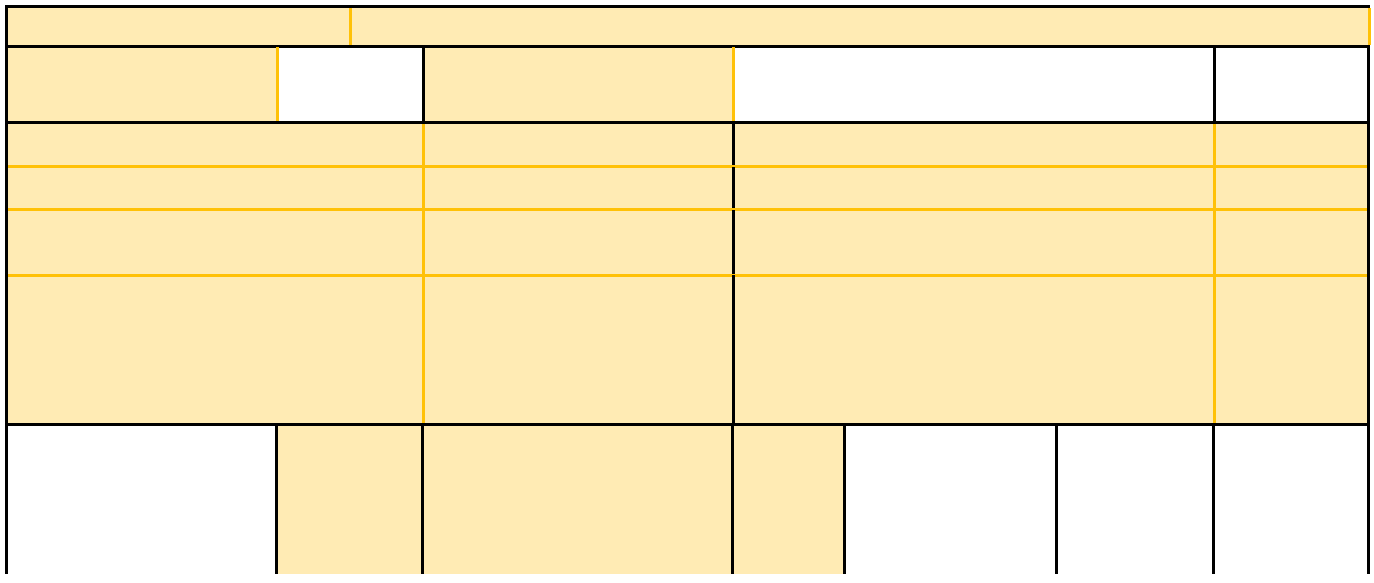
| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

11.

Upgrade In-Service Date: BPF Funding Percentage:

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|
| | | | Col F = Col D | Col G = Col F x | Col H = Col F x Ln 10, | |

| minus Col E | Ln 8, Col B x Ln 11, Col B | Col B x Ln 11, Col B | Col I = Col G + Col H |
|---|---|---|---|



| | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
|---|---|---|---|---|---|---|---|
| 12. | | | | - | N/A | #DIV/0! | N/A |
| 13. | | | | - | N/A | #DIV/0! | N/A |
| 14. | | | | - | N/A | #DIV/0! | N/A |
| 15. | | | | - | N/A | #DIV/0! | N/A |
| 16. | | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | | - | | #DIV/0! | #DIV/0! |
| 18. | | | | - | | #DIV/0! | #DIV/0! |
| 19. | | | | - | | #DIV/0! | #DIV/0! |
| 20. | | | | - | | #DIV/0! | #DIV/0! |
| 21. | | | | - | | #DIV/0! | #DIV/0! |
| 22. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

# Attachment 12, SPP Regional Projects

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

**SPP REGIONAL UPGRADE DETAILS:**

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| Line | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |
| 7. | Upgrade Description: | Column B |
| 8. | SPP UID # : | NTPCC w/o Incentives: #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: #DIV/0! |
| 11. | Upgrade In-Service Date: | BPF Funding Percentage: |

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|
| | | | Col F = Col D minus Col E | Col G = Col F x Ln 8, Col B x Ln 11, Col B | Col H = Col F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
| Column C | Column D | Column E | Column F | Column G | Column H | Column I |

| | | | | |
|---|---|---|---|---|
| 12. | | - | N/A | #DIV/0! | N/A |
| 13. | | - | N/A | #DIV/0! | N/A |

| | | | | | |
|---|---|---|---|---|---|
| 14. | | - | N/A | #DIV/0! | N/A |
| 15. | | - | | #DIV/0! | #DIV/0! |
| 16. | | - | | #DIV/0! | #DIV/0! |
| 17. | | - | | #DIV/0! | #DIV/0! |
| 18. | | - | | #DIV/0! | #DIV/0! |
| 19. | | - | | #DIV/0! | #DIV/0! |
| 20. | | - | | #DIV/0! | #DIV/0! |
| 21. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment
12

Pg. _ of _

## Attachment 12, SPP Regional Projects

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

**SPP REGIONAL UPGRADE DETAILS:**

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| Line | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |
| 7. | Upgrade Description: | |

| | Column A | | | Column B |
|---|---|---|---|---|
| 8. | SPP UID # : | | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |
| 11. | Upgrade In-Service Date: | | BPF Funding Percentage: | |

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|
| | | | Col F = Col D minus Col E | Col G = Col F x Ln 8, Col B x Ln 11, Col B | Col H = Col F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
| Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| 12. | | | - | N/A | #DIV/0! | N/A |

| | | | | | |
|---|---|---|---|---|---|
| 13. | | - | N/A | #DIV/0! | N/A |
| 14. | | - | | #DIV/0! | #DIV/0! |
| 15. | | - | | #DIV/0! | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 16. | - | | #DIV/0! | #DIV/0! |
| 17. | - | | #DIV/0! | #DIV/0! |
| 18. | - | | #DIV/0! | #DIV/0! |
| 19. | - | | #DIV/0! | #DIV/0! |
| 20. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 21. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | - | #DIV/0! | #DIV/0! | #DIV/0! |

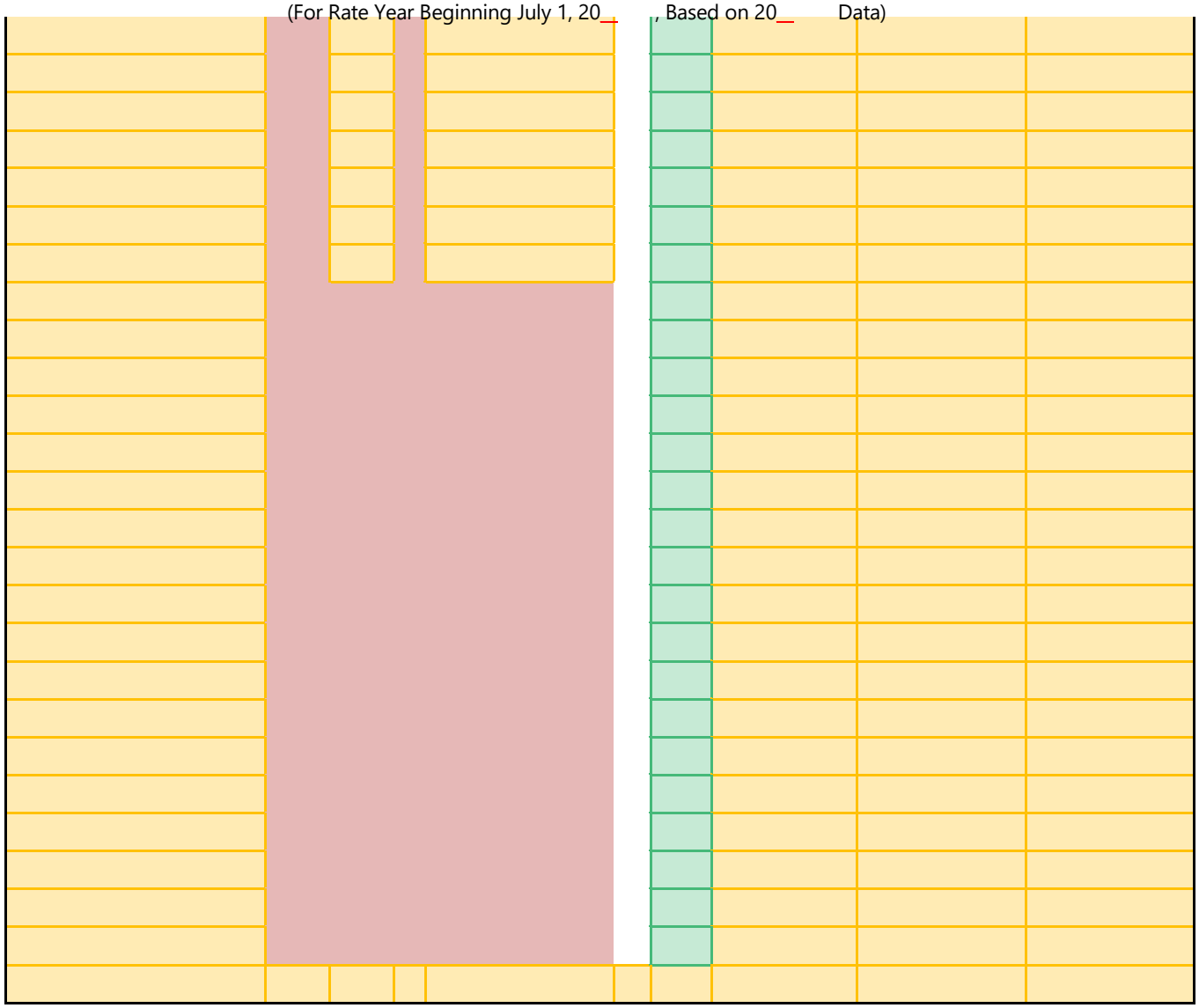
Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment
12

Pg. __ of ___

**Attachment 12, SPP Regional Projects**

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)



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Line

| | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! |

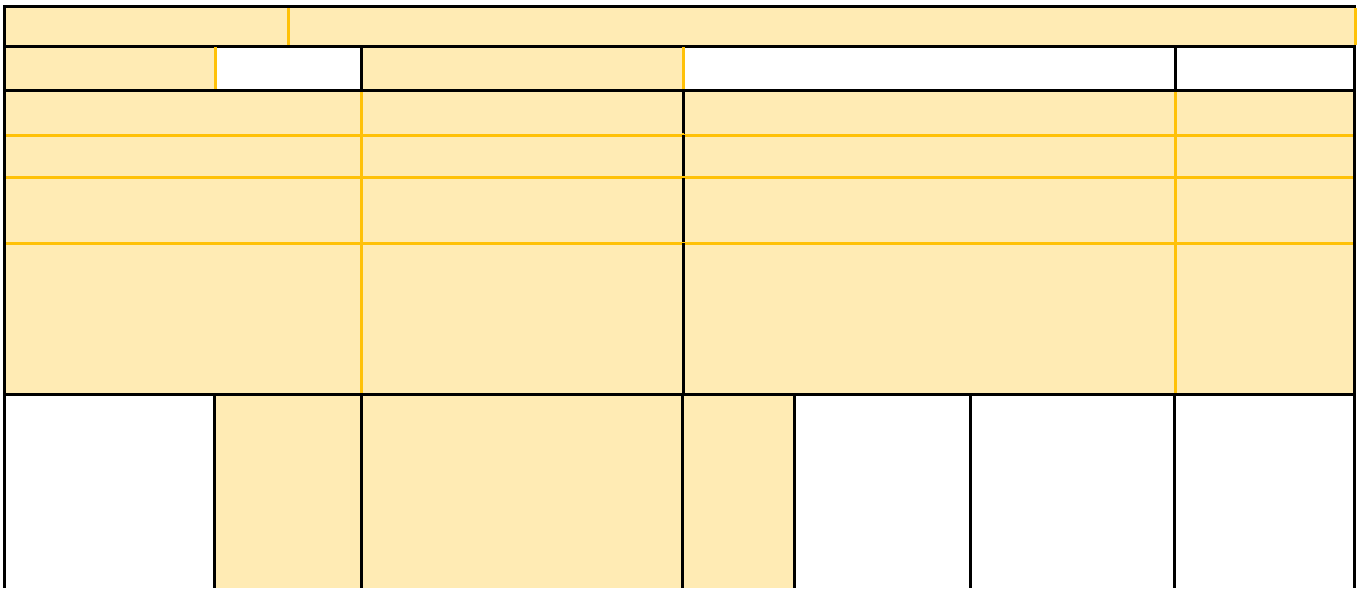
7. Upgrade Description:

| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

11. Upgrade In-Service Date: BPF Funding Percentage:

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|
| | | | Col F = Col D | Col G = Col F | Col H = Col F x | |

| | minus | x Ln 8, Col B x | Ln 10, Col B x Ln | Col I = Col G |
|---|---|---|---|---|
| | Col E | Ln 11, Col B | 11, Col B | + Col H |



| | Column C | Column D | Column E | Column F | Column G | Column H | Column I |
|---|---|---|---|---|---|---|---|
| 12. | | | | - | N/A | #DIV/0! | N/A |
| 13. | | | | - | | #DIV/0! | #DIV/0! |
| 14. | | | | - | | #DIV/0! | #DIV/0! |
| 15. | | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | | - | | #DIV/0! | #DIV/0! |
| 18. | | | | - | | #DIV/0! | #DIV/0! |
| 19. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
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| 23. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment 12

Pg. _ of __

## Attachment 12, SPP Regional Projects

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

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Line

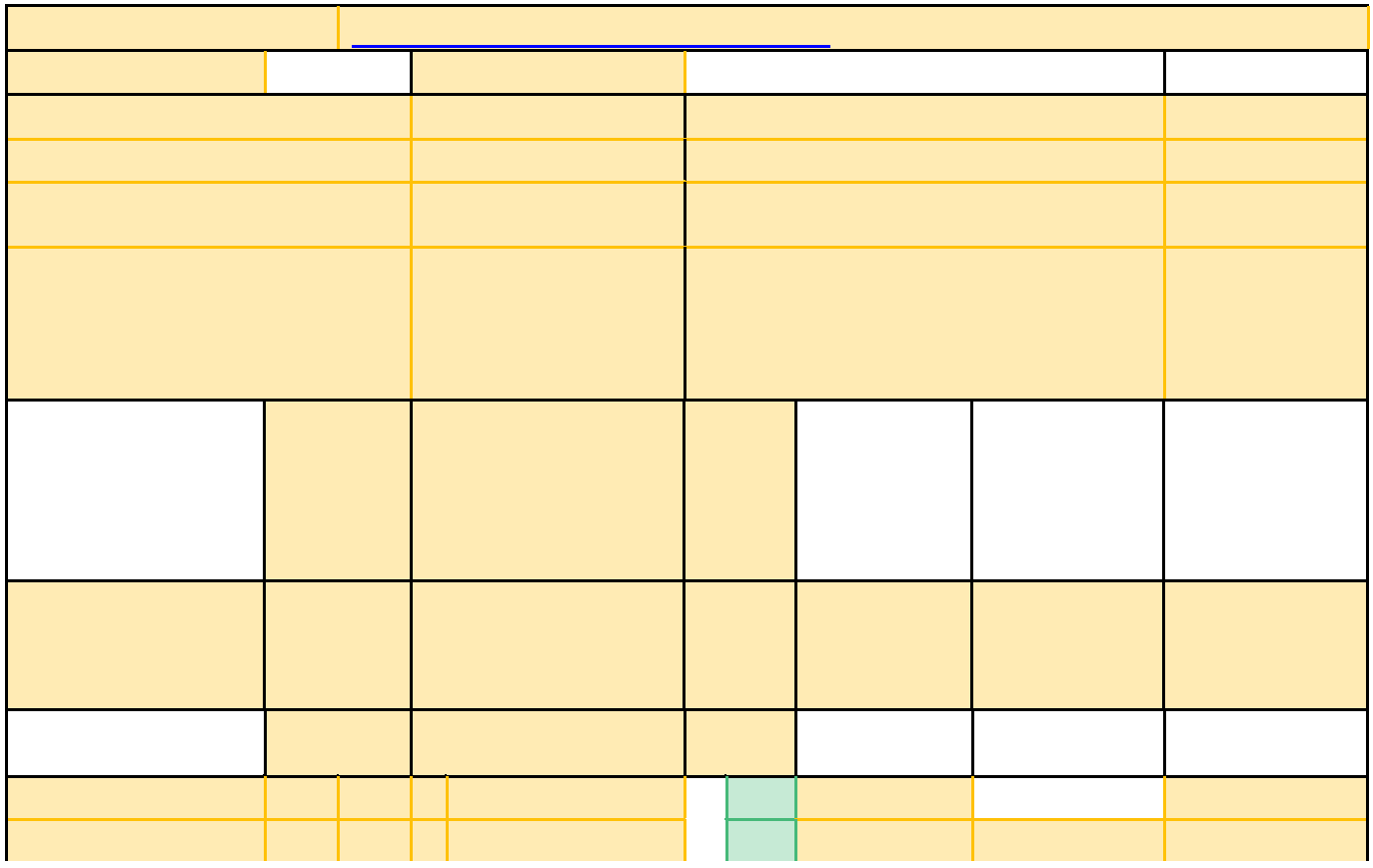
| Line | | | |
|---|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! | |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! | |
| 7. | Upgrade Description: | Sub 170 (Nichols St) to Sub 80 (Sedalia) 69KV | |
| | | Column A | Column B |
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |
| 11. | | | |

Upgrade In-Service Date:

BPF Funding Percentage:

| Year | | | Year-End Net Plant Col F = Col D minus Col E | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|
| | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | | | | |
| | | | | Col G = Col F x Ln 8, Col B x Ln 11, Col B | Col H = Col F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
| Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| 12. | | | - | | - | - |
| 13. | | | - | | #DIV/0! | #DIV/0! |
| 14. | | | - | | #DIV/0! | #DIV/0! |
| 15. | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 18. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 19. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 20. | | - | #DIV/0! | #DIV/0! | #DIV/0! |



| | | | | |
|---|---|---|---|---|
| 21. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 22. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment 12

Pg. ___ of ____

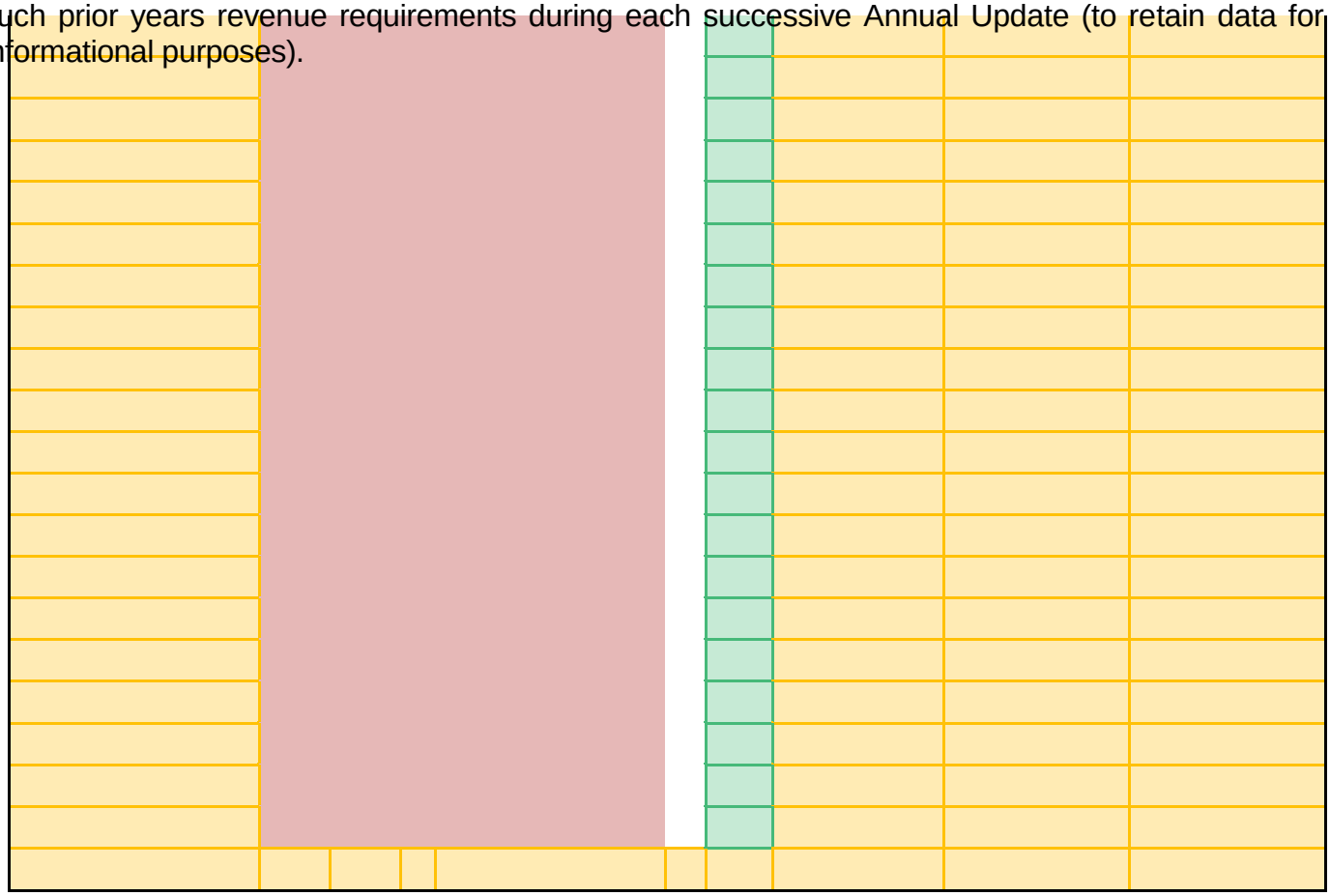
## Attachment 12, SPP Regional Projects

(For Rate Year Beginning July 1, 20__ , Based on 20__ Data)

**SPP REGIONAL UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. Empire reserves the option, but not the obligation, to "lock in"

such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).



| Line | | | |
|---|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! | |
| 4. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | | - |
| 5. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | | #DIV/0! |
| 6. | Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | #DIV/0! | |
| 7. | Upgrade Description: | | |

| | Column A | | Column B |
|---|---|---|---|
| 8. | SPP UID # : | NTPCC w/o Incentives: | #DIV/0! |
| 9. | SPP NTC Approval Letter Date: | Incentive ROE (See Note 1, below): | |
| 10. | Upgrade Status: | ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: | #DIV/0! |

11.

Upgrade In-Service Date:

BPF Funding Percentage:

| Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant | ATRR w/o Incentive ROE | Incentive ATRR | ATRR to be collected by SPP |
|---|---|---|---|---|---|---|
| | | | Col F = Col D minus Col E | Col G = Col F x Ln 8, Col B x Ln 11, Col B | Col H = Col F x Ln 10, Col B x Ln 11, Col B | Col I = Col G + Col H |
| Column C | Column D | Column E | Column F | Column G | Column H | Column I |
| 12. | | | - | | - | - |
| 13. | | | - | | #DIV/0! | #DIV/0! |
| 14. | | | - | | #DIV/0! | #DIV/0! |
| 15. | | | - | | #DIV/0! | #DIV/0! |
| 16. | | | - | | #DIV/0! | #DIV/0! |
| 17. | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 18. | | | - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 19. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 20. | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 21. | | - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | |
|---|---|---|---|---|
| 22. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 23. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 24. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 25. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 26. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 27. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 28. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 29. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 30. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 31. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 32. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 33. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 34. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 35. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 36. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 37. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 38. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 39. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 40. | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 41. | - | #DIV/0! | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

**Attachment 12**
**Page __ of __**

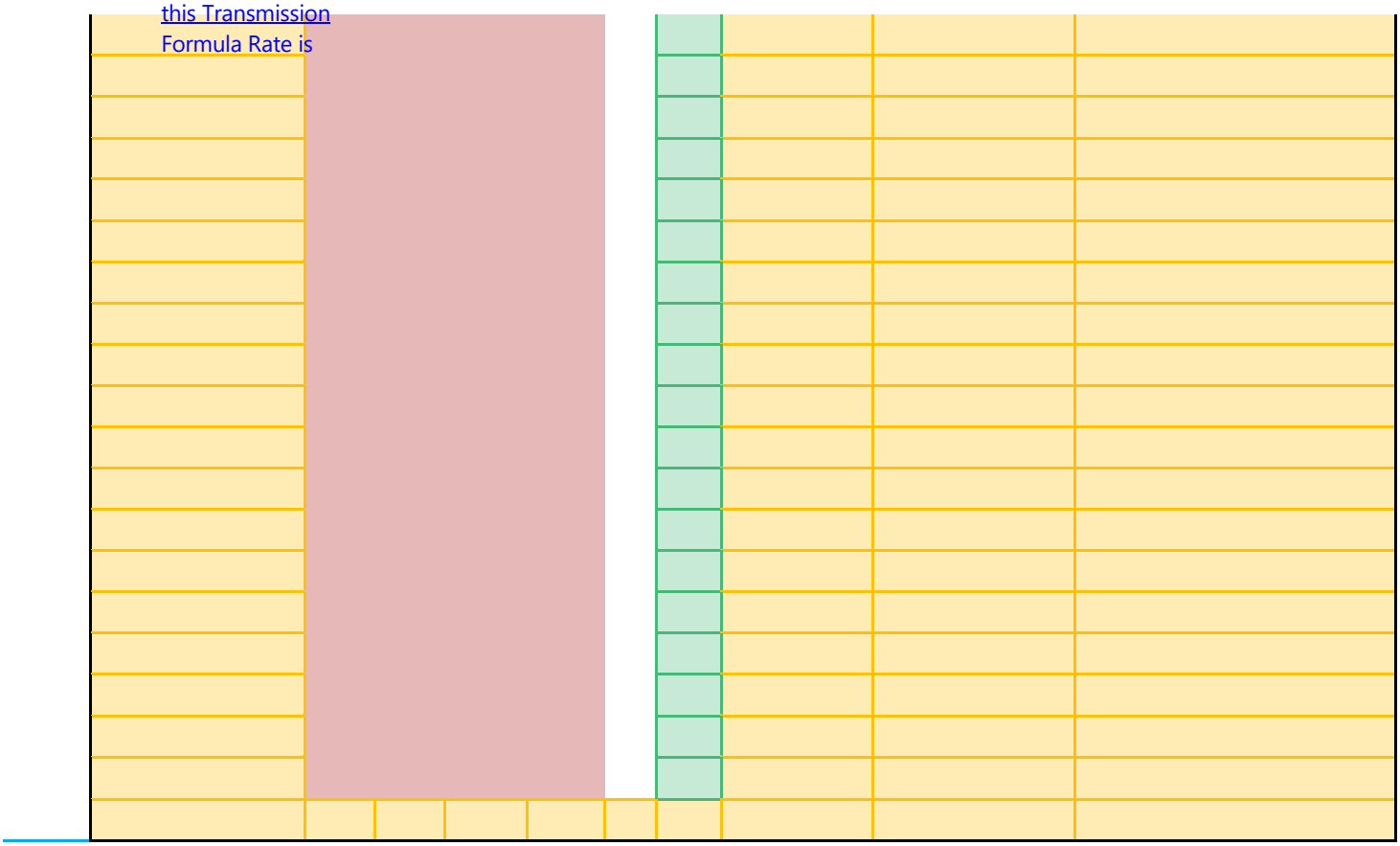
Attachment 12, SPP Regional Projects

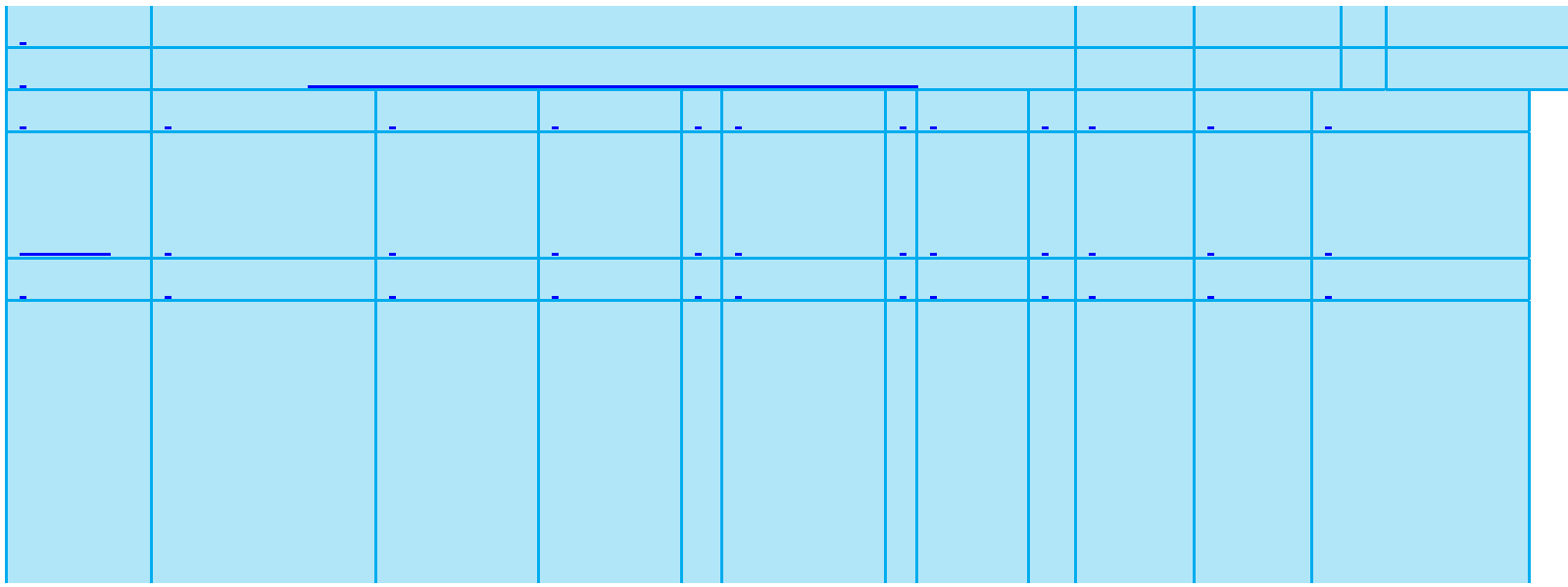
(For Rate Year Beginning July 1, 20 , Based on 20 Data)

SPP REGIONAL UPGRADE DETAILS:

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of

this Transmission
Formula Rate is





updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. Empire reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

| Line | | |
|---|---|---|
| 1. | Gross Revenue Requirement [From Appendix A, Line 115] | #DIV/0! |
| 2. | Total Net Transmission Plant [From Appendix A, Line 13] | #DIV/0! |
| 3. | Net Transmission Plant Carrying Charge (NTPCC) w/o incentives [Line 1 / Line 2] | #DIV/0! |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 4. | | Tax Gross-Up Factor [From | | | | | | | | | - |
| | | | | | | | | | | | |
| | | | | | | | | | | | |
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|---|---|---|---|---|---|---|---|---|
| 5. | Appendix A, Ln. 102] Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] Percentage Point increase in NTPCC for each 1.00% of "Incentive ROE" [(0.0100/Line 4) x Line 5 x 100] | | | | | | #DIV/0! | |
| 6. | | | | | | | #DIV/0! | |
| 7. | Upgrade Description: | | | | | | | |
| | | | Column A | | | | Column B | |
| 8. | SPP UID # : | | | NTPCC w/o Incentives: Incentive ROE (See Note 1, below): ROE Incentive Adder to NTPCC [Line 6 X Line 9, Col. B]: BPF Funding Percentage: | | | #DIV/0! | |
| 9. | SPP NTC Approval Letter Date: | | | | | | | 0.00% |
| 10. | Upgrade Status: | | | | | | #DIV/0! | |
| 11. | Upgrade In-Service Date: | | | | | | | |
| | Year | Year-End Gross Plant Investment | Year-End Accumulated Depreciation | Year-End Net Plant Col F = | ATRR w/o Incentive ROE Col G = | Incentive ATRR Col H = | ATRR to be collected by SPP | |

| | | | | | | | Col D minus Col E | | Col F x Ln 8, Col B x Ln | Col F x Ln 10, Col B x | Col I = Col G + Col H |
|---|---|---|---|---|---|---|---|---|---|---|---|
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|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 11, Col B | Ln 11, Col B | |
| | | Column C | Column D | | Column E | Column F | | Column G | Column H | Column I |
| 12. | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 13. | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 14. | | | | | | | | | #DIV/0! | #DIV/0! |
| 15. | | | | | | | | | #DIV/0! | #DIV/0! |
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| 30. | | | | | | | | | #DIV/0! | #DIV/0! |
| 31. | | | | | | | | | #DIV/0! | #DIV/0! |
| 32. | | | | | | | | | #DIV/0! | #DIV/0! |
| 33. | | | | | | | | | #DIV/0! | #DIV/0! |
| 34. | | | | | | | | | #DIV/0! | #DIV/0! |
| 35. | | | | | | | | | #DIV/0! | #DIV/0! |
| 36. | | | | | | | | | #DIV/0! | #DIV/0! |
| 37. | | | | | | | | | #DIV/0! | #DIV/0! |
| 38. | | | | | | | | | #DIV/0! | #DIV/0! |
| 39. | | | | | | | | | #DIV/0! | #DIV/0! |
| 40. | | | | | | | | | #DIV/0! | #DIV/0! |
| 41. | | | | | | | | | #DIV/0! | #DIV/0! |

Note 1: The Incentive ROE percentage shall

remain at zero, except as

authorized by FERC through a separate Section 205 filing for specific SPP projects.

**Attachment 12**
**Page __ of __**

**ADDENDUM 18 TO ATTACHMENT H - Page 29 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

## Attachment 13, Excess/Deficient ADIT

(For Rate Year Beginning July 1, 20__, Based on 20__ Data)

## Attachment 13 - Excess Deferred Taxes Regulatory Liability (Account 254.4)(Unprotected)

| Line No | Description | Account | Balance Before | 100% Non-Transmissi | Include in TFR | Plant Related | TFR | e Tax Refor | on Base |
|---|---|---|---|---|---|---|---|---|---|


Labor
Related
Cl
assificat
i
o
n

| | (a) | (b) | m Change (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Acc Df Tx-Ozark Beach Loss Gen | 190112 | | | - | | | Unprotected |
| 2 | Def ITC Cr-Adv Coal | 190113 | | | - | | | Unprotected |
| 3 | Def Tax Asset - Reg Plan Amort | 190114 | | | - | | | Unprotected |
| 4 | Def Tx Asset-Gas Inventory Adj | 190117 | | - | - | | | Unprotected |
| 5 | Def Fd Inc Tx-Acr Rate Ref-Ark | 190122 | | | - | | | Unprotected |
| 6 | Def Inc Tax - Hedge Trans Gain | 190123 | | | - | | | Unprotected |
| 7 | Def Fd Tax Asset - Misc | 190124 | | - | - | | | Unprotected |
| 8 | FAS123 Deferred Tax Asset | 190125 | | | - | | | Unprotected |
| 9 | Def Tx Asset - Gas Acquisition | 190126 | | - | - | | | Unprotected |
| 10 | Def Tx Net Operating Loss | 190230 | | | - | | | Unprotected |
| 11 | Def Fd Inc Tx-Of & Dir Def Com | 190260 | | | - | | | Unprotected |
| 12 | Def Inc Tx-Def Tx Asset Fas109 | 190320 | | | - | | | Unprotected |
| 13 | Def Inc Tx-Pbop Costs | 190330 | | | - | | - | Unprotected |

**ADDENDUM 18 TO ATTACHMENT H - Page 30 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 14 | Def Inc Tx-Postret Ben-Pension | 190331 | | | - | | - | Unprotected |
| 15 | Acm Def Inc Tx - Alt Minmn Tax | 190350 | | | - | | | Unprotected |
| 16 | Deferred Tax - FAS 158 | 190356 | | | - | | | Unprotected |
| 17 | SWPA Oz Beach Def Tx - AR | 190410 | | | - | | | Unprotected |
| 18 | SWPA Oz Beach Def Tx - | 190410 | | | | | | Unprote |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | KS | 20 | | | | | | cted |
| 1 | SWPA Oz Beach Def Tx - | 1904 | | | | | | Unprote |
| 9 | MO | 30 | | - | | | | cted |





| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20 | SWPA Oz Beach Def Tx - OK | 190440 | | - | | | | | Unprotected |
| 21 | SWPA Oz Beach Def Tx - FERC | 190450 | | - | | | | | Unprotected |
| 22 | Accm Def Fed Inc Tx-2Nd 5Yr Mn | 283100 | - | - | | | | | Unprotected |
| 23 | Def Tax Liab-Iatan Def Charges | 283116 | - | - | | | | | Unprotected |
| 24 | Def Inc Tax - Hedge Trans Loss | 283123 | | - | - | | | | Unprotected |
| 25 | Def Tx Liab - Gas Acquisition | 283126 | | - | | | | | Unprotected |
| 26 | Deferred Tax Liab Fuel Costs | 283139 | - | - | | | | | Unprotected |
| 27 | Def Tx Liability Goodwill | 283251 | - | - | | | | | Unprotected |
| 28 | Def Tx-ITC Tx Basis Red-Iatan | 283366 | - | - | | | | | Unprotected |
| 29 | Accm Def Fed Inc Tx-Lic Softwr | 283400 | | - | | | - | | Unprotected |
| 30 | Acc Def Tx-Loss Reacq Debt | 283900 | | - | - | | | | Unprotected |
| 31 | Def Inc Tax - FAS158 | 283914 | | - | | | - | | Unprotected |
| 32 | Def Inc Tax-Deftx Liab Fas 109 | 283915 | - | - | | | | | Unprotected |
| 33 | Def Tx Liab-Equity AFUDC | 283917 | | - | - | | | | Unprotected |
| 34 | Def Inc Tx Ice Storm Exp | 283921 | | - | - | | | | Unprotected |

**ADDENDUM 18 TO ATTACHMENT H - Page 31 of 47**

**The ~~Empire District Electric Company~~**

**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | | | | |
|---|---|---|---|---|
| 35 | Total Accumulated Deferred Income Taxes: | - | - | - |
| 36 | Current Tax Rate: | | ~~38.09%~~ | ~~38.09%~~ |
| 37 | Line 35 / Line 36 | | | |
| 38 | Tax Rate TFR Template (2018 Forward): | | ~~25.64%~~ | ~~25.64%~~ |
| 39 | Balance of ADIT after Reform: | | | |
| 40 | Excess ADIT (Regulatory Liability): | | | |
| 41 | Allocators | | ~~0.0000%~~ | ~~0.0000%~~ |
| 42 | Total Excess ADIT Liability (FERC Account 254) | | | |

**ADDENDUM 18 TO ATTACHMENT H - Page 32 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

Attachment 13
Page 1 of 4

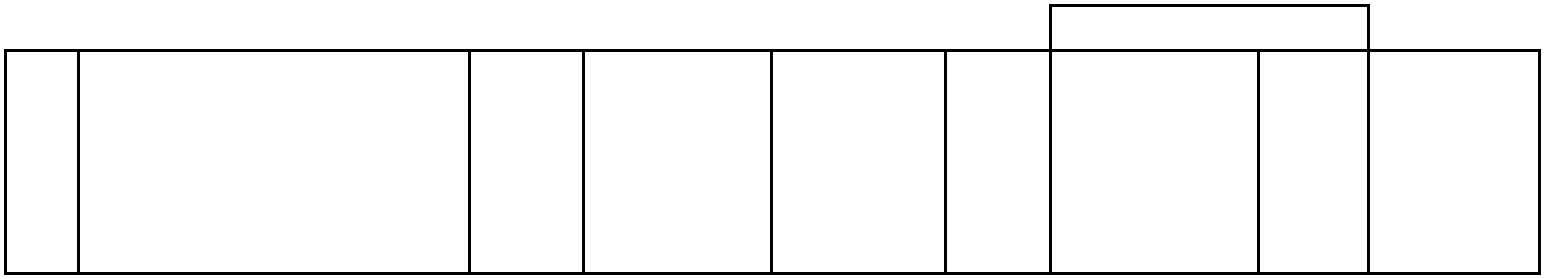
## Attachment 13, Excess/Deficient ADIT

(For Rate Year Beginning July 1, 20__, Based on 20__ Data)

## Attachment 13 - Excess Deferred Taxes Regulatory Liability (Account 254.4)(Plant Related)

| Line No | Description | Account | Balance Before Tax Reform Change | 100% Non-Transmission | Include in TFR Rate Base | TFR Plant Related | TFR Labor Related | Classification |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | Def Inc Tx - Disallow Plant | 1902 11 | | | - | | | Plant Related |
| 2 | Def Fd Inc Tx-Contrb-Aid Const | 1903 10 | | | - | | | Plant Related |
| 3 | Acm Def Inc Tx-Int Capitalized | 1903 40 | | | - | | | Plant Related |
| 4 | Accum Def Fed Inc Tx-Ld Elect | 2821 00 | | | - | - | | Plant Related |
| 5 | Accum Def Fed Inc Tx-Ld Ks Jur | 2821 20 | | | - | - | | Plant Related |
| 6 | Acc Def Fed Inc Tx-LD NonUt DR | 2821 30 | | | - | | | Plant Related |
| 7 | Acc Def Fed Inc Tx-LD NonUT CR | 2821 35 | | | - | | | Plant Related |
| 8 | Accum Def Fed Inc Tx-Ld Ok Jur | 2821 40 | | | - | - | | Plant Related |
| 9 | Accm Def Fed Inc Tx-Ld Ferc Jr | 2821 50 | | | - | - | | Plant Related |
| 10 | Accm Def Fed Inc Tx-Ld Water | 2822 00 | | - | - | | | Plant Related |
| 11 | Accumul Def Inc Tx-Ld Gas | 2823 00 | | - | - | | | Plant Related |

| | | | | | | |
|---|---|---|---|---|---|---|
| 12 | Acc Def Tax-Repair Allowance | 2831 03 | | - | - | Plant Related |





**ADDENDUM 18 TO ATTACHMENT H - Page 33 of 47**
**The ~~Empire District Electric Company~~**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | | | |
|---|---|---|---|
| 1 3 | Total Accumulated Deferred Income Taxes: | - | - |
| 1 4 | Current Tax Rate: | ~~38.09%~~ | ~~38.09%~~ |
| 1 5 | Line 13 / Line 14 | | |
| 1 6 | Tax Rate TFR Template (2018 Forward): | ~~25.64%~~ | ~~25.64%~~ |
| 1 7 | Balance of ADIT after Reform: | | |
| 1 8 | Excess ADIT (Regulatory Liability): | | |
| 1 9 | Allocators | ~~0.0000%~~ | ~~0.0000%~~ |
| ~~2~~ 0 | ~~Total Excess ADIT Liability~~ (FERC Account 254) | | |

**ADIT Allocator:**
Plant Allocator
Labor Allocator

Based on Allocator contained in TFR Template (2017 Data) 5-9-18.xls

**ADDENDUM 18 TO ATTACHMENT H - Page 34 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

Attachment 13
Page 2 of 4

## Attachment 13, Excess/Deficient ADIT

(For Rate Year Beginning July 1, 20__, Based on 20__ Data)

| | Attachment 13 - Deficient Deferred Taxes Regulatory Asset (Account 182.3)(Unprotected) | | | | | TFR | | |
|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Account | Balance Before Tax Reform Change | 100% Non-Transmission | Include in TFR Rate Base | Plant Related | Labor Related | Classification |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | | | | | - | | | Unprotected |
| 2 | | | | | - | | | Unprotected |
| 3 | | | | | - | | | Unprotected |
| 4 | | | | - | - | | | Unprotected |
| 5 | | | | | - | | | Unprotected |
| 6 | | | | | - | | | Unprotected |
| 7 | | | | - | - | | | Unprotected |
| 8 | | | | | - | | | Unprotected |
| 9 | | | | - | - | | | Unprotected |
| 10 | | | | | - | | | Unprotected |
| 11 | | | | | - | | | Unprotected |

**ADDENDUM 18 TO ATTACHMENT H - Page 35 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 12 | | | - | | | | Unprotected |
| 13 | | | - | | | - | Unprotected |
| 14 | | | - | | | - | Unprotected |
| 15 | | | - | | | | Unprotected |
| 16 | | | - | | | | Unprotected |
| 17 | | | - | | | | Unprotected |
| 18 | | | - | | | | Unprotected |
| 19 | | | - | | | | Unprotected |
| 20 | | | - | | | | Unprotected |
| 21 | | | - | | | | Unprotected |
| 22 | | - | - | | | | Unprotected |
| 23 | | - | - | | | | Unprotected |
| 24 | | | - | | - | | Unprotected |
| 25 | | | - | | | | Unprotected |
| 26 | | - | - | | | | Unprotected |
| 27 | | - | - | | | | Unprotected |
| 28 | | - | - | | | | Unprotected |
| 29 | | | - | | | - | Unprotected |
| 30 | | | - | | - | | Unprotected |
| 31 | | | - | | | - | Unprotected |
| 32 | | - | - | | | | Unprotected |

**ADDENDUM 18 TO ATTACHMENT H - Page 36 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 33 | | | | | | | Unprotected |
| 33 | | | | | - | - | |
| 33 | | | | | | | Unprotected |
| 34 | | | | | - | - | |
| 35 | Total Accumulated Deferred Income Taxes: | - | - | - | - | - | |
| 36 | Current Tax Rate: | | | | | 0.00% | 0.00% |
| 37 | Line 35 / Line 36 | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 38 | Tax Rate TFR Template (2018 Forward): | | | | | 0.00% | 0.00% |
| 39 | Balance of ADIT after Reform: | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 40 | Deficient ADIT (Regulatory Asset): | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 41 | Allocators | | | | | 0.0000% | 0.0000% |
| 42 | Total Deficient ADIT Asset (FERC Account 182.3) | | | | | #DIV/0! | #DIV/0! |

**ADDENDUM 18 TO ATTACHMENT H - Page 37 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

Attachment 13
Page 3 of 4

## Attachment 13, Excess/Deficient ADIT

(For Rate Year Beginning July 1, 20__, Based on 20__ Data)

**Attachment 13 - Deficient Deferred Taxes Regulatory Asset (Account 182.3)(Plant Related)**

| Line No. | Description | Account | Balance Before Tax Reform Change | 100% Non-Transmission | Include in TFR Rate Base | TFR Plant Related | Labor Related | Classification |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | | | | | - | | | Plant Related |
| 2 | | | | | - | | | Plant Related |
| 3 | | | | | - | | | Plant Related |
| 4 | | | | | - | - | | Plant Related |
| 5 | | | | | - | - | | Plant Related |
| 6 | | | | | - | | | Plant Related |
| 7 | | | | | - | | | Plant Related |
| 8 | | | | | - | - | | Plant Related |
| 9 | | | | | - | - | | Plant Related |
| 10 | | | | - | - | | | Plant Related |
| 11 | | | | - | - | | | Plant Related |

**ADDENDUM 18 TO ATTACHMENT H - Page 38 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

| | | | | |
|---|---|---|---|---|
| 1 | | | | Plant Related |
| 2 | | - | - | |
| 13 | Total Accumulated Deferred Income Taxes: | - | - | - |
| 14 | Current Tax Rate: | | 0.00% | 0.00% |
| 15 | Line 13 / Line 14 | #DIV/0! | #DIV/0! | #DIV/0! |
| 16 | Tax Rate TFR Template (2018 Forward): | | 0.00% | 0.00% |
| 17 | Balance of ADIT after Reform: | #DIV/0! | #DIV/0! | #DIV/0! |
| 18 | Deficient ADIT (Regulatory Asset): | #DIV/0! | #DIV/0! | #DIV/0! |
| 19 | Allocators | | 0.0000% | 0.0000% |
| 20 | Total Deficient ADIT Asset (FERC Account 182.3) | | #DIV/0! | #DIV/0! |

**ADIT Allocator:**
Plant Allocator
Labor Allocator

Based on Allocator contained in TFR Template (2017 Data) 5-9-18.xls

**ADDENDUM 18 TO ATTACHMENT H - Page 39 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

Attachment 13
Page 4 of 4

**ADDENDUM 18 TO ATTACHMENT H - Page 40 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

## Attachment 14, Summary of Excess/Deficient ADIT Amortizations

(For Rate Year Beginning July 1, 20__, Based on 20__ Data)

### Attachment 14 - Summary of Deficient Deferred Income Tax Amortizations

| Line No | Description (Impacts) | Source | Amount | Proposed Amortization Period | Estimated Annual Amortization | Notes |
|---|---|---|---|---|---|---|
| | | | | Attachment 14 | | |
| 1 | Protected Property Rate Base | Attachment 15 | #DIV/0! | ARAM | #DIV/0! | **(1)** |
| 2 | Unprotected Property Rate Base | Attachment 13 & 15 | #DIV/0! | 1 Year | #DIV/0! | **(2)** |
| 3 | **Total Deficient Deferred Income Taxes** | | #DIV/0! | | #DIV/0! | |

### Attachment 14 - Summary of Excess Deferred Income Tax Amortizations

| Line No | Description (Impacts) | Source | Amount | Proposed Amortization Period | Estimated Annual Amortization | Notes |
|---|---|---|---|---|---|---|
| 1 | Protected Property Rate Base | Attachment 15 | #DIV/0! | ARAM | | **(1)** |
| 2 | Unprotected Property Rate Base | Attachment 13 & 15 | | 1 Year | | **(2)** |
| 3 | **Total Excess Deferred Income Taxes** | | #DIV/0! | | - | |

**Notes:**

**(1)** Protected means that the normalization rules provide that excess deferred taxes to be flowed-back to customers must use the IRS mandated Average Rate Assumption Method (ARAM).

| | | | | | | |
|---|---|---|---|---|---|---|
| **(2)** Unprotected excess deferred taxes are not subject to the normalization rules. | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |

**ADDENDUM 18 TO ATTACHMENT H - Page 41 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

Attachment 14
Page 1 of 1

**ADDENDUM 18 TO ATTACHMENT H - Page 42 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ADDENDUM 18 TO ATTACHMENT H - Page 43 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ADDENDUM 18 TO ATTACHMENT H - Page 44 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ADDENDUM 18 TO ATTACHMENT H - Page 45 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ADDENDUM 18 TO ATTACHMENT H - Page 46 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

**ADDENDUM 18 TO ATTACHMENT H - Page 47 of 47**
**The Empire District Electric Company**
**(For Rate Year Beginning July 1, 20 , Based on 20 Data)**

## Attachment 15, Excess/Deficient ARAM Amortization

(For Rate Year Beginning July 1, 20 , Based on 20 Data)

## Attachment 15 - Excess Deferred Taxes Amortization Using ARAM

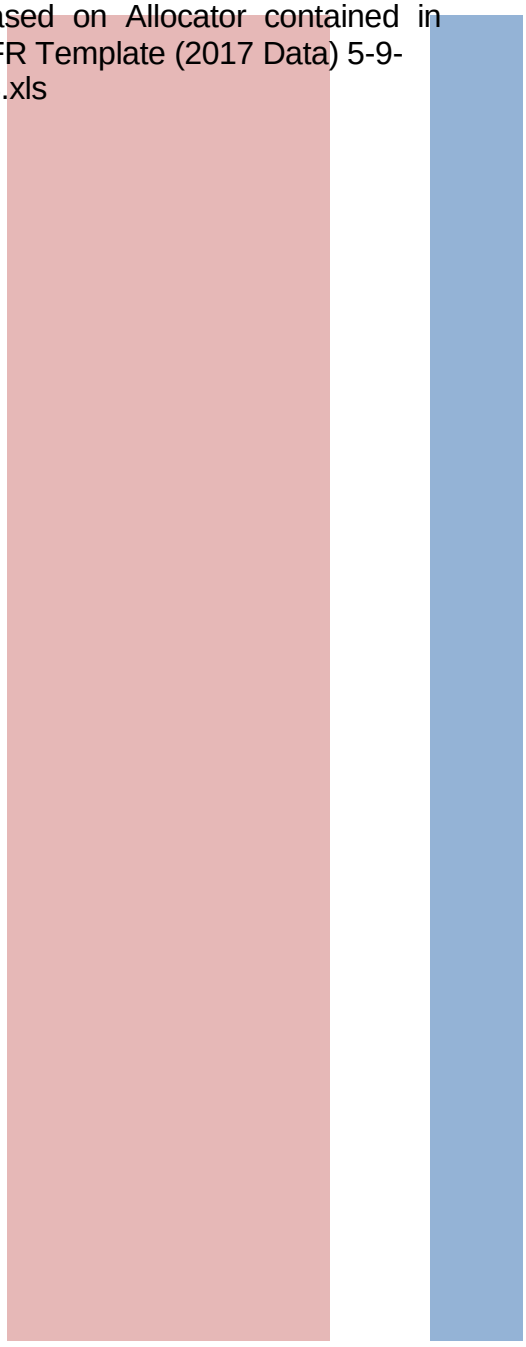
| Line No | Description | (a) | Account | (b) | Include TFR Rate Base | (c) | Tax Rate at 12/31/20 17 | (d) | Balance Before Tax Net of Reflow | Tax Rate after Rate | Balance at 12/31/20 17 | (e) | (f) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Def Inc Tax - Disall | | 1902 11 | | - | | | | ADIT/Tax | | #DIV/0! | #DIV/0! | 0.00% |
| 2 | | | 1903 | | - | | | | | | #DIV/0! | #DIV/0! | 0.00% |
| 3 | Owned Plant Def Fed Inc Tx-Contrb-Aid Const | | 190340 | | - | | | | | | #DIV/0! | #DIV/0! | 0.00% |
| | Acm Def Inc Tx-Int Capitalized | | | | | | | | | | | Excess Tax Reserve | |

| (h) | (i) | | | | Col. (e) | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| #DIV/0! | Allocated Excess Protected ADIT #DIV/0! | Allocator | Beginning Prot | #DIV/0! | Ending Balance Protected Excess Def Taxes #DIV/0! | | | Current Year Annual Amortization | | | | | | | |
| #DIV/0! | #DIV/0! | | mulectatived Ex | Cu | #DIV/0! | | | | | | | | | | |
| #DIV/0! | #DIV/0! | | Amce | #DIV/0! | #DIV/0! | | | | | | | | | | |
| | (j) | (k) | ortiss | e | (n) = + (m) | | (l) | (o) Table 15A, Col. (f) | | | | | | | |
| | #DIV/0! | 0.0000% | zati | | #DIV/0! | | | #DIV/0! | | | | | | | |
| | #DIV/0! | 0.0000% | Def Taxes | on | #DIV/0! | | | #DIV/0! | | | | | | | |
| | #DIV/0! | 0.0000% | | (m) Table | #DIV/0! | | | #DIV/0! | | | | | | | |
| | | | (l) | | | | | | | | | | | | |
| | | | 15A | , | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Accum Def Fed Inc Tx-Ld Elect | 282100 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Accum Def Fed Inc Tx-Ld Ks Jur | 282120 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | Accum Def Fed Inc Tx-Ld Ok Jur | 282130 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | Accm Def Fed Inc Tx-Ld Ferc Jr | 282135 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | Acc Def Tax-Repair Allowance | 282140 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | Def Inc Tax - Hedge Trans Loss | 282150 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 10 | Acc Def Tx-Loss Reacq Debt | 282200 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | Def Tx Liab-Equity AFUDC | 282300 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 12 | Def Inc Tx Ice Storm Exp | 283103 | - | #DIV/0! | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.0000% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 13 | Total Accumulated Excess Deferred Income Taxes: | | - | | | #DIV/0! | #DIV/0! | | #DIV/0! | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

**ADIT Allocator:**
Plant Allocator

Based on Allocator contained in TFR Template (2017 Data) 5-9-18.xls



| | |
|---|---|
| **Tax Gross-Up Calculation** | |
| Federal Income Tax Rate | |
| State Income Tax Rate or Composite Rate | |
| Federal Income Tax Deductible for State Purposes | |
| T | 0.00 % |
| T/(1-T) | |
| Tax Gross-up Percentage (1/(1-T)) | 100.00% |

| | |
|---|---|
| **Excess ADIT Protected and Unprotected Allocator:** | |
| Protected | #DIV/0! |
| Unprotected | #DIV/0! |
| Total: | - |

Based on Audit Trail 2018 EMP Comparison Report_2018 12 26.xlsx

Note: Source is cumulative sum of values reported since 2018 on Attachment 14 Summary of Excess Deferred Income Tax Amortizations Excel Line 18 Column F

## Attachment 15 - Deficient Deferred Taxes Amortization Using ARAM

| Line No | Description | Account | Balance Before Tax Reform 1/20 Change | Tax Rate at 12/31/2017 | Balance Before Tax Reform/ Tax Rate at 12/31/2017 | Balance of ADIT after Tax Reform | Deficient ADIT | Allocator |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 1 | Def Inc Tax - Disallowed Plant | 190211 | - | 21% | #DIV/0! | #DIV/0! | #DIV/0! | |
| 2 | Def Fed Inc Tx-Contrb-Aid Const | 190310 | - | | 0.0 | 0.0 | 0.0 | |
| 3 | Acm Def Inc Tx-Int Capitalized | 190340 | - | | #DIV/0! | #DIV/0! | #DIV/0! | |
| 4 | Accum Def Fed Inc Tx-Ld Elect | 282100 | - | | 0% | 0% | 0% | |
| 5 | Accum Def Fed Inc Tx-Ld Ks Jur | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! | |
| 6 | Accum Def Fed Inc Tx-Ld Ok Jur | 2820 | - | | (e) | 0.0 | #DIV/0! | |
| | | | | | (f) | | | |
| | | 282130 | Balance Before Tax Reform 1/20 Change | Tax Rate at 12/31/2017 | (g) | #DIV/0! | 0.0 | |
| | | | | | #DIV/0! | #DIV/0! | #DIV/0! | |
| | | | | | 0.0 | 0.0 | 0.0 | |
| | | | | | #DIV/0! | #DIV/0! | #DIV/0! | |
| | | | | | 0% | 0% | 0% | |
| | | | | | V/0! | V/0! | V/0! | |
| | | | | | #DIV/0! | #DIV/0! | #DIV/0! | |
| | | | | | 0.0 | 0.0 | 0.0 | |
| | | | | | #DIV/0! | #DIV/0! | #DIV/0! | |
| | | | | | 0% | 0% | 0% | |
| | | | | | V/0! | V/0! | V/0! | |

| | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Current Year Annual Accretion | i.e. From Cell G117, etc. | | | | | | | | | | | | | | |

(o) Table 15B, Col. (f)

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | 0.00% | | | | |
| 7 | Accm Def Fed Inc Tx-Ld Ferc Jr | 282135 | - | #DIV/0! | 0.0% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.00% | #DIV/0! | | #DIV/0! | | | |
| 8 | Acc Def Tax-Repair Allowance | 282140 | - | #DIV/0! | 0.0% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.00% | #DIV/0! | | #DIV/0! | | | |
| 9 | Def Inc Tax - Hedge Trans Loss | 282150 | - | #DIV/0! | 0.0% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.00% | #DIV/0! | | #DIV/0! | | | |
| 10 | Acc Def Tx-Loss Reacq Debt | 282200 | - | #DIV/0! | 0.0% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.00% | #DIV/0! | | #DIV/0! | | | |
| 11 | Def Tx Liab-Equity AFUDC | 282300 | - | #DIV/0! | 0.0% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.00% | #DIV/0! | | #DIV/0! | | | |
| 12 | Def Inc Tx Ice Storm Exp | 283103 | - | #DIV/0! | 0.0% | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | 0.00% | #DIV/0! | | #DIV/0! | | | |
| 13 | Total Accumulated Deficient Deferred Income Taxes: | | - | | | #DIV/0! | #DIV/0! | | #DIV/0! | | #DIV/0! | - | #DIV/0! | - | | |

**ADIT Allocator:**

Plant Allocator
Based on Allocator contained in TFR Template (2017 Data) 5-9-18.xls

**Tax Gross-Up Calculation**

Federal Income Tax Rate
State Income Tax Rate or

Composite Rate Federal Income Tax Deductible

| | |
|---|---|
| for State Purposes | |
| T | 0.00 % |
| T/(1-T) | 0.00 % |
| Tax Gross-up Percentage (1/(1-T)) | 100.00% |

**Deficient ADIT Protected and Unprotected Allocator:**

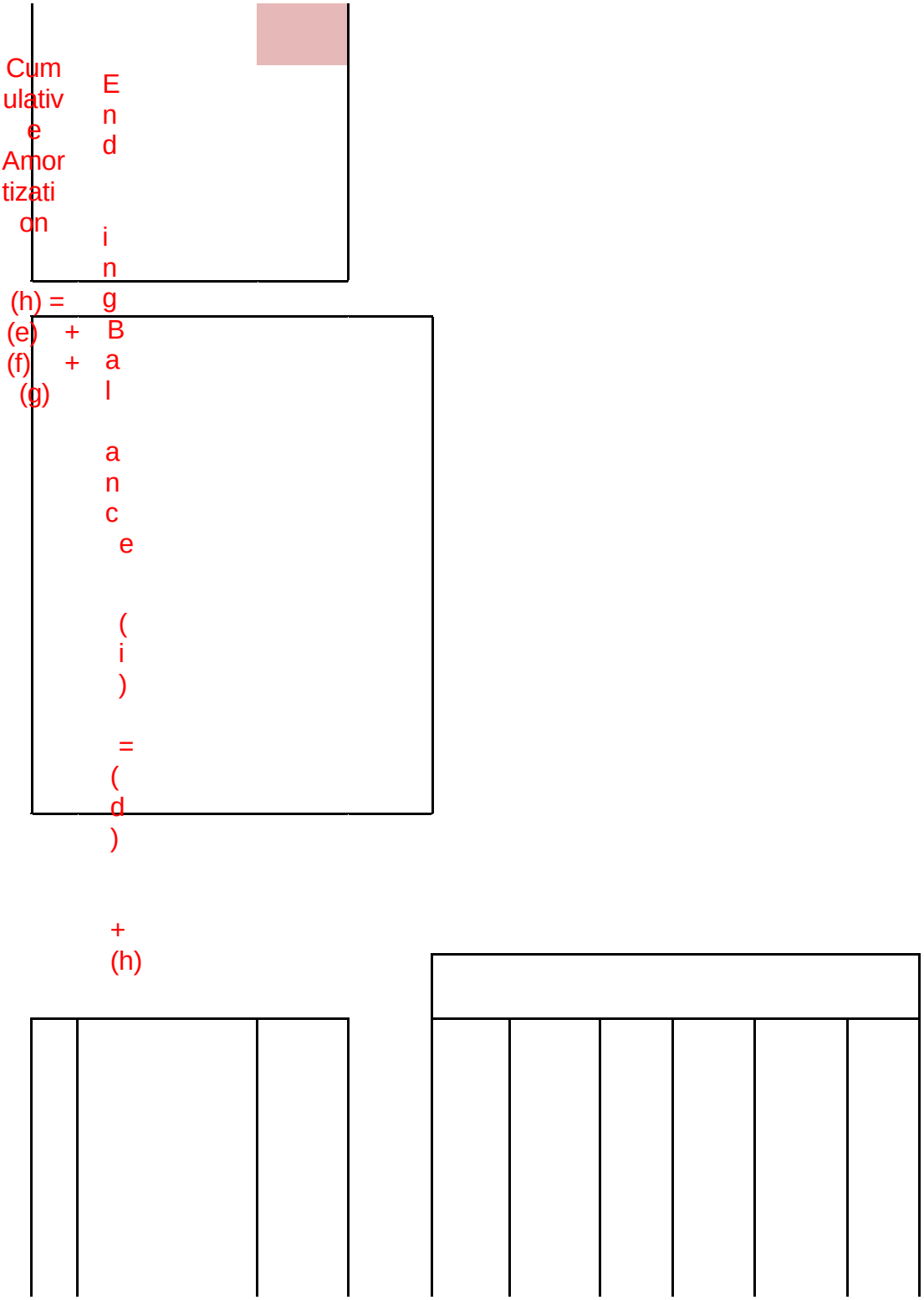
| | |
|---|---|
| Protected | #DIV/0! |
| Unprotected | #DIV/0! |
| Total: | - |

Based on Audit Trail 2018 EMP Comparison Report_2018 12 26.xlsx

Attachment 15
Page 1 of 1

Table 15 A - Allocated Transmission Protected Excess Deferred Taxes

| Line No | a) | Description | Acco unt | (c) | Beginning Balance | Prior Years Amortization | Prior Year Adjustment | Current Year Annual Amortization |
|---|---|---|---|---|---|---|---|---|
| ( | | (b) | | | (d) | (e) | (f) | (g) |


Cumulative Amortization
End ing Balance (i) = (d) + (h)
(h) = (e) + (f) + (g)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Def Inc Tax - Disallowed | 1902 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 1 | Plant | 11 | | | | | |
| | Def Fed Inc Tx-Contrb- | 1903 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 2 | Aid Const | 10 | | | | | |
| | Acm Def Inc Tx-Int | 1903 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | Capitalized | 40 | | | | | |
| | Accum Def Fed Inc Tx- | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | Ld Elect | 00 | | | | | |
| | Accum Def Fed Inc Tx- | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Ld Ks Jur | 20 | | | | | |
| | Accum Def Fed Inc Tx- | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | Ld Ok Jur | 30 | | | | | |
| | Accm Def Fed Inc Tx- | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | Ld Ferc Jr | 35 | | | | | |
| | Acc Def Tax-Repair | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | Allowance | 40 | | | | | |
| | Def Inc Tax - Hedge Trans | 2821 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | Loss | 50 | | | | | |
| | Acc Def Tx- | | | | | | |
| 1 | Loss Reacq | 2822 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 0 | Debt | 00 | | | | | |
| | Def Tx Liab- | | | | | | |
| 1 | Equity | 2823 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 1 | AFUDC | 00 | | | | | |
| | Def Inc Tx | | | | | | |
| 1 | Ice Storm | 2831 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 2 | Exp | 03 | | | | | |
| | Total Accumulated | | | | | | |
| 1 | Excess Deferred | | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | Income Taxes: | | - | - | - | | |

| System Amount | Allocation Factor | Allocated Amount |
|---|---|---|

| | | | |
|---|---|---|---|
| | ARAM Detail Excel | 0.00 | |
| 1 | Spreadsheet (e.g. TFR 1.9 | 000 | |
| 4 | ARAM Detail 2019.01.14) | % | - |

Notes:
Column (e): Prior Years Amortization for each subaccount based on column (h) of this Table 15 A from the prior year's TFR Update.
Column (f): Attachment 11, Reconciliation, Columns F and G, as appropriate, for adjustments to the balance and amortization of Excess ADIT. The total adjustment(s) should be allocated based on each FERC subaccount as a ratio of all FERC subaccounts in column (d) of this Table 15 A. If the adjustment(s) pertains to a specific FERC subaccount(s), the adjustment(s) should be directly assigned to the applicable FERC subaccount(s) rather than being allocated.
Column (g): Transmission ARAM amount allocated based on the beginning balance for each FERC subaccount as a ratio of all subaccounts in column (d).

Table 15 B - Allocated Transmission Protected Deficient Deferred Taxes

Table to be developed.

**ADDENDUM 18 TO ATTACHMENT H**
**Transmission Formula Rate Implementation Protocols**

## I. Annual Update

1. The transmission formula rate template of The Empire District Electric Company ("Empire") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Empire for transmission service in the Empire zone of the Southwest Power Pool, Inc. ("SPP") footprint. Empire must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") and the rates for Network Integration Transmission Service and Point-to-Point Transmission Service in the Empire zone of the SPP footprint, as well as rates for Scheduling, System Control and Dispatch Service under the Empire Open Access Transmission Tariff ("Schedule 1 Service").

2. The Formula Rate shall be applicable to service on and after July 1 of each calendar year through June 30 of the following calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before June 1 of each calendar year, Empire shall:

   (a) recalculate the ATRR and the rates for zonal Network Integration Transmission Service, zonal Point-to-Point Transmission Service, and Schedule 1 Service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

   (b) provide its Annual Update to SPP and cause such information to be posted on SPP's website and OASIS. Within five (5) days of such posting, Empire shall provide notice of such posting via an e-mail distribution list. Interested Parties may contact Empire to request to be added to the e-mail distribution list.

4. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date." Any delay in the Publication Date will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these Protocols.

5. The Annual Update for the Rate Year shall:

   (a) include a workable populated rate formula template with fully functional spreadsheets showing the calculation of the Annual Update and underlying workpapers in native format with all formulas and links intact;

   (b) to the extent specified in the Formula Rate, be based upon Empire's FERC Form No. 1 for the most recent calendar year, and, to the extent specified in the Formula Rate, upon the books and records of Empire consistent with FERC accounting regulations, policies, and practices;

(c) as and to the extent specified in the Formula Rate, provide sufficiently detailed

workpapers and supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the FERC Form No. 1;

(d) provide sufficient information to enable Interested Parties (as that term is defined in Section II of these Protocols) to replicate the calculation of the formula results from the Formula Rate;

(e) identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

(f) identify all material adjustments made to the Formula Rate data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;

(g) With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

a. The initial implementation of an accounting standard or policy;

b. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

c. correction of errors and prior period adjustments that impact the revenue requirement;

d. the implementation of new estimation methods or policies that change prior estimates; and

e. changes to income tax elections.

ii. Identify items included in the Formula Rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Formula Rate;

iv. Provide, for each item identified pursuant to items I.5.g.i.a - I.5.g.i.c of these Protocols, a narrative explanation of the individual impact of such changes on charges billed under the Formula Rate.

(h) not seek to modify the Formula Rate.

## II. Review of Annual Update

1. Empire shall host an open meeting among Interested Parties, to be held no sooner than thirty (30) days after the Publication Date and no later than June 30 each year ("Annual Meeting"). Empire shall make available to Interest Parties remote access to the Annual Meeting. No less than seven (7) days prior to such Annual Meeting, Empire shall provide Interested Parties notice on SPP's website and OASIS of the time, date, location and remote access information for the Annual Meeting, and shall provide notice of such meeting via the e-mail distribution list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual Meeting shall (i) permit Empire to explain and clarify its Annual Update and (ii) provide Interested Parties an opportunity to seek information and clarifications from Empire about the Annual Update.

2. Each year Empire shall endeavor to coordinate with other transmission owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

## III. Information Exchange Procedures

1. Interested Parties shall have until September 15 following the Publication Date (unless such period is extended with the written consent of Empire or by FERC order) to serve reasonable information and document requests on Empire ("Information Exchange Period"). If September 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

   (a) the extent or effect of an Accounting Change;

   (b) whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

   (c) the proper application of the Formula Rate and procedures in these Protocols;

   (d) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;

   (e) the prudence of actual costs and expenditures;

   (f) the effect of any change to the underlying Uniform System of Accounts or the

Formula Rate template; or

(g) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. Empire shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receiving such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day. Empire shall respond to all information and document requests by no later than October 15 following the Publication Date, unless the Information Exchange Period is extended by Empire or FERC.

3. Empire shall cause to be posted on SPP's website and OASIS all information requests from Interested Parties and Empire's response(s) to such requests; except, however, if responses to information and document requests include material deemed by Empire to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Empire and the requesting party.

4. Empire shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing Empire's Annual Update.

## IV. Challenge Procedures

1. Interested Parties shall have until November 15 following the Publication Date (unless such period is extended with the written consent of Empire or by FERC order) to review the inputs, supporting explanations, allocations, and calculations ("Review Period") and to notify Empire in writing, which may be made electronically, of any specific Informal Challenges. The period of time from the Publication Date until November 15 shall be referred to as the Review Period. If November 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursing a Formal Challenge with respect to any issue for that Annual Update but is not barred form pursing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

2. A party submitting an Informal Challenge to Empire must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and

provide an appropriate explanation and documents to support its challenge. Empire shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. Empire, and where applicable, SPP, shall

appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If Empire disagrees with such challenge, Empire will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after November 15, and Empire must respond to all Informal Challenges by no later than December 15, unless the Review Period is extended by Empire or FERC.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

(a) A Formal Challenge shall:

i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or Protocols;

ii. Explain how the action or inaction violates the filed rate formula or Protocols;

iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

a. The extent or effect of an Accounting Change;

b. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

c. The proper application of the Formula Rate and procedures in these Protocols;

d. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts or the Applicable Form; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission

proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(b) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on Empire. Service to Empire must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on Empire's Informational Filing required under Section VIof these Protocols.

4. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these Protocols; (3) the proper application of the Formula Rate and procedures in these Protocols; (4) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the Applicable Form; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

5. Empire will cause to be posted on SPP's website and OASIS all Informal Challenges from Interested Parties and Empire's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by Empire to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Transmission Owner and the requesting party.

6. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by Empire will be reported in the Informational Filing required pursuant to Section VI of these Protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

7. An Interested Party shall have until March 1 following the Review Period (unless such date is extended with the written consent of Empire to continue efforts to resolve the

Informal Challenge) to make a Formal Challenge with FERC, which shall be served on Empire on the date of such filing as specified in Section IV.3.b above. A Formal Challenge shall be filed in the same docket as Empire's Informational Filing discussed in Section VI of these Protocols. Empire shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

8. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Empire shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

9. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Empire to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

10. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

11. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or the Applicable Form, shall first raise the matter with Empire in accordance with this Section IV before pursuing a Formal Challenge.

## V. Changes to Annual Update

1. A change to the Formula Rate fixed inputs related to rate of return on equity ("ROE"), depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than Pensions, the 55% cap on the share of common equity in the capital structure and ROE incentives for SPP regional projects may not be made absent an appropriate filing with the FERC pursuant to Federal Power Act Section 205 or Section 206; provided, however, that Empire may make a limited Section 205 filing to change depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than Pensions, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed change(s) are just and reasonable, and not unduly discriminatory. Any filing to change the ROE, capital structure or the 55% cap on common equity is not considered a limited filing.

2. If Empire files any corrections to correct a Mistake in its FERC Form No. 1 during a Rate

Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next

effective Rate Year, with interest computed in accordance with 18 C.F.R. § 35.19a. See Worksheet 11 of the Formula Rate template. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as, but not limited to, arithmetic and other inadvertent computational errors, erroneous Form No. 1 references or the like. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process. Corrections to erroneous FERC Form No. 1 references in the Formula Rate template may be made in the Annual Update without a Section 205 or 206 filing. There is no deadline for any Interested Party or Empire to notify the other party of any mistake in any FERC Form No. 1 data or specific data applied in the Formula Rate template.

3. Any changes to the data inputs, including but not limited to revisions to Empire's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a**.**

## VI. Informational Filings

1. By January 15 of each year, Empire shall submit to FERC an informational filing ("Informational Filing") of its Annual Update. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that Empire has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, Empire shall provide notice of the Informational Filing via the e-mail distribution list and by posting the docket number assigned to Empire's Informational Filing on SPP's website and OASIS.

2. Any challenges to the implementation of Empire's Formula Rate must be made through the Challenge Procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

# ADDENDUM 19 TO ATTACHMENT H – Part 1

## Reserved for Future Use

# ADDENDUM 19 TO ATTACHMENT H – Part 2

## Reserved for Future Use

# ADDENDUM 19 TO ATTACHMENT H – Part 3

## Reserved for Future Use

## ADDENDUM 20 TO ATTACHMENT H - Part 1

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Rate Year 0
Historic Year - 2
Total Pages 9
2

# Sunflower Electric Power Corporation (SEPC)

## Rate Formula Template
## Table of Contents

**Overview**

The formula is calculated in two steps. The first step is to fill out Tabs A-1 thru A-11, and the Actual Gross Rev Req tab with data from the previous year's KCC Annual Report. This data input results in the calculation of the actual annual transmission revenue requirement (Actual ATRR) for the previous year, as shown in the Actual Net Rev Req tab. The results of this calculation are presented to the customers for review in accordance with the Protocols.

The TU (True-up) tab uses the Actual ATRR from the Actual Net Rev Req tab and compares it to the Projected ATRR (without the True-up for a prior year) that customers were billed for the same period. Interest is added to the difference and the adjusted true-up then is included in the Projected Net Rev Req tab.

The projected O&M and plant balances are calculated in Tabs P-1 thru P-5. These sheets feed into the Projected Gross Rev Req tab and ultimately into the Projected Net Rev Req tab. The RTO Projects Smry tab retrieves project specific data from other tabs to calculate the amount of revenue requirements associated with those projects which are contained in the total Projected Gross Revenue Requirement amount. The Spon Projects Smry tab does the same process for Sponsored projects. The total revenue requirements for these two groups of upgrades and revenue credits are subtracted from the SEPC total revenue requirement to obtain the Zonal ATRR (line 20, before true-up). This calculation is shown on the Projected Net Rev Req tab. This tab also calculates the point-to-point zonal rates. SPP rates are set on the trued up Base Plan Net Revenue Requirements, Balanced Portfolio Net Revenue Requirements, and ITP/Priority Projects Net Revenue Requirements as well as the trued up Zonal Net Revenue Requirements. The specific charges are defined under the SPP Open Access Transmission Tariff.

The FBR is set up initially to address the revenue requirements for six separate special categories: 1) Base Plan, 2) Balanced Portfolio, 3) Integrated Transmission Plan Priority 1, 4) Integrated Transmission Plan Priority 2, 5) Sponsored, and 6) Third Party Projects. From time-to-time it may become necessary to add other categories of special projects.

Cells highlighted in light blue are data input cells. Some cells may reference the results from other calculations in the formula. Such cell references may change from year to year, requiring manual adjustment of the reference or the direct entry of the proper value.


| Page | Tab | Description |
|---|---|---|
| 2 | Variance Analysis | Summary of differences in projected and actual costs for the true-up year |
| 3 | Summary | Summary of projected revenue requirements, point to point rates, and Schedule 1 rates. |
| | Actual Net Rev | Actual net revenue requirements for most recent |

| | | |
|---|---|---|
| **4** | Req | calendar year |
| | Actual Gross Rev | Actual gross revenue requirements for most recent |
| **5-9** | Req | calendar year |

| | |
|---|---|
| **10** | Actual Sch 1 Rev Req |
| **11-12** | A-1 (Act. Rev. Credits) |
| **13** | A-2 (Act. Divisor) |
| **14** | A-3 (Act ADIT) |
| **15-16** | A-4 (Act. Excluded Assets) |
| **17** | A-5 (Act. Depreciation Rate) |
| **18** | A-6 (Act. Taxes Other) |
| **19-35** | A-7 (Act. RTO Directed Projects) |
| **36** | A-8 (Act. Sponsored Projects) |
| **37-44** | A-9 (Act. Incentive Plant) |
| **45** | A-10 (Act. Third Party Proj) |
| **46** | A-11 (Act. A&G) |
| **47-48** | A-12 (Act. 13-Mo & BOY and EOY Aver.) |
| **49** | A-13 (Actual Comp Bid Proj) |
| **50-51** | TU (True-up) |
| **52-64** | RTO Project Smry |
| **65-66** | Spon Project Smry |
| **67-68** | Third Party Project Smry |
| | Projected Net Rev |
| **69** | Req |
| **70-74** | Projected Gross Rev Req |

Actual revenue requirements for Schedule 1

Actual revenue credits

Actual transmission system load

Actual Accumulated Deferred Income Taxes (ADIT)

Assets excluded from transmission rate base

Depreciation rates for each account

Actual taxes other than income taxes

Actual RTO-directed projects: Base Plan, Balanced Portfolio, and ITP/Priority Projects

Actual sponsor-funded projects

Actual incentive returns

Actual projects constructed by SEPC for Third Parties

Actual Administrative and General Expenses

Actual 13-Month averages and BOY-EOY averages for rate base items

Actual Competitive Bid Projects

True-up adjustment and interest calculation

Actual and projected RTO-directed projects

Actual and projected Sponsor-funded projects

Actual and projected Third Party projects

Projected net revenue requirements for next calendar year

Projected gross revenue requirements for next calendar year

| | | |
|---|---|---|
| **75** | Projected Schedule 1 Rev Req | Projected revenue requirements for Schedule 1 |
| **76-80** | P-1 (Proj Trans Plant) | Projected transmission plant for next calendar year and incentive returns |
| **81** | P-2 (Proj. Exp. & Rev. Credits) | Projected expenses and revenue credits for next calendar year |
| **82** | P-3 (Proj. Trans. Network Load) | Projected transmission system load |
| **83-89** | P-4 (Proj. RTO Projects) | Projected RTO-directed projects: Base Plan, Balanced Portfolio, ITP/Priority Projects |
| **90** | P-5 (Proj. Sponsored. Projects) | Projected sponsor-funded projects |
| **91** | P-6 (Proj. Third Party Projects) | Projected projects constructed by SEPC for Third Parties |
| **92** | P-7 (Proj Comp Bid Proj) | Projected Competitive Bid Projects |

# Sunflower Electric Power Corporation (SEPC)
# Rate Formula Template
# Projected Revenue Requirements
# For the 12 months ended - December 31, 0

| Line No. | (1) Description | (2) Source | (3) | (4) Amount | |
|---|---|---|---|---|---|
| | **A. Net Revenue Requirement Including True-Up** | | | | |
| 1 | Base Plan Net Revenue Requirements | Projected Net Rev Req, L43 | #DIV/0! | | |
| 2 | Balanced Portfolio Net Revenue Requirement | Projected Net Rev Req, L44 | #DIV/0! | | |
| 3 | ITP/Priority Projects-1 Net Revenue Requirement | Projected Net Rev Req, L45 | #DIV/0! | | |
| 4 | ITP/Priority Projects-2 Net Revenue Requirement | Projected Net Rev Req, L46 | #DIV/0! | | |
| 5 | Sponsored Projects Net Revenue Requirements | Projected Net Rev Req, L47 | #DIV/0! | | |
| 6 | Third Party Projects Net Revenue Requirements | Projected Net Rev Req, L48 | #DIV/0! | | |
| 7 | Total | Sum (L1:L6) | | #DIV/0! | |
| 8 | | | | | |
| 9 | Zonal Net Revenue Requirement | Projected Net Rev Req, L51 | | #DIV/0! | |
| 10 | | | | | |
| 11 | **B. Point-to-Point Service** | | | | |
| 12 | SEPC 12-CP. Peak Demand | WP P-3, L15 | | #DIV/0! | MW |
| 13 | | | | | |
| 14 | Annual Point-to-Point Rate in $/MW - Year | L9 / L12 | | #DIV/0! | |
| 15 | Monthly Point-to-Point Rate in $/MW - Month | L14 / 12 months | | #DIV/0! | |
| 16 | Weekly Point-to-Point Rate in $/MW - Weekly | L14 / 52 weeks | | #DIV/0! | |
| 17 | Daily On-Peak Point-to-Point Rate in $/MW - Day | L14 / 260 days | | #DIV/0! | |
| 18 | Daily Off-Peak Point-to-Point Rate in $/MW - Day | L14 / 365 days | | #DIV/0! | |
| 19 | Hourly On-Peak Point-to-Point Rate in $/MW - Hour | L17 / 16 hours | | #DIV/0! | |
| 20 | Hourly Off-Peak Point-to-Point Rate in $/MW - Hour | L18 / 24 hours | | #DIV/0! | |
| 21 | | | | | |
| 22 | **C. Schedule 1 ARR** | | | | |
| 23 | Net Schedule 1 Revenue Requirement for Zone | Projected Sch 1 Rev Req, L12 | | #DIV/0! | |

**D. Schedule 1 Rate Calculations**

| | | | |
|---|---|---|---|
| SEPC 12-CP. Peak Demand | WP P-3, L15 | #DIV/0! | MW |

| | | | |
|---|---|---|---|
| 28 | Annual Point-to-Point Rate in $/MW - Year | L23 / L26 | #DIV/0! |
| 29 | Monthly Point-to-Point Rate in $/MW - Month | L28 / 12 | #DIV/0! |
| 30 | Weekly Point-to-Point Rate in $/MW - Week | L28 / 52 | #DIV/0! |
| 31 | Daily Point-to-Point Rate in $/MW - Day | L28 / 365 | #DIV/0! |
| 32 | Hourly Point-to-Point Rate in $/MW - Hour | L28 / 8760 | #DIV/0! |

# Sunflower Electric Power Corporation (SEPC)
# Rate Formula Template
# Actual Net Revenue Requirements
# For the 12 months ended - December 31, -2

| Line No. | (1) Description | (2) Reference | (3) | (4) | (5) Amount |
|---|---|---|---|---|---|
| | **REVENUE REQUIREMENTS** (including approved incentives, if any) | | | | |
| 1 | Total Transmission Facilities Gross Revenue Req. | Act Gross Rev, Pg. 2, L101, Col. 6 | | | #DIV/0! |
| 2 | Less: Non-transm. Related Competitive Bid Proj. Adjust. | A-7, L77, Col. q | | - | |
| 3 | Adjusted Total Transm. FacilitiesGross Revenue Req. | L1 - L2 | | | #DIV/0! |
| 4 | | | | | |
| 5 | Base Plan Net Revenue Requirements | WP A-7, L59+ L63, Col. r | #N/A | | |
| 6 | Balanced Portfolio Net Revenue Requirement | WP A-7, L67, Col. r | #N/A | | |
| 7 | ITP/Priority Projects-1 Net Revenue Requirement | WP A-7, L71, Col. r | #N/A | | |
| 8 | ITP/Priority Projects-2 Net Revenue Requirement | WP A-7, L75, Col. r | #N/A | | |
| 9 | Sponsored Net Revenue Requirements | WP A-8, L4, Col. m | #DIV/0! | | |
| 10 | Third Party Projects Net Revenue Requirements | WP A-10, L4, Col. n | #N/A | | |
| 11 | Total | Sum (L5:L10) | | #N/A | #N/A |
| 12 | | | | | |
| 13 | Zonal Gross Revenue Requirement | L1 - L11 | | | #DIV/0! |
| 14 | | | | | |
| 15 | **REVENUE CREDITS** | | | | |
| 16 | | | | | |
| 17 | Zonal Gross Revenue Credit | WP A-1, L90 | | $ - | |
| 18 | | | | | |
| 19 | **NET REVENUE REQUIREMENT** | | | | |
| 20 | Base Plan Net Revenue Requirements | L5 | #N/A | | |
| 21 | Balanced Portfolio Net Revenue Requirement | L6 | #N/A | | |
| 22 | ITP/Priority Projects-1 Net Revenue Requirement | L7 | #N/A | | |
| 23 | ITP/Priority Projects-2 Net Revenue Requirement | L8 | #N/A | | |

| | | | |
|---|---|---|---|
| 24 | Sponsored Project Net Revenue Requirements | L9 | #DIV/0! |
| 25 | Third Party Projects Net Revenue Requirements | L10 | #N/A |

| | | | | |
|---|---|---|---|---|
| 26 | Total | Sum (L20:L25) | #N/A | |
| 27 | | | | |
| 28 | Zonal Net Revenue Requirement | L13 - L17 | | #DIV/0! |
| 29 | | | | |

# Sunflower Electric Power Corporation (SEPC)

## Rate Formula Template

## Actual Gross Revenue Requirements

## For the 12 months ended - December 31, -2

| Line | (1) Description | (2) KCC Annual Report/Workpaper | (3) Total Company | (4) | (5) Allocator | | (6) Transmission (Col 3 times Col 5) |
|---|---|---|---|---|---|---|---|
| 1 | **RATE BASE:** | | | | | | |
| 2 | PLANT IN SERVICE (13 month averages) | | | | | | |
| 3 | Production | WP A-12, Pg. 1, L1, L2 & L34 | $ - | | NA | | $ - |
| 4 | Transmission (Excludes Capital Leases) | WP A-12, Pg. 1, L3 & L35 Note N | - | | DA | 1.000 00 | - |
| 5 | Less: Excluded Plant | WP A-4, Pg. 1, L13 Note J & K | | $ - | DA | 1.000 00 | - |
| 6 | Distribution | WP A-12, Pg. 1, L5 & L36 | - | | NA | | |
| 7 | General | WP A-12, Pg. 1, L6 & L37 | - | | WS | #DIV /0! | #DIV/0! |
| 8 | Intangible & Other | WP A-12, Pg. 1, L7 | - | | WS | #DIV /0! | #DIV/0! |
| 9 | TOTAL GROSS PLANT | Sum (L3:L8) - L5 Note P | $ - | | | | #DIV/0! |
| 10 | | | | | | | |
| 11 | ACCUMULATED DEPRECIATION (13 month averages) | | | | | | |
| 12 | Production | WP A-12, Pg. 1, L11 & L12 | $ - | | NA | | $ - |
| 13 | Transmission (Excludes Capital Leases) | WP A-12, Pg. 1, L13, Note N | - | | DA | 1.000 00 | - |
| 14 | Less: Excluded Plant | WP A-4, Pg. 1, L13 Note J & K | | $ - | DA | 1.000 00 | - |
| | | WP A-12, Pg. 1, | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 15 | Distribution | L15 | - | NA | | |
| 16 | General | WP A-12, Pg. 1, L16 | - | WS | #DIV/0! | #DIV/0! |
| 17 | Intangible & Other | WP A-12, Pg. 1, L17 | - | WS | #DIV/0! | #DIV/0! |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | TOTAL ACCUM. | Sum (L12:L17) - | $ | | | | |
| 18 | DEPRECIATION | L14 Note P | - | | | | #DIV/0! |
| 19 | | | | | | | |
| | NET PLANT IN SERVICE (13 month | | | | | | |
| 20 | averages) | | | | | | |
| | | | $ | | | | $ |
| 21 | Production | L3- L12 | - | | | | - |
| | Transmission (Excludes Capital | | | | | | |
| 22 | Leases) | L4- L13 | - | | | | - |
| | | | | $ | | | |
| 23 | Less: Excluded Plant | L5- L14 | | - | | | - |
| 24 | Distribution | L6- L15 | - | | | | |
| 25 | General | L7- L16 | - | | | | #DIV/0! |
| | Intangible & Other | | | | | | |
| 26 | | L8- L17 | - | | | | #DIV/0! |
| | | | $ | | | | |
| 27 | TOTAL NET PLANT | L9- L18 | - | | | | #DIV/0! |
| 28 | | | | | | | |
| | CONTRUCTION | | | | | | |
| 29 | WORK IN PROGRESS | | | | | | |
| | | WP A-12, Pg. 1, | $ | | | | $ |
| 30 | Production | L29 | - | | NA | | - |
| | | WP A-12, Pg. 1, | | | | 1.000 | |
| 31 | Transmission | L30 | - | | DA | 00 | - |
| 32 | Less: CWIP Assoc. | WP A-4 Pg. 2, | | $ | DA | 1.000 | |
| | with Third Party, Sponsored Projects, and Other Excluded Plant | L37 | | - | | 00 | - |
| | | WP A-12, Pg. 1, | | | | | |
| 33 | Distribution | L31 | - | | | | |
| | | WP A-12, Pg. 1, | | | | #DIV | |
| 34 | General Plant | L32 | - | | WS | /0! | #DIV/0! |
| | | L30 + L31 - L32 | $ | | | | |
| 35 | Total | + L33 + L34 | - | | | | #DIV/0! |
| 36 | | | | | | | |
| | ADJUSTMENTS TO | | | | | | |
| 37 | RATE BASE | | | | | | |
| | Accumulated Deferred | | $ | | | 1.000 | $ |
| 38 | Income Taxes | WP A-3 | - | | DA | 00 | - |
| 39 | Reserved for future use | | | | | | |
| | Reserve Funds (Non- | WP A-12, Pg. 2, | | | | 1.000 | |
| 40 | Escrowed) | L47 | #DIV/0! | | DA | 00 | #DIV/0! |
| | Unamortized Abandoned | WP A-12, Pg. 2, | | | | 1.000 | |
| 41 | Transmission Plant | L49, Note Q | - | | DA | 00 | - |
| | TOTAL | | | | | | |
| 42 | ADJUSTMENTS | Sum (L38:L41) | #DIV/0! | | | | #DIV/0! |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 43 | | | | | | | |
| | LAND HELD FOR | WP A-12, Pg. 2, | $ | | | 1.000 | $ |
| 44 | FUTURE USE | L55 Note B | - | | DA | 00 | - |
| 45 | | | | | | | |
| 46 | WORKING CAPITAL | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 47 | CWC | | | | | |
| 48 | O&M Expense less Fuel and Purchased Power | KCC Pg. 36-1, L40b - Pg. 34, L2b -L8b-L35b | $ - | NA | | |
| 49 | O&M Expense Allocated to Transmission | Pg. 2, L74, Col (6) | | | | #DIV/0! |
| 49a | Taxes Other Than Income Taxes included in lines 48 or 49 | | $ - | | | $ - |
| 50 | | Calculated Note C | $ - | | | #DIV/0! |
| 51 | Materials & Supplies--Transmission | WP A-12, Pg. 1, L59 + L62 | - | TP | #DIV /0! | #DIV/0! |
| 52 | Materials & Supplies--Other | WP A-12, Pg. 1, L57+L58+L60+ L61+L63 | - | NA | | |
| 53 | Stores Expense | WP A-12, Pg. 2, L66 | - | WS | #DIV /0! | #DIV/0! |
| 54 | Prepayments (Account 165) | WP A-12, Pg. 2, L70 (Note D) | - | GP | #DIV /0! | #DIV/0! |
| 55 | | | | | | |
| 56 | TOTAL WORKING CAPITAL | Sum (L50:L55) | $ - | | | #DIV/0! |
| 57 | | | | | | |
| 58 | Rate Base | Sum(L27, L35, L42, L44, L56) | #DIV/0! | RB = | #DIV /0! | #DIV/0! |



Actual Gross Rev Req Page 2 of 5

## Sunflower Electric Power Corporation (SEPC)

**Rate Formula Template**

## Actual Gross Revenue Requirements

**For the 12 months ended - December 31, -2**

| | (1) | (2) | (3) | (4) | | (5) | (6) |
|---|---|---|---|---|---|---|---|
| **Line** | **Description** | **KCC Annual Report/Workpaper** | **Total Company** | | **Allocator** | | **Transmission** (Col 3 times Col 5) |
| 59 | **O&M:** | | | | | | |
| 60 | Transmission | KCC Report Pg. 35, L17, Col. b | $ - | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 61 | Less: Transmission by Others Acct. 565 | KCC Report Pg. 35, L6, Col. b (Note E) | - | | |

| | | | |
|---|---|---|---|
| 62 | Less: Transmission Leases & Facility Charges | 83 | DEPRECIATION |
| 63 | Less Acct. 561 Expense Recovered Through Sch. 1 | 84 | |
| | | 85 | **TAXES** |
| 64 | Total Transmission O&M | 86 | LABOR RELATED |
| 65 | A&G -Adjusted | | |
| 66 | Plus: Safety Advertising | | |
| 67 | Plus Association Dues Directly Related to Transmission | | |
| 68 | Plus: Advertising - Transmission | | |
| 69 | Plus: Research - Transmission | | |
| 70 | Plus: Regulatory Exp -Transmission | | |
| 71 | Plus: Corporate Visibility -Transmission | | |
| 72 | Subtotal A&G | | |
| 73 | Transmission Lease Payments & Facility Charges | | |
| 74 | TOTAL O&M | | |
| 75 | | | |
| 76 | **DEPRECIATION EXPENSE** | | |
| 77 | Production | | |
| 78 | Transmission | | |
| 79 | Distribution | | |
| 80 | General | | |
| 81 | Intangible & Other | | |
| 82 | Amortization of Abandoned Transmission Plant | | |
| | TOTAL | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| SEPC Records (Note F) | - | | | WP A-11, L9 | - | WS | /0! | #DIV/0! |
| Actual Sch 1 Rev Req, L10 - L60 | | | | WP A-11, L10 | - | DA | 1.000 00 | - |
| | | | | WP A-11, L15 | - | DA | 1.000 00 | - |
| | | | | WP A-11, L20 | - | DA | 1.000 00 | - |
| | | | | WP A-11, L25 | - | DA | 1.000 00 | - |
| | | | | WP A-11, L31 | - | WS | #DIV /0! | #DIV/0! |
| | | | | L65 + Sum(L66:L71) | $ - | | | #DIV/0! |
| | | | | L62 (Note A) | - | DA | 1.000 00 | - |
| | | | | L64 + L72 + L73 | $ - | | | #DIV/0! |
| | | | | KCC Report Pg. 38, L7, Col. c | $ - | NA | 0.000 00 | $ - |
| | | | | KCC Report Pg. 38, L7, Col. D + Pg. 8, L5, Col. C (Note T) (Note M) | - | TP | #DIV /0! | #DIV/0! |
| | | | | KCC Report Pg. 38, L7, Col. e | - | NA | 0.000 00 | - |
| | | | | KCC Report Pg. 38, L7, Col. f | - | WS | #DIV /0! | #DIV/0! |
| | | | | SEPC Records Acct. 407 (Note Q) | - | WS | #DIV /0! | #DIV/0! |
| Sum(L61:L63) (Note H) | $ #DIV/0! | TP | #DIV/0! | | - | DA | 1.000 00 | - |
| WP A-11, L8 | $ #DIV/0! | WS | #DIV/0! | Sum(L77:L82) (Note I) | $ - | | | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 87 | Payroll | WP A-6, L9 | $ - | WS | #DIV /0! | #DIV/0! |
| 88 | Highway and vehicle | WP A-6, L9 | - | WS | #DIV /0! | #DIV/0! |
| 89 | PLANT RELATED | | | | | |
| 90 | Property | WP A-6, L9, (Note L) | | GP | #DIV /0! | #DIV/0! |
| 91 | Gross Receipts | WP A-6, L9 | - | NA | | - |
| 92 | Other | WP A-6, L9 | - | GP | #DIV /0! | #DIV/0! |
| 93 | INCOME (Transmission only) | WP A-6, L14 | - | DA | 1.000 00 | - |
| 94 | TOTAL TAXES | Sum(L87:L93) | $ - | | | #DIV/0! |
| 95 | | | | | | |
| 96 | **RETURN** | | | | | |
| 97 | Return before incentives | L156 | $ - | RB | #DIV /0! | #DIV/0! |
| 98 | Incentive return | L166 | | | | #N/A |
| 99 | Total Return | L97 + L98 | | | | #DIV/0! |
| 100 | | | | | #DIV /0! | |
| 101 | **GROSS REV. REQUIREMENT WITH INCENTIVES** | L74 + L83 + L94 + L99 | | | | #DIV/0! |
| 102 | LESS: Gross Revenue Requirements for Incentives | L98 | | | | #N/A |
| 103 | | | | | | |
| 104 | **GROSS REV. REQUIREMENT WITHOUT INCENTIVES** | L101 - L102 | | | | #DIV/0! |



Actual Gross Rev Page 3 of 5

## Sunflower Electric Power Corporation (SEPC)

**Rate Formula Template**

## Actual Gross Revenue Requirements

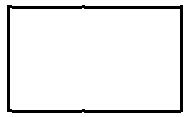
**For the 12 months ended - December 31, -2**

(1) (2) (3) (4) (5) (6)

| Line | Description | KCC Annual Report/Workpaper | Total Company | Allocator | Transmission |
|---|---|---|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | **TRANSMISSION PLANT INCLUDED** | | | | | | (Col 3 times |
| 105 | **IN FORMULA** | | | | | | Col 5) |
| | Total transmission plant, | | | | | | |
| | incl. capital and | WP A-12, L3 + | $ | | | 1.000 | $ |
| 106 | operating leases | L4 + L10 + L35 | - | | DA | 00 | - |
| | Less: Substation, 34kV, | | | | | | |
| | & Radial Lines to Distr. | WP A-4, L11 | | | | 1.000 | |
| 107 | Plt. | (Note J) | | - | DA | 00 | - |
| | Less: Total GSU in | WP A-4, L4 | | | | 1.000 | |
| 108 | Transmission Plant | (Note K) | | - | DA | 00 | - |
| | Transmission plant | L106 - L107 - L | $ | | | | $ |
| 109 | included in rates | 108 | - | | | | - |
| | Percentage of transmission plant | | | | TP | #DIV | |
| 110 | included in rates | L109 / L106 | | | = | /0! | |
| 111 | | | | | | | |
| | **GROSS AND NET PLANT** | | | | | | |
| 112 | **ALLOCATORS** | | | | | | |
| | GROSS PLANT IN SERVICE (ACTUAL | | | | | | |
| 113 | HISTORICAL COST) | | | | | | |
| | | | $ | | | | $ |
| 114 | Production | Pg 1, L3 | - | | NA | | - |
| | Total transmission plant, including leases | WP-12, L3 + L4 | | | | 1.000 | |
| 115 | (Note R) | + L10 + L35 | - | | DA | 00 | - |
| | | | | | | 1.000 | |
| 116 | Less: Excluded Plant | Pg 1, L5 | | - | DA | 00 | - |
| 117 | Distribution | Pg 1, L6 | - | | NA | | - |
| | General & Intangible | | | | | #DIV | |
| 118 | | Pg 1, L7 + L8 | - | | WS | /0! | #DIV/0! |
| | TOTAL GROSS | L114 + L115 - L 116 + L 117 + | $ | | GP | #DIV | |
| 119 | PLANT | L118 | - | | = | /0! | #DIV/0! |
| 120 | | | | | | | |
| 121 | ACCUMULATED DEPRECIATION (ACTUAL HISTORICAL COST) | | | | | | |
| | | | $ | | | | $ |
| 122 | Production | Pg 1, L12 | - | | NA | | - |
| | Total transmission plant, including leases | WP-12, L13 + L14 + L19 | - | | DA | 1.000 00 | - |
| 124 | Less: Excluded Plant | Pg 1, L14 | | - | DA | 1.000 00 | - |
| 125 | Distribution | Pg 1, L15 | - | | | | - |
| | | | | | | #DIV | |
| 126 | General & Intangible | Pg 1, L16 + L17 | - | | WS | /0! | #DIV/0! |
| | | L122 + L123 - L | | | | | |

| | | | | |
|---|---|---|---|---|
| | TOTAL ACCUM. | 124 + L 125 + | $ | |
| 127 | DEPRECIATION | L126 | - | #DIV/0! |
| 128 | | | | |





| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 129 | NET PLANT IN SERVICE (ACTUAL HISTORICAL COST) | | | | | | | |
| 130 | Production | L114 - L122 | $ - | | | | | $ - |
| 131 | Total transmission plant, including leases | L115 - L123 | - | | | | | - |
| 132 | Less Excluded Plant | L116 - L124 | | - | | | | - |
| 133 | Distribution | L117 - L125 | - | | | | | - |
| 134 | General & Intangible | L118 - L126 | - | | | | | #DIV/0! |
| 135 | TOTAL NET PLANT | L130 + L131 - L 132 + L 133 + L134 | $ - | | NP = | #DIV /0! | | #DIV/0! |
| 136 | | | | | | | | |
| 137 | **WAGES & SALARY ALLOCATOR (WS)** | | | | | | | |
| 138 | Production | KCC Pg. 37, L1, Col. d | $ - | | | - | | $ - |
| 139 | Transmission | KCC Pg. 37, L2, Col. d | - | | TP | #DIV /0! | | #DIV/0! |
| 140 | Distribution | KCC Pg. 37, L3, Col. d | - | | | - | | - |
| 141 | Other (excluding A&G) | KCC Pg. 37, L4. L5 & L6, Col. d | - | | | - | | - |
| 142 | Total | Sum (L138:L141) | $ - | | | | | #DIV/0! |
| 143 | Wage & Salary Allocator Calculation | Col 6, L142 / Col 3, L142 | | | | | WS = | #DIV/0! |

Actual Gross Rev Req Page 4 of 5



## Sunflower Electric Power Corporation (SEPC)

**Rate Formula Template**

## Actual Gross Revenue Requirements

**For the 12 months ended - December 31, -2**

| (1) | (2) | (3) | (4) | (5) | (6) |
|---|---|---|---|---|---|
| | **KCC Annual Report/Workpa** | **Total** | | **All oca** | **Transm** |

| Line | Description | per | Company | tor | ission (Col 3 times Col 5) |
|---|---|---|---|---|---|
| 144 | **RETURN (R)** | | | | |

| | | | |
|---|---|---|---|
| 145 | TIER Test Used to Establish Return Requirements | | |
| 146 | LT Debt | KCC Pg. 5, L11, Avg. of Col. c & Col. d | $ - |
| 147 | LT Interest Expense (Acct. 427) | KCC Pg. 8, L15, Col. c | - |
| 148 | ST Interest (Acct. 431) | KCC Pg. 8, L17, Col. c | - |
| 149 | Total Interest Expense | L147 + L148 | $ - |
| 150 | Target TIER Return | (Note O) | 2.0300 |
| 151 | Requirements (ST and LT Interest plus Margin) | L149 * L150 | $ - |
| 152 | Less: Non Operating Income | KCC Pg. 8, L23, Col. C | - |
| 153 | Plus: Acct 432 and 428, net expense | KCC Pg. 8, L16, Col. C | - |
| 154 | Plus: Amortization of Acquisition Costs | KCC Pg. 46 (Acct. 425) - L81 (Note G) | |
| 155 | Plus: Reserved for Future Use | | |
| 156 | Net Operating Return Req. (accrual basis) | L151 - L152 + L153 + L154 + L 155 | $ - |
| 157 | | | |
| 158 | Average LT Interest Rate | L147 / L146 | #DIV/0! |
| 159 | Average Return on Rate Base | L156 / L58 | #DIV/0! |



## Sunflower Electric Power Corporation (SEPC)

## Rate Formula Template

## Actual Gross Revenue Requirements

## For the 12 months ended - December 31, -2

General Note: References to pages in this formula rate are indicated as: (Pg. #, L(in) #, Col.#).

References to data from SEPC's Annual Report to the KCC are indicated as: (Pg. #, L(in) #, Col. #)

**Note**

| | |
|---|---|
| A | Allocator is DA=1.00. If any leases are determined by Commission order to be excluded, the allocator for this line will be adjusted to reflect the appropriate includable percent. |
| B | Includes only Land Held for Future Use associated with Transmission facilities. |

Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission,

C

D 3

E 4

F

G

H

I

J

K
L

M

N
O

P

Q

R
S

T
U
V
W

**Line**

1

2

reduced by taxes other than income taxes that are included in transmission O&M on L74, Col. 6.

Prepayments are the electric related prepayments booked to Acct. 165 and reported on SEPC's KCC Annual Report Pg. 17, L20, Col. b.

Expenses recorded in Account 565, Trans

mission of Electricity by Others, are not recoverable through the formula rate.

Lease and joint facilities charges included on L62, page 2 of 5, are those costs attributable to transmission service.

This line shall not be populated unless authorized by the Commission.

Transmission O&M on this line does not include any SPP charges for Schedule 1-A of the SPP OATT.

Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template.

Removes transmission plant determined by Commission order to be excluded from RTO transmission rate base to the extent that plant balances are not adjusted.

Removes generator step-up facilities determined by Commission order to be excluded from RTO transmission rate base to the extent plant balances are not adjusted. SEPC records this investment in a transmission plant account.

If the transmission related component of property tax is specifically identified in SEPC's KCC Annual Report, then a TP allocator shall be used. Property tax shall be allocated to transmission by the GP allocator if transmission related property tax is not specifically identified in the KCC Annual Report.

To the extent amortization of abandoned transmission plant has not been authorized for recovery, or has been included in line 82, it will not be included in line 78.

Does not include leases since return associated with leased facilities is included in the lease payment.

The approved TIER ratio will be established by the FERC and include the the RTO incentive adder. No change in TIER may be made absent a filing with the FERC. Any incentive ROEs approved by the FERC are shown by project in Worksheet A-9.

Excluded plant (line 5) is removed from the calculation of plant in the transmission column (column 6), but it not removed from the calculation of plant in the total company column (column 3).

The Unamortized Abandoned Transmission Plant can only be included in rate base if authorized by the Commission.

The GP allocator is primarily used to allocate prepaid insurance payments; and Sunflower provides property insurance for leased facilities.

Reserved for future use.

Includes depreciation of capital lease improvements. Includes annual amortization of $59,779, as authorized in KCC Docket 14-MKEE-170-TAR, for the period January 1, 2020 through December 31, 2024.

Reserved for future use.

Reserved for future use.

Reserved for future use.

**ALLOCATION FACTORS**

| Allocators | Description | Source | Amount |
|---|---|---|---|
| **RB** | Percentage of rate base attributable to transmission | Pg. 2, L58, Col.5 | #DIV/0! |
| **TP** | Percentage of transmission plant included in rate base. | Pg. 3, L110, Col.5 | #DIV/0! |
| **WS** | Percentage of transmission labor included in rates | Pg. 3, L143, Col.6 | #DIV/0! |
| **DA** | Direct assignment | | 1.00000 |

| | | | | |
|---|---|---|---|---|
| 5 | **GP** | Ratio of allocated transmission, general, & intangible plant to total gross plant. | Pg. 3, L119, Col.5 | #DIV/0! |
| 6 | **NA** | Not applicable for the transmission formula rate. | | - |
| 7 | **NP** | Ratio of net transmission, general, & intangible plant to total net plant. | Pg. 3, L135, Col.5 | #DIV/0! |

# Sunflower Electric Power Corporation (SEPC)
# Rate Formula Template
# Utilizing FERC KCC Annual Report Data
# Actual Schedule 1 Revenue Requirements
# For the 12 months ended - December 31, -2

| Line No. | (1) Description | (2) Reference | (3) Amount |
|---|---|---|---|
| **A** | | | |
| | **Schedule 1 ARR** | | |
| 1 | Total Scheduling, System Control and Dispatch Service | KCC Annual Report, Pg. 35, L2, col. B | $ - |
| 2 | Plus: Acct. 556 SPP NERC Compliance Charges | NERC Quarterly Assessments (50% of total) | - |
| 3 | Less: Scheduling, System Control and Dispatch Services | Acct. 561.4 | - |
| 4 | Less: Transmission Service Studies | Acct. 561.6 | - |
| 5 | Less: Reliability, Planning & Standards Dev. Services | Acct. 561.8 | - |
| 6 | Total | L1 + L2 - L3 - L4 - L5 | $ - |
| 7 | Reserved for future use. | | |
| 8 | Less: PTP Service Credit | WP A-1, Pg. 1, L26a | - |
| 9 | Net Schedule 1 Revenue Requirement for Zone | L6 + L7 - L8 | $ - |
| 10 | Acct. 561 Expenses Recovered Through Sch. 1 Charges | L1 - Sum(L3:L5) | $ - |
| **B** | | | |
| | **Schedule 1 Rate Calculations** | | |

M

| | | | | |
|---|---|---|---|---|
| 11 | SEPC 12-CP. Peak Demand | WP A-2, L14 | - | W |
| 12 | Annual Point-to-Point Rate in $/MW - Year | L9 / L11 | #DIV/0! | |
| 13 | Monthly Point-to-Point Rate in $/MW - Month | L12 / 12 | #DIV/0! | |

| | | | |
|---|---|---|---|
| 14 | Weekly Point-to-Point Rate in $/MW - Week | L12 / 52 | #DIV/0! |
| 15 | Daily Point-to-Point Rate in $/MW - Day | L12 / 365 | #DIV/0! |
| 16 | Hourly Point-to-Point Rate in $/MW - Hour | L12 / 8760 | #DIV/0! |

# Sunflower Electric Power Corporation (SEPC)
# Revenue Credits
# For the 12 Months Ended December 31, -2

| Line | Description | Total Company | Non-Transmission | Transmission |
|---|---|---|---|---|
| 1 | **I. Rent from Electric Property, Account 454 (Note 10)** | | | |
| | Account 4540001 - Other Rev -Rent | $ | $ | $ |
| 2 | Electric Property | - | - | - |
| 3 | Transmission: | | | |
| 4 | Farm Land Rental | $ - | | |
| 5 | Rental From Cell Phone Attaches / Equipment Facilities | - | | |
| 6 | Rental | - | | |
| 7 | Rental Substation Property - Cell Towers | - | | |
| 8 | Other Rental | - | | |
| 9 | Total Transmission | | $ - | |
| 10 | (Revenue related to transmission facilities for pole attachments, rentals, etc. Provide data sources and explanations in Section V, Notes below.) | | | |
| 11 | | | | |
| 12 | **II. Other Operating Revenues To Reduce Revenue Requirement** | | | $ - |

| | | |
|---|---|---|
| 1 | | |
| 3 | | |
| 1 | | $ |
| 4 | **III. Other Electric Revenue, Account 456** | - |
| 1 | | |
| 5 | (Provide data sources and necessary explanations in Notes below.) | |

| | | |
|---|---|---|
| 16 | **Less:** | 9 |
| 17 | | 4 |
| 18 | | 0 |
| 19 | | 4 |
| 20 | | 1 |
| 21 | | |
| 22 | | |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | | |
| 28 | | |
| 29 | | |
| 30 | | |
| 31 | | |
| 32 | | |
| 33 | | |
| 34 | | |
| 35 | | |
| 36 | | |
| 37 | | |
| 38 | | |
| 39 | | |

| | | | |
|---|---|---|---|
| | P Tariff | | |
| TO's LSE Direct Assignment Revenue Credits (Explanation required if populated) | Wholesale Distribution Revenue (WDR) | $ - | - |
| TO's LSE Sponsored Upgrade Revenue Credits (Explanation required if populated) | Schedule 1 Revenue | | - |
| TO's LSE Sch. 11 Rev. from Sponsored or Direct Assign Facilities - Network Credits (Explanation required if populated) | Schedule 1 Point-to-Point Revenue included in line 26 | - | |
| | Schedule 2 Revenue | | - |
| | Schedules 3-6 Revenue | | - |
| TO's LSE Sch. 11 Rev. from Sponsored or Direct Assign Facilities - PtP Credits (Explanation required if populated) | Revenue for TO's Facilities Under Schedule 11 | | |
| | Zonal Network Revenue for TO's Facilities Under Schedule 11 | - | |
| | Region-wide Network Revenue for TO's Facilities Under Schedule 11 | - | |
| | Zonal Point-to-Point Revenue for TO's Facilities Under Schedule 11 | - | |
| TO's LSE Network Upgrades for Generation Interconnection - Credits (Explanation required if populated) | Region-wide Point-to-Point Revenue for TO's Facilities Under Schedule 11 | - | |
| | Subtotal | $ - | |
| | Less: Rev. From Sch. 11 Projects Not In Service as of 12/31/-2 or Excess Sch. 11 Rev. (Note 8). | - | |
| | Net Schedule 11 Revenue Associated With Special Projects in Service during -2 | | - |
| Point-To-Point Revenue for GFAs Associated with Load Included in the Divisor (Explanation required if poulated) | Other - Revenue from bundled transmission service to Members. (Note 3) | | - |
| Network Service Revenue (Schedule 9) Associated With Load Included in the Divisor (Note 3) | Other - Power Supply Related Revenues | | - |
| Revenue Associated with Transmission Plant E x c l u d e d F r o m S P | Other - | | |
| | Other - | - | |
| | Other - Revenue associated with covering losses. | | - |

| | | | |
|---|---|---|---|
| 42 | Other - Revenue from TDC type charges to members | | - |
| 43 | **Total Adjustments Net 456 Account Transmission Related Activity** | | $ - |
| 44 | | | $ - |
| 45 | **IV. Total Revenue Credits to Apply to Transmission Revenue Requirements** | | |



Workpaper A-1 Page 2 of 2

# Sunflower Electric Power Corporation (SEPC)
# Revenue Credits
# For the 12 Months Ended December 31, -2

| Line | Description | Source | Amount |
|---|---|---|---|
| 46 | Total Sch. 11 Revenue Received in -2 | L34 | $ - |
| 47 | | | |
| 48 | Net Projected ATRR for Projects Completed as of 12/31/-2 for which Revenue was Received in -2 | Note 10, Note 2 | |
| 49 | Johnson to Pioneer 115kV Line | | $ - |
| 50 | Johnson Corner Capacitor Bank =1 | | - |
| 51 | Johnson Corner Capacitor Bank =2 | | - |
| | Buckner - Spearville | | |

| | | |
|---|---|---|
| 5 | 345 kV Ckt 1 | |
| 2 | Terminal Upgrades | - |
| 5 | Walkemeyer Tap - Walkemeyer 345/115 | |
| 3 | kV | - |

| | | |
|---|---|---|
| 5 | Ingalls 115 kV Cap | |
| 4 | Bank | - |
| 5 | Lane Scott 115 kV | |
| 5 | Cap Bank | - |
| | Holcomb to Fletcher | |
| 5 | 115kV Line | |
| 6 | (Wheatland) | - |
| 5 | Holcomb to Plymell | |
| 7 | 115kV (MKEC) | - |
| 5 | Plymell to Pioneer | |
| 8 | Tap 115kV (MKEC) | - |
| 5 | Mingo 345/115 kV | |
| 9 | Ckt 2 Transformer | - |
| 6 | Mingo 345 kV | |
| 0 | Terminal Upgrades | - |
| 6 | Pratt Capacitor Bank | |
| 1 | 115 kV | - |
| 6 | Harper Capacitor | |
| 2 | Bank 115 kV | - |
| 6 | WEPL-Cimarron | |
| 3 | Plant 115 kV Line | - |
| 6 | Pratt - St. John | |
| 4 | 115kV Line Rebuild | - |
| 6 | Clifton - Greenleaf | |
| 5 | 115kV Line (Note G) | - |
| | Medicine Lodge | |
| | 138/115kV | |
| 6 | Transformer (64% | |
| 6 | BPF) | - |
| 6 | Heizer - Mullergren | |
| 7 | 115kV | - |
| 6 | Plainville 115kV | |
| 8 | Capacitor Bank | - |
| 6 | Flatridge - Harper | |
| 9 | 138kV (54.3% BPF) | - |
| | Flatridge - Medicine | |
| 7 | Lodge 138kV (57.6% | |
| 0 | BPF) | - |
| | Medicine Lodge - | |
| 7 | Pratt 115kV (57.7% | |
| 1 | BPF) | - |
| 7 | Ellsworth - Bushton | |
| 2 | 115kV | - |
| 7 | Jewell - Smith Center | |
| 3 | 115kV | - |
| 7 | Elm Creek 345/230 | |
| 4 | kV Transformer | - |
| 7 | Elm Creek 345 kV | |
| 5 | Terminal Upgrades | - |
| 7 | Elm Creek 230 kV | |
| 6 | Terminal Upgrades | - |

| | | |
|---|---|---|
| | Elm Creek - Summit | |
| 7 | 345 kV Ckt 1 | |
| 7 | (ITCGP) | - |
| 7 | Harper - Rago 138 | |
| 8 | kV Ckt 1 | - |

| | | | | | |
|---|---|---|---|---|---|
| 79 | | Ellsworth 115 kV Cap Bank | | | - |
| 80 | | Anthony - Harper 138 kV Ckt 1 | | | - |
| 81 | | Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1 | | | - |
| 82 | | Harper - Rago 138 kV Ckt 1 | | | - |
| 83 | | Total Projected ATRR for Projects Completed as of 12/31/-2 | Sum(L49:L82) | (Total goes in L36) | $ - |
| 84 | | | | | |
| 85 | Net Schedule 11 Revenue | | L46 - L83 | (Total goes in L35) | $ - |
| 86 | | | | | |
| 87 | Point-to-Point Revenue for TO's Facilities Under Schedule 11 | | L32 + L33 | | $ - |
| 88 | | | | | |
| 89 | Revenue Credits to be Applied to Base Plan Projects ATRR in -2 | | Lessor of L85 & L87 | | $ - |
| 90 | Revenue Credits to be Applied to Zonal Revenue Requirements-2 | | L91 - L89 | | - |
| 91 | | Total Revenue Credits Applied to Transmission ATRR | L45 | | $ - |
| 92 | | | | | |

**Notes:**

(1) Data for this worksheet came from SEPC's Annual Report to the KCC and the Company's General Ledger.

(2) Project list is subject to expansion based on the number of base plan projects for the given year.

(3) Bundled transmission service for Sch. 1, 2, 3, 5 & 6, WDR and loss billed to the SEPC Members. See Note 2 as well.

(4) Reserved for future use.

)
(
5 Reserved for future use.
)

(6) Revenue from other entities to cover use of administrative assets. The non-transmission portion is equal to Actual Revenue * (1-WS Allocator).

(7) Reserved for future use.

(8) Schedule 11 revenue for projects not yet completed as of 12/31/-2 and excess revenue (i.e., revenue less ATRR) for Sch. 11 projects completed by 12/31/-2 are assigned as a revenue credit against Transmission ATRR. See page 2, L85

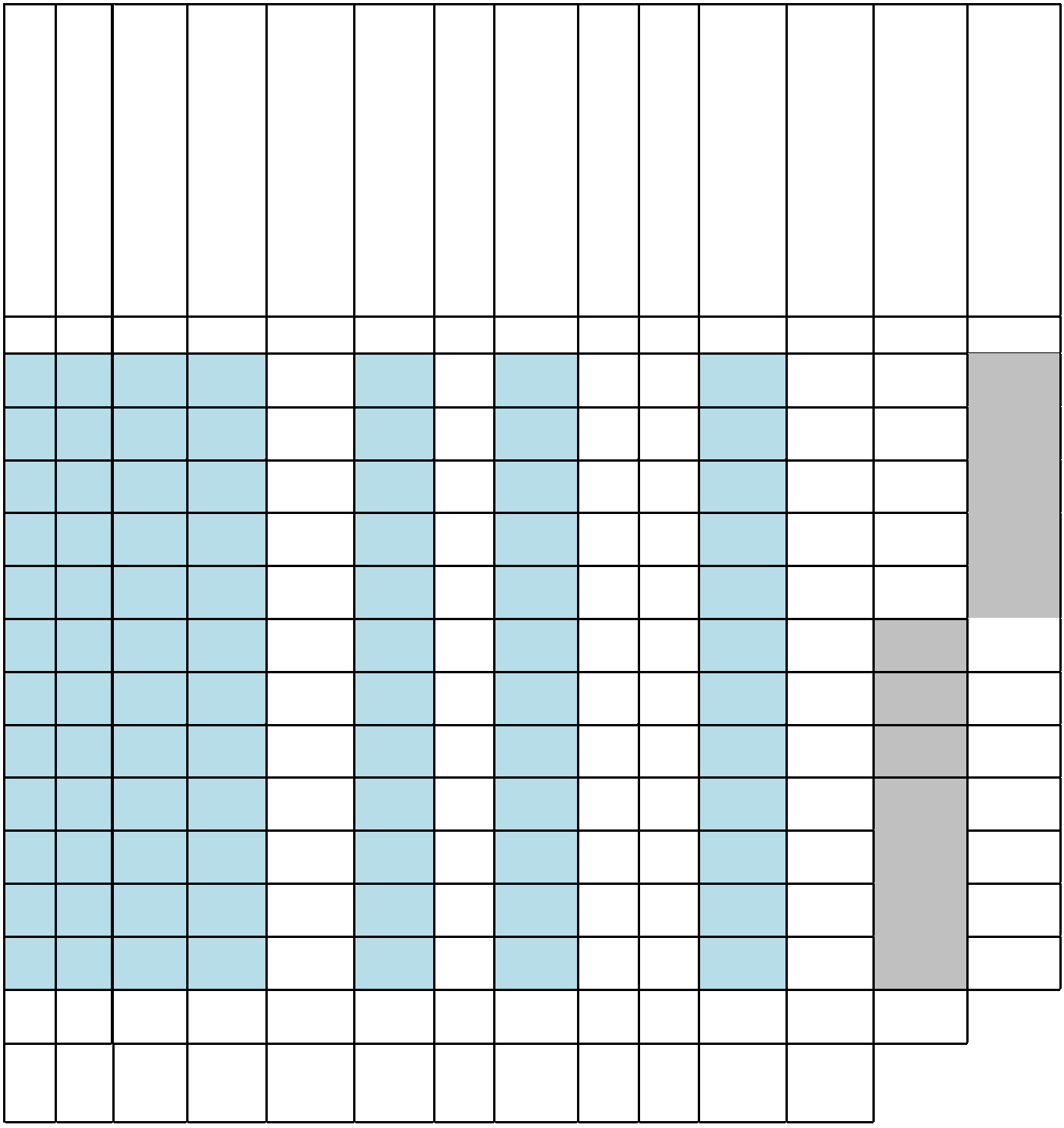
(9) The Net Revenue Requirement with True-up from Projection for Actual Period, Schedule "Projected Net Rev Req," taken from the FBR two years prior to the current one (i.e., when the ATRR for these projects was established).

(10) Excludes lease revenue on assets expected to be recorded as long-term leases.

# Sunflower Electric Power Corporation (SEPC)
# Determination of Transmission Network Load (MW)
# For the 12 months ended December 31, -2

| Line | Date | Hour Ending | SEPC's Native System Peak Load | Adjustment | Adjusted SEPC's Native System Peak Load | Plus: 3rd Party Network Load (incl. gen.) | Reserve for Future Use | Plus: Grandfather Agreements | Reserve for Future Use | Reserve for Future Use | Less: Load Not Connected to the SEPC Transmission System | SEPC's Transmission System Load (e-f+g+h+i+j-k) | Average Transmission Network Load for January thru May | Percentage of Aver. Jan - May Load |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | ( c ) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
| 1 | | | - | - | - | - | - | - | | | - | - | - | |
| 2 | | | - | - | - | - | - | - | | | - | - | - | |
| 3 | | | - | - | - | - | - | - | | | - | - | - | |
| 4 | | | - | - | - | - | - | - | | | - | - | - | |
| 5 | | | - | - | - | - | - | - | | | - | - | - | |
| 6 | | | - | - | - | - | - | - | | | - | - | | #DIV/0! |
| 7 | | | - | - | - | - | - | - | | | - | - | | #DIV/0! |
| 8 | | | - | - | - | - | - | - | | | - | - | | #DIV/0! |
| 9 | | | - | - | - | - | - | - | | | - | - | | #DIV/0! |
| 10 | | | - | - | - | - | - | - | | | - | - | | #DIV/0! |
| 11 | | | - | - | - | - | - | - | | | - | - | | #DIV/0! |
| 12 | To | | - | - | - | - | - | - | | | - | - | | #DIV/0! |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | tal 12 - | - | n/a | - | - | - | - | - | - | - | - | - | |
| 14 | CP | - | n/a | - | - | - | - | - | - | - | - | | |



Notes:

Column (n) :This column reflects the relationship of the actual load for each month (September, October, November and December) as a percentage of the average transmission network load for January through August. For example, the September percentage in column (n) is equal to the September load in column (l) divided by the 8-month average of column (m) shown on line 13.

# Sunflower Electric Power Corporation (SEPC)
# Allocation of ADIT
# For the 12 months ended December 31, -2

SEPC is a taxable cooperative subject to income taxes to the extent that income or losses are allocated to nonpatron
activity. The ADIT as of 12/31/-2 is zero. See the income tax notes to the combined financial statements found in the
-2 Audit Report for additional information on the calculation of ADIT.

**Notes**

| | |
|---|---|
| A | Deferred taxes and accumulated deferred taxes will not be included in the formula without prior Commission approval. |

# Sunflower Electric Power Corporation (SEPC)
# Excluded Assets--Assets Transferred from Transmission Rate Base
# As of December 31, -2

| Line | | 13-Month Average Balance | | |
|---|---|---|---|---|
| | | Plant in Service (Note A) | Depr. Reserve | Net |
| 3 | **I. GSU Values Transferred from Transmission** | | | |
| 4 | Total GSUs 1 1 | | | |
| 5 | 1 2 | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |

| | | | | | |
|---|---|---|---|---|---|
| in Transmission Plant | **Transferred** | | | | |
| | Radial Lines | $ - | $ - | $ - | |
| | Substation Facilities Transf to Distribution Plt. | - | - | - | |
| **II. Radial Lines, 34kV and Substation Facilities** | 34 kV Lines | - | - | - | |
| | Less: Substation Facilities Transf to Trans. Plant | - | - | - | |
| | Net Substation, 34kV, & Radial Lines to Dist. Plt | $ - | $ - | $ - | |

| | | | | |
|---|---|---|---|---|
| 13 | **III. Net Transfer From Trans. (L4 + L11)** | $ - | $ - | $ - |

Note A Includes Completed Plant Not Yet Classified.



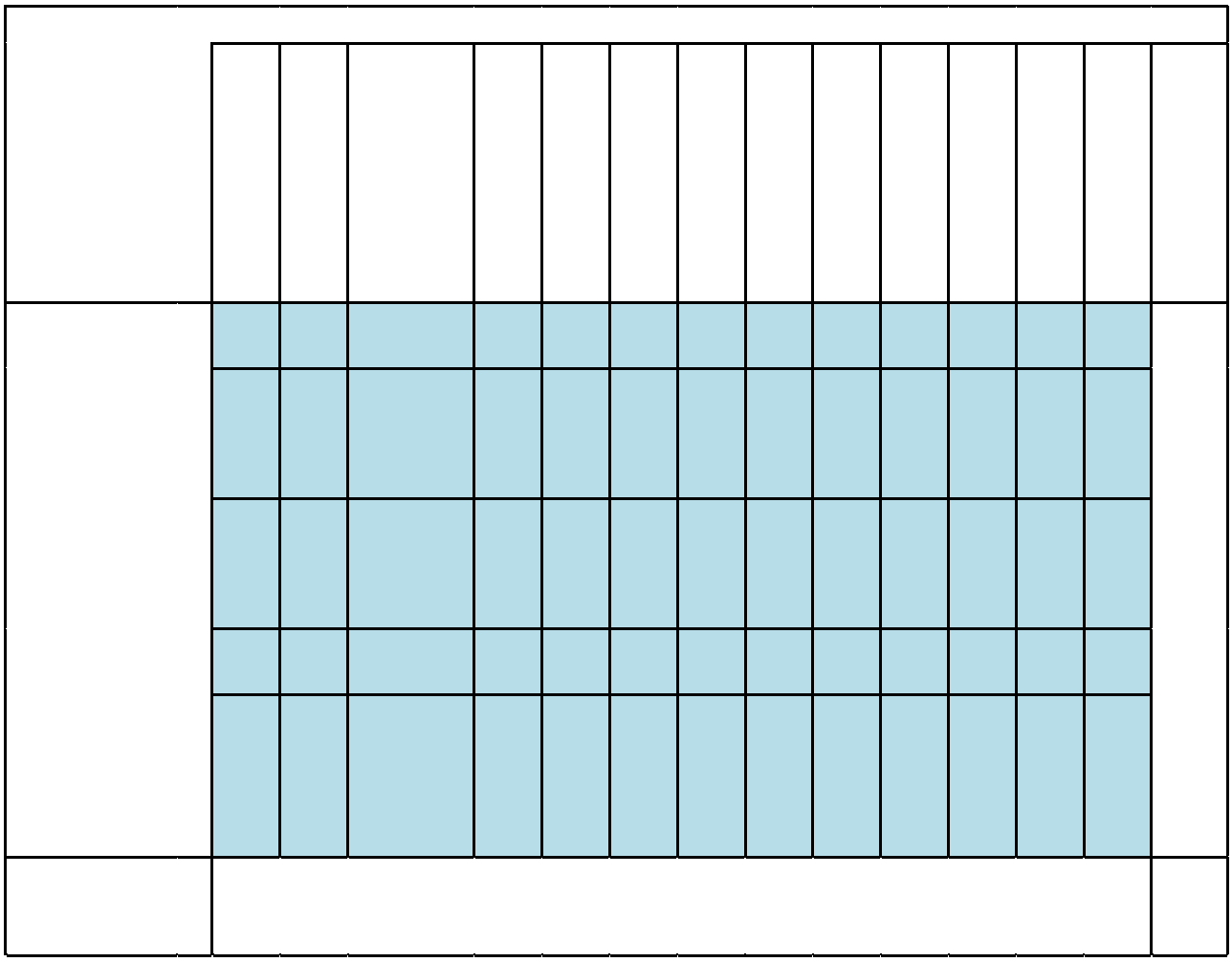


# Sunflower Electric Power Corporation (SEPC)
# Excluded Assets--Assets Transferred from Transmission Rate Base
# As of December 31, -2

**IV. 13 Month Average - Gross Plant**

| | | Gross Plant | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | | **-3** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **13 Months Avg Balance** |
| | | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | |
| 14 | GSU | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 15 | Radial Lines and other excluded plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 16 | Substation - Transferred to Dist. Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | 34 kV Lines | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 18 | Less: Substa. Facil. Tranf to Transm. Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | Total - Excluded Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |



**V. 13 Month Average - Accumulated Deprecation**

**Accumulated Depreciation**

| | | -3 Dec | -2 Jan | -2 Feb | -2 Mar | -2 Apr | -2 May | -2 Jun | -2 Jul | -2 Aug | -2 Sep | -2 Oct | -2 Nov | -2 Dec | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 20 | GSU | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | Radial Lines and other excluded plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | Substation - Transferred to Dist. Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 23 | 34 kV Lines | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 24 | Less: Substa. Facil. Tranf to Transm. Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | Total - Excluded Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**VI. 13 Month Average -Net Plant**

**Net Plant** (Gross Plant less Accumulated Depreciation)

| | | -3 Dec | -2 Jan | -2 Feb | -2 Mar | -2 Apr | -2 May | -2 Jun | -2 Jul | -2 Aug | -2 Sep | -2 Oct | -2 Nov | -2 Dec | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26 | GSU Radial Lines | - | - | - | - | - | - | - | - | - | - | - | - | - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | and other | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| 2 | excluded | | | | | | | | | | | | | | $ |
| 7 | plant | | | | | | | | | | | | | | - |
| 2 | Substation - | | | | | | | | | | | | | | $ |
| 8 | Transferred | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | to Dist. Plant | | | | | | | | | | | | | | | |
| 29 | | | | | | | | | | | | | | | $ - | |
| | 34 kV Lines | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| | Less: Substa. Facil. Tranf | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| 30 | to Transm. Plant | | | | | | | | | | | | | | $ - | |
| 31 | Total - Excluded Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |

**VII. 13 Month Average - CWIP**

**CWIP**

| | | **-3** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **13 Months** | (Note B) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Dec** | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Avg Balance** | **Adjustment to Rate Base** |
| 32 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | GSU | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| | Radial Lines and other | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 33 | excluded plant | | | | | | | | | | | | | | $ - | $ - |
| | Substation - Transferred | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 34 | to Dist. Plant | | | | | | | | | | | | | | $ - | |
| 35 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 34 kV Lines | - | - | - | - | - | - | - | - | - | - | - | - | - | | |
| | Less: Substa. Facil. Tranf | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - |
| 36 | to Transm. Plant | | | | | | | | | | | | | | $ - | |
| | Total - | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Excluded | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | | $ | $ |
| 7 | Assets | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Account 106 - Completed Plant Not Yet Classified - Add to Excluded Gross Plant**

| | | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | 13 Months |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | Avg Bal |
| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | ance |
| 37 | GSU | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 38 | Radial Lines and other excluded plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 39 | Substation - Transferred to Dist. Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 40 | 34 kV Lines Less: | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 41 | Substa. Facil. Tranf to Transm. Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 42 | Total - Excluded Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note B: In accordance with 18 C.F.R. §§ 35.25(c)(3) and 35.25(e), without prior approval from the Commission, no more than 50 percent of CWIP may be included in the rate base. No AFUDC will be calculated on the portion of CWIP included in rate base.

Workpaper
A-5
Page 1 of 1

# Sunflower Electric Power Corporation (SEPC)
# Worksheet A-5 - Depreciation Rates
# As of December 31, -2

| Line | A/C | Description | Rate |
|---|---|---|---|
| 1 | 301 | Organization | 4.09% |
| 2 | 302 | Franchises | N.A. |
| 3 | 303 | Misc Intangible Plant | N.A. |
| 4 | 350 | Land & Land Rights | N.A. |
| 5 | 352 | Structures and Improvements | 2.07% |
| 6 | 353 | Station Equipment | 2.79% |
| 7 | 354 | Towers and Fixtures | 1.31% |
| 8 | 355 | Poles and Fixtures | 4.11% |
| 9 | 356 | Overhead Conductors and Devices | 1.92% |
| 10 | 357 | Underground Conduit | N.A. |
| 11 | 358 | Underground Conductors and Devices | N.A. |
| 12 | 389 | Land and Land Rights | N.A. |
| 13 | 390 | Structures and Improvements | 2.37% |
| 14 | 391 | Office Furniture and Equipment | 8.57% |
| 15 | 39106 | Gen Plt-SJ OffMachines1987 | N.A. |
| 16 | 39102 | Gen Plt-Computer Hardware | N.A. |
| 17 | 39104 | Gen Plt-Software | N.A. |
| 18 | 392 | Transportation Equipment | 4.85% |
| 19 | 393 | Stores Equipment | .33% |
| 20 | 394 | Tools, Shop and Garage Equipment | 4.17% |
| 21 | 395 | Laboratory Equipment | 1.75% |
| 22 | 396 | Power Operated Equipment | 1.48% |
| 23 | 397 | Communication Equipment | 4.54% |
| 24 | 398 | Miscellaneous Equipment | 7.39% |
| 25 | 399 | Other Tangible Property | N.A. |

| | | | | |
|---|---|---|---|---|
| 26 | | | | |
| 27 | Weighted Average Transmission Depreciation Rate | | | |
| 28 | Transmission Depreciation Expense in -2 | | Actual Gross Rev Req L78, Col (3) | $ - |

| | | | |
|---|---|---|---|
| 29 | Transm. Plant in Service (12 mo. avg. Dec., -3 to Nov., -2) | WP A-12, L10 | $ - |
| 30 | Average Annual Transmission Depreciation Rate | L28 / L29 | #DIV/0! |
| 31 | Average Monthly Transmission Depreciation Rate | L30 / 12 | #DIV/0! |

**Notes**

# Sunflower Electric Power Corporation (SEPC)
# Taxes
# For the 12 Months Ended December 31, -2

Source: KCC Annual Report, Pg. 42

| Line No | Description | Electric Acct 408, 409 | Excluded | Adjusted | Payroll | Highway & Vehicle | Property | Gross Receipts, Uses & KC Earning Tax | Other | Other Misc | Total of Cost Distribution |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Ad Valorem | - | - | - | | | - | | | | - |
| 2 | Excise | - | - | - | | - | | | | | - |
| 3 | Franchise - Corporate | - | - | - | | | | - | | | - |
| 4 | Payroll (Note A) | - | - | - | - | | | | | | - |
| 5 | Transaction | - | - | - | | | | - | | | - |
| 6 | Property Taxes (Note A) | - | - | | | | | | | | |
| 7 | KC Earnings | - | - | - | | | | - | | | - |
| 8 | Miscellaneous | - | - | - | | | | | - | | - |
| 9 | Subtotal | - | - | - | - | - | - | - | - | - | - |
| 10 | | | | | | | | | | | |
| 11 | Income Taxes (Note B) | Total Company | Non-Transmission | Transmission | | | | | | | |
| 12 | Federal | - | - | - | | | | | | | |
| 13 | State | - | - | - | | | | | | | |
| 14 | Income Taxes | - | - | - | | | | | | | |
| 15 | Total | - | | | | | | | | | |

**Notes**

A In accordance with RUS accounting guidelines, most of these taxes are distributed directly to the various O&M and construction accounts.

B Income taxes reflect accounts 408 and 409 apportioned between transmission and non-transmission.

C Deferred taxes and accumulated deferred taxes will not be included in the formula without prior Commission approval.

# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

| Line | Description | Source | Total System | |
|---|---|---|---|---|
| 1 | Transm. Gross Plant, incl. Leases, excl. Excluded Plant | Actual Gross Rev Req L109, Col 6 | $ - | |
| 2 | Transmission Net Plant in Service (Excludes Leases) | Actual Gross Rev Req L22, Col. 6 | $ - | |
| 3 | Plus: Net Plant Attributable to Capital Lease Projects | A-12, Pg. 1, L23 | - | Investment associated with capital leases is recorded on Sunflower's books. |
| 4 | Less: Net Plant Excl. for O&M, Other Taxes and General Plant | | - | |
| 5 | Adjusted Net Plant for O&M and Other Taxes | L2 + L3 - L4 | $ - | |
| 6 | Transmission O&M (includes allocation of A&G) | Actual Gross Rev Req L74 - L73 | #DIV/0! | Excludes lease payments and Facilities charges |
| 7 | Percent of Net Plant | L6 / L5 | #DIV/0! | |
| 8 | Other Taxes | Actual Gross Rev Req L94 | #DIV/0! | |
| 9 | Percent of Net Plant | L8 / L5 | #DIV/0! | |
| 10 | General & Intangible Plant Allocation | Actual Gross | #D | |

| | | | |
|---|---|---|---|
| 1 | | Rev Req L80 + | IV/ |
| 1 | Depreciation | L81 | 0! |
| 1 | Return | Actual Gross | #D |
| 2 | | Rev Req | IV/ |
| | | | 0! |

| | | | |
|---|---|---|---|
| | | ((L25+L26) / L27)*L97 | |
| 13 | Total | L11 + L12 | #DIV/0! |
| 14 | Percent of Net Plant | L13 / L5 | #DIV/0! |
| 15 | Return (New Facilities) | Actual Gross Rev Req L158 * L150 | #DIV/0! |





# Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

**I. Summary of Actual RTO Directed Transmission Projects** (Note A)

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Project** | | | **In Service** | **Gross** | | **O & M and A & G Allocated** | **Other** | **General Plant** | **Depreciation Ex** | | **Non Incentive** | **Incentive** | **Gross Revenue Requi** | **Revenue C** | **Net Revenue Requ** | **Non-Transm Related Competitive Bid Adj** | **Adjusted Net Revenue Requ** |

| ct No | Project ID | Description | Date | Plant | Net Plant | ~~Expense~~ | Taxes | Allocation | pense | Return | Returns | rements | redit | irements | ustment | irements |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **A. Base Plan Projects (Sunflower Owned)** | | | (see below) | (see below) | (f * L7) | (f * L9) | (f * L14) | (see below) | (f * L15) | (WP A-9) | (g+h+i+j+k+l+m) | Note B | (n - o) | | (p) + (q) |
| 16 | 1 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 17 | 2 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 18 | 3 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 19 | 4 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 20 | 5 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 21 | 6 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 22 | 7 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 23 | 8 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 24 | 9 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 25 | 10 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 26 | 11 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 27 | 12 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 28 | 13 | 0 | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |
| 29 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | #N/A | #N/A | | #N/A |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | 14 | 0 | 0 | A | A | /A | A | A | /0! | A | A | A | /A | /A |
| 3 | | | $0.0 | #N/ | #N/ | #N | #N/ | #N/ | #D IV | #N/ | #N/ | # N/ | #N | #N |
| 0 | 15 | 0 | 0 | A | A | /A | A | A | /0! | A | A | A | /A | /A |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 16 | 0 | | $0.00 | | | | | | | | | | | |
| 32 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 17 | 0 | | $0.00 | | | | | | | | | | | |
| 33 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 18 | 0 | | $0.00 | | | | | | | | | | | |
| 34 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 19 | 0 | | $0.00 | | | | | | | | | | | |
| 35 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 20 | 0 | | $0.00 | | | | | | | | | | | |
| 36 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 21 | 0 | | $0.00 | | | | | | | | | | | |
| 37 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 22 | 0 | | $0.00 | | | | | | | | | | | |
| 38 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 23 | 0 | | $0.00 | | | | | | | | | | | |
| 39 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 24 | 0 | | $0.00 | | | | | | | | | | | |
| 40 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 25 | 0 | | $0.00 | | | | | | | | | | | |
| 41 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 26 | 0 | | $0.00 | | | | | | | | | | | |
| 42 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 27 | 0 | | $0.00 | | | | | | | | | | | |
| 43 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 28 | 0 | | $0.00 | | | | | | | | | | | |
| 44 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 29 | 0 | | $0.00 | | | | | | | | | | | |
| 45 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 30 | 0 | | $0.00 | | | | | | | | | | | |
| 46 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 31 | 0 | | $0.00 | | | | | | | | | | | |
| 47 | | | $0.00 | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | # N/A | #N/A | #N/A |
| 32 | 0 | | $0.00 | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | | $0.0 | | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | | #N/A | # N/A | #N/A | | #N/A | | | |
| 8 | 33 | 0 | 0 | | | | /A | A | A | /0! | A | | A | A | /A | | /A | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | **C. Balanced Portfolio Projects** | | | | | |
| 49 | 34 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 50 | 35 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 51 | 36 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 52 | 37 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 53 | 38 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 54 | 39 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 55 | 40 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 56 | 41 | | | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 57 | 42 | | | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 58 | 43 | | | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 59 | Total Base Plan Projects (Sunflower Owned) | | | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| | **B. Base Plan Projects (Capital Lease)** | | | | | | | | | |
| 60 | 1 | 0 | $0.00 | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 61 | 2 | 0 | Description | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 62 | 3 | 0 | Description | #N/A | | #N/A | #N/A | #N/A | #N/A | |
| 63 | Total Base Plan Projects (Capital Leases) | | | #N/A | | #N/A | #N/A | #N/A | #N/A | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 77 | | | | | | | | | | | |
| 64 | | 1 | 0 | Description | **Priority 2 Projects** | #N/A | | #N/A | #N/A | #N/A | #N/A |
| 65 | | 2 | 0 | Description | | #N/A | | #N/A | #N/A | #N/A | #N/A |
| 66 | | 3 | 0 | Description | | #N/A | | #N/A | #N/A | #N/A | #N/A |
| 67 | | Total Balanced Portfolio Projects | | | | #N/A | $0.00 | Description | #N/A | #N/A | #N/A | #N/A |
| | | **D. ITP Priority 1 Projects** | | | | | | | | | | |
| 68 | | | | | Total ITP Priority 2 Projects | | | | #N/A | #N/A | #N/A | #N/A |
| 69 | | | | | | | | | #N/A | #N/A | #N/A | #N/A |
| 70 | | | | | Total Non-Transmission Related Competitively Bid Project Adjustment | | | | #N/A | #N/A | #N/A | #N/A |
| 71 | | | | | | | | | #N/A | #N/A | #N/A | #N/A |
| | | 1 | $0.00 | Description | | #N/A | | | | | | |
| 72 | | 2 | $0.00 | Description | | #N/A | | | #N/A | #N/A | #N/A | #N/A |
| 73 | | 3 | $0.00 | Description | | #N/A | | | #N/A | #N/A | #N/A | #N/A |
| 74 | | Total ITP Priority 1 Projects | | | | #N/A | | | #N/A | #N/A | #N/A | #N/A |
| 75 | | **E. ITP** | | | | | | | #N/A | #N/A | #N/A | #N/A |
| 76 | | | | | | | | | | | | |

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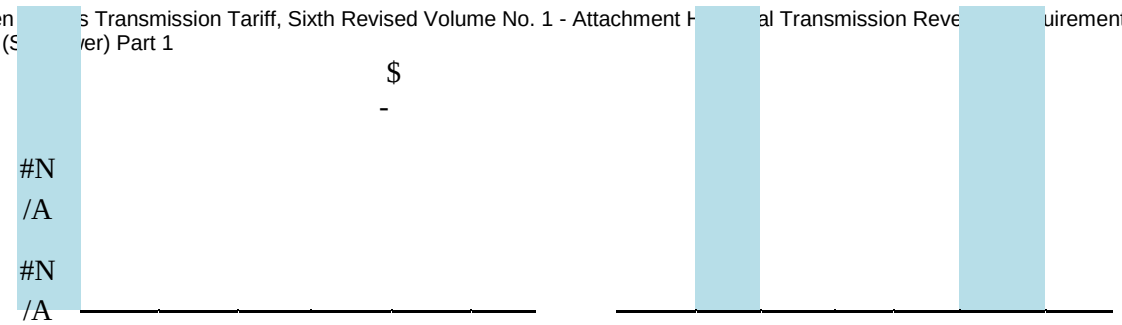
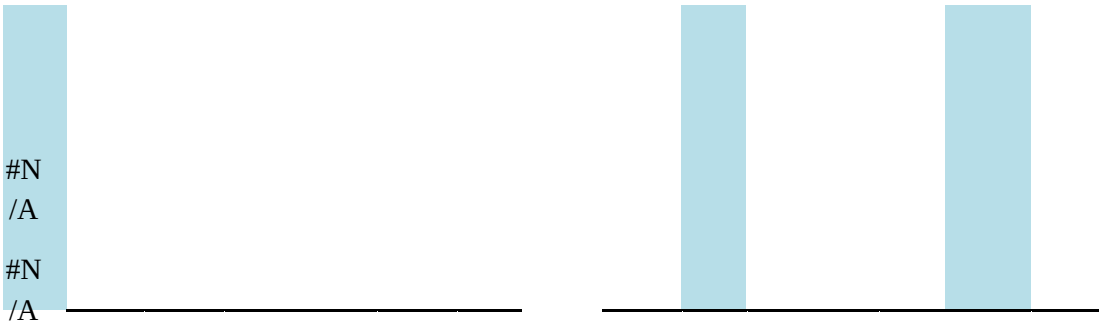
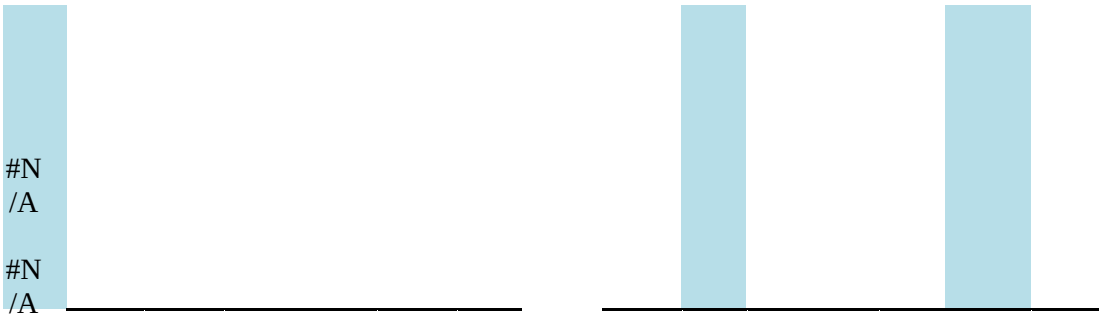


#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #N #N #N
/0! A /A /A /A

#D
IV #N/ #$N #N $ #N
/0! A /A /A - /A



#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #$N #N $ #N
/0! A /A /A - /A



#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #N #N #N
/0! A /A /A /A
#D
IV #N/ #N #N #N
/0! A /A /A /A

#D
IV #N/ #$N #N $ #N
/0! AA /A /A - /A

| | | Description | A-7 Column | A-13 Line No(s) |
|---|---|---|---|---|
| Note A: | For competitively bid projects, data for columns e through l are taken from Worksheet A-13, col. j. | Gross Plant | (e) | L1 |
| | | Net Plant | (f) | L3 |
| | | O&M, A&G Expense | (g) | L10 * L3 |
| | | Other Tax Expense | (h) | L12 * L3 |
| | | General Plant Expense | (i) | L14 * L3 |
| | | Depreciation Expense | (j) | L21 |
| | | Non-Incentive Return | (l) | L8 * L3 |
| Note B: | Reserved for future use. | | | |



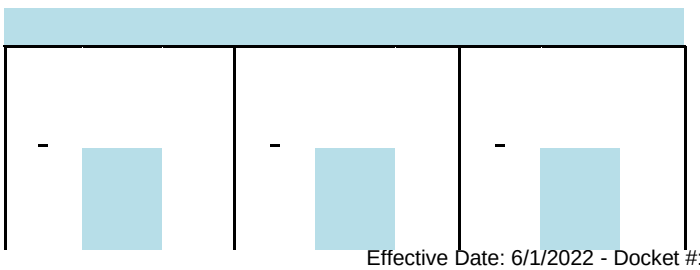


## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects:**

| | Pro | Pro | Pro |
|---|---|---|---|

| **ject** | **ject** | **ject** |
|---|---|---|
| **:** ***1*** | **:** ***2*** | **:** ***3*** |
| SPP Proj. ID | SPP Proj. ID – | SPP Proj. ID |



| | Year | Month | Plant Balance by Month | Depr. Rate / 12 (notes C & D) | Depreciation Expense | Plant Balance by Month | Depr. Rate / 12 (notes C & D) | Depreciation Expense | Plant Balance by Month | Depr. Rate / 12 (notes C & D) | Depreciation Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | Dec | $ | | | $ | | | $ | | |
| 8 | -3 | | - | | | - | | | - | | |
| 7 | | Jan | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 9 | -2 | | - | | | - | | | - | | |
| 8 | | Feb | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 0 | -2 | | - | | | - | | | - | | |
| 8 | | Mar | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 1 | -2 | | - | | | - | | | - | | |
| 8 | | Apr | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 2 | -2 | | - | | | - | | | - | | |
| 8 | | May | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 3 | -2 | | - | | | - | | | - | | |
| 8 | | Jun | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 4 | -2 | | - | | | - | | | - | | |
| 8 | | Jul | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 5 | -2 | | - | | | - | | | - | | |
| 8 | | Aug | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 6 | -2 | | - | | | - | | | - | | |
| 8 | | Sep | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 7 | -2 | | - | | | - | | | - | | |
| 8 | | Oct | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 8 | -2 | | - | | | - | | | - | | |
| 8 | | Nov | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 9 | -2 | | - | | | - | | | - | | |
| 9 | | Dec | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 0 | -2 | | - | | | - | | | - | | |
| | | | | Sum | | | Sum | | | Sum | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 9<br>1 | | | | | line<br>s 79<br>- 90 | #D<br>IV/<br>0! | | line<br>s 79<br>- 90 | #D<br>IV<br>/0! | | line<br>s 79<br>- 90 | #D<br>IV<br>/0! |

| | | | | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Gross Plant** | **Total Accm. Deprec.** | **Net Plant** | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | | **13 Month Averages** | | **13 Month Averages** | | | **13 Month Averages** | | |
| 2010 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2011 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2012 | $ - | $ - | $ - | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2013 | $ - | $ - | $ - | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2014 | $ - | $ - | $ - | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2015 | $ - | $ - | $ - | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2016 | $ - | $ - | $ - | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2017 | $ - | $ - | $ - | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2018 | $ - | $ - | $ - | 2018 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | 19 | - | - | - | 19 | - | - | - | - | - | - | - | - | - | |
| | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | 20 | - | - | - | 20 | - | - | - | - | - | - | - | - | - | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 105 | | | | | | | | | | | | | | |
| 106 | 20 21 | $ - | $ - | $ - | 20 21 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 107 | 20 22 | $ - | $ - | $ - | 20 22 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 108 | 20 23 | $ - | $ - | $ - | 20 23 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 109 | 20 24 | $ - | $ - | $ - | 20 24 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 110 | 20 25 | $ - | $ - | $ - | 20 25 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 111 | 20 26 | $ - | $ - | $ - | 20 26 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 112 | 20 27 | $ - | $ - | $ - | 20 27 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 113 | 20 28 | $ - | $ - | $ - | 20 28 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 114 | 20 29 | $ - | $ - | $ - | 20 29 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 115 | 20 30 | $ - | $ - | $ - | 20 30 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 116 | 20 31 | $ - | $ - | $ - | 20 31 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 117 | 20 32 | $ - | $ - | $ - | 20 32 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | |
|---|---|---|---|---|---|
| Notes: (C) | See WP A-5 (Act Depreciation Rate). | | | | |

(D) This rate will reflect any future FERC approved depreciation rates.

(E) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.

(F) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

(G) Accumulated Depreciation will be brought forward from the prior year for each project.





## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| | | **Project: *4*** | | | **Project: *5*** | | | **Project: *6*** | | | **Project: *7*** | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Year** | **Month** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** |

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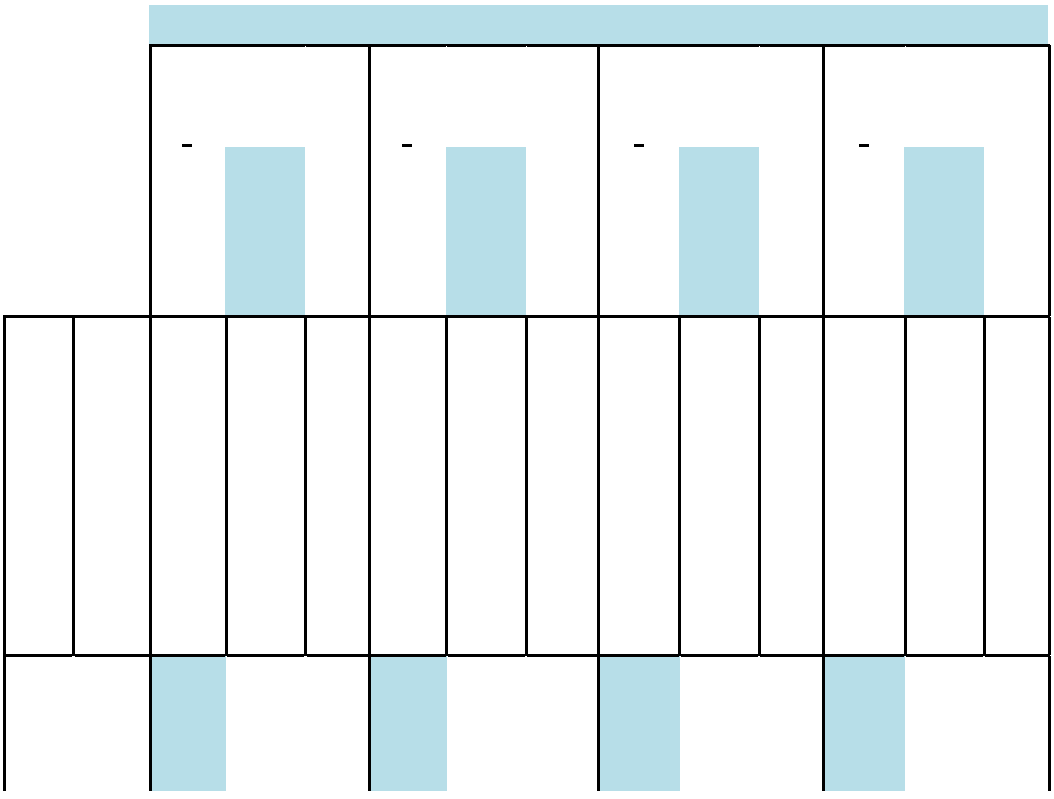

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| 19 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 21 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 22 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 23 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 24 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 25 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 26 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 27 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 28 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 29 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30 | -2 | Dec | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
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| 3 | | - | V/ | | - | IV/ | | - | IV | | - | IV |
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| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
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| | | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | **Year** | | | | | | | | | | | | |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

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| 144 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 145 | 20 | - | - | - | - | - | - | - | - | - | - | - | - |
| 144 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 146 | 21 | - | - | - | - | - | - | - | - | - | - | - | - |
| 144 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 147 | 22 | - | - | - | - | - | - | - | - | - | - | - | - |
| 144 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 148 | 23 | - | - | - | - | - | - | - | - | - | - | - | - |
| 144 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 149 | 24 | - | - | - | - | - | - | - | - | - | - | - | - |
| 150 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 150 | 25 | - | - | - | - | - | - | - | - | - | - | - | - |
| 151 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 151 | 26 | - | - | - | - | - | - | - | - | - | - | - | - |
| 152 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 152 | 27 | - | - | - | - | - | - | - | - | - | - | - | - |
| 153 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 153 | 28 | - | - | - | - | - | - | - | - | - | - | - | - |
| 154 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 154 | 29 | - | - | - | - | - | - | - | - | - | - | - | - |
| 155 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 155 | 30 | - | - | - | - | - | - | - | - | - | - | - | - |
| 156 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 156 | 31 | - | - | - | - | - | - | - | - | - | - | - | - |
| 155 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

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| 7 | 32 | | - | - | - | - | - | - | - | - | - | - | - | - |
| | Notes | See WP A-5 (Act | | | | | | | | | | | | |

: Depreciation Rate).
(C) This rate will reflect any future FERC approved depreciation rates.
(D)
(E) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report. BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F) Accumulated Depreciation will be brought forward from the prior year for each project.
(G)





## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***8*** | | **Project:** | ***9*** | | **Project:** | ***10*** | | **Project:** | ***11*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Balance by** | **Depr. Rate / 12 (notes C** | **Depreciation Expe** | **Plant Balance by** | **Depr. Rate / 12 (notes C** | **Depreciation Ex** | **Plant Balance by** | **Depr. Rate / 12 (notes C** | **Depreciation Expe** | **Plant Balance by** | **Depr. Rate / 12 (notes C** | **Depreciation Expe** |

| | Year | Month | Month & D) | nse | Month & D) | pense | Month & D) | nse | Month & D) | e |
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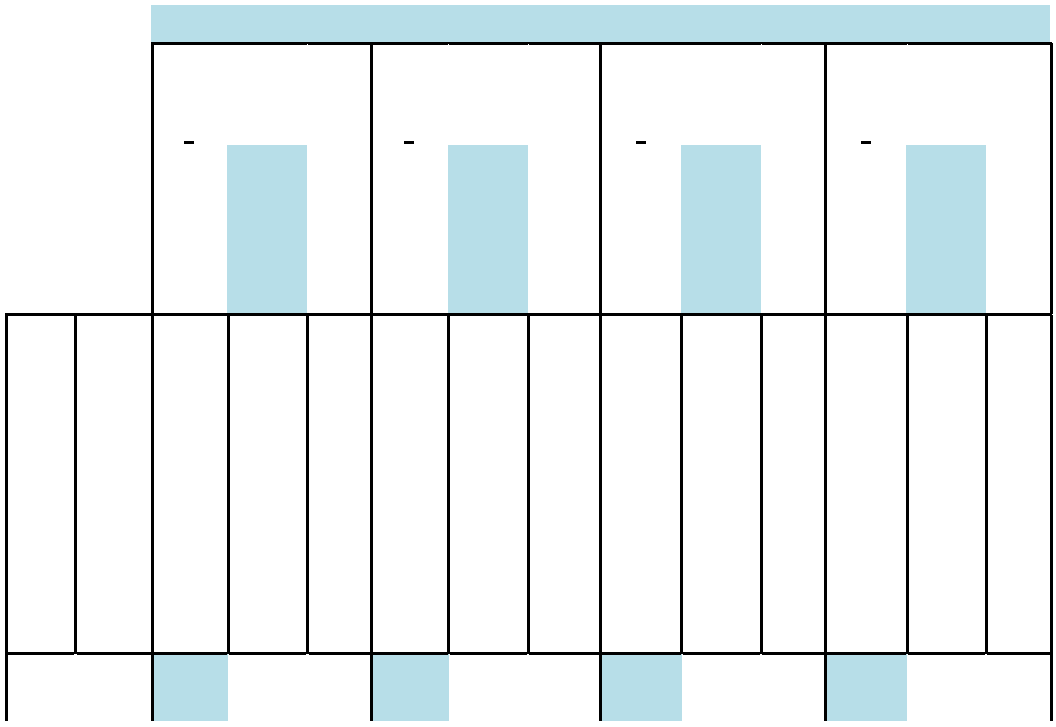
| 1 | -3 | Dec | - | | - | | - | | - | |



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| 7 | -2 | Sep | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! | |
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| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | **Year** | | | | | | | | | | | | |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

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| 187 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 22 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 188 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 23 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 189 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 24 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 190 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 25 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 191 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 26 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 192 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 27 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 193 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| | 28 | | - | - | - | - | - | - | - | - | - | - | - | - |
| 194 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
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| 195 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
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Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D)
(E) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
(F) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(G) Accumulated Depreciation will be brought forward from the prior year for each project.



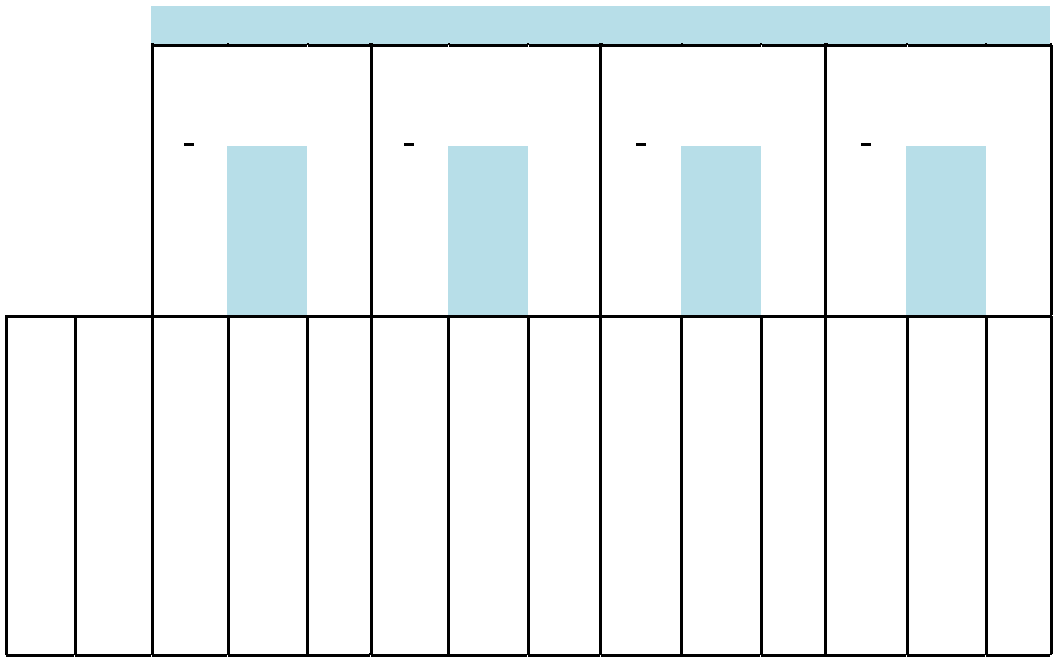


## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***12*** | | **Project:** | ***13*** | | **Project:** | ***14*** | | **Project:** | ***15*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Balanc** | **Depr. Rate / 12 (not** | **Depreciation** | **Plant Balanc** | **Depr. Rate / 12 (not** | **Depreciatio** | **Plant Bal** | **Depr. Rate / 12 (not** | **Depreciation** | **Plant Bal** | **Depr. Rate / 12 (not** | **Depreciation** |

| Year | Month | e by Month | es C & D) | Ex pe ns e | e by Month | es C & D) | n Ex pe nse | anc e by Month | es C & D) | Ex pe ns e | anc e by Month | es C & D) | Ex pe ns e |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

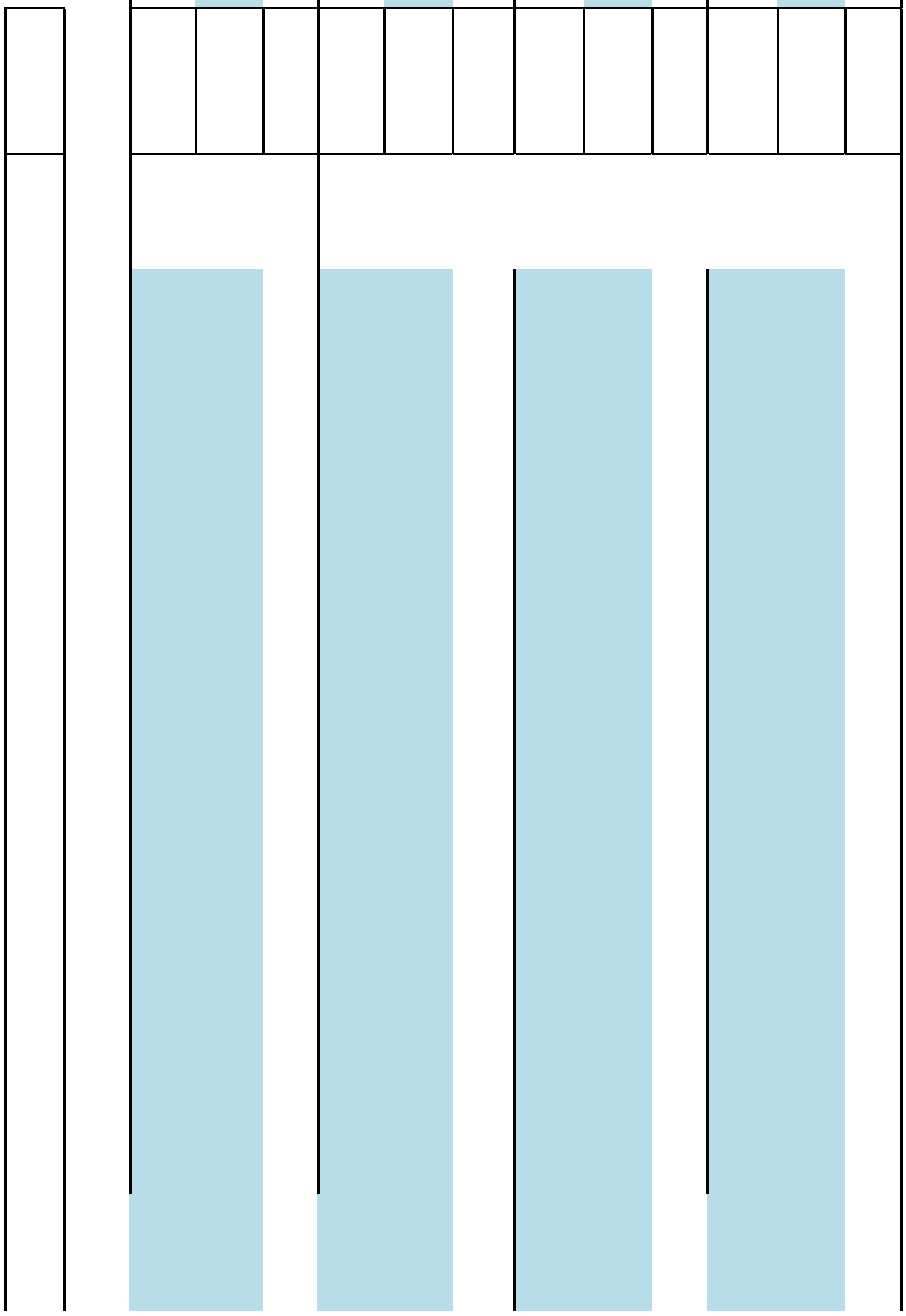


| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | | | $ | | | $ | | | $ | | | $ | | |
| 18 | -3 | Dec | - | | | - | | | - | | | - | | |
| 19 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -1 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -3 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -4 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -5 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -6 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -7 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -8 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | -9 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 21 | | | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 2 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 1 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 199-210-3 EOY Accum. Depr: | | | 199-210-3 EOY Accum. Depr: | | | 199-210-3 EOY Accum. Depr: | | | 199-210-3 EOY Accum. Depr: | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | | | | | | | | | |
| 2 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 224 | 2019 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 225 | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 226 | 2021 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 227 | 2022 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 228 | 2023 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 229 | 2024 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 230 | 2025 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 231 | 2026 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 232 | 2027 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 233 | 2028 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 234 | 2029 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 235 | 2030 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 236 | 2031 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 31 | | - | - | - | | - | - | | - | - | - | | - | - | - | |
| 2 | | | | | | | | | | | | | | | | | |
| 3 | 20 | | $ | $ | $ | | $ | $ | $ | $ | $ | $ | | $ | $ | $ | |
| 7 | 32 | | - | - | - | | - | - | - | - | - | - | | - | - | - | |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
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(E) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F) Accumulated Depreciation will be brought forward from the prior year for each project.
(G)



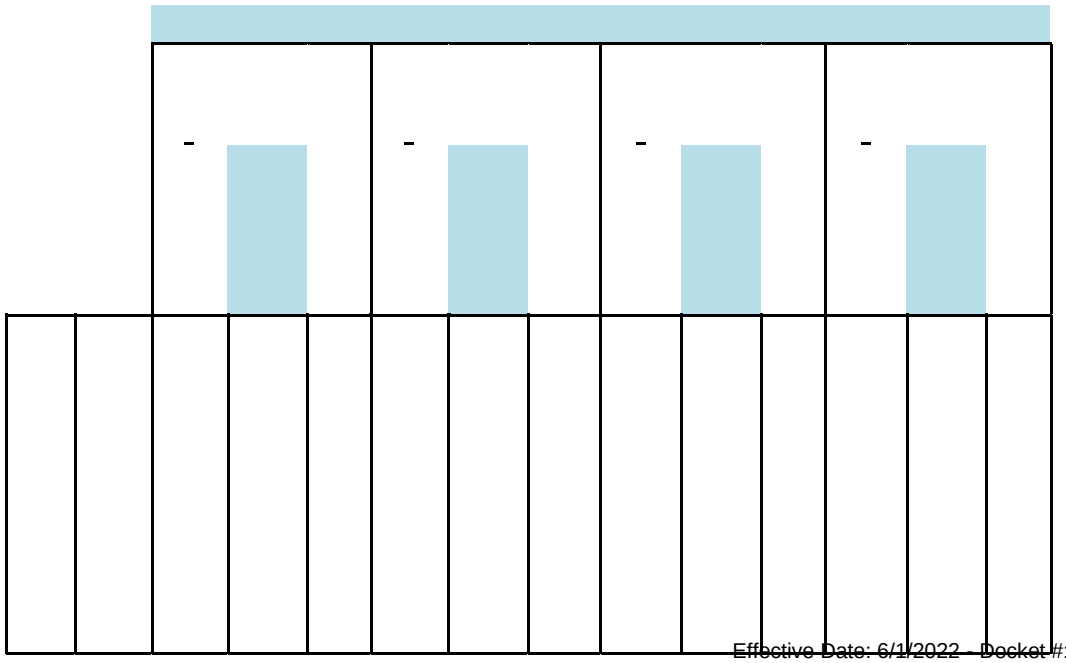


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***16*** | | **Project:** | ***17*** | | **Project:** | ***18*** | | **Project:** | ***19*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia ti** | **Plant Bal** | **Depr. Rate / 12** | **Depreciation** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** |

| Year | Month | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

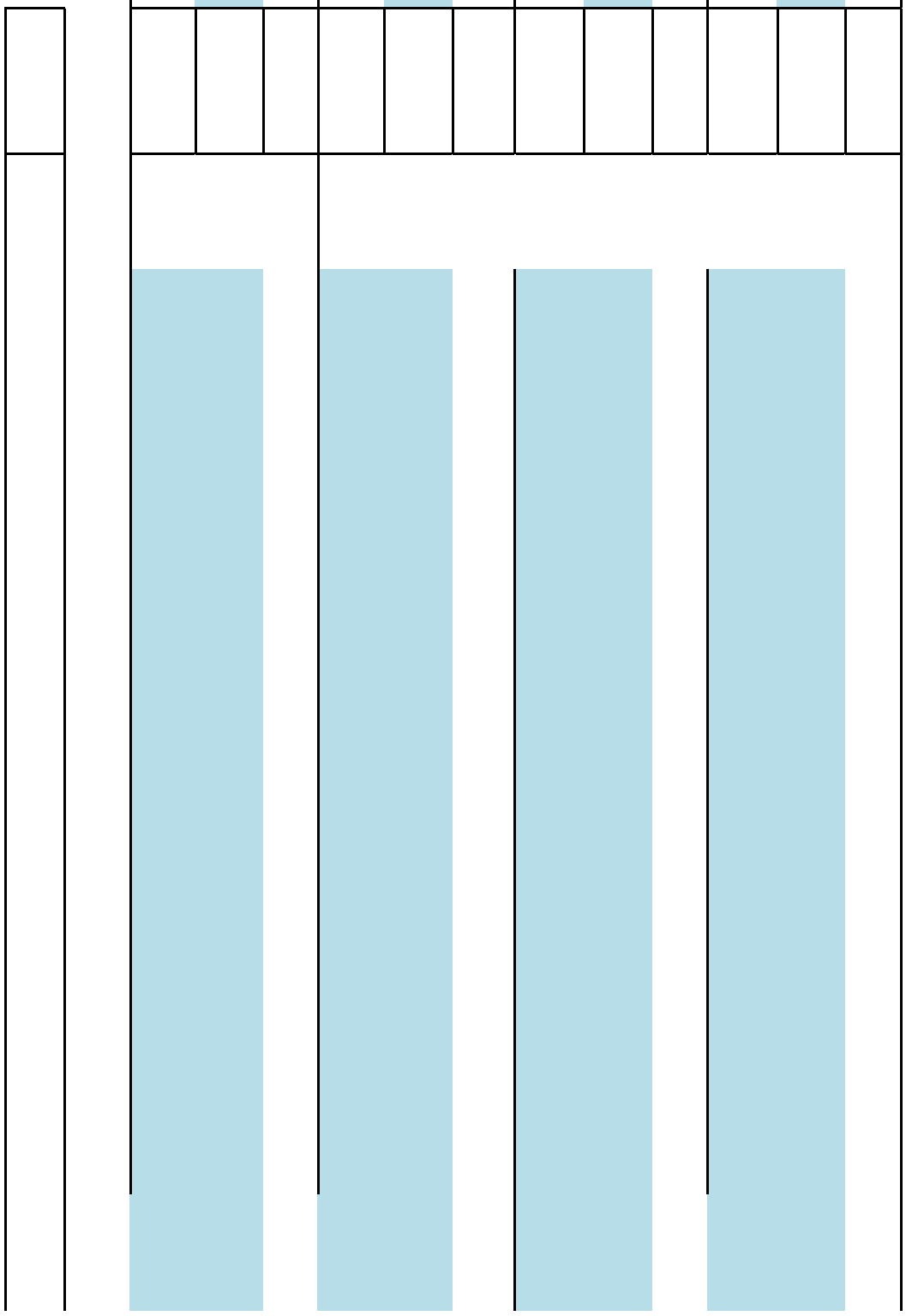


| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 38 | -3 | Dec | | | | | | | | | | | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 39 | -2 | Jan | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 40 | -2 | Feb | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 41 | -2 | Mar | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 42 | -2 | Apr | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 43 | -2 | May | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 44 | -2 | Jun | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 45 | -2 | Jul | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 46 | -2 | Aug | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 47 | -2 | Sep | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 48 | -2 | Oct | $ - | | | $ - | | | $ - | | | $ - | | |
| 24 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 49 | -2 | Nov | $ - | | | $ - | | | $ - | | | $ - | | |
| 25 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 2 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 5 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 239 - 250 | | | 239 - 250 | | | 239 - 250 | | | 239 - 250 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | | - | | | - | | | - | | | - | | |
| | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | | | | | | | | | |
| 6 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 264 | 20<br>19 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 265 | 20<br>20 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 266 | 20<br>21 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 267 | 20<br>22 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 268 | 20<br>23 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 269 | 20<br>24 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 270 | 20<br>25 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 271 | 20<br>26 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 272 | 20<br>27 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 273 | 20<br>28 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 274 | 20<br>29 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 275 | 20<br>30 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | |
| 277 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 31 | | - | - | - | | - | - | | - | - | - | | - | - | - | |
| 2 | | | | | | | | | | | | | | | | | |
| 7 | 20 | | $ | $ | $ | | $ | $ | $ | $ | $ | $ | | $ | $ | $ | |
| 7 | 32 | | - | - | - | | - | - | - | - | - | - | | - | - | - | |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
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(G)



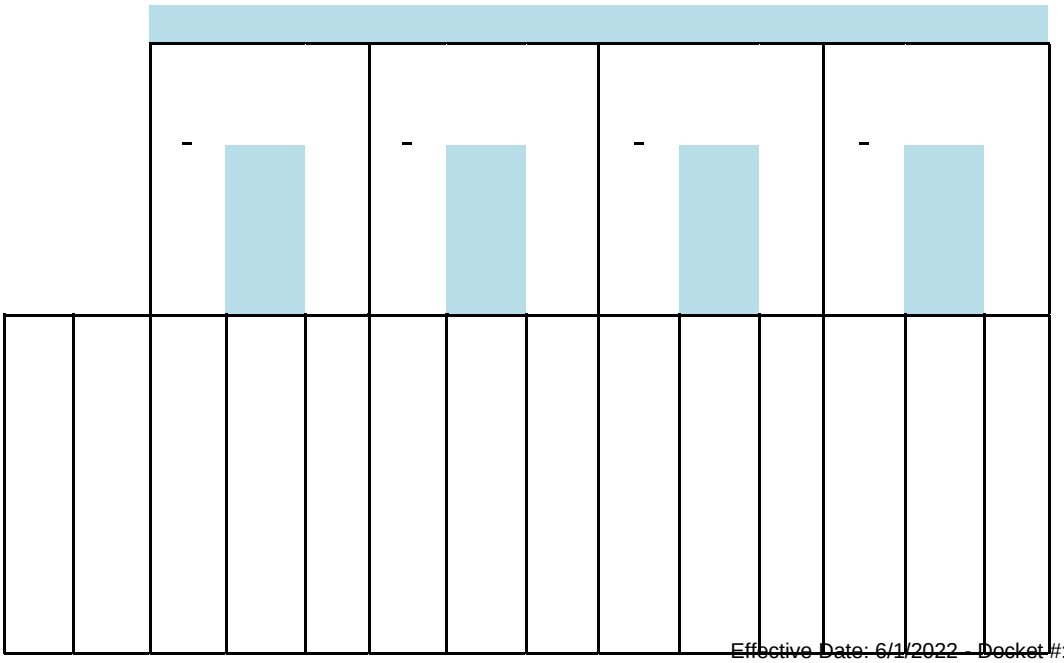


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***20*** | | **Project:** | ***21*** | | **Project:** | ***22*** | | **Project:** | ***23*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia ti** | **Plant Bal** | **Depr. Rate / 12** | **Depreci a** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** |

| Year | Month | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 28 | -3 | Dec | | | | | | | | | | | | |
| 29 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 31 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 32 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 33 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 34 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 35 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 36 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 37 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 38 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 39 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 40 | | | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 2 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 9 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 279-290 | | | 279-290 | | | 279-290 | | | 279-290 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | | - | | | - | | | - | | | - | | |
| | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

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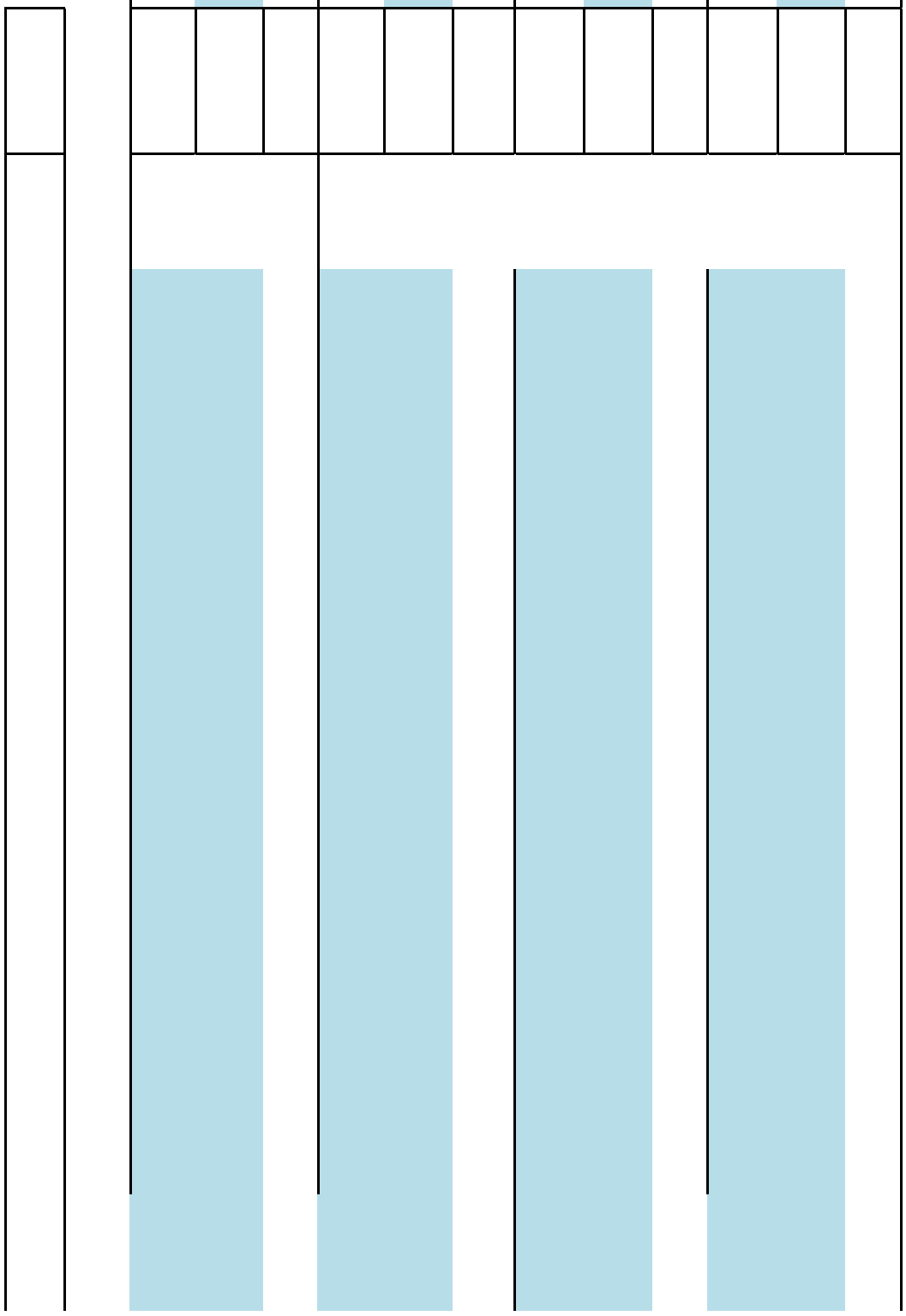
| 3 | | | | | | | | | | | | | | |
| 0 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 304 | 20<br>19 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 305 | 20<br>20 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 306 | 20<br>21 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 307 | 20<br>22 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 308 | 20<br>23 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 309 | 20<br>24 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 310 | 20<br>25 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 311 | 20<br>26 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 312 | 20<br>27 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 313 | 20<br>28 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 314 | 20<br>29 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 315 | 20<br>30 | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- | $<br>- |
| 311 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 31 | | - | - | - | | - | - | | - | - | - | | - | - | - | |
| 3 | | | | | | | | | | | | | | | | | |
| 1 | 20 | | $ | $ | $ | | $ | $ | $ | $ | $ | $ | | $ | $ | $ | |
| 7 | 32 | | - | - | - | | - | - | - | - | - | - | | - | - | - | |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
(E) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F) Accumulated Depreciation will be brought forward from the prior year for each project.
(G)



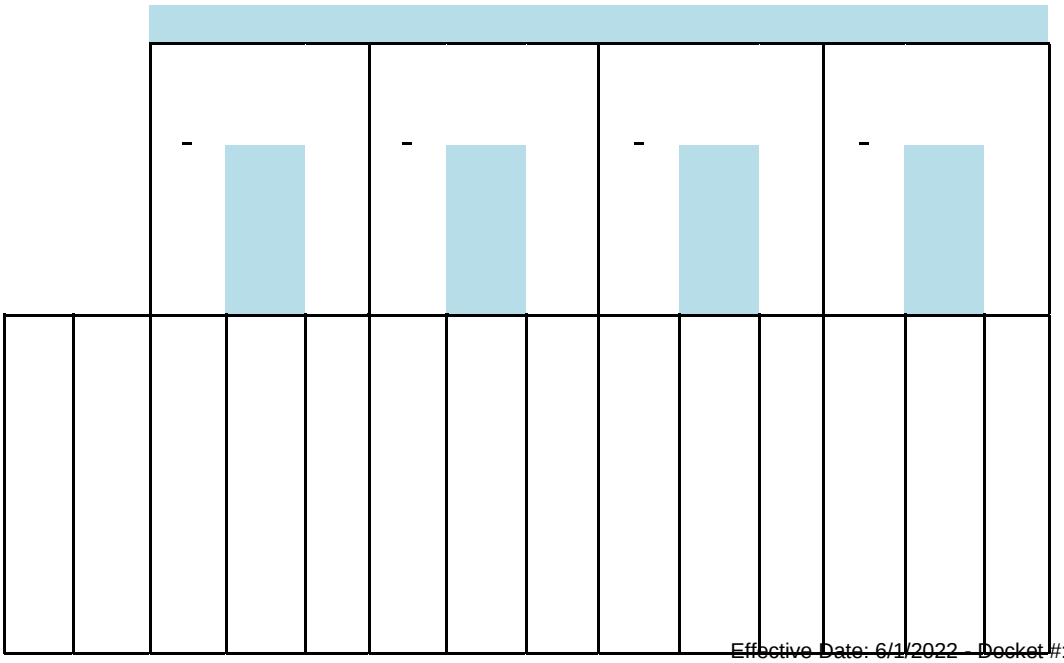


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***24*** | | **Project:** | ***25*** | | **Project:** | ***26*** | | **Project:** | ***27*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia ti** | **Plant Bal** | **Depr. Rate / 12** | **Depreci a** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** |

| Year | Month | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31 | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 38 | -3 | Dec | | | | | | | | | | | | |
| 39 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 40 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 41 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 42 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 43 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 44 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 45 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 46 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 47 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 48 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 49 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 33 | | | $ | #DIV/0 | #DIV/ | $ | #DIV/0 | #DIV/ | $ | #DIV/0 | #DIV | $ | #DIV/0 | #DIV |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 3 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 3 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 319-330-3 | | | 319-330-3 | | | 319-330-3 | | | 319-330-3 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | EOY Accum. Depr: | - | | EOY Accum. Depr: | - | | EOY Accum. Depr: | - | | EOY Accum. Depr: | - | |
| | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

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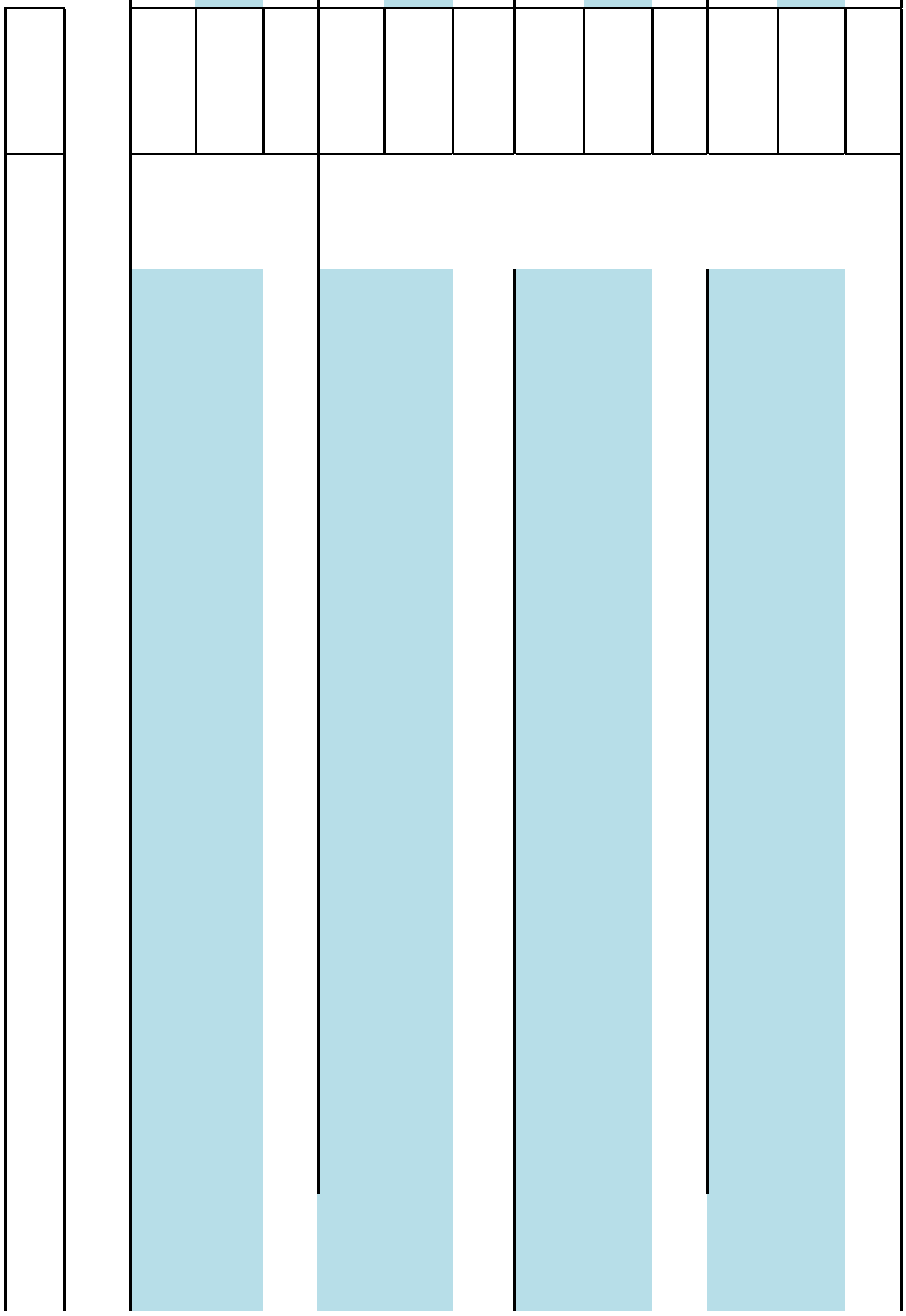
| 3 | | | | | | | | | | | | | | |
| 4 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | 19 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | 20 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 34 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 6 | 21 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 34 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 7 | 22 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 34 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 8 | 23 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 34 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 9 | 24 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 0 | 25 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | 26 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 2 | 27 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 28 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 4 | 29 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 5 | 30 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 35 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

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| 6 | 31 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | | | | | | | | | | | | | | | |
| 5 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | 32 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
(E) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F) Accumulated Depreciation will be brought forward from the prior year for each project.
(G)



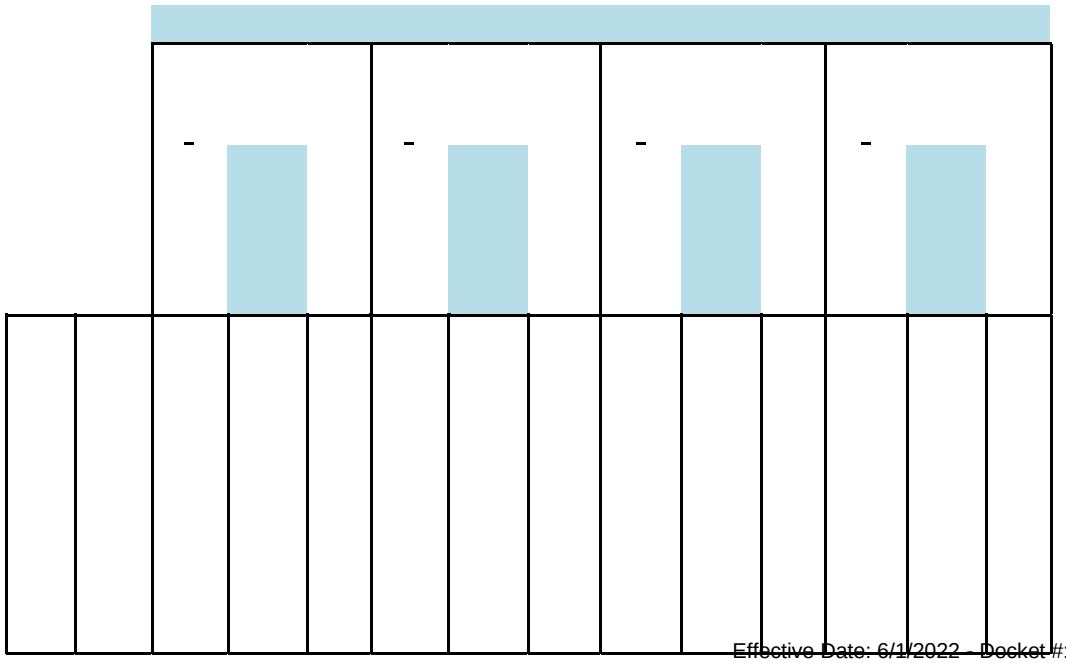


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***28*** | | **Project:** | ***29*** | | **Project:** | ***30*** | | **Project:** | ***31*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia ti** | **Plant Bal** | **Depr. Rate / 12** | **Depreciation** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** |

| Year | Month | Balance by Month | (notes B & C) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 35 | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 38 | -3 | Dec | | | | | | | | | | | | |
| 39 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 40 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 41 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 42 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 43 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 44 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 45 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 46 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 47 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 48 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 49 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 37 | | | $ | #DIV/0 | #DIV/0 | $ | #DIV/0 | #DIV/0 | $ | #DIV/0 | #DIV/0 | $ | #DIV/0 | #DIV/0 |

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| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 3 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 7 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 359 - 370 | | | 359 - 370 | | | 359 - 370 | | | 359 - 370 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

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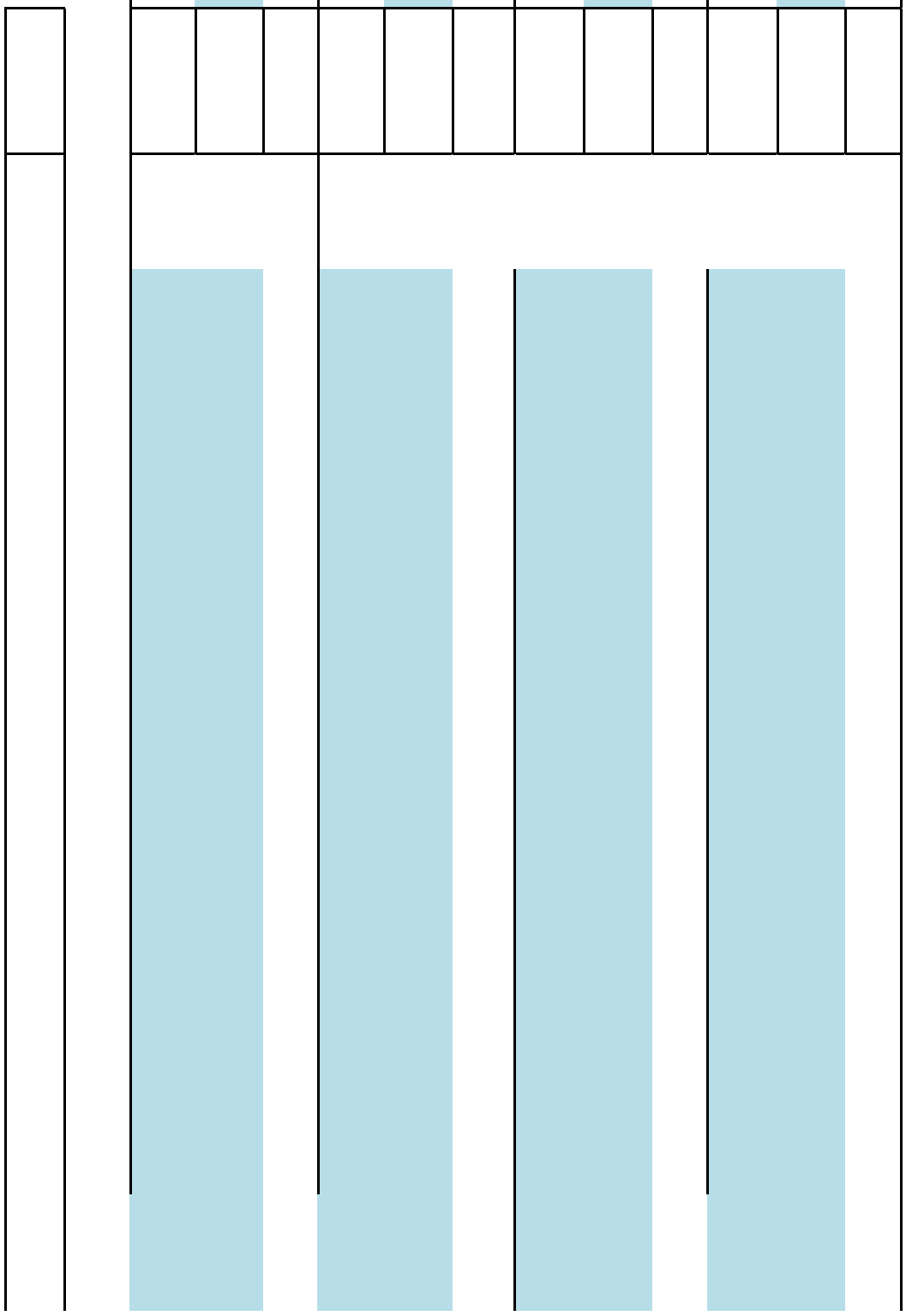
| 3 | | | | | | | | | | | | | | |
| 8 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 384 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 19 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 385 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 20 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 386 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 21 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 387 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 22 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 388 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 23 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 389 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 24 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 390 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 25 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 391 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 26 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 392 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 27 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 393 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 28 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 394 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 29 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 395 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| | 30 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 396 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

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| 6 | 31 | | - | - | - | | - | - | | - | - | - | | - | - | - | |
| 3 | | | | | | | | | | | | | | | | | |
| 9 | 20 | | $ | $ | $ | | $ | $ | $ | $ | $ | $ | | $ | $ | $ | |
| 7 | 32 | | - | - | - | | - | - | - | - | - | - | | - | - | - | |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
(E) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F) Accumulated Depreciation will be brought forward from the prior year for each project.
(G)



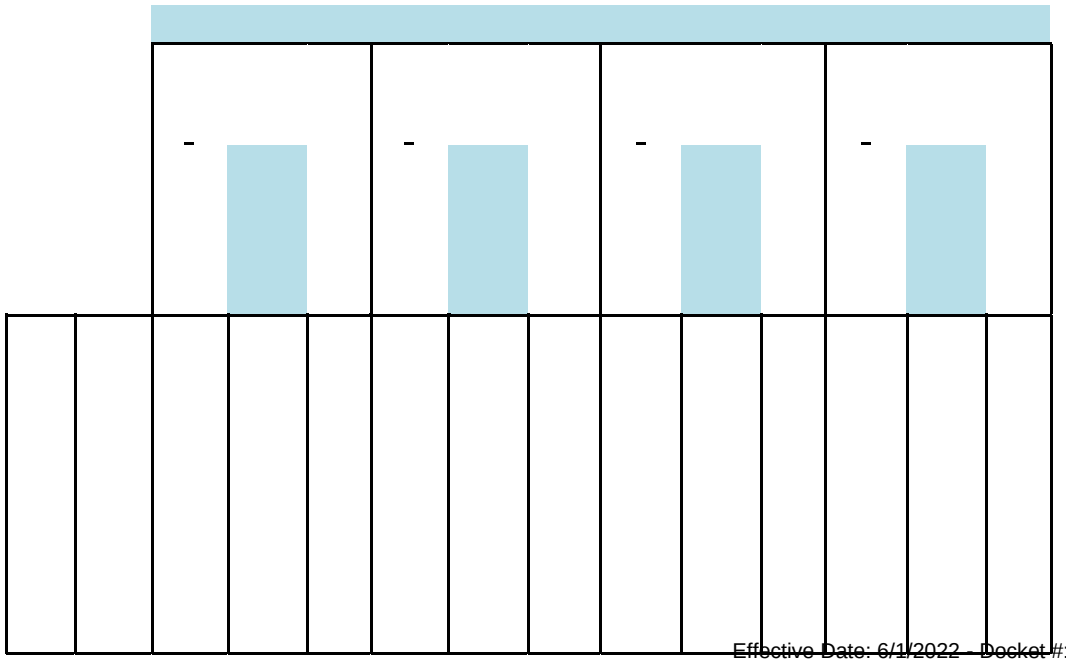


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***32*** | | **Project:** | ***33*** | | **Project:** | ***34*** | | **Project:** | ***35*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia ti** | **Plant Bal** | **Depr. Rate / 12** | **Depreciation** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** |

| Year | Month | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 39 | | | $ - | | | $ - | | | $ - | | | $ - | | |
| 38 | -3 | Dec | | | | | | | | | | | | |
| 39 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 40 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 41 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 42 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 43 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 44 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 45 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 46 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 47 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 48 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 49 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 41 | | | $ | #DIV/0 | #DIV/ | $ | #DIV/0 | #DIV/ | $ | #DIV/0 | #DIV | $ | #DIV/0 | #DIV |

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| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 4 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 1 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 399 - 410 | | | 399 - 410 | | | 399 - 410 | | | 399 - 410 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | | - | | | - | | | - | | | - | | |
| | | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | **Year** | | | | | | | | | | | | |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2010 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | - | - | - | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | - | - | - | - | - | - | - | - | - | - | - | - |

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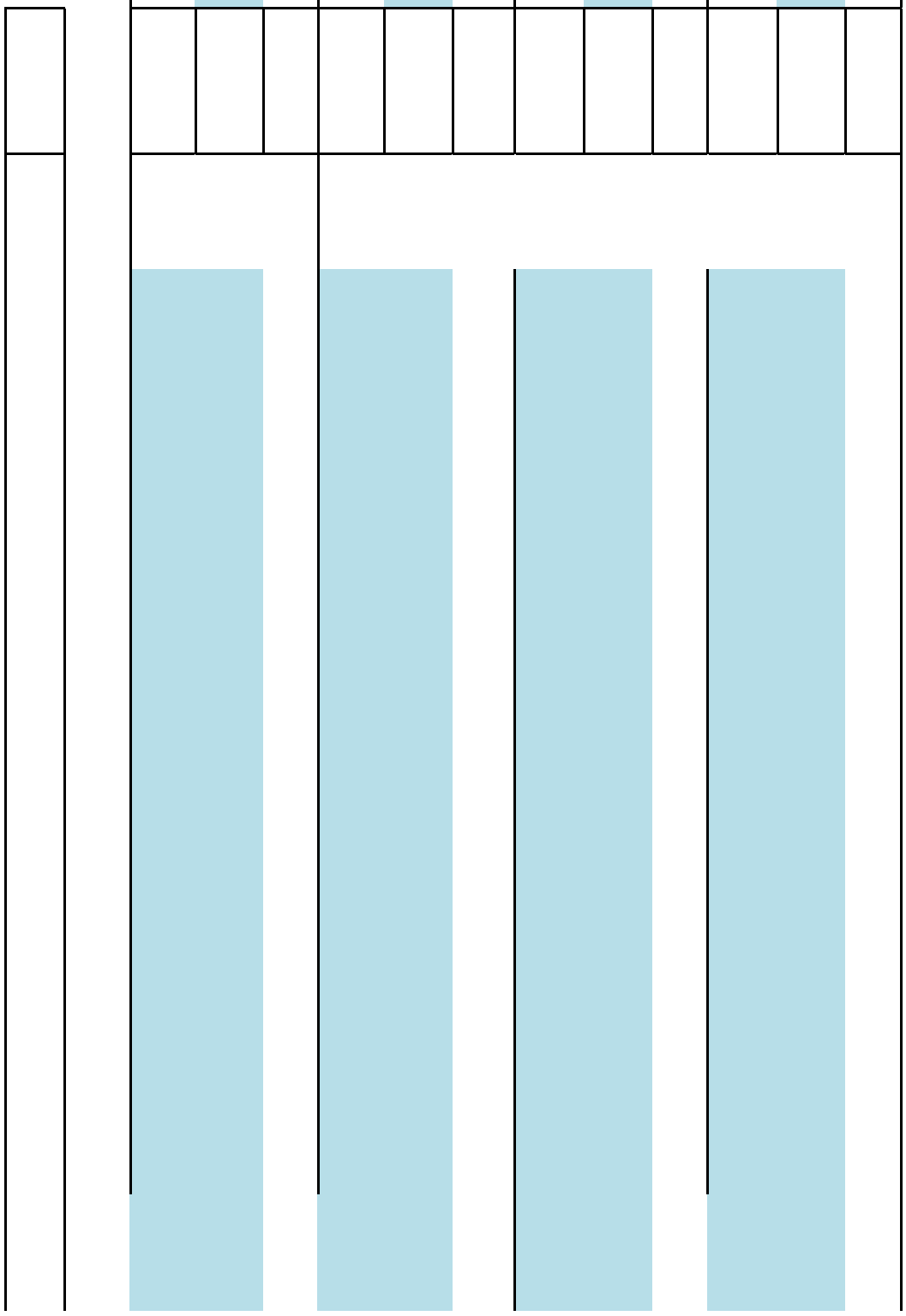
| 4 | | | | | | | | | | | | | | |
| 2 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 42 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 43 | 19 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 42 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 45 | 20 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 42 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 46 | 21 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 42 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 47 | 22 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 42 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 48 | 23 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 42 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 49 | 24 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 50 | 25 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 51 | 26 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 52 | 27 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 53 | 28 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 54 | 29 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 55 | 30 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 43 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 31 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | | | | | | | | | | | | | | | | | |
| 3 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | 32 | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
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(G)





# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***36*** | | **Project:** | ***37*** | | **Project:** | ***38*** | | **Project:** | ***39*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia ti** | **Plant Bal** | **Depr. Rate / 12** | **Depreci a** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** | **Plant** | **Depr. Rate / 12** | **Deprecia ti** |

| Year | Month | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
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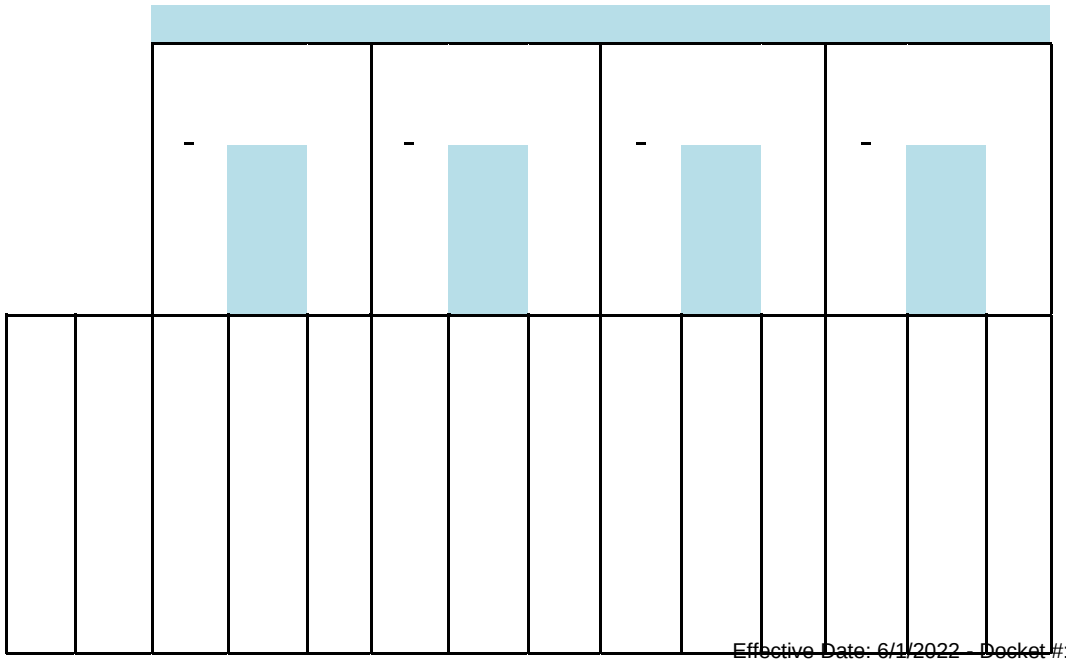

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| 43 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 38 | -3 | Dec | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 39 | -2 | Jan | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 40 | -2 | Feb | | | | | | | | | | | | |
| 44 | | Mar | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 41 | -2 | | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 42 | -2 | Apr | | | | | | | | | | | | |
| 44 | | May | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 43 | -2 | | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 44 | -2 | Jun | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 45 | -2 | Jul | | | | | | | | | | | | |
| 44 | | Aug | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 46 | -2 | | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 47 | -2 | Sep | | | | | | | | | | | | |
| 44 | | | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 48 | -2 | Oct | | | | | | | | | | | | |
| 44 | | Nov | $ - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | $ #DIV/0! | - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 49 | -2 | | | | | | | | | | | | | |
| 44 | | | $ | #DIV/0! | $ #DIV/0! | | #DIV/0! | $ #DIV/0! | | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |
| 45 | | | | | | | | | | | | | | |

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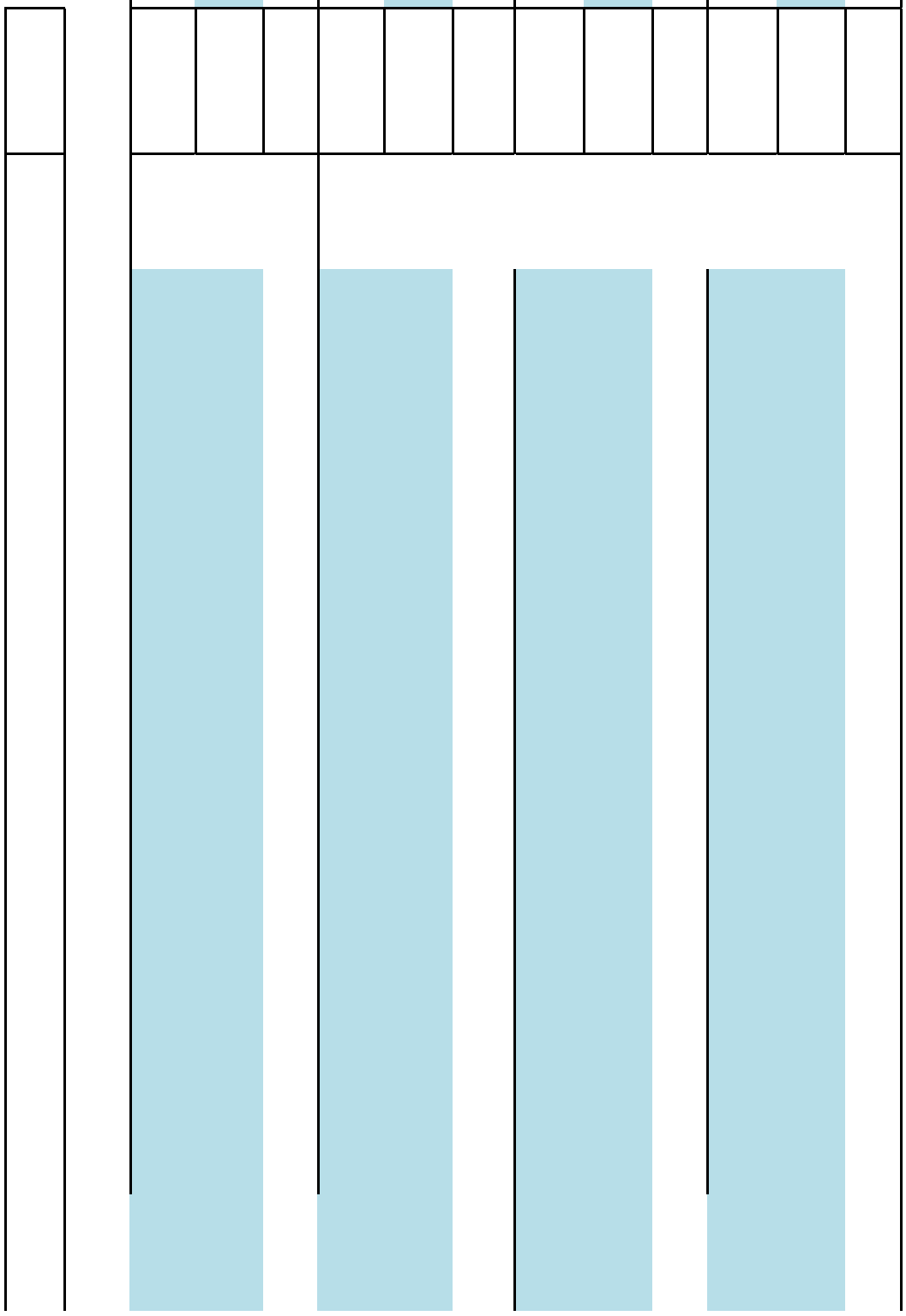
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 4 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 5 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 439 - 450 | | | 439 - 450 | | | 439 - 450 | | | 439 - 450 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | | - | | | - | | | - | | | - | | |
| | | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | **Year** | | | | | | | | | | | | |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | | | | | | | | | | | | | |
| 6 | 20 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | 18 | | - | - | - | - | - | - | - | - | - | - | - | - |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 46 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 47 | 19 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 46 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 50 | 20 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 46 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 61 | 21 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 46 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 72 | 22 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 46 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 83 | 23 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 46 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 94 | 24 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 05 | 25 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 16 | 26 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 27 | 27 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 38 | 28 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 49 | 29 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 50 | 30 | - | - | - | - | - | - | - | - | - | - | - | - | |
| 47 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 31 | | - | - | - | | - | - | - | | - | - | - | | - | - | - |
| 4 | | | | | | | | | | | | | | | | | |
| 7 | 20 | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 7 | 32 | | - | - | - | | - | - | - | | - | - | - | | - | - | - |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
(E) BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F) Accumulated Depreciation will be brought forward from the prior year for each project.
(G)



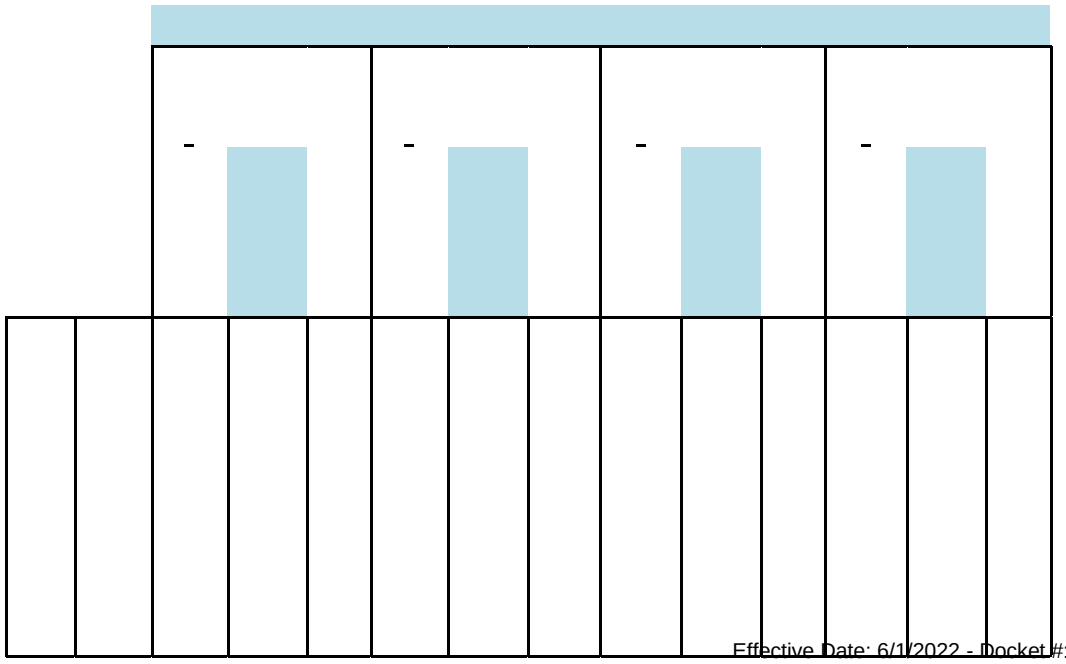


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**II. Calculation of Net Plant for *Sunflower Owned* Base Plan Funded Projects (cont'd):**

| **Project:** | ***36*** | | **Project:** | ***37*** | | **Project:** | ***38*** | | **Project:** | ***39*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| **Plant Bal** | **Depr. Rate / 12** | **Deprecia** | **Plant Bal** | **Depr. Rate / 12** | **Depreciat** | **Plant** | **Depr. Rate / 12** | **Deprecia** | **Plant** | **Depr. Rate / 12** | **Deprecia** |

| Year | Month | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | tion Expense | Balance by Month | (notes C & D) | on Expense | Balance by Month | (notes C & D) | on Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

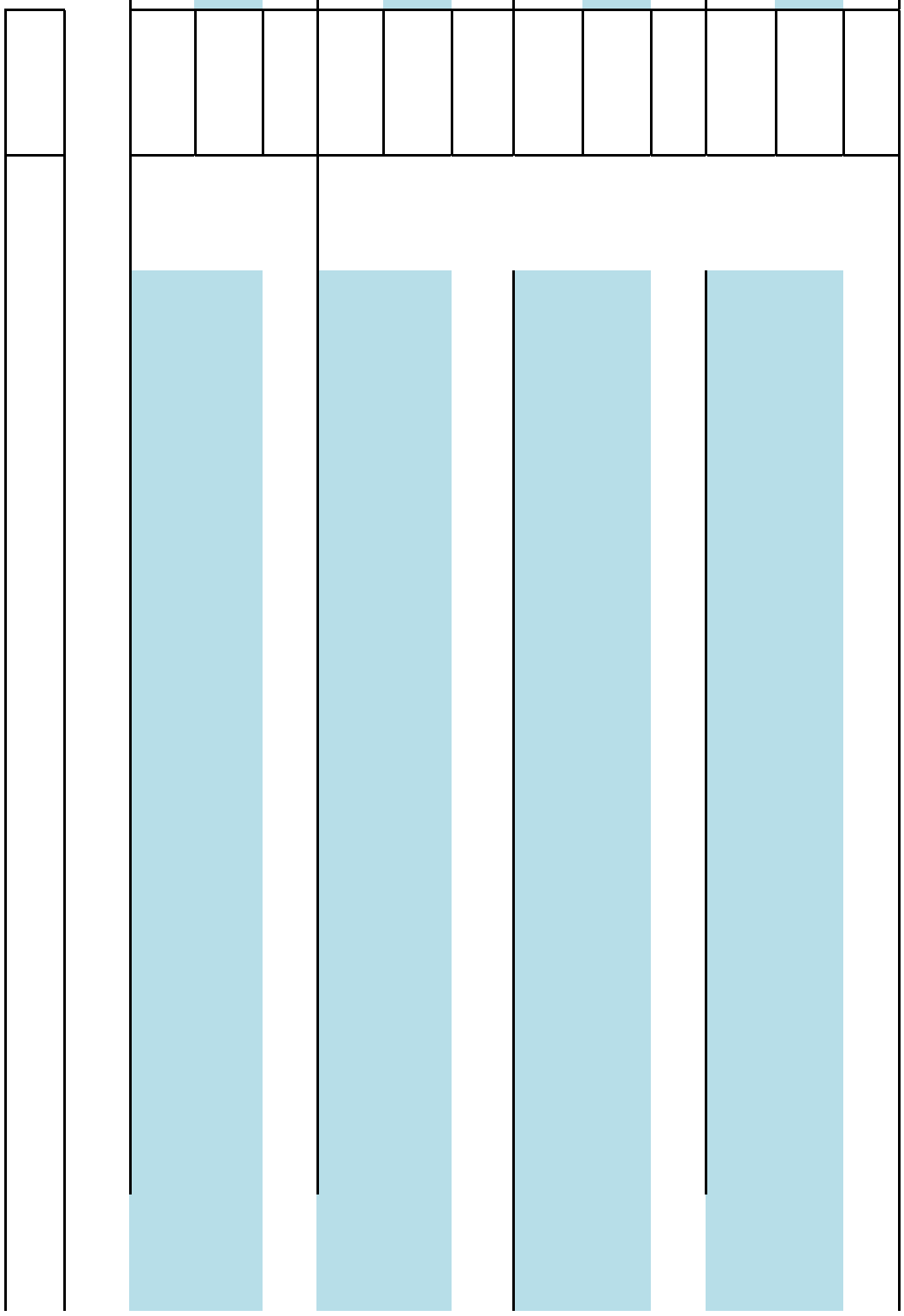


| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 47 | | | $ - | | | $ - | | | $ - | | | $ - | | | |
| 48 | -3 | Dec | | | | | | | | | | | | | |
| 49 | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 50 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 51 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 52 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 53 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 54 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 55 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 56 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 57 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 58 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 59 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | -2 | Dec | - | ! | 0! | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | Su | # | | Su | | | Su | | | Su | |
| 4 | | | | m | DI | | m | #D | | m | #D | | m | #D |
| 9 | | | | line | V/ | | line | IV/ | | line | IV | | line | IV |
| 1 | | | | s | 0! | | s | 0! | | s | /0! | | s | /0! |

| | | 479 - 490 | | | 479 - 490 | | | 479 - 490 | | | 479 - 490 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | | -3 EOY Accum. Depr: | | |
| | | - | | | - | | | - | | | - | | |
| | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | | | | | | |
| 0 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 3 | 18 | - | - | - | - | - | - | - | - | - | - | - | - | |



| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 504 | 19 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 505 | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 506 | 21 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 507 | 22 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 508 | 23 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 509 | 24 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 510 | 25 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 511 | 26 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 512 | 27 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 513 | 28 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 514 | 29 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 515 | 30 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 511 | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 31 | | - | - | - | | - | - | | - | | - | | - | - | | - |
| 5 | | | | | | | | | | | | | | | | | |
| 1 | 20 | | $ | $ | $ | | $ | $ | | $ | | $ | | $ | $ | | $ |
| 7 | 32 | | - | - | - | | - | - | | - | | - | | - | - | | - |

Notes:
(C) See WP A-5 (Act Depreciation Rate). This rate will reflect any future FERC approved depreciation rates.
(D)
(E) BPF projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.
BPF projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.
(F)
Accumulated Depreciation will be brought forward from the prior year for each project.
(G)



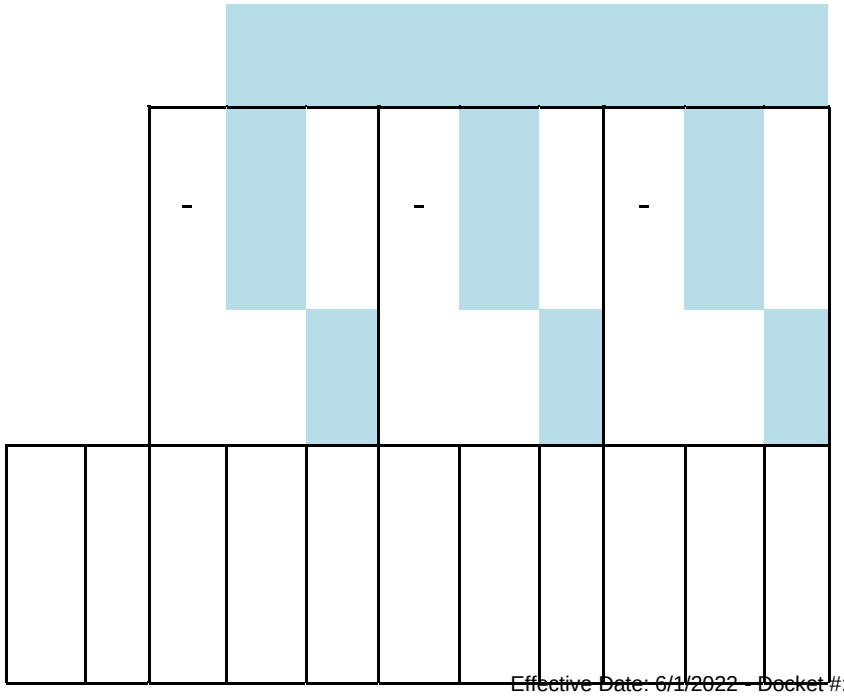


# Sunflower Electric Power Corporation (SEPC)
# Actual RTO Directed Transmission Projects
# For the 12 months ended - December 31, -2

**III. Calculation of Net Plant for *Capital Lease* Base Plan Funded (BPF) Projects:**

| *Description* | | *Description* | | *Description* | |
|---|---|---|---|---|---|
| **Project: *1*** | | **Project: *2*** | | **Project: *3*** | |
| SPP Proj. ID | | SPP Proj. ID | | SPP Proj. ID | |
| Sum of monthly lease payments | $ - | Sum of monthly lease payments | $ - | Sum of monthly lease payments | |
| **Plant** | **Equiv** | **Plant** | **Equ** | **Plant** | **Equ** |

| Year | Month | nt Balance by | Annual Rate | alent Amorti | Balance by Month | Annual Rate | iv alent Am | Balance by Month | Annual Rate | iv alent Am |
|---|---|---|---|---|---|---|---|---|---|---|



| | | | **Month** | | **zation Expense** | | **ortization Expense** | | **ortization Expense** |
|---|---|---|---|---|---|---|---|---|---|
| 158 | -3 | Dec | $ - | | $ - | | $ - | | |
| 159 | -2 | Jan | $ - | 7.15% | $ - | $ - | $ - | $ - | $ - |
| 160 | -2 | Feb | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 161 | -2 | Mar | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 162 | -2 | Apr | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 163 | -2 | May | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 164 | -2 | Jun | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 165 | -2 | Jul | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 166 | -2 | Aug | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 167 | -2 | Sep | $ - | 7.15% | $ - | $ - | 0.00% $ - | $ - | 0.00% $ - |
| 168 | | Oct | $ | 7.15 | $ | $ | 0.00 $ | $ | 0.00 $ |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | -2 | t | - | 5% | - | - | 0% | - | - | 0% | - |
| 1 | | | | | | | | | | | |
| 6 | | N | $ | 7.1 | $ | $ | 0.0 | $ | $ | 0.0 | $ |
| 9 | -2 | ov | - | 5% | - | - | 0% | - | - | 0% | - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 170 | | | | -2 | Dec | $ - | 7.15% Sum lines 159 - 170 | $ - | $ - | 0.00% Sum lines 159 - 170 | $ - | $ - | 0.00% Sum lines 159 - 170 | $ - |
| 172 | | | **Total** | | | -3 EOY Accum. Amort: | - | | -3 EOY Accum. Amort: | - | | -3 EOY Accum. Amort: | - | |
| 173 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| 174 | | **13 Month Averages** | | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| 175 | 2010 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 176 | 2011 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 177 | 2012 | $ - | $ - | $ - | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 178 | 2013 | $ - | $ - | $ - | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 179 | 2014 | $ - | $ - | $ - | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 180 | 2015 | $ - | $ - | $ - | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | | | | |
| 8 | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | |
| 1 | 16 | - | - | - | 16 | - | - | - | - | - | - | - | - | - | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 182 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 183 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 184 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 185 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 186 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 187 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 188 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 189 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 190 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 191 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 192 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 193 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 194 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 195 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | 29 | - | - | - | 29 | - | - | - | - | - | - | - | - | - | | |
| 1 | | | | | | | | | | | | | | | | |
| 9 | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ | $ | | |
| 5 | 30 | - | - | - | 30 | - | - | - | - | - | - | - | - | - | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 196 | 2031 | $ - | $ - | $ - | 2031 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 197 | 2032 | $ - | $ - | $ - | 2032 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |



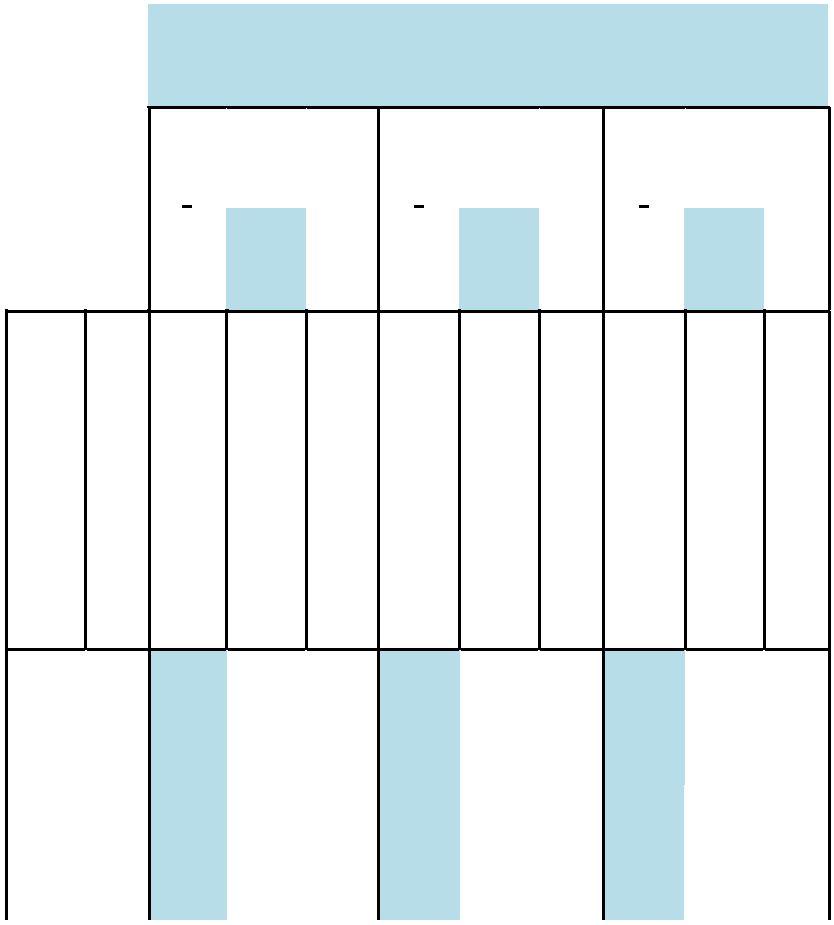


## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

| **V. Calculation of Net Plant for Balanced Portfolio (BP) Projects :** | | | *Description* **Project: SPP Proj. ID** | ***7*** | | *Description* **Project: SPP Proj. ID** | ***8*** | | *Description* **Project: SPP Proj. ID** | ***9*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Month** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** |
| 198 | -3 | Dec | $ - | | | $ - | | | $ - | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1999 | | -2 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |

-



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2020 | -2 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2021 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2022 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2023 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2024 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2025 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2026 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2027 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2028 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2029 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 2030 | -2 | Dec | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| | | | | Sum lines | | | Sum lines | | | Sum lines | | |
| 2031 | | | | 199-210 | #DIV/0! | | 199-210 | #DIV/0! | | 199-210 | #DIV/0! | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 2 | | | -3 EOY Accum. | - | -3 EOY Accum. | - | -3 EOY Accum. | - | |
| 1 | | | | | | | | | |
| 2 | **Total** | | | | | | | | |

| | | | | | | Depr: | | | | | | Depr: | | | | Depr: | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 213 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| 214 | | **13 Month Averages** | | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| 215 | 2010 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 216 | 2011 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 217 | 2012 | $ - | $ - | $ - | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 218 | 2013 | $ - | $ - | $ - | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 219 | 2014 | $ - | $ - | $ - | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 220 | 2015 | $ - | $ - | $ - | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 221 | 2016 | $ - | $ - | $ - | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 222 | 2017 | $ - | $ - | $ - | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 223 | 2018 | $ - | $ - | $ - | 2018 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 224 | 2019 | $ - | $ - | $ - | 2019 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | | | | | | | | |
| 2 | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | 20 | - | - | - | 20 | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 26 | 20 | 21 | $ - | $ - | $ - | 20 | 21 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 27 | 20 | 22 | $ - | $ - | $ - | 20 | 22 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | 20 | 23 | $ - | $ - | $ - | 20 | 23 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 29 | 20 | 24 | $ - | $ - | $ - | 20 | 24 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | 20 | 25 | $ - | $ - | $ - | 20 | 25 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | 20 | 26 | $ - | $ - | $ - | 20 | 26 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | 20 | 27 | $ - | $ - | $ - | 20 | 27 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | 20 | 28 | $ - | $ - | $ - | 20 | 28 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 34 | 20 | 29 | $ - | $ - | $ - | 20 | 29 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 35 | 20 | 30 | $ - | $ - | $ - | 20 | 30 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 36 | 20 | 31 | $ - | $ - | $ - | 20 | 31 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 37 | 20 | 32 | $ - | $ - | $ - | 20 | 32 | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | |
|---|---|
| Notes | See WP A-5 (Act |

| | | | |
|---|---|---|---|
| : (C) (D) | Depreciation Rate). This rate will reflect any future FERC | | |

approved depreciation rates.

(E) BP projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.

(F) BP projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

(G) Accumulated Depreciation will be brought forward from the prior year for each project.

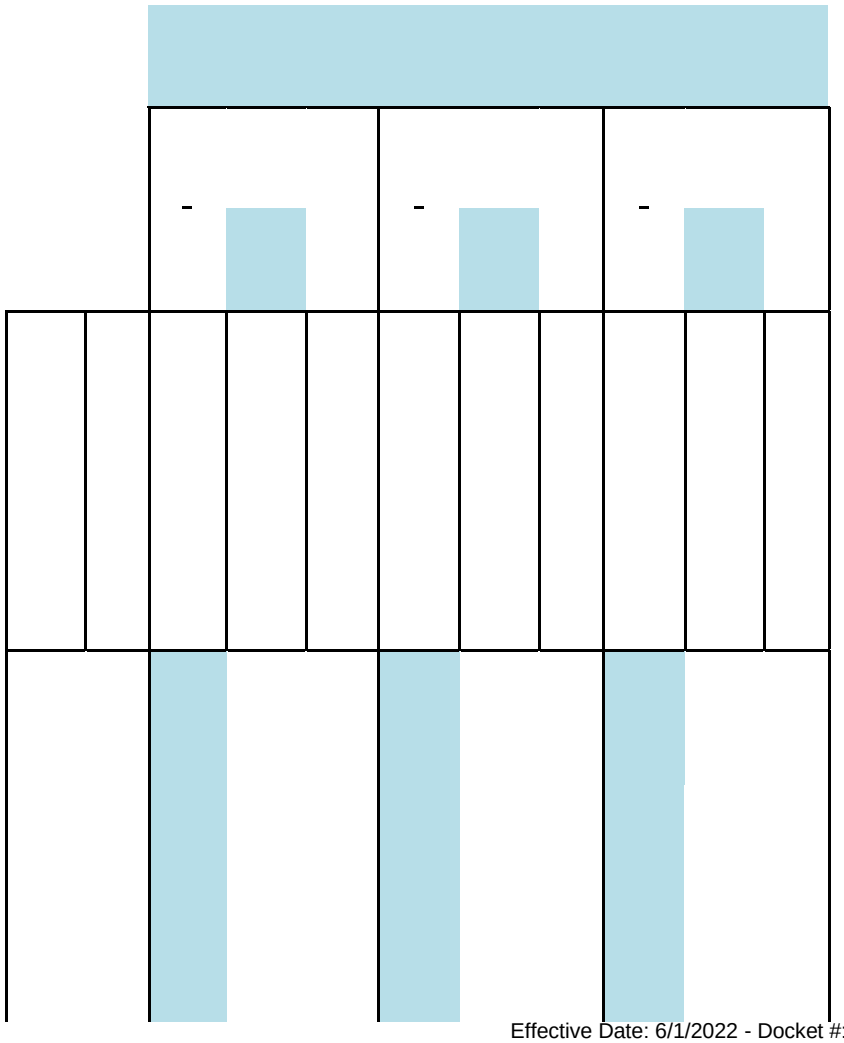




## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

| **VI. Calculation of Net Plant for ITP / Priority 1 Projects** | | | *Description* **Project: SPP Proj. ID** | ***1*** | | *Description* **Project: SPP Proj. ID** | ***2*** | | *Description* **Project: SPP Proj. ID** | ***3*** | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Month** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** |
| 23 | | Dec | $ - | | | $ - | | | $ - | | |
| 28 | -3 | | | #DI | #D | | #DI | #D | | #DI | #D |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | Ja | $ | V/0 | IV/ | $ | V/0 | IV | $ | V/0 | IV |
| 9 | -2 | n | - | ! | 0! | - | ! | /0! | - | ! | /0! |
| | | | | #DI | #D | | #DI | #D | | #DI | #D |
| | | Fe | $ | V/0 | IV/ | $ | V/0 | IV | $ | V/0 | IV |
| 2 | -2 | b | - | ! | 0! | - | ! | /0! | - | ! | /0! |



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 40 | | | | | | | | | | | | |
| 241 | -2 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 242 | -2 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 243 | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 244 | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 245 | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 246 | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 247 | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 248 | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 249 | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 250 | -2 | Dec | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| | | | | Sum lines | | | Sum lines | | | Sum lines | | |
| 251 | | | | 239-250 | #DIV/0! | | 239-250 | #DIV/0! | | 239-250 | #DIV/0! | |
| | | | -3 EO | | | -3 EO | | | -3 EO | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 252 | **Total** | | Y Accum. Depr: | - | Y Accum. Depr: | - | Y Accum. Depr: | - | | |

| | Year | Gross Plant | Accm. Deprec. | Net Plant | Year | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **13 Month Averages** | | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2010 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2011 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2012 | $ - | $ - | $ - | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2013 | $ - | $ - | $ - | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2014 | $ - | $ - | $ - | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2015 | $ - | $ - | $ - | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2016 | $ - | $ - | $ - | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2017 | $ - | $ - | $ - | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2018 | $ - | $ - | $ - | 2018 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | 2019 | $ - | $ - | $ - | 2019 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | 20 | - | - | - | 20 | - | - | - | - | - | - | - | - |
| | 20 | $ | $ | $ | 20 | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | 21 | - | - | - | 21 | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 66 | | | | | | | | | | | | | | |
| 267 | 2022 | $ - | $ - | $ - | 2022 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 268 | 2023 | $ - | $ - | $ - | 2023 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 269 | 2024 | $ - | $ - | $ - | 2024 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 270 | 2025 | $ - | $ - | $ - | 2025 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 271 | 2026 | $ - | $ - | $ - | 2026 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 272 | 2027 | $ - | $ - | $ - | 2027 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 273 | 2028 | $ - | $ - | $ - | 2028 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 274 | 2029 | $ - | $ - | $ - | 2029 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 275 | 2030 | $ - | $ - | $ - | 2030 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 276 | 2031 | $ - | $ - | $ - | 2031 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 277 | 2032 | $ - | $ - | $ - | 2032 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Notes: (C) See WP A-5 (Act Depreciation Rate).

| | | | |
|---|---|---|---|
| (D) | This rate will reflect any future FERC approved depreciation rates. | | |

(E) ITP/Priority 1 projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.

(F) ITP/Priority 1 Project with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

(G) Accumulated Depreciation will be brought forward from the prior year for each project.



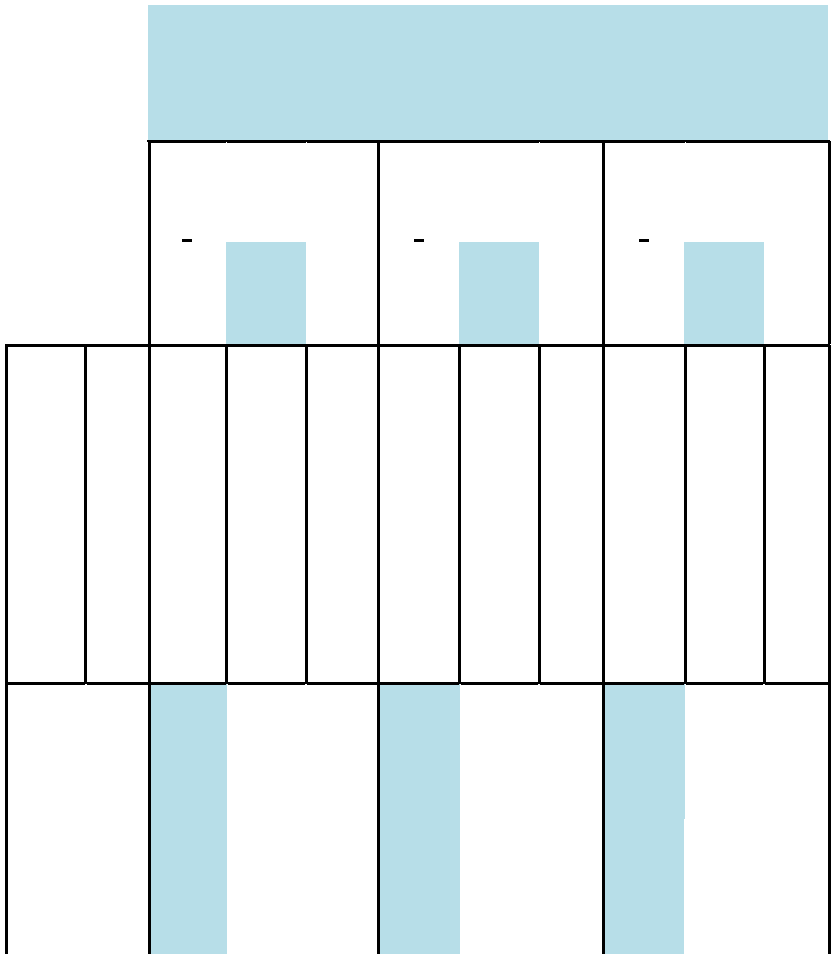


## Sunflower Electric Power Corporation (SEPC)
## Actual RTO Directed Transmission Projects
## For the 12 months ended - December 31, -2

**VII. Calculation of Net Plant for ITP / Priority 2 Projects**

| | | | *Description* **Project: SPP Proj. ID** | *1* | | *Description* **Project: SPP Proj. ID** | *2* | | *Description* **Project: SPP Proj. ID** | *3* | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Year** | **Month** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes C & D)** | **Depreciation Expense** |
| 27 | | Dec | $ - | | | $ - | | | $ - | | |
| 28 | -3 | | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | #DI | #D | | #DI | #D | | #DI | #D |
| 7 | | Ja | $ | V/0 | IV/ | $ | V/0 | IV | $ | V/0 | IV |
| 9 | -2 | n | - | ! | 0! | - | ! | /0! | - | ! | /0! |



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 280 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 281 | | Feb | $ - | | | $ - | | | $ - | | | |
| 282 | -2 | | | | | | | | | | | |
| 283 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 284 | | Mar | $ - | | | $ - | | | $ - | | | |
| 285 | -2 | | | | | | | | | | | |
| 286 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 287 | | Apr | $ - | | | $ - | | | $ - | | | |
| 288 | -2 | | | | | | | | | | | |
| 289 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 290 | | May | $ - | | | $ - | | | $ - | | | |
| 291 | -2 | | | | | | | | | | | |
| 292 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 293 | | Jun | $ - | | | $ - | | | $ - | | | |
| 294 | -2 | | | | | | | | | | | |
| 295 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 296 | | | $ - | | | $ - | | | $ - | | | |
| 297 | -2 | Jul | | | | | | | | | | |
| 298 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 299 | | Aug | $ - | | | $ - | | | $ - | | | |
| 300 | -2 | | | | | | | | | | | |
| 301 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 302 | | Sep | $ - | | | $ - | | | $ - | | | |
| 303 | -2 | | | | | | | | | | | |
| 304 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 305 | | Oct | $ - | | | $ - | | | $ - | | | |
| 306 | -2 | | | | | | | | | | | |
| 307 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 308 | | Nov | $ - | | | $ - | | | $ - | | | |
| 309 | -2 | | | | | | | | | | | |
| 310 | | | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 311 | | Dec | $ - | | | $ - | | | $ - | | | |
| 312 | -2 | | | | | | | | | | | |
| | | | | Sum lines | | | Sum lines | | | Sum lines | | |
| 291 | | | | 279 - 290 | #DIV/0! | | 279 - 290 | #DIV/0! | | 279 - 290 | #DIV/0! | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 292 | **Total** | | -3 EOY Accum. | - | -3 EOY Accum. | - | -3 EOY Accum. | - |

| | | | | | | Depr: | | | | | | Depr: | | | | Depr: | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 293 | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| 294 | | **13 Month Averages** | | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | | | | |
| 295 | 2010 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 296 | 2011 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 297 | 2012 | $ - | $ - | $ - | 2012 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 298 | 2013 | $ - | $ - | $ - | 2013 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 299 | 2014 | $ - | $ - | $ - | 2014 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 300 | 2015 | $ - | $ - | $ - | 2015 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 301 | 2016 | $ - | $ - | $ - | 2016 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 302 | 2017 | $ - | $ - | $ - | 2017 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 303 | 2018 | $ - | $ - | $ - | 2018 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 304 | 2019 | $ - | $ - | $ - | 2019 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 305 | 2020 | $ - | $ - | $ - | 2020 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 306 | 20 | $ - | $ - | $ - | 20 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 307 | 21 | - | - | - | 21 | - | - | - | - | - | - | - | - | - |
| 308 | 22 | - | - | - | 22 | - | - | - | - | - | - | - | - | - |
| 309 | 23 | - | - | - | 23 | - | - | - | - | - | - | - | - | - |
| 310 | 24 | - | - | - | 24 | - | - | - | - | - | - | - | - | - |
| 311 | 25 | - | - | - | 25 | - | - | - | - | - | - | - | - | - |
| 312 | 26 | - | - | - | 26 | - | - | - | - | - | - | - | - | - |
| 313 | 27 | - | - | - | 27 | - | - | - | - | - | - | - | - | - |
| 314 | 28 | - | - | - | 28 | - | - | - | - | - | - | - | - | - |
| 315 | 29 | - | - | - | 29 | - | - | - | - | - | - | - | - | - |
| 316 | 30 | - | - | - | 30 | - | - | - | - | - | - | - | - | - |
| 317 | 31 | - | - | - | 31 | - | - | - | - | - | - | - | - | - |
| | 32 | - | - | - | 32 | - | - | - | - | - | - | - | - | - |

Notes See WP A-5 (Act

: Depreciation Rate).

(C) This rate will reflect any future FERC

approved depreciation rates.

(E) ITP/Priority 2 projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the KCC Annual Report.

ITP/Priority 2 Project with incentives granted by FERC should be included in Sheet A-9 as well as

(F) this sheet.

Accumulated Depreciation will be brought forward from

(G) the prior year for each project.

# Sunflower Electric Power Corporation (SEPC)
# Actual Sponsored Upgrades
# For the 12 months ended - December 31, -2

Note: Line numbers in the table below refer to Workpaper A-7 (Act. RTO Directed Proj)

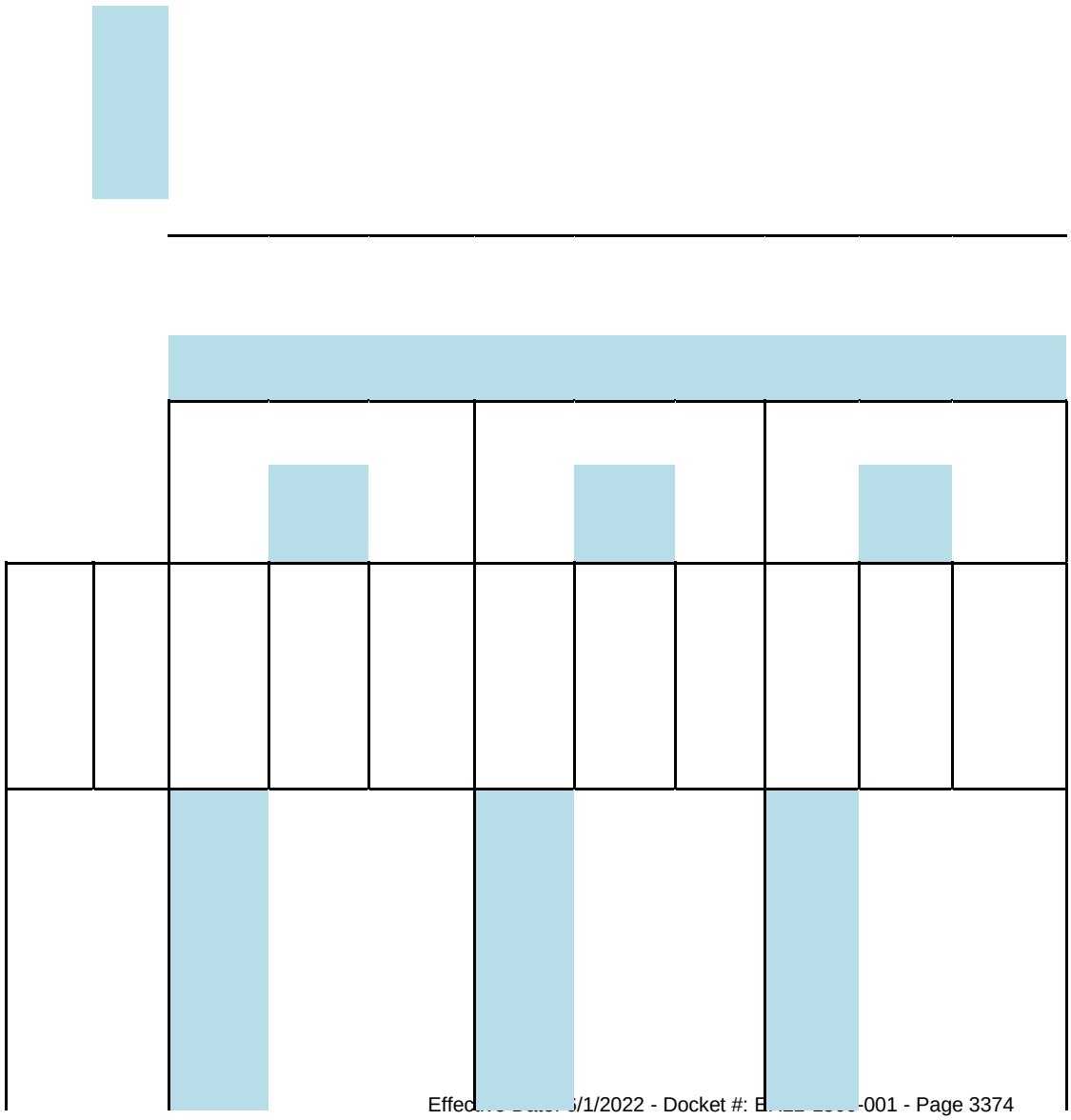
**I. Summary of Actual Sponsored Projects**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Project No** | **Project ID** | **Description** | **In Service Date** | **Gross Plant** (see below) | **Net Plant** (see below) | **O&M and A&G Expense** (f * L7) | **Other Taxes** (f * L9) | **General Plant Allocation** (f * L14) | **Depreciation Expense** (see below) | **Non Incentive Return** (f * L15) | **Incentive Return** (WP A-9) | **Revenue Requirements** (g + h + i + j+ k +l) |
| 1 | 1 | 0 | 0 | | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! |
| 2 | 2 | 0 | 0 | | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! |
| 3 | 3 | 0 | 0 | | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! |
| 4 | Total | | | | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #DIV/0! |

**II. Calculation of Net Plant for Sponsored Upgrade:**

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | **Project:** SPP Proj. ID | ***1*** | | **Project:** SPP Proj. ID | ***2*** | | **Project:** SPP Proj. ID | ***3*** | |
| 6 | | | | | | | | | | | | | |
| 7 | | | **Year** | **Month** | **Plant Balance by Month** | **Depr. Rate / 12 (notes A & B)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr. Rate / 12 (notes A & B)** | **Depreciation Expense** | **Plant Balance by Month** | **Depr Rate / 12 (notes A & B)** | **Depreciation Expense** |
| 8 | | | -3 | Dec | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 9 | | | -2 | Jan | $ - | #DIV/ | #DIV/ | $ - | #DIV/ | #DI | $ - | #DIV | #DIV/0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | -2 | Feb | - | 0! | 0! | - | 0! | V/0! | - | /0! | ! |
| | | | | $ | #DIV/ | #DIV/ | $ | #DIV/ | #DI | $ | #DIV | #DIV/0 |
| 11 | | -2 | Mar | - | 0! | 0! | - | 0! | V/0! | - | /0! | ! |
| | | | | $ | #DIV/ | #DIV/ | $ | #DIV/ | #DI | $ | #DIV | #DIV/0 |
| 12 | | -2 | Apr | - | 0! | 0! | - | 0! | V/0! | - | /0! | ! |



| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | | | -2 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 14 | | | -2 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 15 | | | -2 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 16 | | | -2 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 17 | | | -2 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 18 | | | -2 | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 19 | | | -2 | Nov | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | | | -2 | Dec | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 21 | | | | | | | #DIV/0! | | | #DIV/0! | | | #DIV/0! |
| | | | | | -3 EOY Accum. | | | -3 EOY Accum. | | | -3 EOY Accum. | | |
| 22 | | **Total Accm** | | | Deprc: | - | | Deprc: | - | | Deprc: | - | |
| 23 | **Year** | **Gross Plant** | **Deprec.** | **Net Plant** | **Year** | **Gross Plant** | **Accm Depr.** | **Net Plant** | **Gross Plant** | **Accm Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr** | **Net Plant** |
| 24 | | **13 Month Averages** | | | | **13 Month Averages** | | | **13 Month Averages** | | | **13 Month Averages** | | |
| | 2020 | $ - | $ - | $ - | 2010 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 25 | 10 | - | - | - | 0 | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | 2011 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 26 | 11 | - | - | - | 1 | - | - | - | - | - | - | - | - | - |
| | 2020 | $ - | $ - | $ - | 2012 | | | $ - | | | $ - | | | $ - |
| 27 | 12 | - | - | - | 2 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2013 | | | $ - | | | $ - | | | $ - |
| 28 | 13 | - | - | - | 3 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2014 | | | $ - | | | $ - | | | $ - |
| 29 | 14 | - | - | - | 4 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2015 | | | $ - | | | $ - | | | $ - |
| 30 | 15 | - | - | - | 5 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2016 | | | $ - | | | $ - | | | $ - |
| 31 | 16 | - | - | - | 6 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2017 | | | $ - | | | $ - | | | $ - |
| 32 | 17 | - | - | - | 7 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2018 | | | $ - | | | $ - | | | $ - |
| 33 | 18 | - | - | - | 8 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2019 | | | $ - | | | $ - | | | $ - |
| 34 | 19 | - | - | - | 9 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2020 | | | $ - | | | $ - | | | $ - |
| 35 | 20 | - | - | - | 0 | | | - | | | - | | | - |
| | 2020 | $ - | $ - | $ - | 2021 | | | $ - | | | $ - | | | $ - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 36 | 21 | - | - | - | 1 | | - | | - | | - | | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | | |
| 37 | 22 | - | - | - | 2 | | - | | - | | - | | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | | |
| 38 | 23 | - | - | - | 3 | | - | | - | | - | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | |
| 39 | 24 | - | - | - | 4 | | - | | - | | - | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | |
| 40 | 25 | - | - | - | 5 | | - | | - | | - | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | |
| 41 | 26 | - | - | - | 6 | | - | | - | | - | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | |
| 42 | 27 | - | - | - | 7 | | - | | - | | - | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | |
| 43 | 28 | - | - | - | 8 | | - | | - | | - | |
| | 20 | $ | $ | $ | 202 | | $ | | $ | | $ | |
| 44 | 29 | - | - | - | 9 | | - | | - | | - | |
| | 20 | $ | $ | $ | 203 | | $ | | $ | | $ | |
| 45 | 30 | - | - | - | 0 | | - | | - | | - | |
| | 20 | $ | $ | $ | 203 | | $ | | $ | | $ | |
| 46 | 31 | - | - | - | 1 | | - | | - | | - | |
| | 20 | $ | $ | $ | 203 | | $ | | $ | | $ | |
| 47 | 32 | - | - | - | 2 | | - | | - | | - | |

**Notes:**

(A) See WP A-5 (Act Depreciation Rate).

(B) This rate will reflect any future FERC approved depreciation rates.

(C) Sponsored Upgrade Projects that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Annual Report.

(D) Sponsored Projects with incentives granted by FERC should be included in Sheet A-9 as well as this sheet.

(E) Accumulated Depreciation will be brought forward from the prior year for each project.

# Sunflower Electric Power Corporation (SEPC)
# Actual Incentive Plant
# For the 12 months ended - December 31, -2

**I. Summary of Actual Incentive Projects**

| | | Average Return New Debt | # DIV/0! | Source: WP A-7, L15 | | | | |
|---|---|---|---|---|---|---|---|---|
| (a) | | (b) | | (c) | (d) | (e) | (f) | |
| **Project** | **Proj** | | | **In Service** | **Gross Plant** | **Incentive** | **Incentive Return** | |

| No. | Sect ID | Description | Date | Plant | Depr. Res. | Adder |
|---|---|---|---|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | (see below) | (see below) | (see below) |
| | **A. Base Plan Projects** | | | | | | |
| 1 | 1 | 0 | 0 | | #N/A | #N/A | #N/A |
| 2 | 2 | 0 | 0 | | #N/A | #N/A | #N/A |
| 3 | 3 | 0 | 0 | | #N/A | #N/A | #N/A |
| 4 | 4 | 0 | 0 | | #N/A | #N/A | #N/A |
| 5 | 5 | 0 | 0 | | #N/A | #N/A | #N/A |
| 6 | 6 | 0 | 0 | | #N/A | #N/A | #N/A |
| 7 | Total | | | | #N/A | #N/A | #N/A |
| | **B. Balanced Portfolio Projects** | | | | | | |
| 8 | 1 | 0 | 0 | | #N/A | #N/A | #N/A |
| 9 | 2 | 0 | 0 | | #N/A | #N/A | #N/A |
| | | | | | #N | # | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | | | | | / | N/ | #N |
| 0 | | 3 | 0 | 0 | A | A | /A |
| | | | | | | # | |
| 1 | | | | | # | N/ | #N |
| 1 | Total | | | | N | A | /A |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | / A |

**C. ITP Priority #1 Projects**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 12 | | 1 | 0 | 0 | # N / A | # N/ A | #N /A |
| 13 | | 2 | 0 | 0 | # N / A | # N/ A | #N /A |
| 14 | | 3 | 0 | 0 | # N / A | # N/ A | #N /A |
| 15 | Total | | | | # N / A | # N/ A | #N /A |

**D. ITP Priority #2 Projects**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 15 | | 1 | 0 | 0 | # N / A | # N/ A | #N /A |
| 16 | | 2 | 0 | 0 | # N / A | # N/ A | #N /A |
| 17 | | 3 | 0 | 0 | # N / A | # N/ A | #N /A |
| 18 | Total | | | | # N / A | # N/ A | #N /A |

**E. Sponsored Projects**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 19 | | 1 | 0 | 0 | # N / A | # N/ A | #N /A |
| 20 | | 2 | 0 | 0 | # N / A | # N/ A | #N /A |
| 21 | | | | | # N / | # N/ | #N |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | | 3 | 0 | 0 | A | A | /A |
| | | | | | # | | |
| | | | | | N | # | |
| 2 | | | | | / | N/ | #N |
| 2 | Total | | | | A | A | /A |

**F. Third Party Projects**

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | | | | #N/A | #N/A | #N/A |
| 24 | 1 | 0 | 0 | #N/A | #N/A | #N/A |
| 25 | 2 | 0 | 0 | #N/A | #N/A | #N/A |
| 26 | 3 | 0 | 0 | #N/A | #N/A | #N/A |
| 27 | Total | | | #N/A | #N/A | #N/A |
| 28 | Total for All Incentive Projects | | | #N/A | #N/A | #N/A |

(A) Special incentive (Depreciation Rate or TIER) may be utilized for specific incentive transmission projects if approved by the FERC.

(B) The formula is set up to accommodate an incentive TIER Adder. If FERC grants an ROE adder, it may be converted to a TIER adder using the following formula: TIER Adder = (ROE Adder * Equity Ratio) / Average System Interest Rate. If FERC grants a different incentive, the formula may need to be modified accordingly.

Workpaper A-9 Page 2 of 8



**Sunflower Electric Power Corporation (SEPC)**
**Actual Incentive Plant**
**For the 12 months ended - December 31, -2**

## II. Base Plan Projects

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | **Project: 1** | TIERA- | | **Project: 2** | TIERA- | | **Project: 3** | TIERA- | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | dder (B) | | | | dder (B) | | | | dder (B) | |
| | | | | SPP Proj. ID | | Avg Interest Rate Incentive Return | #DIV/0! | SPP Proj. ID | | Avg Interest Rate Incentive Return | #DIV/0! | SPP Proj. ID | | Avg Interest Rate Incentive Return | #DIV/0! |
| 29 | | | | | | | | | | | | | | | |
| 30 | | | | | | | #DIV/0! | | | | #DIV/0! | | | | #DIV/0! |
| 31 | | | | **Plant Balance by Month** | **Deprec. Rate/12** | **Depreciation Expense** | | **Plant Balance by Month** | **Deprec. Rate/12** | **Depreciation Expense** | | **Plant Balance by Month** | **Deprec. Rate/12** | **Depreciation Expense** | |
| 32 | | -3 | Dec | $ - | | | | $ - | | | | $ - | | | |
| 33 | | -2 | Jan | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 34 | | -2 | Feb | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 35 | | -2 | Mar | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| | | | A | | #D | #DI | | | #D | #DI | | | #D | #DI | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | - | p | | $ | IV | V/ | | | $ | IV | V/ | | | $ | IV | V/ |
| 6 | | 2 | r | | - | /0! | 0! | | | - | /0! | 0! | | | - | /0! | 0! |
| | | | M | | | #D | | | | | #D | | | | | #D | |
| 3 | | - | a | | $ | IV | # | | | $ | IV | # | | | $ | IV | # |
| 7 | | 2 | y | | - | /0! | DI | | | - | /0! | DI | | | - | /0! | DI |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | V/0! | | | | V/0! | | | | V/0! |
| | | | | | | | | # | | | | # | | | | # |
| | | | | Jun | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 38 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | Jul | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 39 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | Aug | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 40 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | Sep | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 41 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | Oct | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 42 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | Nov | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 43 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | Dec | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! | | | #DIV/0! | #DIV/0! |
| 44 | | | -2 | | $ | - | | # | $ | - | | # | $ | - | | # |
| | | | | | | | Sum lines 33 - 44 | #DIV/0! | | | Sum lines 33 - 44 | #DIV/0! | | | Sum lines 33 - 44 | #DIV/0! |
| 45 | | | | | | | | | | | | | | | | |
| | | | | | -3 EOY Acc Dep: | | | | -3 EOY Acc Dep: | | | | -3 EOY Acc Dep: | | | |
| 46 | **Total** | | | | | $ - | | | | $ - | | | | $ - | | |
| | **Gross** | **Accu** | **Net** | **Incen** | **G** | | **Incen** | **G** | | **Incen** | **G** | | **Incen** | | | |

| | Year | ss Plant | m Dep r | Plant | tive Re | Year | ross Plant | Acm Depr | Net Plant | tive Re | ross Plant | Acm Depr | Net Plant | tive Re | ross Plant | Acm Depr | Net Plant | tive Re |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | | | | | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | **turnAdder** | | | | | **turnAdder** | | | | **turnAdder** | | | | **turnAdder** | |
| 48 | | **13 Month Averages** | | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | |
| 49 | 2010 | $ - | $ - | $ - | #DIV/0! | 2010 | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | |
| 50 | 2011 | $ - | $ - | $ - | #DIV/0! | 2011 | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | |
| 51 | 2012 | | | | | 2012 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! | |
| 52 | 2013 | | | | | 2013 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! | |
| 53 | 2014 | | | | | 2014 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! | |
| | | | | | | 20 | | | | #DIV/ | | | | #DIV/ | | | | #DIV/ | |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 54 | 2015 | | | | | | 15 | | | | $ - | 0 !#DI | | | | $ - | 0 !#DI | | | | $ - | 0 !#DI |
| 55 | 2016 | | | | | | 20 | | | | $ - | 0 !#DI | | | | $ - | 0 !#DI | | | | $ - | 0 !#DI |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 16 | | V/0!#DIV/0!#DIV/0!#DIV/ | | V/0!#DIV/0!#DIV/0!#DIV/ | | V/0!#DIV/0!#DIV/0!#DIV/ |
| 56 | 2017 | 2017 | $ - | | $ - | | $ - | |
| 57 | 2018 | 2018 | $ - | | $ - | | $ - | |
| 58 | 2019 | 2019 | $ - | | $ - | | $ - | |
| 59 | 2020 | 2020 | $ - | | $ - | | $ - | |
| 60 | 2021 | 2021 | $ - | | $ - | | $ - | |
| 61 | 2022 | 2022 | $ - | | $ - | | $ - | |
| | | 20 | | V/ | | V/ | | V/ |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | | 2 | | $ | 0 | | $ | 0 | | $ | 0 | |
| 2 | 2023 | | 3 | | - | ! | | - | ! | | - | ! | |
| | | | | | | # | | | # | | | # | |
| 6 | | | 2 | | $ | D | | $ | D | | $ | D | |
| 3 | 2024 | | 0 | | - | I | | - | I | | - | I | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 24 | | V/0!#DIV/ | | V/0!#DIV/ | | V/0!#DIV/ |
| 64 | 2025 | | 2025 | $ - | 0!#DIV/ | $ - | 0!#DIV/ | $ - | 0!#DIV/ |
| 65 | 2026 | | 2026 | $ - | 0!#DIV/ | $ - | 0!#DIV/ | $ - | 0!#DIV/ |
| 66 | 2027 | | 2027 | $ - | 0!#DIV/ | $ - | 0!#DIV/ | $ - | 0!#DIV/ |
| 67 | 2028 | | 2028 | $ - | 0!#DIV/ | $ - | 0!#DIV/ | $ - | 0!#DIV/ |
| 68 | 2029 | | 2029 | $ - | 0!#DIV/ | $ - | 0!#DIV/ | $ - | 0!#DIV/ |
| 69 | 2030 | | 2030 | $ - | 0!#DIV/ | $ - | 0!#DIV/ | $ - | 0!#DIV/ |
| | | | 20 | | V/ | | V/ | | V/ |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | | 3 | | $ | 0 | | $ | 0 | | $ | 0 |
| 0 | 2031 | | 1 | | - | ! | | - | ! | | - | ! |
| | | | | | | # | | | # | | | # |
| 7 | | | 2 | | $ | D | | $ | D | | $ | D |
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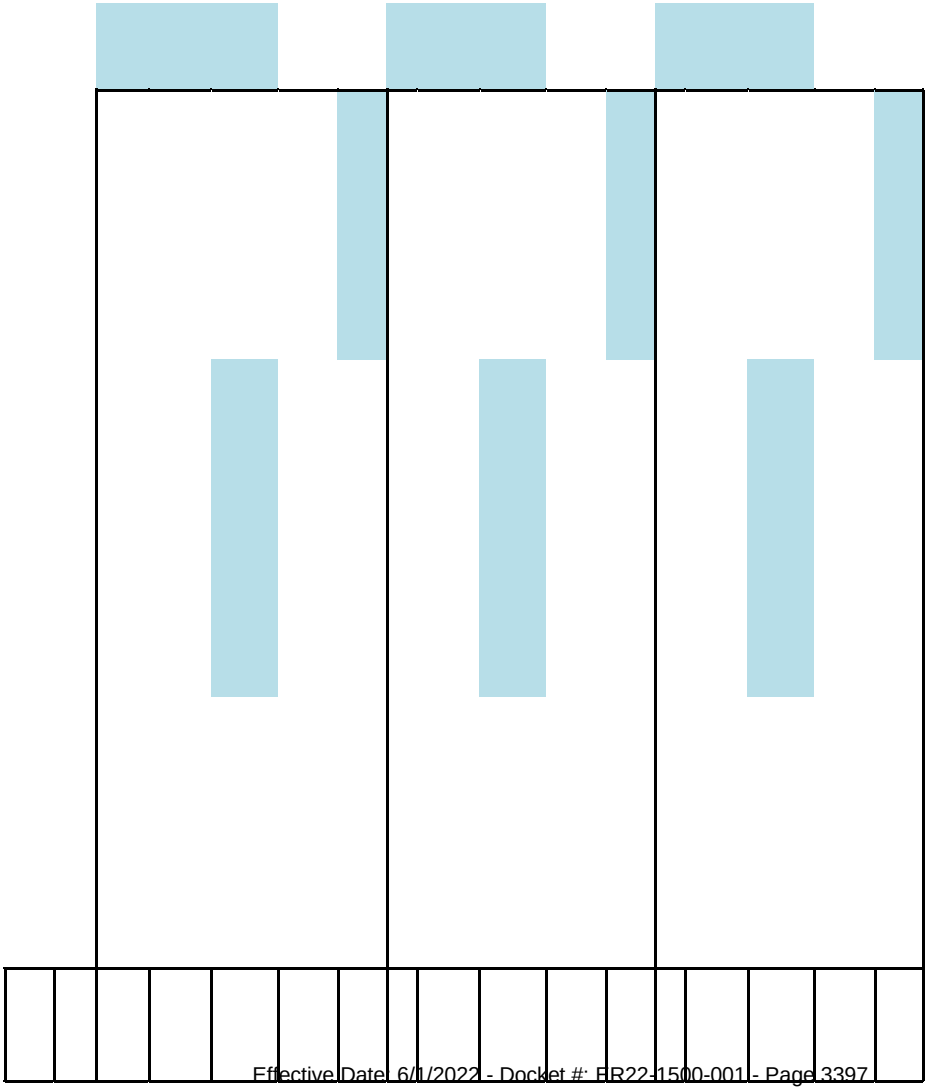
| 74 | | | | | | ur n | 0 ! | | | | ur n | 0 ! | | | | ur n | 0 ! |
| 75 | - | Ye | Mon | Plant | Deprec. | Dep | | Plant | Deprec. | Dep | | Plant | Deprec. | Dep | | | |



| | ar | th | Balance by Month | Rate / 12 | reciation Expense | Balance by Month | Rate / 12 | reciation Expense | Balance by Month | Rate / 12 | reciation Expense |
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| 76 | 7-23 | Dec | $ - | | #DIV/0! | $ - | | #DIV/0! | $ - | | #DIV/0! |
| 77 | 7-22 | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 78 | 7-22 | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 79 | 7-22 | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 80 | 8-22 | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 81 | 8-22 | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 82 | 8-22 | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 83 | 8-22 | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 84 | 8-22 | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 85 | 8-22 | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
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| 88 | | | | | -2 | Dec | $ - | #DIV/0! Sum lines 77-88 | #DIV/0! #DIV/0! | | $ - | #DIV/0! Sum lines 77-88 | #DIV/0! #DIV/0! | | $ - | #DIV/0! Sum lines 77-88 | #DIV/0! #DIV/0! | |
| 89 | | | | | | | | | | | | | | | | | | |
| 90 | | **Total** | | | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | |
| 91 | **Year** | **Gross Plant** | **Accum Depr** | **Net Plant** | **Incentive Return Adder** | **Year** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** |
| 92 | | **13 Month Averages** | | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | **13 Month Averages** | | | |
| 93 | 2010 | $ - | $ - | $ - | #DIV/0! #DI | 2010 | $ - | $ - | $ - | #DIV/0! #DI | $ - | $ - | $ - | #DIV/0! #DI | $ - | $ - | $ - | #DIV/0! #DI |

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| 9 | | | | | | V/0! | 2011 | | | | | V/0! | | | | V/0! | | | | V/0! | | | |
| 4 | 2011 | $ | $ | $ | - | - | - | $ | $ | $ | - | - | - | $ | $ | $ | - | - | - | $ | $ | $ | - | - | - |

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| 103 | 2020 | 2020 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 104 | 2021 | 2021 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 105 | 2022 | 2022 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 106 | 2023 | 2023 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 107 | 2024 | 2024 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 108 | 2025 | 2025 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 109 | 2026 | 2026 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |

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| 11 | 2028 | 2028 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 12 | 2029 | 2029 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 13 | 2030 | 2030 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 14 | 2031 | 2031 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 15 | 2032 | 2032 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |

# Sunflower Electric Power Corporation (SEPC)
## Actual Incentive Plant
## For the 12 months ended - December 31, -2

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## III. Balanced Portfolio Projects

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Project:** | **1** | TIER Adder (B) - Avg Interest Rate Incentive Return | #DIV/0! | **Project:** | **2** | TIER Adder (B) - Avg Interest Rate Incentive Return | #DIV/0! | **Project:** | **3** | TIER Adder (B) - Avg Interest Rate Incentive Return | #DIV/0! |
| | | | | SPP Proj. ID | | | | SPP Proj. ID | | | | SPP Proj. ID | | | |
| | **Year** | **Month** | | **Plant Balance by Month** | **Deprec. Rate / 12** | **Depreciation Expense** | | **Plant Balance by Month** | **Deprec. Rate / 12** | **Depreciation Expense** | | **Plant Balance by Month** | **Deprec. Rate / 12** | **Depreciation Expense** | |
| | -20 | Dec | | $ - | | | | $ - | | | | $ - | | | |
| | -21 | Jan | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| | -22 | Feb | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |

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| | | | | Sum lines 121 - 132 | # DIV/0! | | Sum lines 121 - 132 | # DIV/0! | | Sum lines 121 - 132 | # DIV/0! |
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| 4 | | **Total** | | | | : | - | | | : | - | | | : | - | | |
| 1 | | **G** | **A** | **N** | **I** | | **G** | **Ac** | **N** | **I** | **G** | **Ac** | **N** | **I** | **G** | **Ac** | **N** | **I** |
| 3 | | **r** | **c** | **e** | **n** | **Y** | **ro** | **cm** | **et** | **n** | **ro** | **cm** | **et** | **n** | **ro** | **cm** | **et** | **n** |
| 5 | **Year** | **o** | **c** | **t** | **c** | **e** | **ss** | | **Pl** | **c** | **ss** | | **Pl** | **c** | **ss** | | **Pl** | **c** |

| | | ss Plant | um Depr | Plant | entive Return Adder | ar | Plant | Depr | ant | entive Return Adder | Plant | Depr | ant | entive Return Adder | Plant | Depr | ant | entive Return Adder |
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| 136 | | **13 Month Averages** | | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | **13 Month Averages** | | | |
| 137 | 2010 | $ - | $ - | $ - | #DIV/0! #DIV/0! | 2010 | $ - | $ - | $ - | #DIV/0! #DIV/0! | $ - | $ - | $ - | #DIV/0! #DIV/0! | $ - | $ - | $ - | #DIV/0! #DIV/0! |
| 138 | 2011 | $ - | $ - | $ - | #DIV/0! | 2011 | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! |
| 139 | 2012 | | | | | 2012 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! |
| 140 | 2013 | | | | | 2013 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! |
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| 141 | 2014 | | | | | | 04 | | | | $ - | /0! | | | | $ - | /0! | | | | $ - | /0! | | |

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| 142 | 2015 | 2015 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 143 | 2016 | 2016 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 144 | 2017 | 2017 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 145 | 2018 | 2018 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 146 | 2019 | 2019 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 147 | 2020 | 2020 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 148 | 2021 | 2021 | $ | - | | #DIV/0! | $ | - | #DIV/0! | $ | - |
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| 150 | 2023 | 2023 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 151 | 2024 | 2024 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 152 | 2025 | 2025 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 153 | 2026 | 2026 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 154 | 2027 | 2027 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 155 | 2028 | 2028 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 156 | 2029 | 2029 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |

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| 158 | 2031 | 2031 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 159 | 2032 | 2032 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |





## Sunflower Electric Power Corporation (SEPC)
## Actual Incentive Plant
## For the 12 months ended - December 31, -2

## IV. ITP Priority No. 1 Projects

| | Project: 1 | TIER Adder (B) - Avg Interest Rate | Project: 2 | TIER Adder (B) - Avg Interest Rate | Project: 3 | TIER Adder (B) - Avg Interest Rate |
|---|---|---|---|---|---|---|
| 160 | SPP Proj. ID | #DIV/0! | SPP Proj. ID | #DIV/0! | SPP Proj. ID | #DIV/0! |

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| | Year | Month | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | |
| 16 | -34 | Dec | $ - | | | | $ - | | | | $ - | | | |
| 16 | -25 | Jan | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 16 | -26 | Feb | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 16 | -27 | Mar | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 16 | -28 | Apr | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 16 | -29 | May | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 17 | -30 | Jun | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 17 | -31 | Jul | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |
| 17 | -32 | Aug | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | |

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| 173 | - 2 | Sep | | $ - | #DIV/0! | #DIV/0! | | | $ - | #DIV/0! | #DIV/0! | | | $ - | #DIV/0! | #DIV/0! | |

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| 174 | | | | -2 | Oct | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | | |
| 175 | | | | -2 | Nov | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | | |
| 176 | | | | -2 | Dec | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | | | |
| 177 | | | | | | | Sum lines 165 - 176 | #DIV/0! | | | Sum lines 165 - 176 | #DIV/0! | | | Sum lines 165 - 176 | #DIV/0! | | | |
| 178 | | **Total** | | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | | | |
| 179 | **Year** | **Gross Plant** | **Accum Depr** | **Net Plant** | **Incentive Return Adder** | **Year** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | |
| 180 | | **13 Month Averages** | | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | |

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| 18 | | $ | $ | $ | #DIV/ | 2010 | $ | $ | $ | #DIV/ | $ | $ | $ | #DIV/ | $ | $ | $ | #DIV/ |
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# Sunflower Electric Power Corporation (SEPC)
## Actual Incentive Plant
## For the 12 months ended - December 31, -2

## V. ITP Priority No. 2 Projects

| | | | Project: 1 | | | Project: 2 | | | Project: 3 | | |
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| | | | SPP Proj. ID | TIER Adder (B) Avg Interest Rate Incentive Return | - #DIV/0! | SPP Proj. ID | TIER Adder (B) Avg Interest Rate Incentive Return | - #DIV/0! | SPP Proj. ID | TIER Adder (B) Avg Interest Rate Incentive Return | - #DIV/0! |
| Year | Month | | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense | Plant Balance by Month | Deprec. Rate / 12 | Depreciation Expense |
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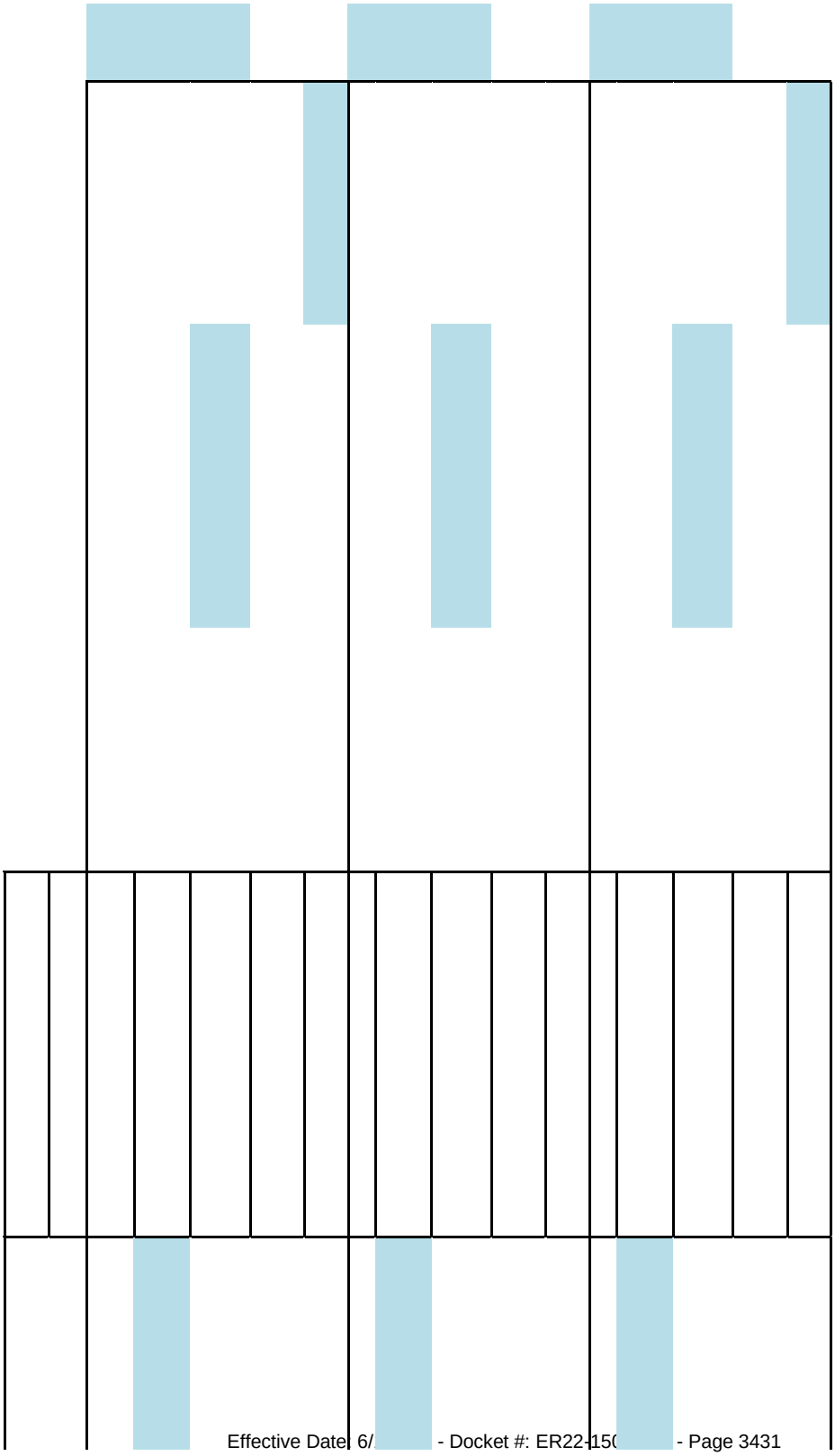

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| | **Year** | | | | | | | | | | | | | | | | | |
| | | **13 Month Averages** | | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | **13 Month Averages** | | | |
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Workpaper A-9 Page 7 of 8

## Sunflower Electric Power Corporation (SEPC)
## Actual Incentive Plant
## For the 12 months ended - December 31, -2

## VI. Sponsored Projects:

| | Project | TIER Adder (B | Project | TIER Adder (B | Project | TIER Adder (B |
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| 265 | | | | | | | Sum lines 253-264 | #DIV/0! | | | Sum lines 253-264 | #DIV/0! | | | Sum lines 253-264 | #DIV/0! | | | |
| 266 | **Total** | | | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | | | |
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| | | | | | **er** | | | | | | | | **er** | | | | | | | | | | | | | **er** |
| 268 | | | **13 Month Averages** | | | | | | **13 Month Averages** | | | | | | | | **13 Month Averages** | | | | | | **13 Month Averages** | | | |
| 269 | 2010 | $ - | $ - | $ - | #DIV/0! | 2010 | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! |
| 270 | 2011 | | | | | 2011 | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! |
| 271 | 2012 | | | | | 2012 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! |
| 272 | 2013 | | | | | 2013 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! |
| 273 | 2014 | | | | | 2014 | | | $ - | #DIV/0! | | | $ - | #DIV/0! | | | $ - | #DIV/0! |
| 274 | 2015 | | | | | 2015 | | | $ - | #DI | | | $ - | #DI | | | $ - | #DI |

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| 276 | 2017 | 2017 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 277 | 2018 | 2018 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 278 | 2019 | 2019 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 279 | 2020 | 2020 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 280 | 2021 | 2021 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 281 | 2022 | 2022 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 282 | 2023 | 2023 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |

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|---|---|---|---|---|---|---|---|---|
| 2084 | 2025 | 2025 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 2085 | 2026 | 2026 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 2086 | 2027 | 2027 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 2087 | 2028 | 2028 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 2088 | 2029 | 2029 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 2089 | 2030 | 2030 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 2090 | 2031 | 2031 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |

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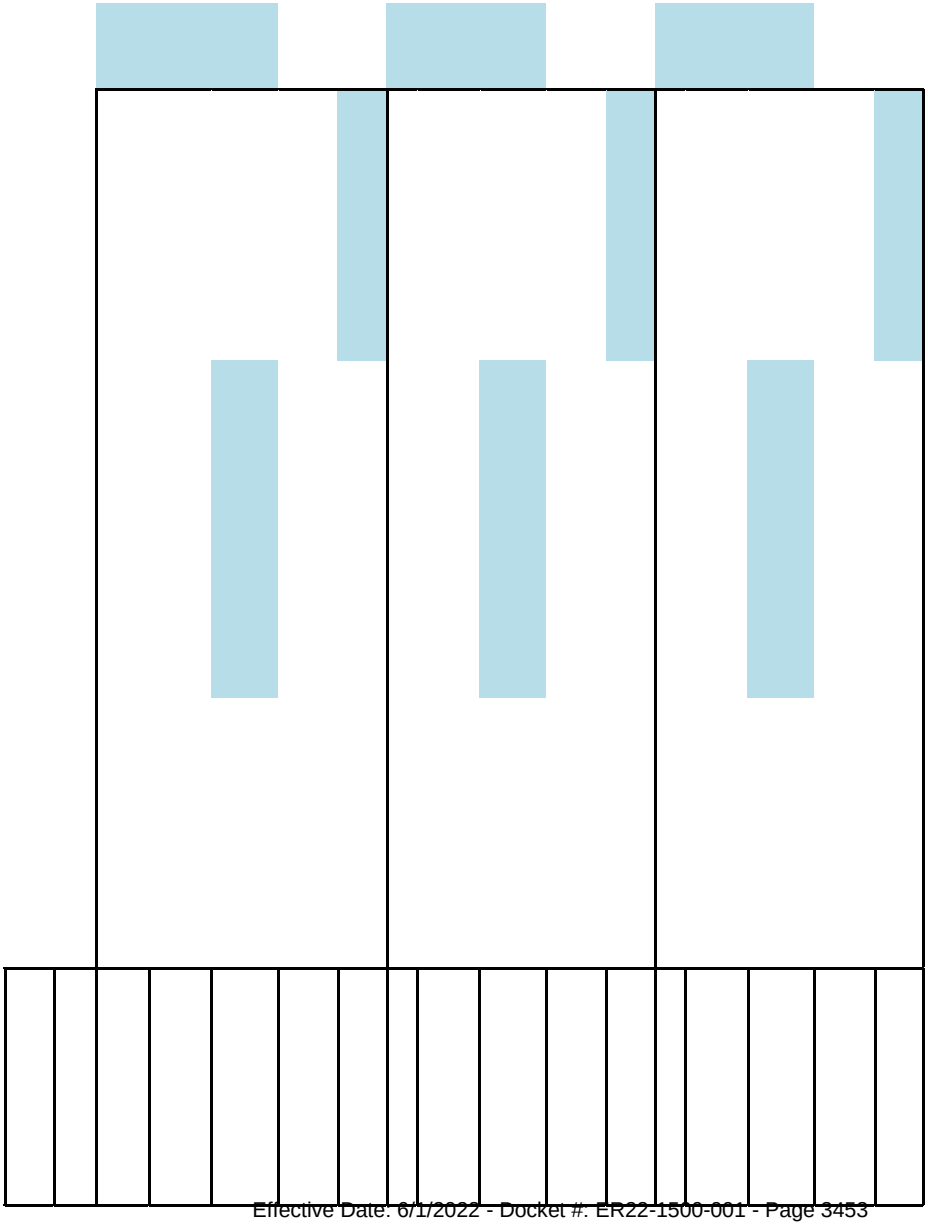
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 291 | 2032 | | 2032 | | | IV/$ - | 0! | | | IV/$ - | 0! | | IV/$ - | 0! |

# Sunflower Electric Power Corporation (SEPC)
## Actual Incentive Plant
## For the 12 months ended - December 31, -2

**VII. Third Party Projects :**

| | Project: 1 | | TIER Adder (B) - Avg Interest Rate Incentive Return | | Project: 2 | | TIER Adder (B) - Avg Interest Rate Incentive Return | | Project: 3 | | TIER Adder (B) - Avg Interest Rate Incentive Return | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | SPP Proj. ID | | #DIV/0! | #DIV/0! | SPP Proj. ID | | #DIV/0! | #DIV/0! | SPP Proj. ID | | #DIV/0! | #DIV/0! |
| | **Plan** | **Depr** | **D** | | **Plan** | **Depr** | **D** | | **Plan** | **Depr** | **D** | |

| Year | Month | Beg. Balance | Rate / 12 | Depreciation | Beg. Balance | Rate / 12 | Depreciation | Beg. Balance | Rate / 12 | Depreciation |
|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | | | | | | | |
| 9 | | | | | | | | | | |
| 5 | | | | | | | | | | |



| | | | by Month | | n Expense | by Month | | n Expense | by Month | | n Expense |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 29-63 | | Dec | $ - | | | $ - | | | $ - | | |
| 29-72 | | Jan | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 29-82 | | Feb | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 29-92 | | Mar | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-02 | | Apr | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-12 | | May | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-22 | | Jun | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-32 | | Jul | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-42 | | Aug | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-52 | | Sep | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-62 | | Oct | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30-0 | | No | $ | #DIV/ | | $ | #DIV/ | | $ | #DIV/ | |

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| 7 | | 2 | v | | - | /0! | 0! | | | - | /0! | 0! | | | - | /0! | 0! | |
| 3 | | | D | | | #D | # DI | | | | #D | # DI | | | | #D | # DI | |
| 0 | | - | e | | $ | IV | V/ | | | $ | IV | V/ | | | $ | IV | V/ | |
| 8 | | 2 | c | | - | /0! | 0! | | | - | /0! | 0! | | | - | /0! | 0! | |

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| | | | | | | | | Sum lines 297 - 308 | # DIV/0! | | | Sum lines 297 - 308 | # DIV/0! | | | Sum lines 297 - 308 | # DIV/0! | | |
| | | | | | | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | | -3 EOY Acc Dep: | $ - | | |
| | **Total** | | | | | | | | | | | | | | | | | | | |
| | | **Gross Plant** | **Accum Depr** | **Net Plant** | **Incentive Return Adder** | **Year** | | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** | **Gross Plant** | **Accm Depr** | **Net Plant** | **Incentive Return Adder** |
| | **Year** | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | **13 Month Averages** | | | | **13 Month Averages** | | | | **13 Month Averages** | | | |
| | 2010 | $ - | $ - | $ - | #DIV/0! | 2010 | | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | $ - | $ - | $ - | #DIV/0! | |
| | | | | | #DIV/ | 20 | | | | | #DIV/ | | | | #DIV/ | | | | #DIV/ | |

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| 1 | | | $ | $ | $ | 0 | 1 | | $ | $ | $ | 0 | | $ | $ | $ | 0 | | $ | $ | $ | 0 |
| 4 | 2011 | | - | - | - | ! | 1 | | - | - | - | ! | | - | - | - | ! | | - | - | - | ! |
| 3 | | | | | | | | | | | | # | | | | | # | | | | | # |
| 1 | | | | | | | 2 | | | | $ | D | | | | $ | D | | | | $ | D |
| 5 | 2012 | | | | | | 0 | | | | - | I | | | | - | I | | | | - | I |

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| | | 12 | V/0!#DIV | V/0!#DIV | V/0!#DIV |
| 316 | 2013 | 2013 | $ - | $ - | $ - |
| 317 | 2014 | 2014 | $ - | $ - | $ - |
| 318 | 2015 | 2015 | $ - | $ - | $ - |
| 319 | 2016 | 2016 | $ - | $ - | $ - |
| 320 | 2017 | 2017 | $ - | $ - | $ - |
| 321 | 2018 | 2018 | $ - | $ - | $ - |
| 3 | | 20 | V/ | V/ | V/ |

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| 2 | | | | 1 | | | $ | 0 | | | $ | 0 | | | $ | 0 |
| 2 | | 2019 | | 9 | | | - | ! | | | - | ! | | | - | ! |
| 3 | | | | | | | | # | | | | # | | | | # |
| 2 | | | | 2 | | | $ | D | | | $ | D | | | $ | D |
| 3 | | 2020 | | 0 | | | - | I | | | - | I | | | - | I |

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| | | 2020 | | #DIV/0! | | #DIV/0! | | #DIV/0! |
| 32024 | 2021 | 2021 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 32025 | 2022 | 2022 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 32026 | 2023 | 2023 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 32027 | 2024 | 2024 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 32028 | 2025 | 2025 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| 32029 | 2026 | 2026 | $ - | #DIV/0! | $ - | #DIV/0! | $ - | #DIV/0! |
| | | 2030 | | #DIV/0! | | #DIV/0! | | #DIV/0! |

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| 3 | | | 2 | | $ | 0 | | $ | 0 | | $ | 0 |
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# Sunflower Electric Power Corporation (SEPC)
# Actual Transmission Plant Related to Third Party Projects
# For the 12 months ended - December 31, -2

**I. Summary of Actual Projects Constructed by SEPC on Behalf of Third Parties**

Note: Line numbers in the table below refer to Workpaper A-7 (Act. RTO Directed Proj)

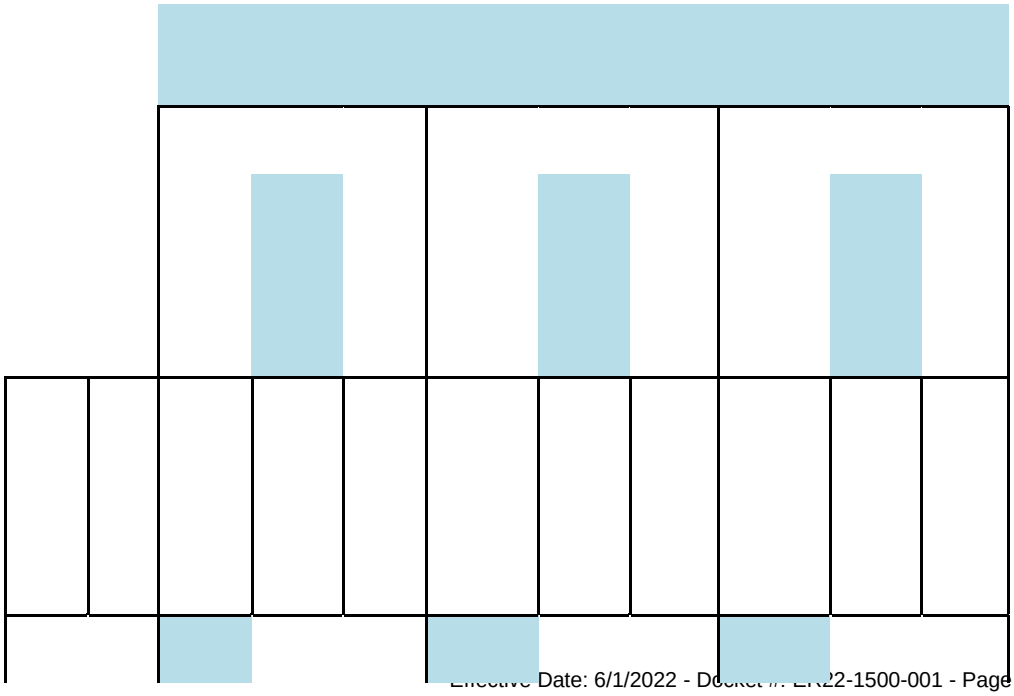
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project No.** | **Project ID** | **Description** | **Third Party** | **In Service Date** | **Gross Plant** | **Net Plant** | **O&M and A&G Expense** | **Other Taxes** | **General Plant Allocation** | **Depreciation Expense** | **Non Incentive Return** | **Incentive Return** | **Revenue Requirements** |
| | | | | | | (see below) | (see below) | (g * L7) | (g * L9) | (g * L14) | (see below) | (g * L15) | (WP A-9) | ( h + i + j+ k +l + m) |
| 1 | 1 | 0 | 0 | 0 | | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #N/A |
| 2 | 2 | 0 | 0 | 0 | | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #N/A |
| 3 | 3 | 0 | 0 | 0 | | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #N/A |
| 4 | Total | | | | | #N/A | #N/A | #N/A | #N/A | #N/A | #DIV/0! | #N/A | #N/A | #N/A |

**II. Calculation of Net Plant for Projects Constructed by SEPC for Third Parties:**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | **Project:** | ***1*** | | **Project:** | ***2*** | | **Project:** | ***3*** | | | |
| 6 | | | | SPP Proj. ID Third Party | | | SPP Proj. ID Third Party | | | SPP Proj. ID Third Party | | | | |
| | | | | **Plant Balance** | **Depr. Rate /12** | **Depreciatio** | **Plant Balan** | **Depr. Rate /12** | **Depreciatio** | **Plant Balan** | **Depr. Rate /12** | **Depreciatio** | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | Year | Month | by Month (Notes A & B) | n Expense | ce by Month | (Notes A & B) | n Expense | ce by Month | (Notes A & B) | n Expense |
| | | Dec | $ | | $ | | | $ | | |
| 8 | -3 | c | - | | - | | | - | | |





| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 9 | | | -2 | Jan | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Fe | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 0 | | | -2 | b | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Ma | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 1 | | | -2 | r | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Ap | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 2 | | | -2 | r | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Ma | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 3 | | | -2 | y | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 4 | | | -2 | Jun | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 5 | | | -2 | Jul | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Au | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 6 | | | -2 | g | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Se | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 7 | | | -2 | p | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | Oc | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 8 | | | -2 | t | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 1 | | | | No | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 9 | | | -2 | v | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 2 | | | | De | | $ | #DI | #DI | $ | | #DI | #DI | $ | | #DI | #DI |
| 0 | | | -2 | c | | - | V/0! | V/0! | - | | V/0! | V/0! | - | | V/0! | V/0! |
| 2 | | | | | | | | #DI | | | | #DI | | | | #DI |
| 1 | | | | | | | | V/0! | | | | V/0! | | | | V/0! |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | -3 EOY Accum. Depr: | | | | -3 EOY Accum. Depr: | | | | -3 EOY Acc Dep: | | |
| 2 | | | **Total Accm** | | | | - | | | | - | | | | - | |
| 2 | **Year** | **Gross Plant** | **Deprec.** | **Net Plant** | **Year** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | | **Gross Plant** | **Accm. Deprec.** | **Net Plant** |
| 2 | | | | | | | | | | **13 Month Averages** | | | | | | |
| 2 | | **13 Month Averages** | | | | **13 Month Averages** | | | | | | | | | | |
| 2 | 20 | $ | $ | $ | 20 | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 5 | 10 | - | - | - | 10 | - | - | - | | - | - | - | | - | - | - |
| 2 | 20 | $ | $ | $ | 20 | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 6 | 11 | - | - | - | 11 | - | - | - | | - | - | - | | - | - | - |
| 2 | 20 | $ | $ | $ | 20 | | | $ | | | | $ | | | | $ |
| 7 | 12 | - | - | - | 12 | | | - | | | | - | | | | - |
| 2 | 20 | $ | $ | $ | 20 | | | $ | | | | $ | | | | $ |
| 8 | 13 | - | - | - | 13 | | | - | | | | - | | | | - |
| 2 | 20 | $ | $ | $ | 20 | | | $ | | | | $ | | | | $ |
| 9 | 14 | - | - | - | 14 | | | - | | | | - | | | | - |

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| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 0 | 15 | - | - | - | 15 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 1 | 16 | - | - | - | 16 | | - | | - | | - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 2 | 17 | - | - | - | 17 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 3 | 18 | - | - | - | 18 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 4 | 19 | - | - | - | 19 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 5 | 20 | - | - | - | 20 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 6 | 21 | - | - | - | 21 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 7 | 22 | - | - | - | 22 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 8 | 23 | - | - | - | 23 | | - | | - | | - |
| 3 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 9 | 24 | - | - | - | 24 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 0 | 25 | - | - | - | 25 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 1 | 26 | - | - | - | 26 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 2 | 27 | - | - | - | 27 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 3 | 28 | - | - | - | 28 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 4 | 29 | - | - | - | 29 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 5 | 30 | - | - | - | 30 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 6 | 31 | - | - | - | 31 | | - | | - | | - |
| 4 | 20 | $ | $ | $ | 20 | | $ | | $ | | $ |
| 7 | 32 | - | - | - | 32 | | - | | - | | - |

**Notes:**

(A) See WP A-5 (Act Depreciation Rate). This rate will reflect any

(B) future FERC approved depreciation rates.

(C) Projects constructed by SEPC on behalf of Third Parties that have been completed and whose costs are in the KCC Annual Report should be entered on this page. If a project is completed in phases over multiple years, that project should be entered in sheet P-4 until the entire project is completed and reported in the Annual Report.

(D) Third Party Projects with incentives granted by FERC should be included in Sheet A-9 as well as on this sheet.

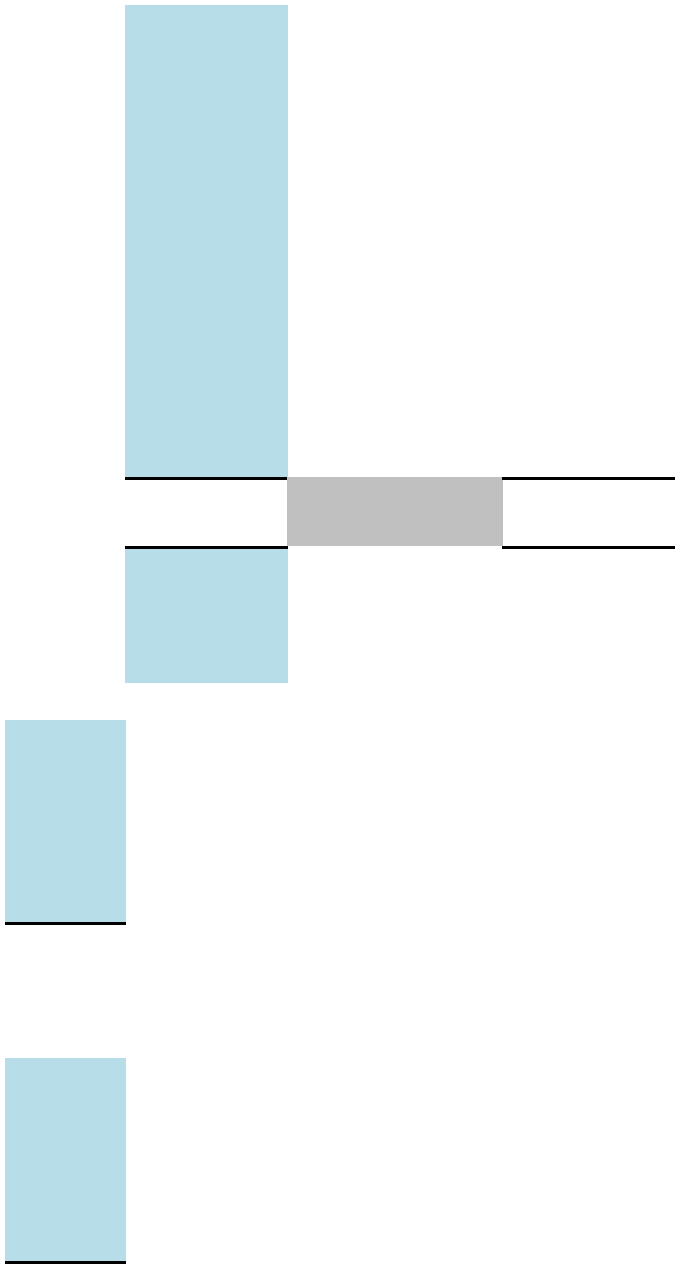
(E) Accumulated Depreciation will be brought forward from the prior year for each project.

# Sunflower Electric Power Corporation (SEPC)
# Administrative & General Expense
# For the 12 months ended - December 31, -2

| Line No | Description | Source | Annual Expense | Allocation Factor | Allocation Rate | Allocated to Transmission |
|---|---|---|---|---|---|---|
| 1 | Administrative & General Expense | Pg.36-1,L31, Col. b | $ - | WS | #DIV/0! | #DIV/0! |
| 2 | Less: General Advertising Costs | | - | WS | #DIV/0! | #DIV/0! |
| 3 | Less: Regulatory Commission Expenses | | - | WS | #DIV/0! | #DIV/0! |
| 4 | Less: Corporate Visibility Expenses | | - | WS | #DIV/0! | #DIV/0! |
| 5 | Less: Misc Nuclear Expenses ( included in Account 930.2) | | - | WS | #DIV/0! | #DIV/0! |
| 6 | Less: Experimental & Gen. Research Exp. | | - | WS | #DIV/0! | #DIV/0! |
| 7 | Less: Industry Association Dues | | - | WS | #DIV/0! | #DIV/0! |
| 8 | Subtotal | | $ - | | | #DIV/0! |
| 9 | Plus Safety Advertising | | - | WS | #DIV/0! | #DIV/0! |
| 10 | Plus Association Dues Directly Related to Transmission | | - | DA | 100.000 0% | $ - |
| 11 | Plus: General Advertising: | | | | | |
| 12 | Transmission Facilities Sitting | $ - | | | | |
| 13 | Transmission Vegetation Management | - | | | | |
| 14 | Transmission Reliability | - | | | | |
| 15 | Total Advertising for Transmission | | $ - | DA | 100.000 0% | $ - |
| 16 | Plus: Transmission Specific Research & Experimental | | | | | |
| 17 | Project #1 | $ - | | | | |
| 18 | Project #2 | - | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 19 | Project #3 | - | | | |
| | Total Research & | $ | | 100.000 | $ |
| 20 | Experimental Expenses | - | DA | 0% | - |
| | Plus Transmission Related Reg. Comm. | | | | |
| 21 | Exp. | | | | |

-



| | | | | | | |
|---|---|---|---|---|---|---|
| 22 | Formula Rate | $ - | | DA | 100.000 0% | $ - |
| 23 | Other-Specifically Assignable to Transmission | - | | DA | 100.000 0% | - |
| 24 | | - | | DA | 100.000 0% | - |
| 25 | Total Transmission Regulatory Expense | | $ - | | | $ - |
| 26 | Plus: Corporate Visibility Expenses: | | | | | |
| 27 | Regulatory | $ - | | | | |
| 28 | Reporting | - | | | | |
| 29 | Compliance | - | | | | |
| 30 | Shareholder Communications | - | | | | |
| 31 | Total Corporate Visibility Expenses | | $ - | WS | #DIV/0 ! | #DIV/0! |
| 32 | Total A&G Expense | | $ - | | | #DIV/0! |

None of the following expenses shall be recovered directly or indirectly through the formula rate:

A. Industry association dues (*e.g.*, EEI, NRECA, KEC and EPRI).

B. The following charges to Account 930.2: nuclear power research expenses, miscellaneous general expenses related to a Nuclear Generating Station; Nuclear Energy Institute fees, assessments and other costs; and any other nuclear-related expenses.

C. Other experimental and general research expenditures (other than those related to transmission which shall be directly assigned to transmission).

D. Expenses to Maintain Corporate Visibility (except such costs related to regulatory, reporting, compliance, and shareholder communications).

E. All regulatory Commission expenses, except for FERC transmission-related dockets, which shall be directly assigned to transmission. Transmission-related dockets shall not include transmission-related rulemakings or notices of inquiry proceedings, except those related to siting or reliability.

Workpaper A-12 Page 1 of 2

# Sunflower Electric Power Corporation (SEPC)
# 13 Month Average Balance and BOY-EOY Average Balances

**I. Plant Additions & Accumulated Depreciation Balances** (Note 1)

Source: SEPC Financial Records. BOY and EOY totals may be found on Pgs. 10 & 11 of SEPC's KCC Annual Report

**Gross Plant** (Note 1) (Note 2)

| Line No | | -3 Dec | -2 Jan | -2 Feb | -2 Mar | -2 Apr | -2 May | -2 Jun | -2 Jul | -2 Aug | -2 Sep | -2 Oct | -2 Nov | -2 Dec | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Production-Steam | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | Production-Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Trans.(Excl. Cap. Lease) | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | Trans. Capital Leases | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | General Plant | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | Intangible & Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | | | | | | | | | Transmission (Excludes Capital Leases) 12 month average December, -3 to November, -2 | | | | | | $ - |
| 10 | Trans. Oper Leases | | | | | | | | | | | | | | $ - |

Source: SEPC Financial Records. BOY and EOY totals may be found on Pg. 38 of SEPC's KCC Annual Report

**Accumulated Depreciation and Amortization** (Note 1) (Note 2)(Note 4)

| -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | 13 Months |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
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| | | | | | | | | | | | | | |

| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Production-Steam | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 12 | Production-Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | Trans.(Excl. Cap. Lease) Trans. | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | Capital Leases | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | General Plant | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | Intangible & Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 18 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 19 | Trans. Oper Leases | | | | | | | | | | | | | | $ - |

**Net Plant** (Gross Plant less Accumulated Depreciation and Amortization)

| | | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | 13 Months Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Balance |
| 20 | Production-Steam | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 21 | Production-Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 22 | Trans.(Excl. Cap. Lease) Trans. | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | - |
| 23 | Capital Leases | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 24 | Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | General Plant | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 26 | Intangible & Other | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 27 | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 28 | Trans. Oper Leases | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Construction Work in Progress** (Note 1)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **-3** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **-2** | **13 Months** |

| | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| Production | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Transmission | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| General Plant | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**Account 106 - Completed Plant Not Yet Classified - Add to Gross Plant**

| | -3 Dec | -2 Jan | -2 Feb | -2 Mar | -2 Apr | -2 May | -2 Jun | -2 Jul | -2 Aug | -2 Sep | -2 Oct | -2 Nov | -2 Dec | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| Production | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Transmission | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Distribution | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| General Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

1. When calculating the "Actual Gross Revenue Requirement," use the actual 13 month account balances for the year being trued-up.
2. For Capital Leases, the Plant-in-Service values are reduced as principal is paid off. No depreciation/amortization expense is recorded as it is included in the lease payment; and no reserves for depreciation are accumulated.
3. In accordance with 18 C.F.R. §§ 35.25(c)(3) and 35.25(e), without prior approval from the Commission, no more than 50 percent of CWIP may be included in the rate base. No AFUDC will be calculated on the portion of CWIP included in rate base.
4. Accumulated Depreciation and Amortization - Trans. (Excl. Cap. Lease) includes accumulated amortization for transmission leasehold improvements.

Workpaper A-12

**Sunflower Electric Power Corporation (SEPC)**

# 13 Month Average Balance and BOY-EOY Average Balances

**II. Adjustments to Rate Base**

| | | | EOY Balance -3 | EOY Balance -2 | Average Balance | 100% Non-Trans. Related | 100% Trans. Related | Plant Related | Labor Related |
|---|---|---|---|---|---|---|---|---|---|
| 39 | **Reserve Funds (Non-Escrowed) (Note A)** | | | | | | | | |
| 40 | Account 228.2 - Reserve for Inj. & Damages | | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 41 | | | $ - | $ - | $ - | - | - | - | - |
| 42 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 43 | | | | | | | | | |
| 44 | | | | Wages & Salary Allocator | | | | | #DIV/0! |
| 45 | | | | Gross Plant Allocator | | | | #DIV/0! | |
| 46 | | | | Direct Assign Allocator | | | 100.000% | | |
| 47 | | | | Allocated to Transmission | | $ - | $ - | #DIV/0! | #DIV/0! |

Note: Each non-escrowed reserve fund will be allocated based on Nontransmission, 100% Transmission, Plant Allocator, or Wages & Salary Allocator, as appropriate.

| | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | 13 Months Avg Bala |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | nce |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | **Unamortized Abandoned** | | | | | | | | | | | | | | |
| 8 | **Trans. Plt.** | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| 149 150 | Account 182.1 CWIP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | **Regulatory Liability for** | | | | | | | | | | | | | | |
| 151 152 | **Transmission** Account 254 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 153 154 155 | **Land Held for Future Use** | | | | | | | | | | | | | | |
| | Trans. Land | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

**III. Working Capital -Material & Supplies, Stores Expense and Prepayments**
Source: SEPC's Annual KCC Report and Corporate Records

(Note 1)

| | | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | 13 Months Avg Balance |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | |
| 156 157 | **Materials and Supplies** | | | | | | | | | | | | | | |
| 157 | Fuel Stocks | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 158 | Production O&M | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 159 | Transmission O&M | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 160 | Distribution O&M | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 161 | Prod. Construction | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 162 | Trans. Construction | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 163 | Dist. | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Construction | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | Total Mat. & | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | Supp. | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | 13 Mo |
| | | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | nths Avg |
| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Balance |
| 6 | **Stroes** | | | | | | | | | | | | | | |
| 5 | **Expense** | | | | | | | | | | | | | | |
| 6 | Total Stores | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | Expense | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | 13 Mo |
| | | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | nths Avg |
| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Balance |
| 6 | **Prepayments** | | | | | | | | | | | | | | |
| 6 | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Prepayments | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | |
| 7 | Total | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Prepayments | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | 13 Mo |
| | | -3 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | -2 | nths |
| | | | | | | | | | | | | | | | Avg |
| | | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Balance |
| 7 | Long-Term | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | Debt | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | Total | | | | | | | | | | | | | | |
| 7 | Membership | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Equity | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

## ADDENDUM 20 TO ATTACHMENT H - Part 2

# Sunflower Electric Power Corporation (SEPC)
# ATRR Calculation for Actual Year Competitively Bid Projects (Notes D, E & F)

Project:

| | Traditional ATRR for Competitive Bid Project | | | ATRR with Bid Commitments (Note A) | | | ATRR with Incremental Costs and/or Bid Commitments (Note A, B) | | |
|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| **Line** | **Description** | **Source** | **Amount** | **Description** | **Source** | **Amount** | **Description** | **Source** | **Amount** |
| 1 | Plant in Service | | | Plant in Service | | | Plant in Service | | |
| 2 | Accumulated Reserves for Depreciation | | | Accumulated Reserves for Depreciation | | | Accumulated Reserves for Depreciation | | |
| 3 | Net Plant | | $ - | Net Plant | | $ - | Net Plant | | $ - |
| 4 | | | | | | | | | |
| 5 | Return Based on Target TIER | | | Return Based on Target TIER | | | Return Based on Target TIER | | |
| 6 | Interest Rate | Actual Gross Rev Req L158 | #DIV/0! | Interest Rate | | | Interest Rate | | |
| | | Actual Gross Rev | 2.0 | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | Req | 30 | | |
| 7 | Target TIER | L150 | 0 | Target TIER | Target TIER |





| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Rate of Return New | | #DIV/0! | Rate of Return New | | 0.000 % | Rate of Return New | | 0.000 % |
| 8 | Projects | | | Project | | | Project | | |
| 9 | | | | | | | | | |
| 10 | O&M and A&G | A-7 (Act. RTO Directed Proj) L7 | #DIV/0! | O&M and A&G | | | O&M and A&G | | |
| 11 | | | | | | | | | |
| 12 | Other Taxes | A-7 (Act. RTO Directed Proj) L9 | #DIV/0! | Other Taxes | | | Other Taxes | | |
| 13 | | | | | | | | | |
| 14 | General Plant | A-7 (Act. RTO Directed Proj) L14 | #DIV/0! | General Plant | | | General Plant | | |
| 15 | | | | | | | | | |
| 16 | Carrying Charge Rate Based on Net Plant | L8 + L10 + L12 + L14 | #DIV/0! | Carrying Charge Rate Based on Net Plant | L8 + L10 + L12 + L14 | 0.000 % | Carrying Charge Rate Based on Net Plant | L8 + L10 + L12 + L14 | 0.000 % |
| 17 | Carrying Charges Based on Net Plant | L3 * L16 | #DIV/0! | Carrying Charges Based on Net Plant | L3 * L16 | $ - | Carrying Charges Based on Net Plant | L3 * L16 | $ - |
| 18 | | | | | | | | | |
| 19 | Depreciation | | | Depreciation | | | Depreciation | | |
| 2 | Average System Depreciation | A-5 (Act Depreciation Rate) | #DIV/ | Depreciation | | | Depreciation | | |

0 Rate L30 0! Rate Rate

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 21 | Depreciation Expense | L1 * L20 | #DIV/0! | Depreciation Expense | L1 * L20 | $ - | Depreciation Expense | L1 * L20 | $ - |
| 22 | | | | | | | | | |
| 23 | Total ATRR Traditional Calculation | L17 + L21 | #DIV/0! | Total ATRR with bid commitments | L17 + L21 | $ - | Total ATRR with increm. commit. costs | L17 + L21 | $ - |
| 24 | | | | | | | Total ATRR with bid commitments | L23 As Bid | $ - |
| 25 | | | | | | | Non-Transmission ATRR (Note C) | L24 - L23 | $ - |

**Note**

A Unless fixed or capped or discounted in the bid, project costs will use the formula rate allocated cost (Col (d)).

B Costs from column (j) to be reflected on A-7 in columns (e) through (n).

C Amount entered on tab A-7 cannot be greater than zero.

D Blue shaded cells represent input cells and are not derived from a formula.

E Tab A-13 will only be used when Sunflower has a competitively bid project in which Sunflower has made commitments in its bid for any of the adjustable line items. If Sunflower has a competitively bid project in which no commitments where made, tab A-13 shall be left blank and the project costs will appear the same as other RTO projects on tab A-7. Only the following items may be adjusted from the Traditional values (Col. d) in developing a Competititive Bid: financing costs, target TIER, depreciation expense, and other cash taxes.

F This spreadsheet will be replicated for each competitively bid project.

# Sunflower Electric Power Corporation (SEPC)
# True-up Adjustment and Timeline

**Timeline Illustration (See FERC approved Sunflower TFR Protocols)**

| Step | Month | Year | | Action |
|---|---|---|---|---|
| 1 | | Year 0 | 2019 | SEPC populates the formula rate using projected costs for Year 1 |
| 2 | | Year 0 | 2019 | Post results of Step 1 |
| 3 | Jan | Year 1 | 2020 | Results of Step 2 go into effect. |
| 4 | Jun | Year 1 | 2020 | SEPC populates the formula rate using projected costs for Year 2 |
| 5 | Jun | Year 1 | 2020 | Post results of Step 4 |
| | Jan | Year | | Results of Step 5 go |

6 n 2 2021 into effect.

| | | | | |
|---|---|---|---|---|
| 7 | Jun | Year 2 | 2021 | SEPC populates the formula rate using actual costs for Year 1 |
| 8 | Jun | Year 2 | 2021 | Calculate the difference between the formula rate calculated in Step 7 and Step 1 |
| 9 | Jun | Year 2 | 2021 | Post results from Step 7 and Step 8 |
| 10 | Jun | Year 2 | 2021 | SEPC populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |
| 11 | Jun | Year 2 | 2021 | Post results of Step 10 |
| 12 | Jan | Year 3 | 2022 | Results of Step 11 go into effect. |

## Reconciliation details for -2

| | | Base Plan (1) | Balance Portfolio (2) | ITP / Priority Project 1 (3) | ITP / Priority Project 2 (4) | Sponsored (5) | Third Party (6) | Zonal Rev Req (7) | Total Rev. Req. (8) |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Actual Revenue Requirements from Step 7 | $ - | #N/A | #N/A | #N/A | #DIV/0! | #N/A | $ - | #N/A |
| 2 | Projected Revenue Requirements from Step 1 (Note A) | - | #N/A | #N/A | #N/A | #DIV/0! | #N/A | - | #N/A |
| | True-up | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 3 | Amount (before interest) | $ - | #N/A | #N/A | #N/A | #DIV/ 0! | #N/A | $ - | #N/A |

# Sunflower Electric Power Corporation (SEPC)
# True-up Adjustment and Timeline

| | | | |
|---|---|---|---|
| 4 | Jun | Year 2 | Post results from Step 7 and Step 8 |
| 5 | Jun | Year 2 | SEPC populates the formula rate using projected costs for Year 3, including true-up adjustment for Year 1 |

**Interest Calculation**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | **FERC Quarterly Interest Rate** | | | | | | | |
| 6 | | Qtr 3 (Previous Year) | | | | | | | |
| 7 | | Qtr 4 (Previous Year) | | | | | | | |
| 8 | | Qtr 1 (Current Year) | | | | | | | |
| 9 | | Qtr 2 (Current Year) | | | | | | | |
| 10 | | Average of the last 4 quarters | Sum(L6:L9) / 4 | | 0.000 0% | | | | |
| 11 | | Compounded Interest Rate | | | 0.000 0% | | | | |

| | **Base Plan** (1) | **Balance Portfolio** (2) | **ITP / Priority Project 1** (3) | **ITP / Priority Project 2** (4) | **Sponsored** (5) | **Third Party** (6) | **Zonal Rev Req** (7) | **Total Rev. Req.** (8) |
|---|---|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | True-Up Amount (line 8c) | | | | #DIV/ | | $ | |
| 2 | (Note B) | #N/A | #N/A | #N/A | 0! | #N/A | - | #N/A |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 3 | Interest on True-up Amount ([Compound Interest Rate / 12 months]*24 mo.) | - | #N/A | #N/A | #N/A | #DIV/ 0! | #N/A | - | #N/A |
| 1 4 | **True-up Adjustment (Note C)** | **$ -** | **#N/A** | **#N/A** | **#N/A** | **#DIV/ 0!** | **#N/A** | **$ -** | **#N/A** |
| 1 5 | 2019 Sunflower Electric Power Corporation True-Up (Note D) | - | - | - | - | - | - | - | - |
| 1 6 | 2019 Mid-Kansas Electric Company, Inc. True-Up (Note D) | - | | | | | | - | - |
| 1 7 | **True-up Adjustment** | **$ -** | **#N/A** | **#N/A** | **#N/A** | **#DIV/ 0!** | **#N/A** | **$ -** | **#N/A** |

**Notes:**

A Enter the Projected Revenue Requirement for the Actual period without a true-up adjustment plus any adjustments, either positive or negative, resulting from corrections of prior years. For 2013 and 2014, set this equal to L2

B If the annual update is for a partial year, not 12 months, then the amount on L12 shall be prorated to represent the number of months in the partial year.

C If the annual update is for a partial year, monthly interest will be multiplied by 18 plus one-half of the months in the partial year.

D The 2018 True-Up was calculated on an individual company basis. Per FERC Docket ER19-2273, the individual company true-ups will be summed together for the merged Sunflower entity. For the 2018 and 2019 individual true-ups, Sunflower will calculate a total collection amount using the transition method attached to the Sunflower protocols.

RTO Project Summary Page 1 of 13

# Sunflower Electric Power Corporation (SEPC)
# RTO Project Summary - Summary of RTO Directed Projects
# Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):
# For the 12 months ended - December 31, 2020

| L | Source | Total System | Development of Applicable Carrying Charges: Base Plan Project | Base Plan Candidate Project | ITP Priority #1 Project | ITP Priority #2 Project | Sponsored Project | Third Party Project |
|---|---|---|---|---|---|---|---|---|

| i | | r | t | j | t | r | r | j | j |
|---|---|---|---|---|---|---|---|---|---|
| n | Descript | c | e | e | f | o | o | e | e |
| e | ion | e | m | c | o | j | j | c | c |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | **t s** | **l i o** | **e c t s** | **e c t s** | **t s** | **t s** |
| 1 | Transmission Gross Plant in Service (excludes leases) | Projected Gross Rev Req L3 - L4 | $ - | | | | | | |
| 2 | Transmission Net Plant in Service (excludes leases) | Projected Gross Rev Req L21 - L22 | #DIV/0! | | | | | | |
| 3 | Plus: Net Plant Attributable to Capital Lease Projects | P-1 (Trans Plant), L187 | $ - | | | | | | |
| | Net Plant Excluded for O&M, Other Taxes and | Note | | | | | | | |

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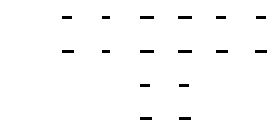

| | | | |
|---|---|---|---|
| | al Plant Adjusted Net Plant for O&M and Other | L2 + L3 - | #DIV/0! |
| 5 | Taxes | L4 | |
| 6 | Transmission O&M (includes allocation of A&G) | Projected Gross Rev Req L65 - L64 | #DIV/0! |
| 7 | Percent of Net Plant | L6 / L5 | #DIV/0! |
| 8 | Other Taxes | Projected Gross Rev Req L85 | #DIV/0! |
| 9 | Percent of Net Plant Gener | L8 / L5 | #DIV/0! |

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| | angible Plant Allocation | | | | | | | | | | |
| 11 | Depreciation | Projected Gross Rev Req L71 + L72 | #DIV/0! | | | | | | | | |
| 12 | Return | Projected Gross Rev Req ((L24 + L25) / L26) * L88 | #DIV/0! | | | | | | | | |
| 13 | Total | L9 + L10 | #DIV/0! | | | | | | | | |
| 14 | Percent of Net Plant | L11 / L5 | #DIV/0! | | | | | | | | |
| 15 | Return (New Facilities) | Actual Gross Rev Req L158 * L150 | #DIV/0! | | | | | | | | |
| | True-Up Ad | True-Up (True-Up | | # | # | # | | | #DIV/0! | # | |

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|---|---|---|---|---|---|---|---|---|---|
| 17 | As a Percent of Actual Projects Revenue Requirements | L14<br>L16 / Col. q below (or the equivalent) | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |



RTO Project Summary Page 2 of 13

## Sunflower Electric Power Corporation (SEPC) RTO Project Summary -



RTO Project Summary Page 3 of 13

## Sunflower Electric Power Corporation (SEPC)

# Summary of RTO Directed Projects

# RTO Project Summary - Summary of RTO Directed Projects

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D): For the 12 months ended - December 31, 2020**

**Base Plan Projects** *(Sunflower Owned)*

Note A: All line references are to page 1 of this worksheet.

Note B: To be completed with any BPP project approved by the Southwest Power Pool.

Note C: This tab shows the amount in column **s** that SPP is required to recover for

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**

**For the 12 months ended - December 31, 2020**

**Base Plan Projects (Sunflower Owned) (continued)**

-

each BPP project.

Note D: Effective carrying charge rate as a percent of net plant before true up is applied.

Note E: For competitively bid projects, data for columns a through n for new Projected Projects are taken from Worksheet P-7.

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) | (v) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | **Non-Transm** | | | | |
| | | | | | | | | | | | | | | | **Gross Rev** | | **Net** | **Related** | **Adjusted Net** | | **Net Revenue** | |
| **In Servi** | **Plant** | **Actual A** | **Actual N** | **Depreci** | **Project** | **Project** | **O** | **Oth** | **Non-Inc** | **General** | | | **Tot** | **Project** | **Req Be** | **Reven** | **Reven** | **Competi** | **Reven** | **True-** | **Require** | **Eff Car** |

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| Line | Project ID | Project Description | Date | Service Delivery Plan @ 12/-2002 | @ 12/-2002 | @ 12/-2002 | um | ion | Added | Net | tive | ant | Accum Deferred Rate | Plan Rate | Expense | Tax | Return | Allocation | Allocation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | |
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| Project ID | Project Description | Return Adder (A-9 as applicable) | Return (f*i)+(f*k) | Expense (a*d) | Adjustments (g+h+j+m+n) | Credits | Requirements (o-p) | Adjustment | Requirements (q o)+(r) | Adjustment *L17) | with True-Up (s+t) | Charge Rate (D) (o/f) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual Projects (Inputs from Worksheet A-7) | | | | | | Note F) | | | | | | |

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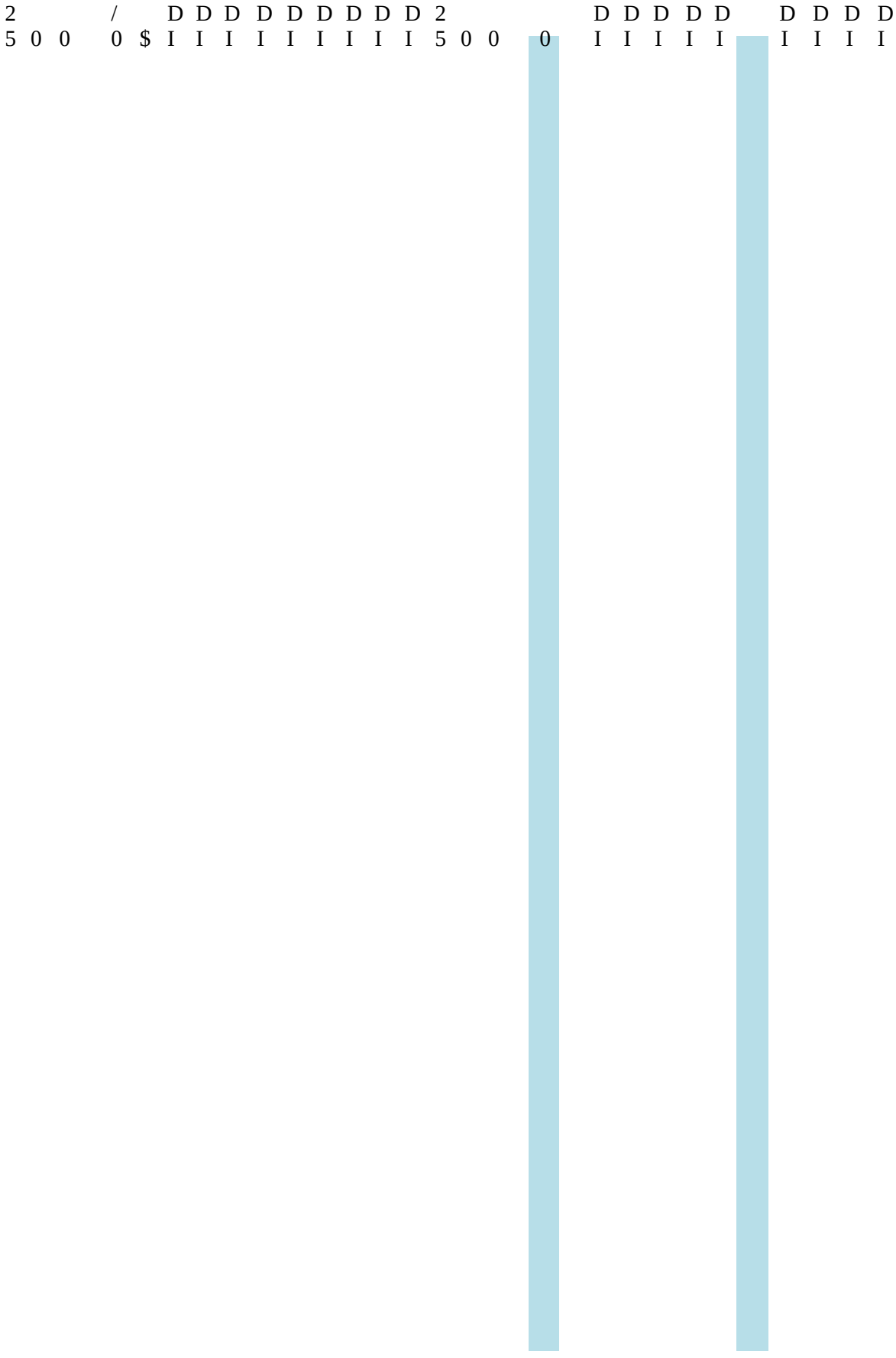
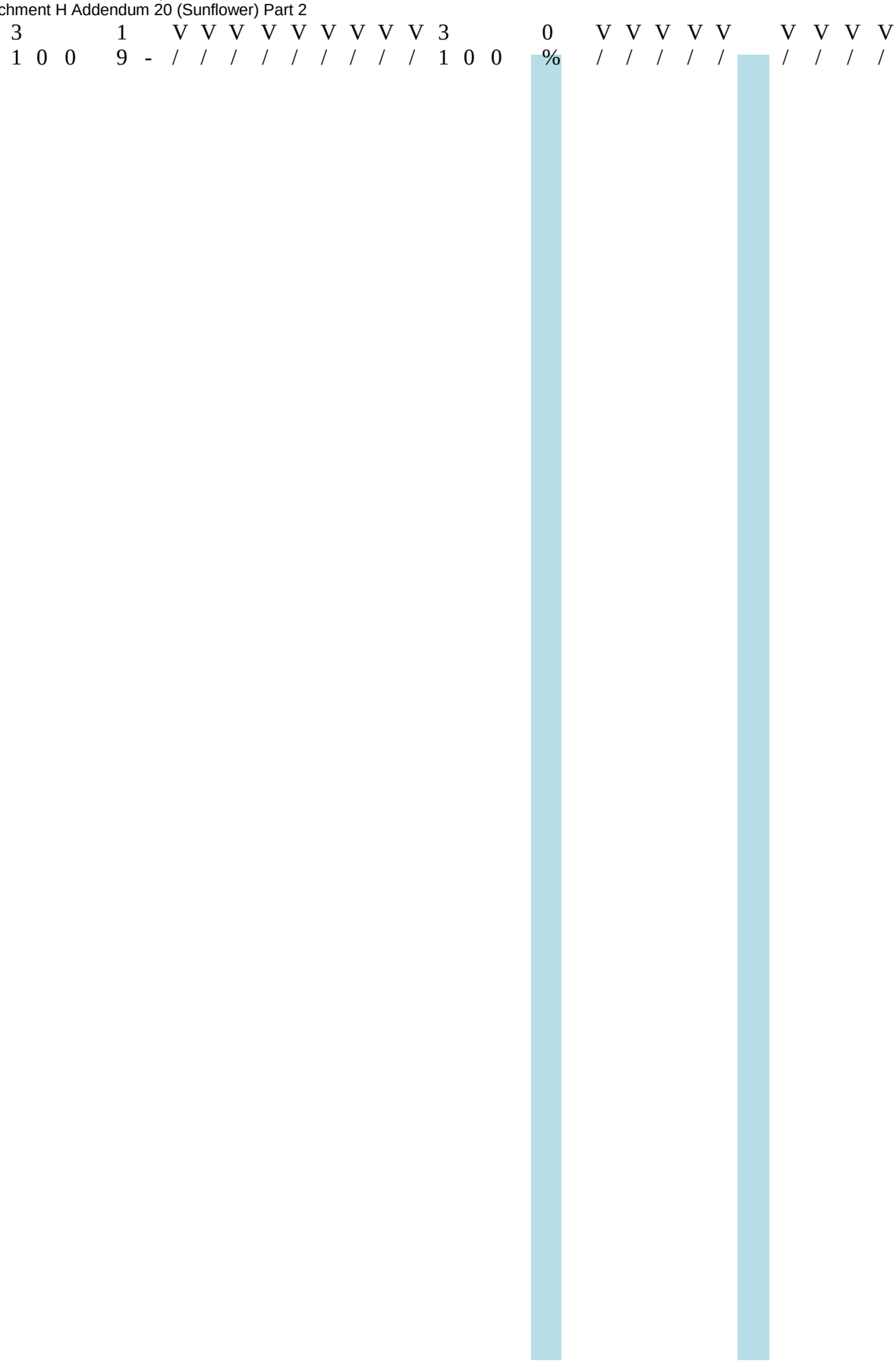


| | | |



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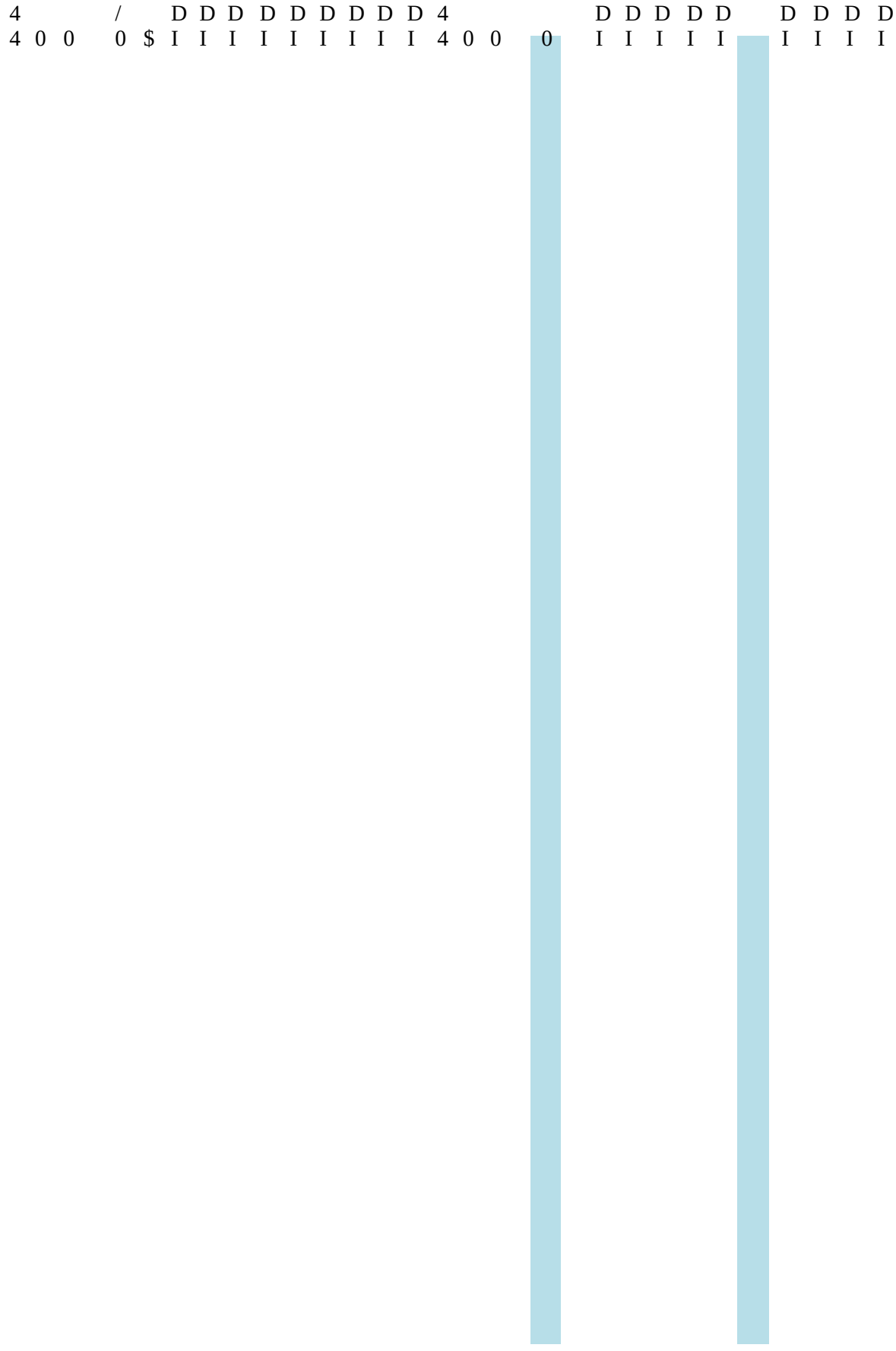
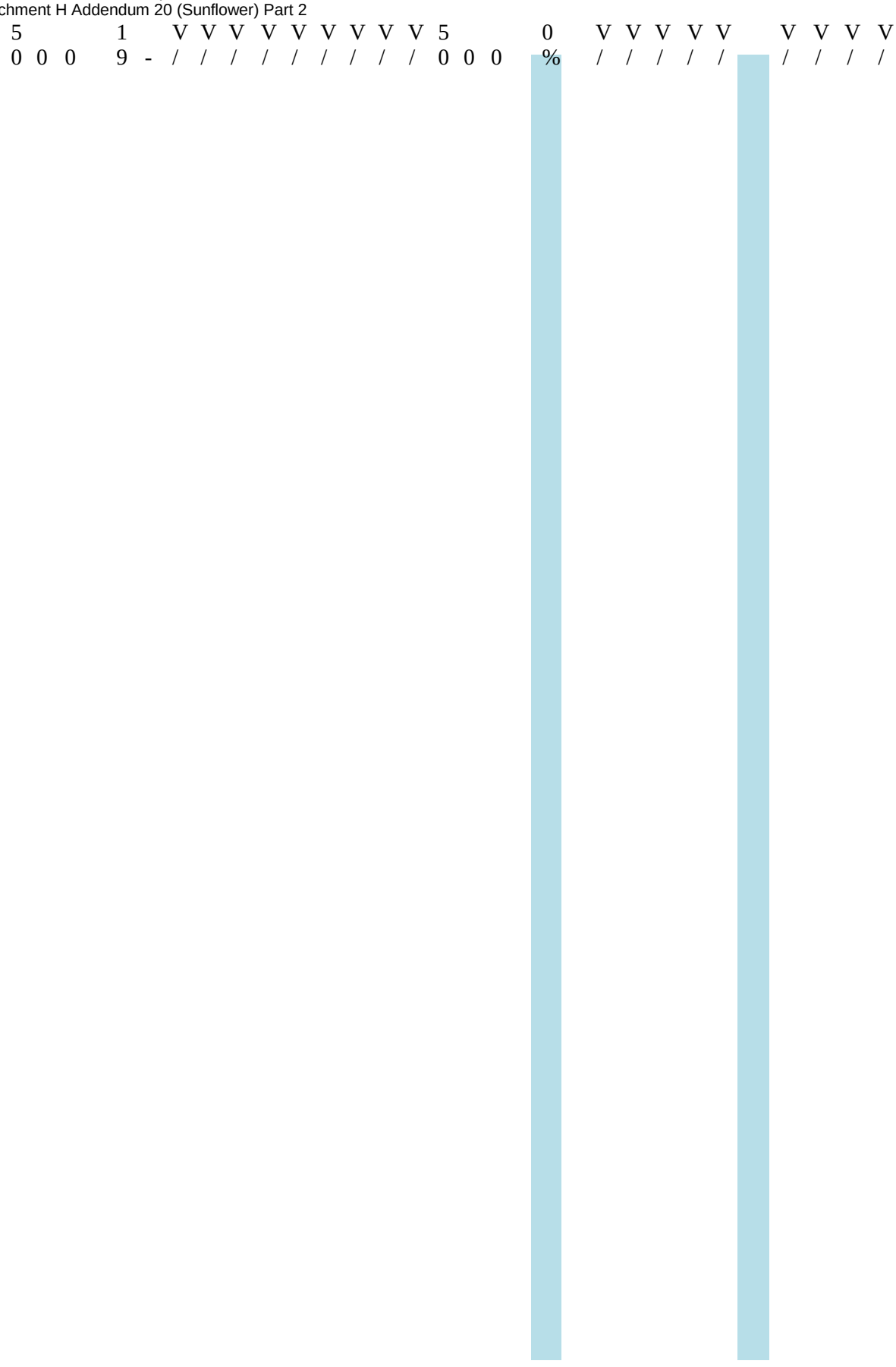


| | | |



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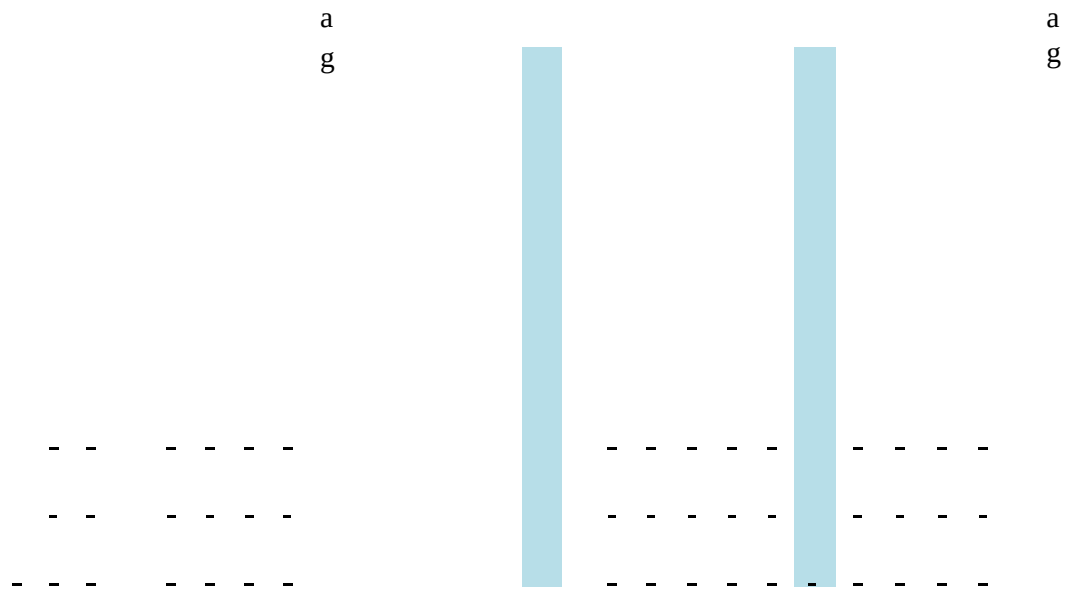
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**Sunflower Electric Power Corporation (SEPC)**
**RTO Project Summary - Summary of RTO Directed Projects**
**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**
**For the 12 months ended - December 31, 2020**

| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|
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| | **Project ID** | **Project Description** | **Service Date** | **Accum Depr** | **Plant Xfer** | **Expense Return** | **Allocation** | **Project ID** | **Project Description** |
|---|---|---|---|---|---|---|---|---|---|
| 62 | | | | | | | | | |
| 63 | | (WPP-4) | | (WPP-4) | | ((ff(a**LL-LL1e795463)))) | (f*1) | | |
| 64 | **Projected *Sunflower Owned* Base Plan Projects (Inputs from Worksheet P-4)** | | | | | | | **Projected projects (Inputs from Worksheet P-4)** | |
| | | | $ | #DI | | ##### DDDDD IIII I | | | |

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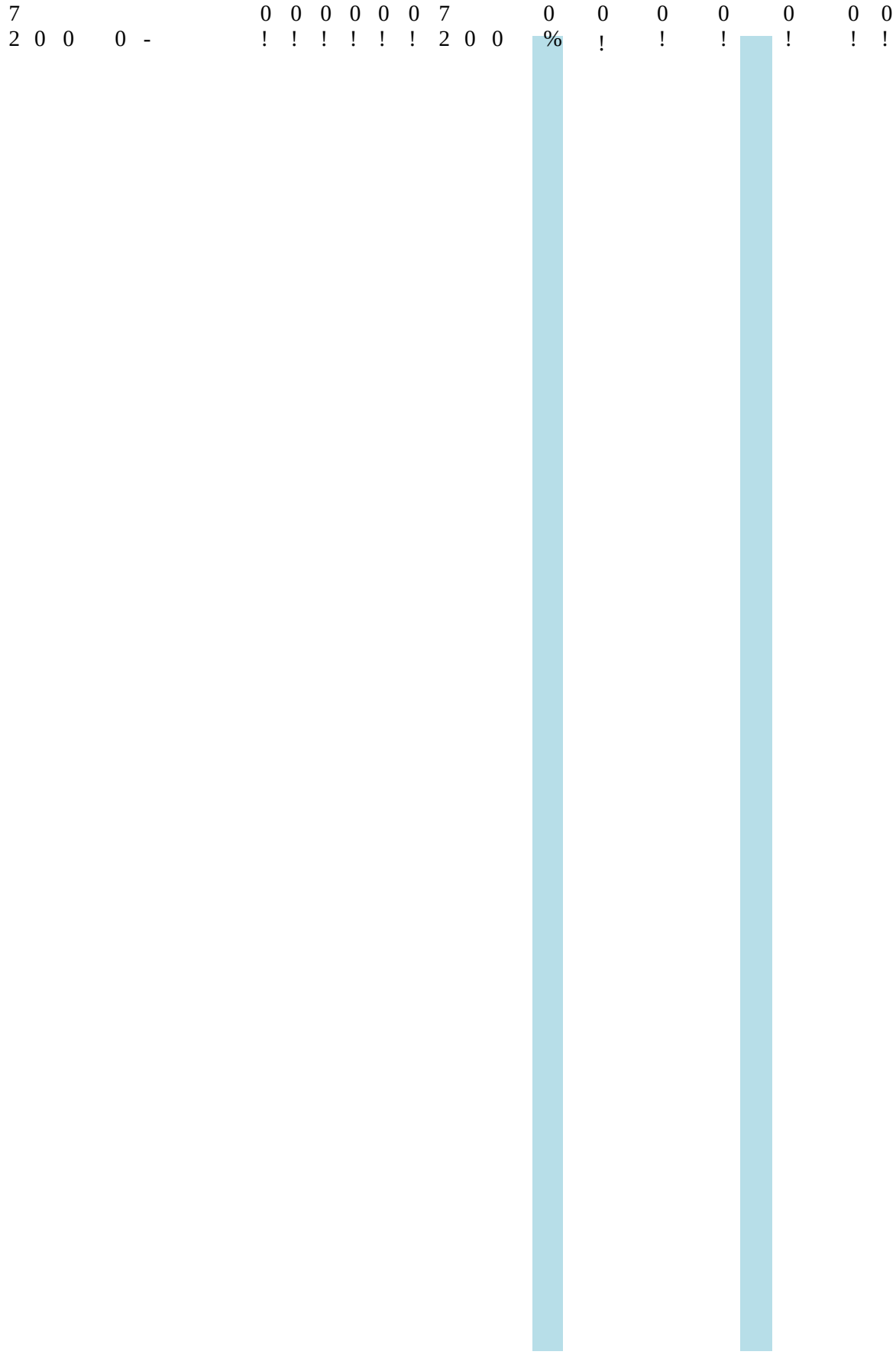
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| | | |

**Sunflower Electric Power Corporation (SEPC)**
**RTO Project Summary - Summary of RTO Directed Projects**
**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**
**For the 12 months ended - December 31, 2020**

| | | |

**(Capital Leases) (continued)**

**Sunflower Electric Power Corporation**

**(SEPC)**

**RTO Project Summary - Summary of RTO Directed Projects**

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**

**For the 12 months ended - December 31, 2020**

**Base Plan Projects**

page 1 of this worksheet.

Note B: To be completed with any BPP project approved by the Southwest Power Pool.

Note C: This tab shows the amount in column **s** that SPP is required to recover for each BPP project.

Note D: Effective carrying charge rate as a percent of net plant before true up is applied.

Note E: For competitively bid projects, data for columns a through n for new Projected Projects are taken from Worksheet P-7.

| ( a ) | ( b ) | ( c ) | ( d ) | ( e ) | ( f ) | ( g ) | ( h ) | ( i ) | ( j ) | ( k ) | ( l ) | ( m ) | ( n ) | ( o ) | ( p ) | ( q ) | ( r ) | ( s ) | ( t ) | ( u ) | ( v ) |
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| | | | | | | | | | | | | | | **Gross** | | **Non-N** | **Adju** | | | | |

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| Line | Project ID | Project Description | Date | In Service | Plant in Service @ 12/-2002 (WPA- | Actual Accum Amor @ 12/-2002 (WPA- | Actual Net Plant @ 12/-2002 (a- | Projected Accum Amort (13mo A | Projected Net Plant (a- | O&M Expenses (f*L | Other Taxes (f*L | General Plant Allocation (f*L1 | Line | Project ID | Project Description | 0 Lease Payments | Req Before Adjustments (g+h+j+ | Revenue Credits Not | Revenue Requirements (o- | Adjustment Requirements (q)+( | Revenue Adjustment (o*L1 | True-up Adjustment (s+ | Net Revenue Requirements (s+ | Eff Carrying Charge Rate (D) (o/ |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | | |

Effective Date: 1/1/2020 - Docket #: ER19-2273-003 - Page 3537

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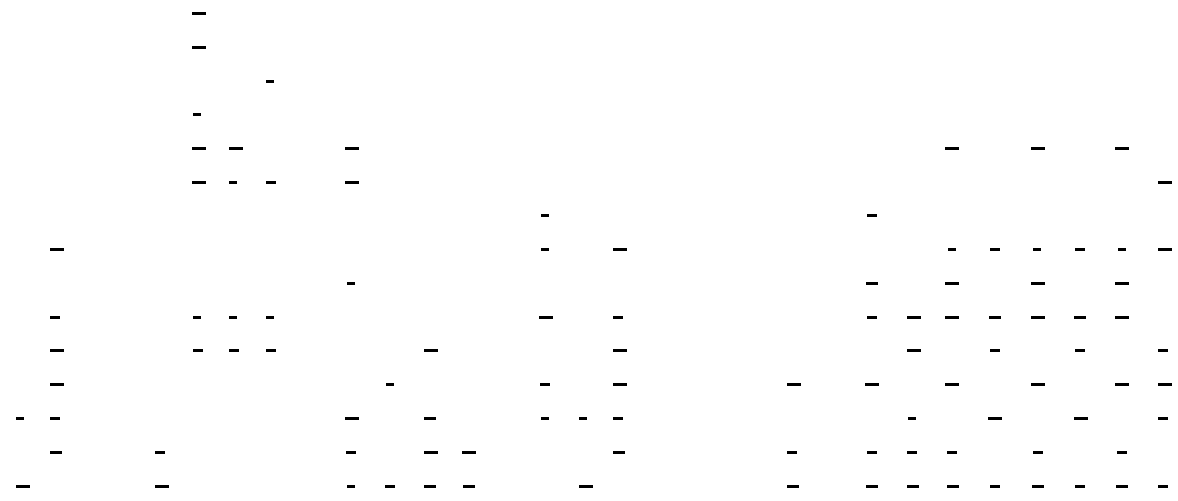
) ) ) g ) ) ) ) ) F ) ) ) ) )



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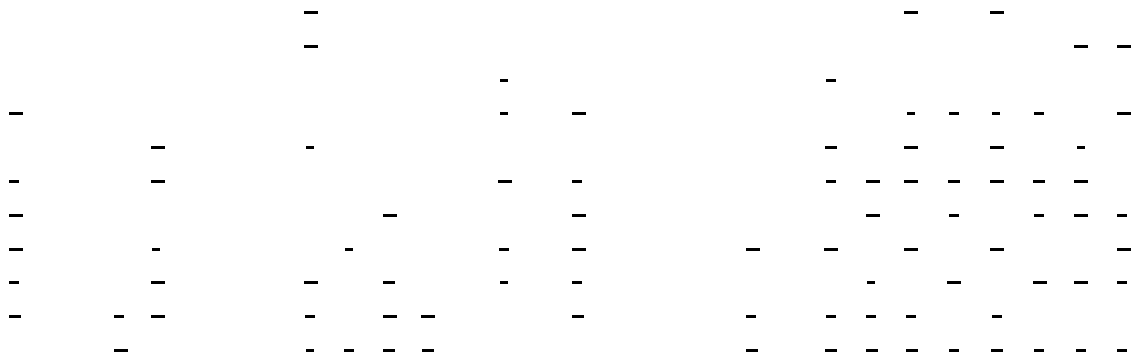

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| 95 | | | | | | | |
| 96 | **Total Capital Lease Base Plan Projects (L86 + L94)** | $ - | $ - | $ - | #DIV/0! | #DIV/0! | #DIV/0! |





**Sunflower Electric Power Corporation (SEPC)**

**RTO Project Summary - Summary of RTO Directed**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 95 | | | | | | | | | |
| 96 | **Total Capital Lease Base Plan Projects (L86 + L94)** | $ - | #DIV/0! | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |





**Sunflower Electric Power Corporation (SEPC)**

**RTO Project Summary - Summary of**

**Projects** **RTO Directed Projects**

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D): For the 12 months ended - December 31, 2020**

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D): For the 12 months ended - December 31, 2020**

**Balanced Portfolio Projects**

**Balanced Portfolio Projects (continued)**

Note A: All line references are to page 1 of this worksheet.
Note B: To be completed with any BPP project approved by the Southwest Power Pool.
Note C: This

tab shows the amount in column **s** that

SPP is required to recover for each BPP project.

Note D: Effective carrying charge rate as a percent of net plant before true up is applied.

Note E: For competitively bid projects, data for columns a through n for new Projected Projects are taken from Worksheet P-7.

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) | (v) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | **Non-Transm Related Comp** | **Adjusted Net Rev** | | | |
| | | | | | | | | | | | | | | | **Gross Rev** | | **Net Rev** | | | | | |
| **In Ser** | **Plant** | **Acc** | **Actua** | **Depre** | **Proj** | **Proje** | **O** | **Oth** | **Non-I** | **Gener** | | **Tot** | **Proje** | **Req B** | **Reven** | **Reven** | | **Reven** | **Tru-** | **Net R** | **Eff C** | |

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| Line | Project ID | Project Description | Date | Service @12/-2002 | Depr @12/-2002 | Plant @12/-2002 | Rate | Accum Depr | Plant | Expenses | Taxes | Return | Allocation | Line | Project ID | Project Description | Return Adder | Return | Expense | Adjustments | Credits | Requirements | Adjustment | Requirements | Adjustment | Requirements | Charge Rate (D) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | (A-9 as applicable) | | | | | | | | | | |
| | | | | (WPA-7) | (WPA-7) | (a-b) | (WPA-5) | 15*(a*d) | (a-b-e) | (f*L7) | (f*L9) | (L15) | (f*L14) | | | | | (f*i)+(f*k) | (a*d) | (g+h+j+m+n) | NA | (o) | | (q)+(r) | (o*L17) | (s+t) | (o/f) |
| 9 | Actual Balanced Portfolio Projects (Inputs from Worksh | | | | | | | | | | | | | 9 | Actual Balanced Portfolio Projects (Inputs from Workshe | | | | | | | | | | | | |

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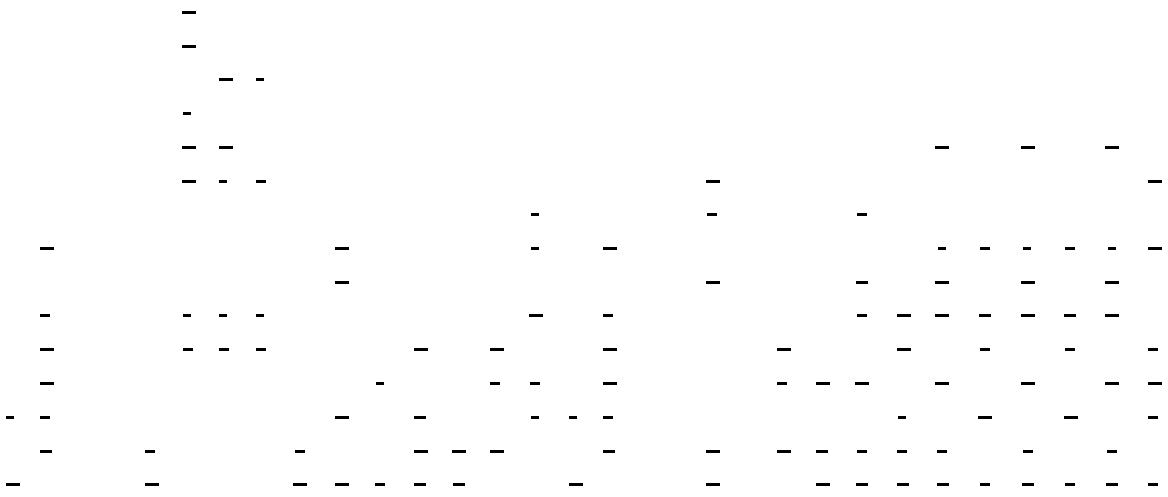

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| 104 | v g | v g | 104 | | ev | Net | Rel | Net |

| 105 | | | In Service | Plant In Service | Project Net Plant | Project Net O&M | Other | Non-Incentivized | General Plant | 105 | | | Total | Project Depr | Req Before | Revenue Neutral | Revenue Neutral | Reduced Composite Tax Bid | Revenue Neutral | True-up | Net Revenue Neutral | Eff Carrying Charge Rate (D) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 106 | Project ID | Project Description | Date | Service 0 | Accum Depr | Plant | Expenses | Taxes | Return | Allocation | 106 | Project ID | Project Description | Return | Expense | Adjustment | Credits | Req Increase | Adjustment | Req Increase | Adjustment | Req Increase |
| 107 | | | | (WPP-4) | (WPP-4) | (a-e) | (f*L7) | (f*L9) | (L15) | (f*L14) | 107 | | | (f*i)+(f*k) | (P-4) | (g+h+j+m+n) | NA | (o) | (q)+(r) | NA | (s) | (o/f) |
| 71 | Projecte | | | | | | | | | | 71 | Projecte | | Return Added (P-1 applicable) | | | | | | | | |

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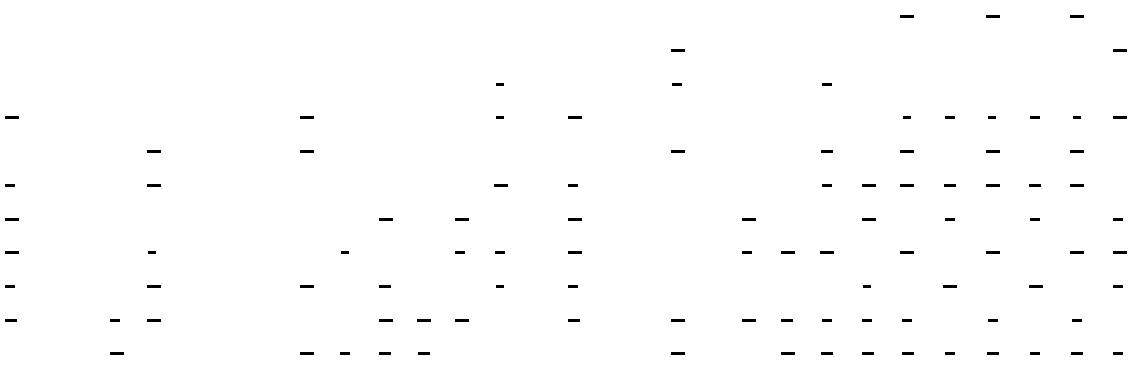
| 8 **Balance** | 8 **Balance** |



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| 1 | **Proje** | | 0 | 0 | 0 | 0 | 0 | 1 | **Proje** | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 |
| 5 | **cts** | - | ! | ! | ! | ! | ! | 5 | **cts** | ! | ! | ! | ! | - | ! | ! | ! | ! |

**(L102 + L113)**

**(L102 + L113)**



**Sunflower Electric Power Corporation (SEPC)**
**RTO Project Summary - Summary of RTO Directed Projects**
**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**
**For the 12 months ended - December 31, 2020**

**IT**



**Sunflower Electric Power Corporation (SEPC)**

**RTO Project Summary - Summary of RTO Directed Projects**

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**
**For the 12 months ended - December 31, 2020**

**ITP/**

**P/ Prio**

**Priority 1 Projects**

**Priority 1 Projects (continued)**

Note A: All line references are to page 1 of this worksheet.

Note B: To be completed with any ITP1 project approved by the Southwest Power Pool.

Note C: This tab shows the amount in column **s** that SPP is required to recover for each ITP1 project.

Note D: Effective carrying charge rate as a percent of net plant

before true
up is
applied.

Note E: For competitively bid projects, data for columns a through n for new Projected Projects are taken from Worksheet P-7.

| Line | Project Description | (a) Data | (b) In Service | (c) Plant Investment | (d) Accumulated Depr | (e) Net Plant | (f) Depreciation Rate | (g) Project Net Plant | (h) Project Additions | (i) O&M Expense | (j) Other Taxes | (k) Non-Incentive Return | (l) Incentive Return | (m) General Plant Allocation | (n) Total Project Expenses | (o) Gross Rev Requirements | (p) Project Deferred Expenses | (q) Rev Credits | (r) Net Rev Requirements | (s) Non-Transmission Related | (t) Total Adjusted Net Rev Requirements | (u) True-up Adjustments | (v) Net Rev Requirements | (w) Effective Carrying Charge |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | Company Total | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | |
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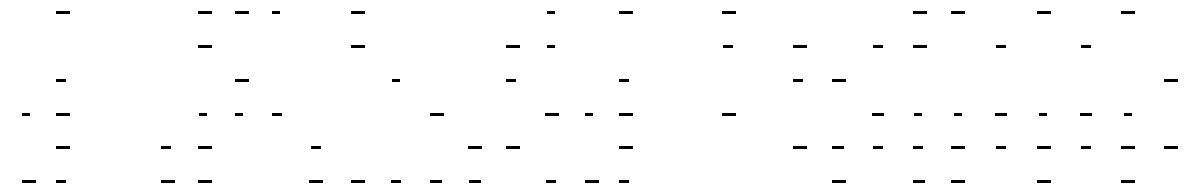

| | ID | ion | @12/-2002 | 2/-2002 | 2/-2002 | | pr | | es | | | ion |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (WPA-7) | (WPA-7) | (a-b) | (WPA-5) | 15*(a*d) | (a-b-e) | (f*L7) | (f*L9) | (L15) | (f*L14) |
| 116 | **Actual ITP/Priority 1 Projects (Inputs from Worksheet A-7)** | | | | | | | | | | | |
| 117 | 0 | Description | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 1 | | Descr | $ | #DI | #DI | #DI | #DI | #DI | #DI | #DI | #DI | #DI |

| | ID | ion | dder | | | ents | | ments | ent | ments | ent | ments | ate(D) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | (A-9 as applicable) | (f*i)+(f*k) | (a*d) | (g+h+j+m+n) | NA | (o) | | (q)+(r) | (o*L17) | (s+t) | (o/f) |
| 116 | **Actual ITP/Priority 1 Projects (Inputs from Worksheet A-7)** | | | | | | | | | | | | |
| 117 | 0 | Description | 0 00% | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
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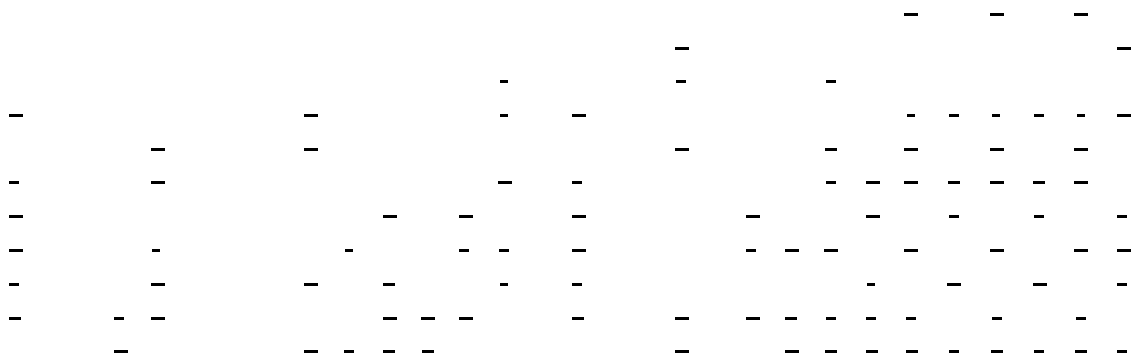
| 1 | **I** | **P** | | **P** | **P** | **O** | **O** | **N** | **G** | 1 | | **T** | **P** | **R** | **R** | **R** | **C** | **R** | **T** | **N** | **E** |
| 2 | **n** | **l** | | **r** | **r** | **&** | **t** | **o** | **e** | 2 | | **o** | **r** | **e** | **e** | **e** | **o** | **e** | **r** | **e** | **f** |
| 4 | **S** | **a** | | **o** | **o** | **M** | **h** | **n** | **n** | 4 | | **t** | **o** | **q** | **v** | **v** | **m** | **v** | **u** | **t** | **f** |

| | Project ID | Project Description | Date | Service 0 | | Account Dep | Plant | Expenses | Tax | Return | Allocation | | Project ID | Project Description | Return Added (P-1 as applicable) | Return | Expense | Adjustment Investment | Credits | Requirements Investment | Adjustment Investment | Requirements Investment | Adjustment Investment | Requirements Investment | Revenue | Carrying Charge Rate (D) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 125 | | | | | | | | | | | | 125 | | | | | | | | | | | | | | |
| 126 | | | | (WPP-4) | | (WPP-4) | (a-e) | (f*L7) | (f*L9) | (L15) | (f*L144) | 126 | | | | (f*i)+(f*k) | (P-4) | (g+h+j+m+n) | NA | (o) | | (q)+(r) | NA | (s) | | (o/f) |
| 1 | Projected ITP/Priority 1 Projects (Inpu | | | | | | | | | | | 1 | Projected ITP/Priority 1 Projects (Inputs from | | | | | | | | | | | | | |

2 **ts** 2 **Workshe**
7 **from** 7 **et P-4)**



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**Sunflower Electric Power Corporation (SEPC)**
**RTO Project Summary - Summary of RTO Directed Projects**
**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**
**For the 12 months ended - December 31, 2020**

**ITP/ Priorit**



**Sunflower Electric Power Corporation (SEPC)**

**RTO Project Summary - Summary of RTO Directed Projects**

**Revenue Requirement of SPP Projects included in SEPC's Projected Revenue Requirements (Note D):**
**For the 12 months ended - December 31, 2020**

**ITP/ Priority 2 Proj**

**y** **ects**
**2** **(con**

**Projects (continued)**

Note A: All line references are to page 1 of this worksheet.

Note B: To be completed with any ITP2 project approved by the Southwest Power Pool.

Note C: This tab shows the amount in column **s** that SPP is required to recover for each ITP2 project.

Note D: Effective carrying charge rate as a percent of net plant before true up is applied.

Note E: For competitively bid projects, data for

columns a through
n for new
Projected Projects

are taken from Worksheet P-7.

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) | (v) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | Non-Transmission Related | | | | |
| | | | | | | | | | | | | | | | Gross Rev | | Net | Related Competitive Bid | Adjusted Net | | | |
| | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | Projected Depr | | | | | | | | |
| | | | | | | | | | | | | | | | Req Before | | | Adjust Transm | | | | |
| | | | | | | | | | | | | | Total | | | | | | | | | |
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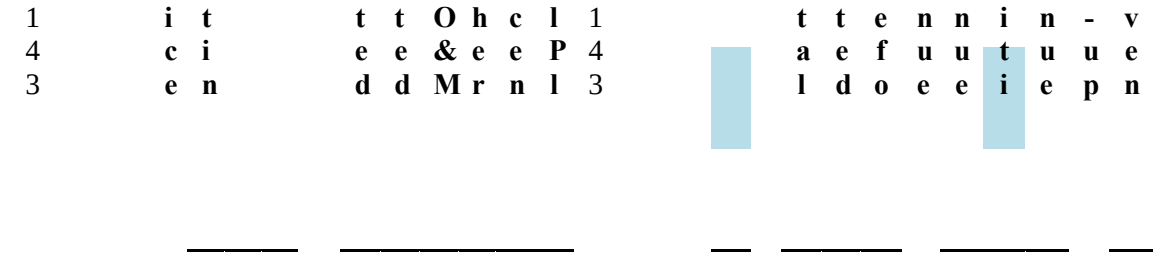
| 3 | | ipt | | I | I | I | I | I | I | I | I | I | 3 | | ipt | | I | I | I | | I | | I | I | I | I |
| 8 | 0 | ion | - | V | V | V | V | V | V | V | V | V | 8 | 0 | ion | 0 | V | V | V | | V | | V | V | V | V |

| | | |



| | Project ID | Project Description | Date | Service 0 | | Accum Depr | Plant | Expenses | Taxes | Return | Allocation | | Project ID | Project Description | Return Added (P-1 as applicable) | | Return | Expense | Adjustments | Credits | Required Revenues | Adjustment | Required Revenues | Adjustment | Required Revenues | Charge Rate (D) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 144 | | | | | | | | | | | | 144 | | | | | | | | | | | | | | |
| 145 | | | | (WPP-4) | | (WPP-4) | (a-e) | (f*L7) | (f*L9) | (L15) | (f*L144) | 145 | | | | (f*i)+(f*k) | | (P-4) | (g+h+j+m+n) | NA | (o) | (q)+(r) | NA | (s) | (o/f) |
| 146 | Projected ITP/Priority 2 Projects (Inputs from Worksheet P-4) | | | | | | | | | | | 146 | Projected ITP/Priority 2 Projects (Inputs from Worksheet P-4) | | 0 | # | | # | # | # | # | # | # | # | # | # |
| 161 | | | | | | | | | | | | | | | | | | | | | | | | | | |

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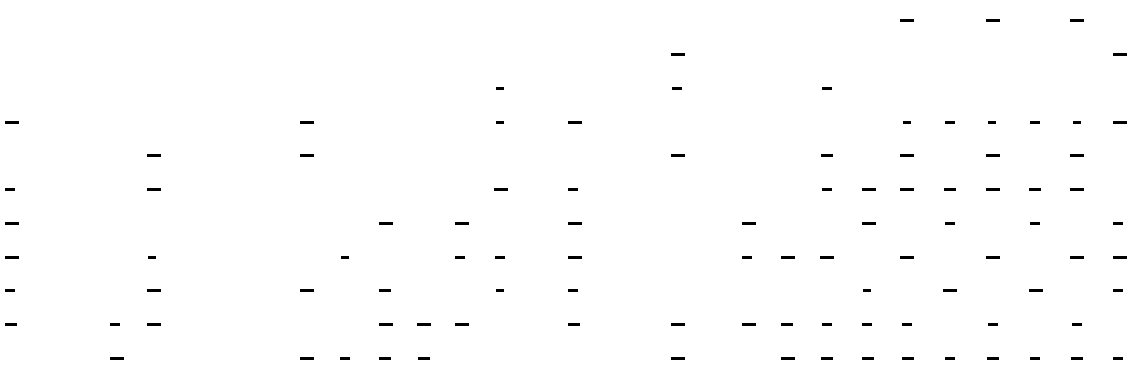
| 4 | | De | | | D | D | D | D | D | D | 4 | | De | | D | | D | | D | | D | | D | D |
| 7 | 0 | scr | | $ | I | I | I | I | I | I | 7 | 0 | scr | 0 | I | $ | I | | I | | I | | I | I |



| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ipt ion | - | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | | | ipt ion | 0 % | V / 0 ! # D I | - | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I |
| 148 | 0 | De scr ipt ion | $ - | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | 148 | 0 | De scr ipt ion | 0 0 % | V / 0 ! # D I | $ - | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I | V / 0 ! # D I |
| 149 | 0 | De scr ipt ion | $ - | V / 0 ! | V / 0 ! | V / 0 ! | V / 0 ! | V / 0 ! | V / 0 ! | 149 | 0 | De scr ipt ion | 0 0 % | V / 0 ! | $ - | V / 0 ! | V / 0 ! | V / 0 ! | V / 0 ! | V / 0 ! | V / 0 ! |
| 150 | | | | | | | | | | 150 | | | | | | | | | | | |
| 151 | | **Total of Projected ITP/Priority 2 Projects** | $ - | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | 151 | | **Total of Projected ITP/ Priority 2 Projects** | | # D I V / 0 ! | $ - | # D I V / 0 ! | # D I V / 0 ! | $ - | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! |
| 152 | | | | | | | | | | 152 | | | | | | | | | | | |
| 153 | | **Total ITP/Priority 2 Projects (L140 + L151)** | $ - | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | 153 | | **Total ITP/ Priority 2 Projects (L140 + L151)** | | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! | $ - | # D I V / 0 ! | # D I V / 0 ! | # D I V / 0 ! |
| 154 | | | | | | | | | | 154 | | | | | | | | | | | |
| | | **Total Non-Trans** | | | | | | | | | | **Total Non-Transmi** | | | | | | | | | |

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| 5 | **on** | | | 5 | **Related** | | | | |
| 5 | **Relat** | | | 5 | **Competi** | | | - | |
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# Sunflower Electric Power Corporation (SEPC)
# Sponsor Funded Project Summary
# Revenue Requirement for Sponsor Funded Projects (SFP) included in SEPC's Projected Revenue Requirements
# For the 12 months ended - December 31, 0

Note A: All line references are to "RTO Project Smry" Workpaper, Pg 1.
Note B: To be completed with any projects sponsored by the host transmission owner.

| Line | Project ID | Project Description | In Service Date | (a) Plant in Service @ 12/-2002 (WP A-8) | (b) Actual Accum Depr. @ 12/-2002 (WP A-8) | (c) Actual Net Plant @ 12/-2002 (a - b) | (d) Depreciation Rate (WP A-5 Rev) | (e) Projected Added Accum. Depr 1.5 * (a * d) | (f) Projected Net Plant (a - b - e) | (g) O&M Expenses (f * L7) | (h) Other Taxes (f * L19) | (i) General Plant Allocation (f * L14) | (j) Non-Incentive Return (L15) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Actual Sponsored Projects (Inputs from Worksheet A-8)** | | | | | | | | | | | |
| 2 | | | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | | | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

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| | | $ | #DIV | #DIV | #DI | #DI | #DI | V/0 | # | #DI | #DI |
| 4 | | - | /0! | /0! | V/0! | V/0! | V/0! | ! | DI | V/0! | V/0! |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | | | #DIV/0! | | |
| 6 | **Total of Actual Sponsored Projects** | | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 7 | | | | | | | | | | | | | |
| 8 | | | | **Projected** | | | | | | | | | |
| 9 | **Project ID** | **Project Description** | **In Service Date** | **Plant in Service @ 12/-2000** | | | **Projected Accum Depr** | **Projected Net Plant** | **O&M Expenses** | **Other Taxes** | **General Plant Allocation** | **Non-Incentive Return** | |
| 10 | | | | | | | | | | (f * L9) | (f * L14) | | |
| 11 | | | | (WP P-5) | | | (WP P-5) | (a - e) | (f * L7) | | | (L15) | |
| 12 | **Projected Sponsored Projects (Inputs from Worksheet P-5)** | | | | | | | | | | | | |
| 13 | | | | $ - | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 14 | | | | $ - | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 15 | | | | $ - | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 16 | | | | | | | | | | | | | |
| 17 | **Total of Projected Sponsored Projects** | | | $ - | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 18 | | | | | | | | | | | | | |
| | **Total Sponsored** | | | | | | | | | #DI | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | **Projects (L6 +** | $ | #DI | #DI | V/0 | # | #DI |
| 9 | **L17)** | - | V/0! | V/0! | ! | DI | V/0! |

V/
0!





# Sunflower Electric Power Corporation (SEPC)
# Sponsor Funded Project Summary
# Revenue Requirement for Sponsor Funded Projects (SFP) included in SEPC's Projected Revenue Requirements
# For the 12 months ended - December 31, 0

| | | | | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Project ID** | | **Project Description** | **Return Adder** (A-8 as applicable) | | **Total Return** (f*j) +(f*k) | **Proj. Depr Expense** (a * d) | **Rev. Req w/o True-up** (g+h+i+m+n) | **True-up Adjustment** (o * L17) | **Adj Revenue Requirement** (o + p) | **Eff. Carrying Charge Rate (C)** (o / f) |
| | | | **Actual Sponsored Projects (Inputs from** | | | | | | | | |
| 1 | | | **Worksheet A-8)** | | | | | | | | |
| 2 | 0 | 0 | | 0.00 % | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | 0 | 0 | | 0.00 % | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | 0 | 0 | 0.00 % | #DIV/0! | #DI V/0! | #DI V/0! | #DI V/0! | #DI V/0! | DI V/ 0! | | |

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|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | | |
| 6 | **Total of Actual Sponsored Projects** | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 7 | | | | | | | | | | |
| 8 | | | | | | | | | | |
| 9 | | | **Return Adder** | **Total Return** | **Proj. Depr Expense** | **Rev. Req w/o True-up** | **True-up Adjustment** | **Adj Revenue Requirement** | **Eff. Carrying Charge Rate (C)** | |
| 10 | **Project ID** | **Project Description** | (P-1 as applicable) | (f*j) +(f*k) | (P-5) | (g+h+i+m+n) | N.A | (o + p) | (o / f) | |
| 11 | | | | | | | | | | |
| 12 | **Projected Sponsored Projects (Inputs from Worksheet P-5)** | | | | | | | | | |
| 13 | 0 | 0 | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 14 | 0 | 0 | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 15 | 0 | 0 | 0.00% | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 16 | | | | | | | | | | |
| 17 | **Total of Projected Sponsored Projects** | | | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |
| 18 | | | | | | | | | | |
| 19 | **Total Sponsored Projects (L6 + L17)** | | | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | |

( Effective carrying charge rate as
C a percent of net plant before true
) up is applied.

# Sunflower Electric Power Corporation (SEPC)
## Third Party Project Summary
## Revenue Requirements for Third Party Projects included in SEPC's Projected Revenue Requirements
## For the 12 months ended - December 31, 0

Note A: All line references are to "RTO Project Smry" Workpaper, Pg 1.
Note B: To be completed with any projects sponsored by the host transmission owner.

| Line | Project ID | Project Description | In Service Date | Third Party | (a) Plant in Service @ 12/-2002 (WP A-10) | (b) Actual Accum Depr. @ 12/-2002 (WP A-10) | (c) Actual Net Plant @ 12/-2002 (a - b) | (d) Depreciation Rate (WP A-5 Rev) | (e) Projected Added Accum. Depr 1.5 * (a * d) | (f) Projected Net Plant (a - b - e) | (g) O&M Expenses (f * L7) | (h) Other Taxes (f * L9) | (i) General Plant Allocation (f * L14) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | **Actual Third Party Projects (Inputs from Worksheet A-8)** | | | | | | | | | | | |
| 2 | 0 | 0 | | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | 0 | 0 | | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | 0 | 0 | | $ - | #DIV/0! | #DI V/0! | #DI V/0! | #DI V/0! | #DI V/0! | #DI V/0! | #DI V/0! | #DI V/0! |

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– – -

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | | | | |
| 6 | **Total of Third Party Projects** | | | $ - | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | | | | | | | | | | | | |
| 8 | | | | **Projected** | | | | | | | | |
| 9 | | | **In Service** | **Plant in** | | | | **Projected** | **Projected Net** | **O&M** | **Other** | **General Plant** |
| 10 | **Project ID** | **Project Description** | **Date** | **Service @ 12/-2000** | | | | **Accum Depr** | **Plant** | **Expenses** | **Taxes** | **Allocation** |
| 11 | | | | (WP P-6) | | | | (WP P-6) | (a - e) | (f * L7) | (f * L9) | (f * L14) |
| 12 | **Projected Third Party Projects (Inputs from Worksheet P-5)** | | | | | | | | | | | |
| 13 | 0 | Description | | $ - | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 14 | 0 | Description | | $ - | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 15 | 0 | Description | | $ - | | | | #DIV/0! | #DIV/0! | | | |
| 16 | | | | | | | | | | | | |
| 17 | **Total of Projected Third Party Projects** | | | $ - | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 18 | | | | | | | | | | | | |
| 19 | **Total Third Party Projects (L6 + L17)** | | | $ - | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | |
|---|---|---|
| | | Third Party Smry |
| | | |
| | | |
| | | |
| | | |

# Sunflower Electric Power Corporation (SEPC)
# Third Party Project Summary
# Revenue Requirements for Third Party Projects included in SEPC's Projected Revenue Requirements
# For the 12 months ended - December 31, 0

| | Project ID | Project Description | (j) Non-Incentive Return | (k) Return Adder (A-8 as applicable) | (l) | (m) Total Return (f*j) +(f*k) | (n) Proj. Depr Expense (a * d) | (o) Rev. Req w/o True-up (g+h+i+m+n) | (p) True-up Adjustment (o * L17) | (q) Adj Revenue Requirement (o + p) | (r) Eff. Carrying Charge Rate (C) (o / f) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Actual Third Party Projects (Inputs from** | | | | | | | | | |
| 1 | | **Worksheet A-8)** | | | | | | | | | |
| 2 | 0 | 0 | #DIV/0! | 0.00% | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | 0 | 0 | #DIV/0! | 0.00% | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | 0 | 0 | #DIV/0! | 0.00% | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | | | | | | | | | | | |
| | | **Total of Third Party** | | | | | | | | | |
| 6 | | **Projects** | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | | | | | | | | | | | |
| 8 | | | | | | | | | | | |
| | | | **Non** | | | | **Proj.** | | **Tru** | **Adj** | |

| | | - | Tota | Dep | Rev. | e- | | Eff. |
|---|---|---|---|---|---|---|---|---|
| 9 | | Ince | l | r | Req | up | Rev | Carrying |

| | Project ID | Project Description | Incentive Return | – Return Adder | | – Expense | w/o True-up | Adjustment | Revenue Requirement | Charge Rate (C) |
|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | | | | Return | | | | | |
| 11 | | | (L15) | (P-1 as applicable) | (f*j) +(f*k) | (P-5) | (g+h+i+m+n) | N.A | (o + p) | (o / f) |
| 12 | **Projected Third Party Projects (Inputs from Worksheet P-5)** | | | | | | | | | |
| 13 | 0 | Description | #DIV/0! | 0.00 % | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 14 | 0 | Description | #DIV/0! | 0.00 % | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 15 | 0 | Description | #DIV/0! | 0.00 % | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | #DIV/0! |
| 16 | | | | | | | | | | |
| 17 | **Total of Projected Third Party Projects** | | | | #DIV/0! | #DIV/0! | #DIV/0! | | #DIV/0! | N.A. |
| 18 | | | | | | | | | | |
| 19 | **Total Third Party Projects (L6 + L17)** | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | N.A |

(C) Effective carrying charge rate as a percent of net plant before true up is applied.

# Sunflower Electric Power Corporation (SEPC)

## Rate Formula Template Projected Net Revenue Requirements

## For the 12 months ended - December 31, 0

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| **Line** | **Description** | **Reference** | | | **Amount** |
| | **A. GROSS REVENUE REQUIREMENT** (including approved incentives, if any) | | | | |
| 1 | Total Transmission Facilities | Projected Gross Rev Req, Pg.2, L92 | | | #DIV/0! |
| 2 | Less: Non-Transmission Related Competitive Bid Project Adjustment | RTO Project Summary L147 | | | - |
| 3 | Adjusted Total Transm. FacilitiesGross Revenue Req. | L1 - L2 | | | #DIV/0! |
| 4 | | | | | |
| 5 | Base Plan Net Revenue Requirements | RTO Project Smry, Base Plan Section, L77 + L96 | #DIV/0! | | |
| 6 | Balanced Portfolio Net Revenue Requirement | RTO Project Smry, Balanced Portfolio Section, L115 | #DIV/0! | | |
| 7 | ITP/Priority Projects-1 Net Revenue Requirement | RTO Project Smry, ITP/Priority-1 Section, L134 | #DIV/0! | | |
| 8 | ITP/Priority Projects-2 Net Revenue Requirement | RTO Project Smry, ITP/Priority-2 Section, L153 | #DIV/0! | | |
| 9 | Sponsored Projects Net Revenue Requirements | Spon Project Smry, L19 | #DIV/0! | | |
| 10 | Third Party Projects Net Revenue Requirements | Third Party Project Smry, L19 | #DIV/0! | | |
| 11 | Total | Sum (L5:L9) | | | #DIV/0! |

12

| | | | | | |
|---|---|---|---|---|---|
| 13 | Zonal Gross Revenue Requirement | L1 - L11 | | | #DIV/0! |
| 14 | | | | | |
| 15 | **B. REVENUE CREDITS** | | | | |
| 16 | Zonal Gross Revenue Credit | WP P-2, L35 | | | $ - |
| 17 | | | | | |
| 18 | **C. NET REVENUE REQUIREMENT AFTER REVENUE CREDITS AND BEFORE TRUE-UP** | | | | |
| 19 | Base Plan Net Revenue Requirements | L5 | #DIV/0! | | |
| 20 | Balanced Portfolio Net Revenue Requirement | L6 | #DIV/0! | | |
| 21 | ITP/Priority Projects-1 Net Revenue Requirement | L7 | #DIV/0! | | |
| 22 | ITP/Priority Projects-2 Net Revenue Requirement | L8 | #DIV/0! | | |
| 23 | Sponsored Projects Net Revenue Requirements | L9 | #DIV/0! | | |
| 24 | Third Party Projects Net Revenue Requirements | L10 | V/0! | | |
| 25 | Total | Sum (L19:L24) | | #DIV/0! | |
| 26 | | | | | |
| 27 | Zonal Net Revenue Requirement | L13 - L16 | | | #DIV/0! |
| 28 | | | | | |
| 29 | **D. TRUE-UP ADJUSTMENTS** | | | | |
| 30 | Total Transmission Facilities | WP TU (True-Up), L17 | | #N/A | |
| 31 | | | | | |
| 32 | Base Plan True-Up | WP TU (True-Up), L17 | $ - | | |
| 33 | Balanced Portfolio True-Up | WP TU (True-Up), L17 | #N/A | | |
| 34 | ITP/Priority Projects-1 True-UP | WP TU (True-Up), L17 | #N/A | | |
| 35 | ITP/Priority Projects-2 True-UP | WP TU (True-Up), L17 | #N/A | | |
| 36 | Sponsored Projects True Up | WP TU (True-Up), L17 | #DIV/0! | | |
| 37 | Third Party Projects True Up | WP TU (True-Up), L17 | #N/A | | |
| 38 | Total | Sum (L32:L35) | | #N/A | |

| | | | |
|---|---|---|---|
| 39 | | | |
| 40 | Zonal True-Up Revenue Requirement | L30 - L38 | #N/A |

| | | | | | |
|---|---|---|---|---|---|
| 41 | | | | | |
| | **E. NET REVENUE REQUIREMENT AFTER** | | | | |
| 42 | **TRUE-UP** | | | | |
| | Base Plan Net Revenue | | #DI | | |
| 43 | Requirements | L19 + L32 | V/0! | | |
| | Balanced Portfolio Net Revenue | | #DI | | |
| 44 | Requirement | L20 + L33 | V/0! | | |
| | ITP/Priority Projects-1 Net | | #DI | | |
| 45 | Revenue Requirement | L21 + L34 | V/0! | | |
| | ITP/Priority Projects-2 Net | | #DI | | |
| 46 | Revenue Requirement | L22 + L35 | V/0! | | |
| | Sponsored Projects Net Revenue | | #DI | | |
| 47 | Requirements | L23 + L36 | V/0! | | |
| | Third Party Projects Net | | #DI | | |
| 48 | Revenue Requirements | L24 + L37 | V/0! | | |
| | | | | #DIV/ | |
| 49 | Total | Sum (L43:L48) | | 0! | |
| 50 | | | | | |
| | | | | | #DIV/ |
| 51 | Zonal Net Revenue Requirement | L27 + L40 | | | 0! |
| 52 | | | | | |
| 53 | **F. Point-to-Point Service** | | | | |
| | Projected SEPC Zone 9 SPP | WP P-3 (Trans. | | | #DIV/ |
| 54 | Aver. 12-Mo. Peak Demand | Network Load), L15 | | | 0! |
| 55 | | | | | |
| | Annual Point-to-Point Rate in | | | | #DIV/ |
| 56 | $/MW - Year | L51 / L54 | | | 0! |
| | Monthly Point-to-Point Rate in | | | | #DIV/ |
| 57 | $/MW - Month | L56 / 12 months | | | 0! |
| | Weekly Point-to-Point Rate in | | | | #DIV/ |
| 58 | $/MW- Weekly | L56 / 52 weeks | | | 0! |
| | Daily On-Peak Point-to-Point | | | | #DIV/ |
| 59 | Rate in $/MW - Day | L56 / 260 days | | | 0! |
| | Daily Off-Peak Point-to-Point | | | | #DIV/ |
| 60 | Rate in $/MW - Day | L56 / 365 days | | | 0! |
| | Hourly On-Peak Point-to-Point | | | | #DIV/ |
| 61 | Rate in $/MW - Hour | L59 / 16 hours | | | 0! |
| | Hourly Off-Peak Point-to-Point | | | | #DIV/ |
| 62 | Rate in $/MW - Hour | L60 / 24 hours | | | 0! |

# Sunflower Electric Power Corporation (SEPC)

## Projected Gross Revenue Requirements For the 12 months ended - December 31, 0

| Line | Description | KCC Annual Report/Worksheet | Total Company | | Allocator | | Transmission (Col. 3 times Col. 5) |
|---|---|---|---|---|---|---|---|
| | | (1) | (2) | (3) | (4) | (5) | (6) |
| | **RATE BASE:** | | | | | | |
| 1 | PLANT IN SERVICE (13 Month Averages) | | | | | | |
| 2 | Production | Act. Gross Rev Req, Pg.1, L3 | $ - | | NA | | |
| 3 | Transmission (Excludes Capital & Operating Leases) | WP P-1, Pg. 4 L156 | - | | DA | 1.000 | $ - |
| 4 | Less Excluded Plant | Act. Gross Rev Req, Pg.1, L5 | | $ - | DA | 1.000 | - |
| 5 | Distribution | Act. Gross Rev Req, Pg.1, L6 | - | | NA | | |
| 6 | General | Act. Gross Rev Req, Pg.1, L7 | - | | WSP | #DIV/0! | #DIV/0! |
| 7 | Intangible & Other | Act. Gross Rev Req, Pg.1, L8 | - | | WS | #DIV/0! | #DIV/0! |
| 8 | TOTAL GROSS PLANT | L2 + L3 - L4 + L5 + L6 + L7 | $ - | | | | #DIV/0! |

9

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | ACCUMULATED DEPRECIATION (13 Month | | | | | | |
| 10 | Averages) | | | | | | |
| | | Act. Gross Rev | $ | | N | | |
| 11 | Production | Req, Pg.1, L12 | - | | A | | |
| | Transmission (Excludes Capital | | #DIV/ | | | | |
| | & Operating | WP P-1, Pg. 4 | 0! | | D | #DI | #DIV |
| 12 | Leases) | L156 | | | A | V/0! | /0! |
| | Less Excluded | Act. Gross Rev | | $ | D | 1.00 | |
| 13 | Plant | Req, Pg.1, L14 | | - | A | 000 | - |
| | | Act. Gross Rev | | | N | | |
| 14 | Distribution | Req, Pg.1, L15 | - | | A | | |
| | General | | | | P | | |
| | | Act. Gross Rev | | | W | #DI | #DIV |
| 15 | | Req, Pg.1, L16 | - | | S | V/0! | /0! |
| | Intangible & | | | | P | | |
| | Other | Act. Gross Rev | | | W | #DI | #DIV |
| 16 | | Req, Pg.1, L17 | - | | S | V/0! | /0! |
| | | L11 + L12 - L13 | | | | | |
| | TOTAL ACCUM. | + L14 + L15 + | #DIV/ | | | | #DIV |
| 17 | DEPRECIATION | L16 | 0! | | | | /0! |
| 18 | | | | | | | |
| | NET PLANT IN SERVICE (13 | | | | | | |
| 19 | Month Averages) | | | | | | |
| | | | $ | | | | |
| 20 | Production | L2 - L11 | - | | | | |
| | Transmission (Excludes Capital | | | | | | |
| | & Operating | | #DIV/ | | | | #DIV |
| 21 | Leases) | L3 - L12 | 0! | | | | /0! |
| | Less Excluded | | | $ | | | |
| 22 | Plant | L4 - L13 | | - | | | - |
| 23 | Distribution | L5 - L14 | - | | | | - |
| | General | | | | | | #DIV |
| 24 | | L6 - L15 | - | | | | /0! |
| | Intangible & | | | | | | #DIV |
| 25 | Other | L7 - L16 | - | | | | /0! |
| | | L20 + L21 - L22 | | | | | |
| | TOTAL NET | + L23 + L24 + | #DIV/ | | | | #DIV |
| 26 | PLANT | L25 | 0! | | | | /0! |
| 27 | | | | | | | |
| | ADJUSTMENTS | | | | | | |
| 28 | TO RATE BASE | | | | | | |
| | Accumulated | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Deferred Income | Act. Gross Rev | $ | D | 1.00 | $ |
| 29 | Taxes | Req, Pg.1, L38 | - | A | 000 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 30 | Reserved for Future Use | | - | D A | 1.00 000 | - |
| 31 | Reserve Funds (Non-Escrowed) | Act. Gross Rev Req, Pg.1, L40 | #DIV/ 0! | D A | 1.00 000 | #DIV /0! |
| 32 | Unamortized Abandoned Transmission Plant | Act. Gross Rev Req, Pg.1, L41 - Amortization | - | D A | 1.00 000 | - |
| 33 | TOTAL ADJUSTMENTS | Sum (L29:L32) | #DIV/ 0! | | | #DIV /0! |
| 34 | | | | | | |
| 35 | LAND HELD FOR FUTURE USE | Act. Gross Rev Req, Pg.1, L44 | $ - | D A | 1.00 000 | $ - |
| 36 | | | | | | |
| 37 | WORKING CAPITAL | | | | | |
| 38 | CWC | | | | | |
| 39 | O&M Expense less Fuel & Purchased Power | Act. Gross Rev Req, Pg.1, L48 | $ - | N A | | |
| 40 | O&M Expense Allocated to Transmission | Pg. 2, L65, Col (6) | | | | #DIV /0! |
| 40a | Taxes Other than Income Included in Lines 39 & 40 | Act. Gross Rev Req, Pg.1, L49a | $ - | | | $ - |
| 41 | Calculated CWC | Calculated (Note C) | $ - | | | #DIV /0! |
| 42 | Materials & Supplies-Transmission | Act. Gross Rev Req, Pg.1, L51 | - | P T P | #DI V/0! | #DIV /0! |
| 43 | Materials & Supplies-Other | Act. Gross Rev Req, Pg.1, L52 | - | N A P | | |
| 44 | Stores Expense | Act. Gross Rev Req, Pg.1, L53 | - | W S | #DI V/0! | #DIV /0! |
| 45 | Prepayments (Account 165) | Act. Gross Rev Req, Pg.1, L54 | - | G P | #DI V/0! | #DIV /0! |
| 46 | | | | | | |
| 47 | TOTAL WORKING CAPITAL | Sum (L41:L46) | $ - | | | #DIV /0! |
| 48 | | | | | | |
| 49 | Rate Base | L26 + L 33 + L 35 + L47 | #DIV/ 0! | | | #DIV /0! |
| | | | | | | Proj. Gross Rev. |

Req.

# Sunflower Electric Power Corporation
# (SEPC)
# Projected Gross Revenue Requirements
## For the 12 months ended - December 31, 0

| | (1) | (2) | (3) | (4) | | (5) | (6) |
|---|---|---|---|---|---|---|---|
| **Line** | **Description** | **KCC Annual Report/Worksheet** | **Total Company** | | **Allocator** | | **Transmission** (Col. 3 times Col. 5) |
| 50 | **O&M** | | | | | | |
| 51 | Transmission | WP P-2, L9 | #DIV/0! | | | | |
| 52 | Less Account 565 | WP P-2, L10 | #DIV/0! | | | | |
| 53 | Less: Embedded Trans. Lease Payments & Facility Charge | WP P-2, L11 | #DIV/0! | | | | |
| 54 | Less Acct. 561 Expense Recovered Through Sch. 1 | Projected Schedule 1 Rev Req, L6 | #DIV/0! | | | | |
| 55 | Total Transmission O&M | L51 - Sum (L52:L53) | #DIV/0! | | PTP | #DIV/0! | #DIV/0! |
| 56 | A&G -Adjusted | WP P-2, L14 | #DIV/0! | | PWS | #DIV/0! | #DIV/0! |
| 57 | Plus: Advertising -Safety | WP P-2, L15 | #DIV/0! | | PWS | #DIV/0! | #DIV/0! |
| 58 | Plus Association Dues Directly Related to Transmission | WP P-2, L16 | #DIV/0! | | DA | 1.00000 | #DIV/0! |
| 59 | Plus: Advertising - Transmission | WP P-2, L17 | #DIV/0! | | DA | 1.00000 | #DIV/0! |
| 60 | Plus: Research - Transmission | WP P-2, L18 | #DIV/0! | | DA | 1.00000 | #DIV/0! |
| | Plus: Regulatory | | #DIV/ | | D | 1.00 | #DIV |

| | | | | | | |
|---|---|---|---|---|---|---|
| 61 | Exp -Transmission | WP P-2, L19 | 0! | A | 000 | /0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Plus: Corporate Visibility - | | | P W | #DI | #DIV |
| 62 | Transmission | WP P-2, L20 | #DIV/ 0! | S | V/0! | /0! |
| 63 | Total A&G | L56 + Sum (L57:L62) | #DIV/ 0! | | | #DIV /0! |
| | Plus: Projected Transmission Lease Payments & | | | D | 1.00 | |
| 64 | Facility Charges | WP P-2, L13 | - | A | 000 | - |
| 65 | TOTAL O&M | L55 + L63 + L64 | #DIV/ 0! | | | #DIV /0! |
| 66 | | | | | | |
| 67 | **DEPRECIATION EXPENSE** | | | | | |
| 68 | Production | Act. Gross Rev Req, Pg. 2, L77 | $ - | N A | | |
| 69 | Transmission | WP P-1, Pg.2 L155 | #DIV/ 0! | P T P | #DI V/0! | #DIV /0! |
| 70 | Distribution | Act. Gross Rev Req, Pg. 2, L79 | - | N A | | |
| 71 | General | Act. Gross Rev Req, Pg. 2, L80 | - | P W S | #DI V/0! | #DIV /0! |
| 72 | Intangible & Other | Act. Gross Rev Req, Pg. 2, L81 | - | P W S | #DI V/0! | #DIV /0! |
| 73 | Amortization of Abandon Transmission Plant | Act. Gross Rev Req, Pg. 2, L82 | - | D A | 1.00 000 | - |
| 74 | TOTAL DEPRECIATION | Sum (L68:L73) | #DIV/ 0! | | | #DIV /0! |
| 75 | | | | | | |
| 76 | **TAXES** | | | | | |
| 77 | LABOR RELATED | | | | | |
| 78 | Payroll | WP P-2, L24 | #DIV/ 0! | P W S | #DI V/0! | #DIV /0! |
| 79 | Highway and vehicle | WP P-2, L25 | #DIV/ 0! | P W S | #DI V/0! | #DIV /0! |
| 80 | PLANT RELATED | | | | | |
| 81 | Property | WP P-2, L27 | #DIV/ 0! | G P | #DI V/0! | #DIV /0! |
| 82 | Gross Receipts | WP P-2, L28 | #DIV/ 0! | N A | | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 83 | Other | WP P-2, L29 | #DIV/0! | G P | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | INCOME | Act. Gross Rev | | D | 1.00 | |
| 84 | (Transmission only) | Req, Pg. 2, L93 | - | A | 000 | 0 |
| | | | #DIV/ | | | #DIV |
| 85 | TOTAL TAXES | Sum (L78:L84) | 0! | | | /0! |
| 86 | | | | | | |
| 87 | **RETURN** | | | | | |
| | Return before | | | | | #DIV |
| 88 | incentives | Pg. 4, L150 | | | | /0! |
| | | | | | | #DIV |
| 89 | Incentive return | Pg. 4, L178 | | | | /0! |
| | | | | | | #DIV |
| 90 | Total Return | L88 + L89 | | | | /0! |
| 91 | | | | | | |
| | **GROSS REV.** | | | | | |
| | **REQ. WITH** | L65 + L74 + L85 | | | | #DIV |
| 92 | **INCENTIVES** | + L90 | | | | /0! |
| | Less: Gross Rev. | | | | | #DIV |
| 93 | Req. for Incentives | L178 | | | | /0! |
| 94 | | | | | | |
| | **GROSS REV.** | | | | | |
| | **REQ. WITHOUT** | | | | | #DIV |
| 95 | **INCENTIVES** | L92 - L93 | | | | /0! |



Proj. Gross Rev. Req. Page 3 of 5

## Sunflower Electric Power Corporation (SEPC)

## Projected Gross Revenue Requirements

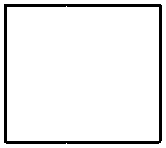
## For the 12 months ended - December 31, 0

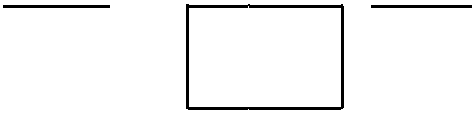
| | (1) | (2) | (3) | (4) | | (5) | (6) |
|---|---|---|---|---|---|---|---|
| **Line** | **Description** | **KCC Annual Report/Worksheet** | **Total Company** | | **Allocator** | | **Transmission** (Col. 3 times Col. 5) |
| | **TRANSMISSION PLANT INCLUDED IN** | | | | | | |

96 **FORMULA**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 97 | Total transmission plant, including capital and operating leases | P-1 (Trans Plant), L156 + L187 | $ - | | D A | 1.00 000 | $ - |
| 98 | Less: Net Substation, 34kV, & Radial Lines to Distr. Plt. | Act. Gross Rev Req, Pg.3, L107 | | - | D A | 1.00 000 | - |
| 99 | Less: Total GSU in Transmission Plant | Act. Gross Rev Req, Pg.3, L108 | | $ - | D A | 1.00 000 | - |
| 100 | Transmission plant included in rates | L97 - L98 - L99 | $ - | | | | $ - |
| 101 | | | | | | | |
| 102 | Percentage of transmission plant included in rates | L100 / L97 | | | P T P = | #DIV/0! | |
| 103 | | | | | | | |
| 104 | **GROSS AND NET PLANT ALLOCATORS** | | | | | | |
| 105 | GROSS PLANT IN SERVICE | Use ACTUAL HISTORICAL COST | | | | | |
| 106 | Production | Act. Gross Rev Req, Pg.3, L114 | $ - | | N A | | |
| 107 | Total transmission plant, including leases | Act. Gross Rev Req, Pg.3, L115 | - | | D A | 1.00 000 | $ - |
| 108 | Less: Excluded Plant | Act. Gross Rev Req, Pg.3, L116 | | - | D A | 1.00 000 | - |
| 109 | Distribution | Act. Gross Rev Req, Pg.3, L117 | - | | N A | | |
| 110 | General & Intangible | Act. Gross Rev Req, Pg.3, L118 | - | | W S | #DIV/0! | #DIV/0! |
| 111 | TOTAL GROSS PLANT | L106 + L107 - L108 + L109 + L110 | $ - | | G P = | #DIV/0! | #DIV/0! |
| 112 | | | | | | | |
| 113 | ACCUMULATED DEPRECIATION | Use ACTUAL HISTORICAL COST | | | | | |
| 114 | Production | Act. Gross Rev Req, Pg.3, L122 | $ - | | N A | | |
| 115 | Total transmission plant, including leases | Act. Gross Rev Req, Pg.3, L123 | - | | D A | 1.00 000 | $ - |
| | Less: Excluded | Act. Gross Rev | | | D | 1.00 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 116 | Plant | Req, Pg.3, L124 | - | A | 000 | - |





| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 117 | Distribution | Act. Gross Rev Req, Pg.3, L125 | - | | N A W S | #DI V/0! | #DIV /0! |
| 118 | General & Intangible | Act. Gross Rev Req, Pg.3, L126 | - | | | | |
| 119 | TOTAL ACCUM. DEPRECIATION | L114 + L115 - L116 + L117 + L118 | $ - | | | | #DIV /0! |
| 120 | | | | | | | |
| 121 | NET PLANT IN SERVICE | Use ACTUAL HISTORICAL COST | | | | | |
| 122 | Production | L106 - L114 | $ - | | | | |
| 123 | Total transmission plant, including leases | L107 - L115 | - | | | | $ - |
| 124 | Less: Excluded Plant | L108 - L116 | | - | | | - |
| 125 | Distribution | L109 - L117 | - | | | | - |
| 126 | General & Intangible | L110 - L118 | - | | | | #DIV /0! |
| 127 | | | | | | | |
| 128 | TOTAL NET PLANT | L122 + L123 - L124 + L125 + L126 | $ - | | N P = | #DI V/0! | #DIV /0! |



Proj. Gross Rev. Req. Page 4 of 5

## Sunflower Electric Power Corporation
## (SEPC)
## Projected Gross Revenue Requirements
## For the 12 months ended - December 31, 0

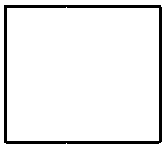
| | (1) | (2) | (3) | (4) | | (5) | (6) |
|---|---|---|---|---|---|---|---|
| **Line** | **Description** | **KCC Annual Report/Worksheet** | **Total Company** | | **Allocator** | | **Transmission** |
| | **WAGES & SALARY ALLOCATOR** | ACTUAL HISTORICAL | | | | | (Col. 3 times Col. |

**(WS)** COST 5)



| | | | | | | |
|---|---|---|---|---|---|---|
| | | Act. Gross Rev | $ | | | |
| 129 | Production | Req, Pg.4, L138 | - | | | |
| | | | | P | | |
| | | Act. Gross Rev | | T | #DI | #DIV |
| 130 | Transmission | Req, Pg.4, L139 | - | P | V/0! | /0! |
| | | Act. Gross Rev | | | | |
| 131 | Distribution | Req, Pg.4, L140 | - | | | |
| | | Act. Gross Rev | | | | |
| 132 | Other | Req, Pg.4, L141 | - | | | |
| | | Sum | $ | | | #DIV |
| 133 | Total | (L129:L132) | - | | | /0! |
| | | | | P | | |
| | Wage & Salary | | | W | | |
| | Allocator | Col 6, L133 / | | S | #DI | |
| 134 | Calculation | Col 3, L133 | | = | V/0! | |
| 135 | | | | | | |
| 136 | | | | | | |
| 137 | | | | | | |
| 138 | | | | | | |
| 139 | | | | | | |
| 140 | | | | | | |
| 141 | **RETURN (R)** | | | | | |
| 142 | | | | | | |
| 143 | **RETURN (R)** | | | | | |
| | Net Plant allocated to Transm. 13 mo. avg. 0, excludes | Projected Gross Rev Req, L26, | | | | #DIV |
| 144 | leases) | Col. (6) | | | | /0! |
| | Net Plant allocated to Transm. 13 mo. avg. -2, excludes | Actual Gross Rev Req, L27, Col. | | | | #DIV |
| 145 | leases) | (6) | | | | /0! |
| 146 | Ratio Net Plant0 / -2 | L144 / 145 | | | | #DIV /0! |
| 147 | | | | | | |
| | Transmission Return for -2 Actual Before | Act. Gross Rev Req, L97, Col. | | | | #DIV |
| 148 | Incentives | (6) | | | | /0! |
| 149 | | | | | | |
| | Transmission Return for 0 | | | | | #DIV |
| 150 | Projected | L146 * L148 | | | | /0! |
| 151 | | | | | | |
| | **GROSS REV.** | | | | | |

152 **REQUIREMENT**



| | | | | | | |
|---|---|---|---|---|---|---|
| | **FOR INCENTIVE PROJECTS** | | | | | |
| | **Plant Granted Incentive ROE** | | | | | |
| 153 | **Adder:** | | | | | |
| 154 | Total Incentive Plant | WP P-1, Pg. 1, L38 | $ - | | | |
| 155 | Less: Total Accumulated Depreciation | WP P-1, Pg. 1, L38 | - | | | |
| 156 | Net Incentive Plant | L154 - L155 | $ - | | | |
| 157 | Incentive Return | WP P-1, Pg. 1, L41 | | | $ - | |
| 158 | | | | | | |
| 159 | | | | | | |
| 160 | | | | | | |
| 161 | | | | | | |
| 162 | | | | | | |
| 163 | **Abandoned Plant:** | | | | | |
| 164 | Unamortized Abandoned Transmission Plant | Pg. 1, L32 | $ - | | | |
| 165 | Return on Abandoned Plant | Actual Gross Rev Req Pg. 4, L159 * L164 | #DIV/0! | | | |
| 166 | Amortization Expense for Abandoned Plant | Pg. 2, L73 | - | | | |
| 167 | Total Recovery for Abandoned Plant | Sum (L165:L166) | | | #DIV/0! | |
| 168 | **TOTAL GROSS REV. REQUIREMENT FOR INCENTIVE PROJ.** | L157 + L161 + L167 | | | | #DIV/0! |
| 169 | | | | | | |
| 170 | **INCENTIVE PLANT (excludes CWIP and Abandoned Plant)** | | **Gross Plant** | **Accum Depr** | **Net Plant** | |
| 171 | Incentive Plant: Projected Base Plan Funded | RTO Project Smry | $ - | $ - | $ - | |
| 172 | Incentive Plant: Projected Balanced Portfolio | RTO Project Smry | - | - | - | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Incentive Plant: | | | | | |
| | Projected ITP / | RTO Project | | | | |
| 173 | Priority Project-1 | Smry | - | - | - | |
| | Incentive Plant: | | | | | |
| | Projected ITP / | RTO Project | | | | |
| 174 | Priority Project-2 | Smry | - | - | - | |
| | Incentive Plant: | | | | | |
| | Projected Sponsor | Spon Project | | | | |
| 175 | Funded | Smry | - | - | - | |
| | Total Incentive | Sum | $ | $ | $ | |
| 176 | Plant | (L171:L175) | - | - | - | |
| | Note: Incentive gross plant and accumulated depreciation values, if applicable, will be calculated by cell references to the RTO Project Smry and Spon Proj | | | | | |
| 177 | Smry tabs. | | | | | |
| | | WP P-1, Pg. 1, | | | | #DIV |
| 178 | **Incentive Return** | L41 | | | | /0! |





# Sunflower Electric Power Corporation (SEPC)
# Projected Gross Revenue Requirements
# For the 12 months ended - December 31, 0

**Notes**

| | |
|---|---|
| A | Reserved for future use. |
| B | Hold for future use |
| C | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, reduced by included taxes other than income taxes. |
| D | Hold for future use |

| **Line** | | **ALLOCATION FACTORS** | |
|---|---|---|---|
| **No.** | **Allocators** | **Description** | **Location of Calculation or First Use of Allocator** |

| | | | |
|---|---|---|---|
| 1 | **PTP** | Percentage of projected | L10 2 |

| | | | |
|---|---|---|---|
| | | transmission plant included in rate base. | |
| 2 | **PWS** | Percentage of projected transmission labor included in rates | L13 4 |
| 3 | **DA** | Direct assignment | |
| 4 | **GP** | Ratio of allocated transmission, general, & intangible plant to total gross plant. | L11 1 |
| 5 | **NA** | Not applicable for the transmission formula rate. | |
| 6 | **NP** | Ratio of net transmission, general, & intangible plant to total net plant. | L12 8 |
| 7 | | | |

**Sunflower Electric Power Corporation (SEPC)**

**Rate Formula Template**

**Projected Schedule 1 Revenue Requirements For the 12 months ended - December 31, 0**

| | | (1) | (2) | (3) | (4) |
|---|---|---|---|---|---|
| | **Line No.** | **Description** | **Reference** | | **Amount** |
| **A.** | **Projected Schedule 1 ARR** | | | | |
| | 1 | Total Load Dispatch & Scheduling | Actual Sch 1 Rev Req, L1 * (P-2 (Exp. & Rev. Credits) L5, Col 5 | | #DIV/0! |
| | 2 | Plus: Acct. 556 SPP NERC Complience Charges | Actual Sch 1 Rev Req, L2 * (P-2 (Exp. & Rev. Credits) L5, Col 5 | | #DIV/0! |
| | 3 | Less: Scheduling, System Control and Dispatch Services | Actual Sch 1 Rev Req, L3 * (P-2 (Exp. & Rev. Credits) L5, Col 5 | | #DIV/0! |
| | 4 | Less: Transmission Service Studies | Actual Sch 1 Rev Req, L4 * (P-2 (Exp. & Rev. Credits) L5, Col 5 | | #DIV/0! |
| | | | Actual Sch 1 Rev Req, L5 * (P-2 (Exp. | | |

| | | | |
|---|---|---|---|
| 5 | Less: Reliability, Planning & | & Rev. Credits) L5, Col 5 | #DIV/ 0! |

| | | | | |
|---|---|---|---|---|
| | Standards Dev. Services | | | |
| 6 | Total | L1 + L2 - L3 - L4 - L5 | #DIV/0! | |
| 7 | Reserved for future use | | #DIV/0! | |
| 8 | Less: PTP Service Credit | Actual Sch. 1 Rev Req, L8 | - | |
| 9 | Revenue Requirement for Schedule 1 | L6 + L7 - L8 | #DIV/0! | |
| 10 | Prior Year True-Up | L26 | - | |
| 11 | | | | |
| 12 | Net Schedule 1 Revenue Requirement for Zone | L9 + L10 | #DIV/0! | |
| | | | | |
| 13 | Acct. 561 Expenses Recovered Through Sch. 1 Charges | L1 - Sum(L3:L5) | #DIV/0! | |

**B.** **Projected Schedule 1 Rate Calculations**

| | | | | |
|---|---|---|---|---|
| 14 | SEPC 12-CP. Peak Demand | WP P-3, L15 | #DIV/0! | MW |
| 15 | | | | |
| 16 | Annual Point-to-Point Rate in $/MW - Year | L12 / L14 | #DIV/0! | |
| 17 | Monthly Point-to-Point Rate $/MW - Month | L16 / 12 | #DIV/0! | |
| 18 | Weekly Point-to-Point Rate $/MW - Week | L16 / 52 | #DIV/0! | |
| 19 | Daily Point-to-Point Rate $/MW - Day | L16 / 365 | #DIV/0! | |
| 20 | Hourly Point-to-Point Rate $/MW - Hour | L16 / 8760 | #DIV/0! | |

**Sched**

**C.** **ule 1 True-UP**

| | | | |
|---|---|---|---|
| | Actual Revenue | Actual Sched 1 Rev | $ |
| 21 | Requirement for -2 | Req, L9 | - |
| | Projected Revenue | Schedule 1 Proj. for the Actual Period ( | |
| 22 | Requirement for -2 | Note A) | - |
| | Revenue Requirement True- | | $ |
| 23 | Up | L21 - L22 | - |
| 24 | | | |
| | Interest on True- | L23 * (FERC Interest | $ |
| 25 | Up: | Rate/12) * 24 | - |
| | Total Annual True- | | $ |
| 26 | Up Adjustment | L23 + L25 | - |

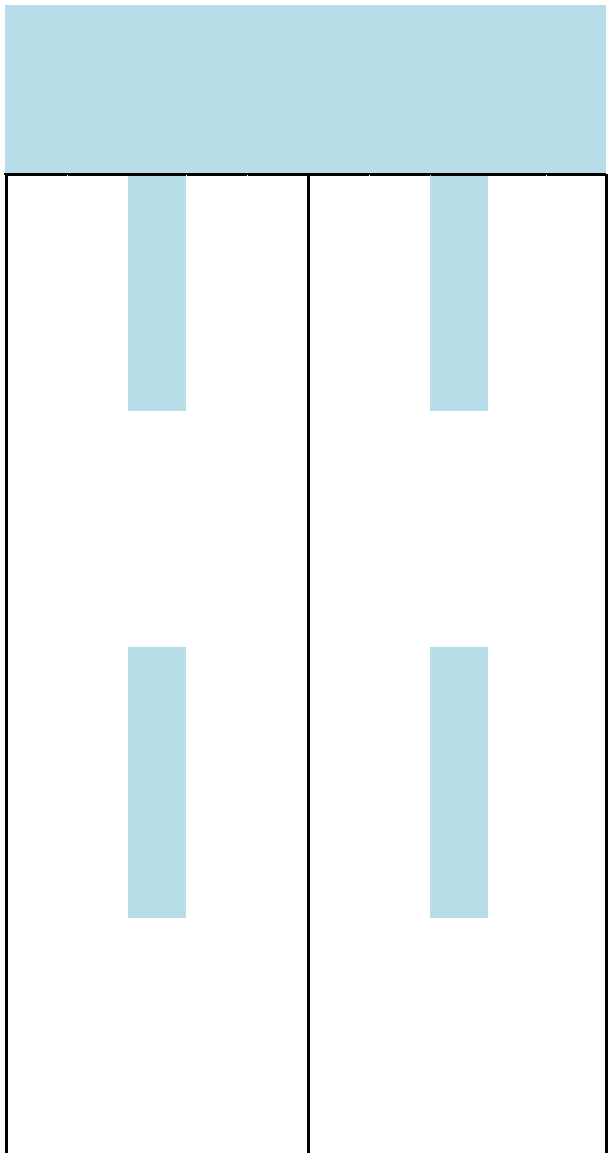
**Notes:**

| | |
|---|---|
| A | Enter the Projected Revenue Requirement for the Actual period, pending the Actual data. For the initial two years, set this equal to the calculated Actual period since there is no true-up. |

# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant
# For the 12 months ended - December 31, 0

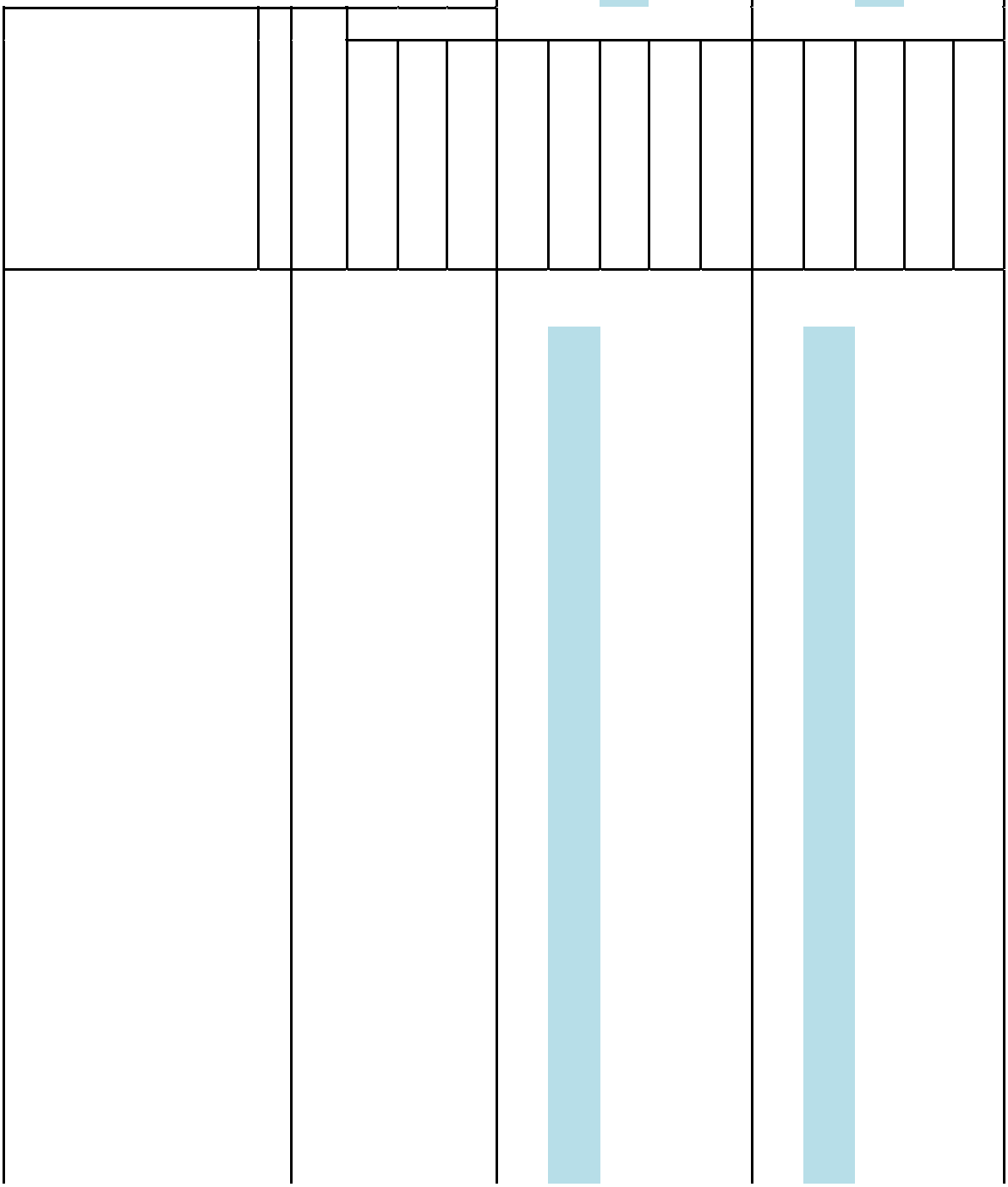
| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Incentive Projects** | *Description* | | | | *Description* | | | |
| 1 | | **Project:** | | | | **Project:** | | | |
| 2 | | Type: | | | | Type: | | | |
| | | Depr. Rate: (A) | 0.0000% | | | Depr. Rate: (A) | 0.0000% | | |
| 3 | | TIER Adder (B) | | | | TIER Adder (B) | | | |
| 4 | | - | Avg. | # DIV | Return A | - | Avg. | # DIV | Return A |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 5 | Interest Rate | /0 ! | dd er | V/ 0! | Interest Rate | /0 ! | dd er | V/ 0! |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Begin. Plant Bal: | $ - | | | Begin. Plant Bal: | $ - | | | |
| 6 | | | | | | | | | | | | | | |
| | | | | | | Begin. Acc. Depr: | - | | | Begin. Acc. Depr: | - | | | |
| 7 | **Total Incentive Plant** | | | | | | | | | | | | | |
| | | | | | | Begin. Year-Mo.: | | | | Begin. Year-Mo.: | | | | |
| 8 | | | | | | | | | | | | | | |
| 9 | | | | **Total** | | | | | | | | | | |
| 1 0 | **Mon** | **Year** | **Gross Plant** | **Depreciation** | **Accum Depr.** | **Gross Plant** | **Depreciation** | **Accum. Depr.** | **Net Plant** | **Gross Plant** | **Depreciation** | **Accum Depr.** | **Net Plant** |
| 1 | | | | | | $ | | | | $ | | | |
| 1 | | | | | | - | | | | - | | | |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Jan | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | Feb | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | Mar | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | Apr | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | May | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | Jun | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | Jul | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Aug | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Sep | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | Oct | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | No | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | Dec | 1 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | Jan | 0 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | Feb | 0 | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | | $ | $ | $ | | $ | $ | $ | $ | | $ | $ | $ | $ |
| 6 | Mar | 0 | | - | - | - | | - | - | - | - | | - | - | - | - |



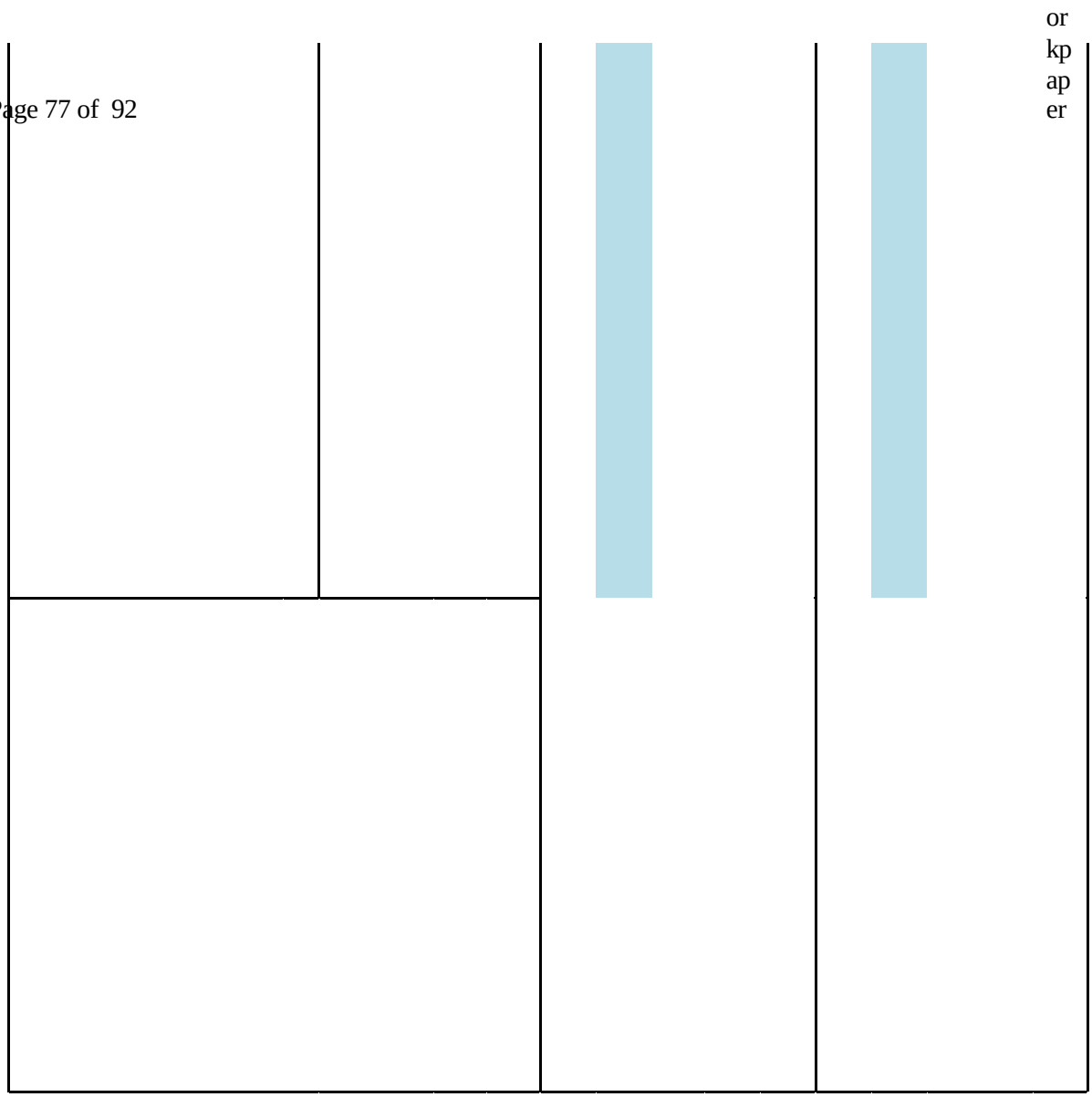
| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | Apr | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | May | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | Jun | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | Jul | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | Aug | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | Sep | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | Oct | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | Nov | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | Dec | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | |
| 3 | | | | $ | | | $ | | | | $ | | | |
| 7 | 12 Mon Tot | | | - | | | - | | | | - | | | |
| 3 | | | $ | | $ | $ | | $ | $ | $ | | $ | $ | |
| 8 | 13 Mon Avg | | - | | - | - | | - | - | - | | - | - | |
| 3 | **Total Approved Project** | | | | | | | | | | | | | |
| 9 | **Incentives:** | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | |
| 0 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | # | | | | | | | | | | | |
| | | | | D | | **Return** | | | | **Return** | | # | | | |
| | | | | I | | **due to** | | # | | **due to** | | D | | | |
| | | | | V | | **Incenti** | | DI | | **Incenti** | | I | | | |
| 4 | **Return due to Incentive** | | | /0 | | **ve** | | V/ | | **ve** | | V/ | | | |
| 1 | **Adder** | | | ! | | **Adder** | | 0! | | **Adder** | | 0! | | | |

(A) Special incentive (Depreciation Rate or TIER) may be utilized for specific incentive transmission projects if approved by the FERC.

(B) The formula is set up to accommodate an incentive TIER Adder. If FERC grants an ROE adder, it may be converted to a TIER adder using the following formula: TIER Adder = (ROE Adder * Equity Ratio) / Average System Interest Rate. If FERC grants a different incentive, the formula may need to be modified accordingly.

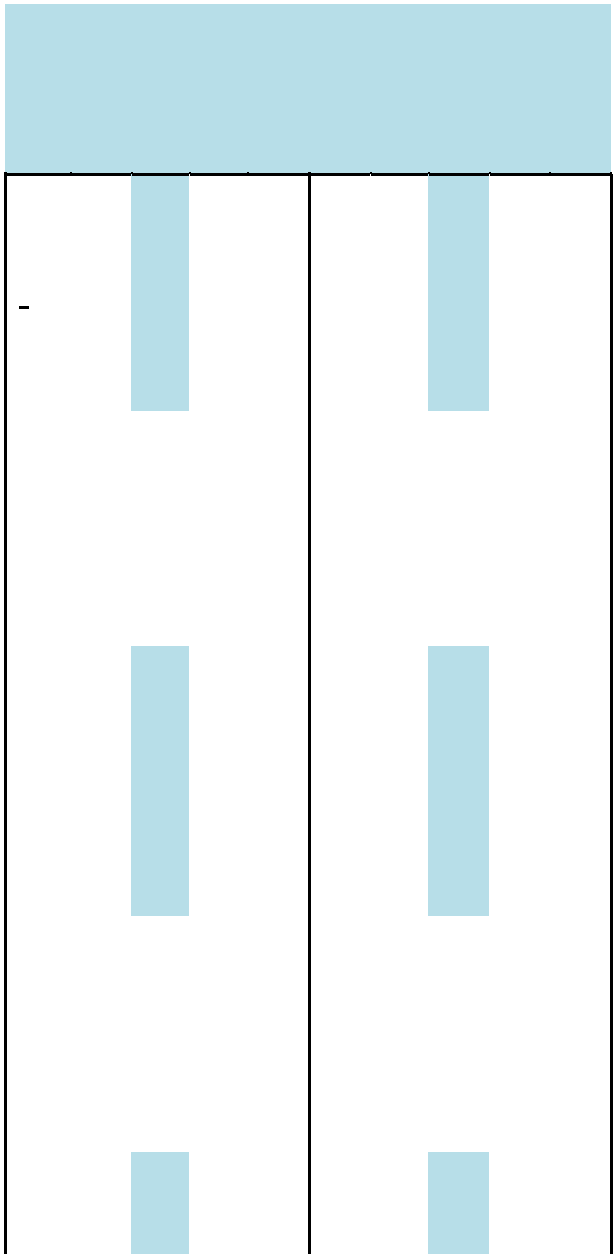
W



# Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Plant
## For the 12 months ended - December 31, 0
## Incentive Projects (continued)

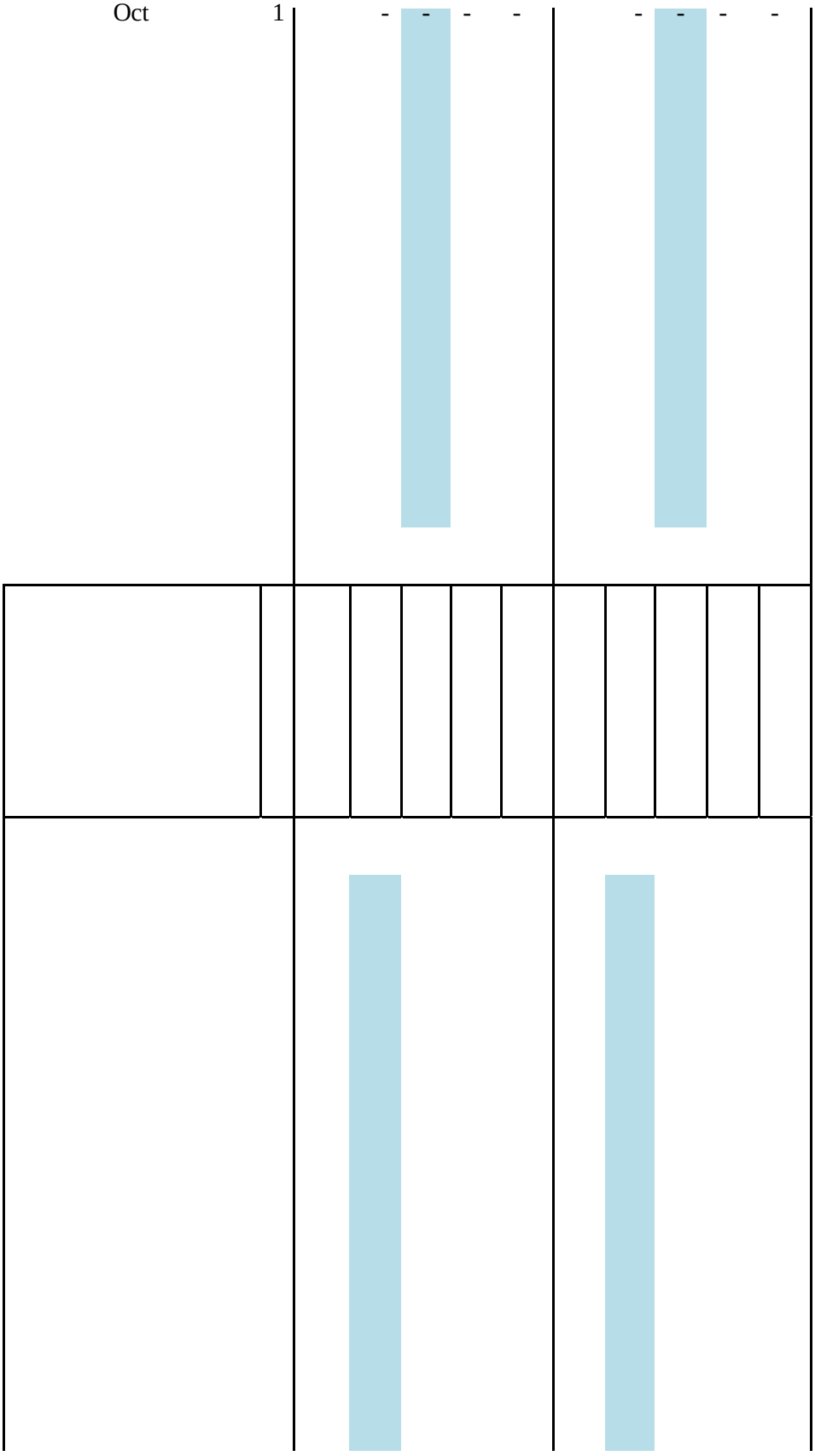
| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | *Description* | | | | *Description* | | | | | |
| 42 | **Project:** | | | | **Project:** | | | | | |
| 43 | Type: | | | | Type: | | | | | |
| | Depr. Rate: | 0.00 | | | Depr. Rate: | 0.00 | | | | |
| 44 | (A) | 0% | | | (A) | 0% | | | | |
| | TIER Adder | | | | TIER Adder | | | | | |
| 45 | (B) | - | | | (B) | - | | | | |
| 46 | Avg. Interest Rate Be | #DIV/0! | Return Adder | #DIV/0! | Avg. Interest Rate Begin. | #DIV/0! | Return Adder | #DIV/0! | | |

| | | | | |
|---|---|---|---|---|
| 4 | gi | $ | Plant | $ |
| 7 | n. | - | Bal: | - |



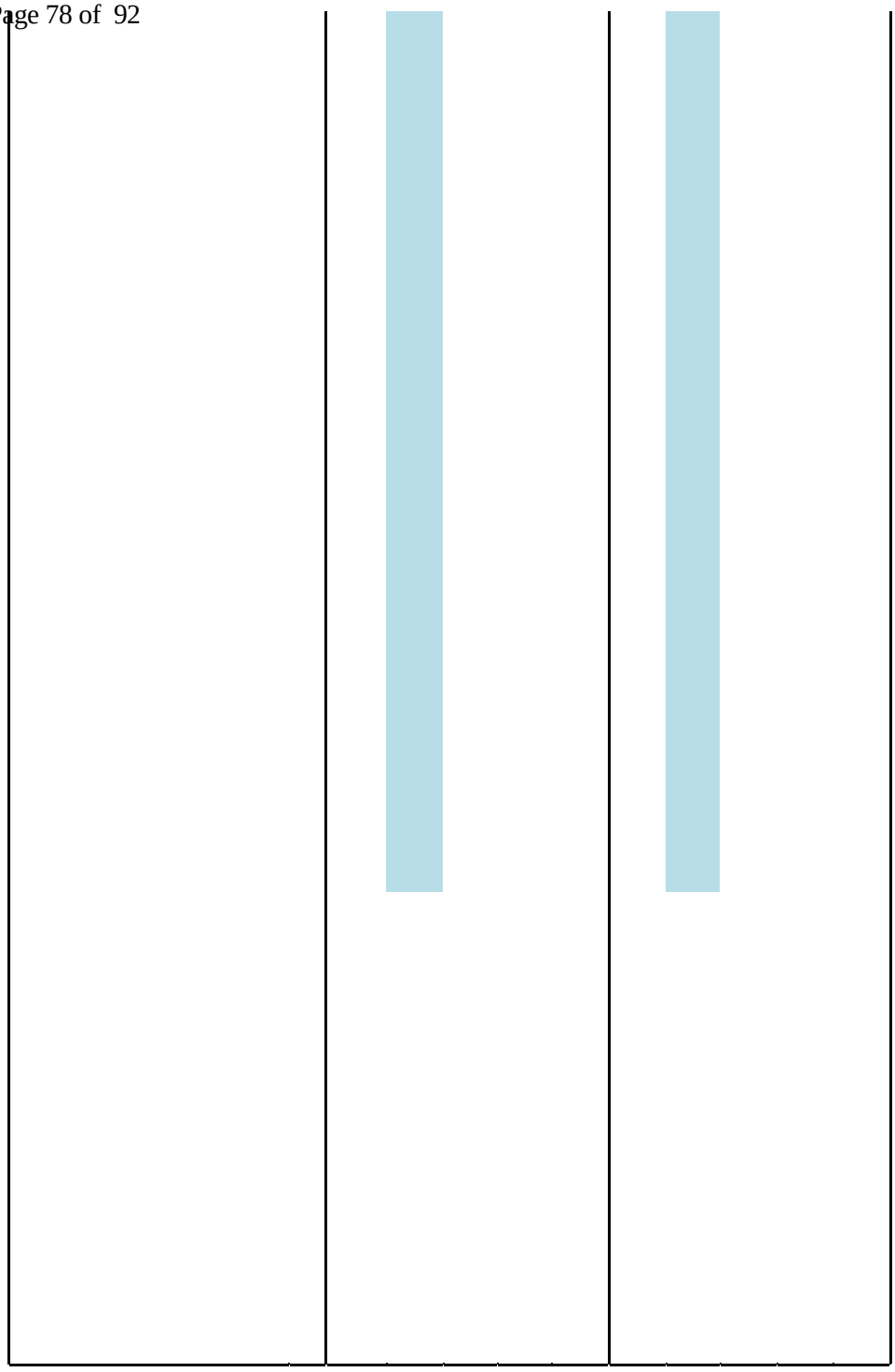
| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Plant Bal: Begin. Acc. Depr: | | - | | Begin. Acc. Depr: | | - | | |
| | | | Begin. Year-Mo.: | | | | Begin. Year-Mo.: | | | | |
| | **Mon** | **Year** | **Gross Plant** | **Depreciation** | **Accum Depr.** | **Net Plant** | **Gross Plant** | **Depreciation** | **Accum Depr.** | **Net Plant** |
| | | | $ - | | | | $ - | | | |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Jan | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Feb | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Mar | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Apr | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | May | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Jun | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Jul | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Aug | 1 | - | - | - | - | - | - | - | - |
| | - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Sep | 1 | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | - | $ | $ | $ | $ | | $ | $ | $ | $ | |
| 2 | Oct | 1 | - | - | - | - | | - | - | - | - | |



| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 6 | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 3 | No | 1 | | | | | | | | |
| 6 | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 4 | Dec | 1 | | | | | | | | |
| 6 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 5 | Jan | 0 | | | | | | | | |
| 6 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | Feb | 0 | | | | | | | | |
| 6 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 7 | Mar | 0 | | | | | | | | |
| 6 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 8 | Apr | 0 | | | | | | | | |
| 6 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 9 | May | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 0 | Jun | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 1 | Jul | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 2 | Aug | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 3 | Sep | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 4 | Oct | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 5 | Nov | 0 | | | | | | | | |
| 7 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | Dec | 0 | | | | | | | | |
| 7 | | | | | | | | | | |
| 7 | | | | | | | | | | |
| 7 | | | | $ - | | | | $ - | | |
| 8 | Total | | | | | | | | | |
| 7 | | | $ - | | $ - | $ - | $ - | | $ - | $ - |
| 9 | 13 Mo. Avg. | | - | | - | - | - | | - | - |
| 8 | | | | | | | | | | |
| 0 | | | | | | | | | | |
| 8 | | | | | | | | | | |
| 1 | | | | | | | | | | |
| | | | **Return due to Incentive Adder** | | #DIV/0! | | **Return due to Incentive Adder** | | #DIV/0! | |

or
kp



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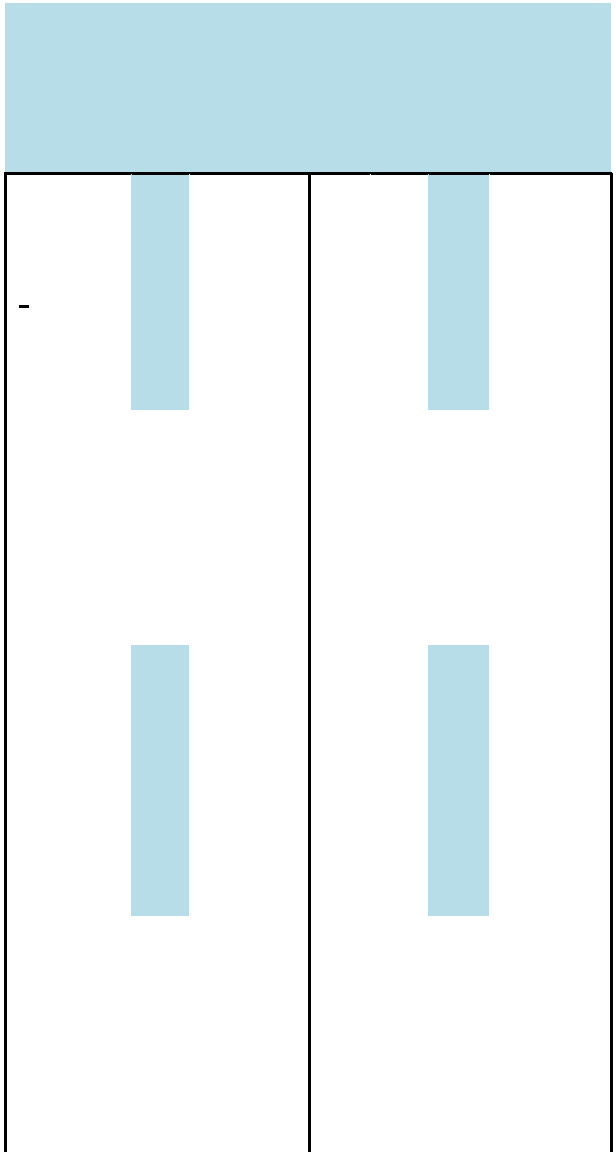
# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant
# For the 12 months ended - December 31, 0
## Incentive Projects (continued)

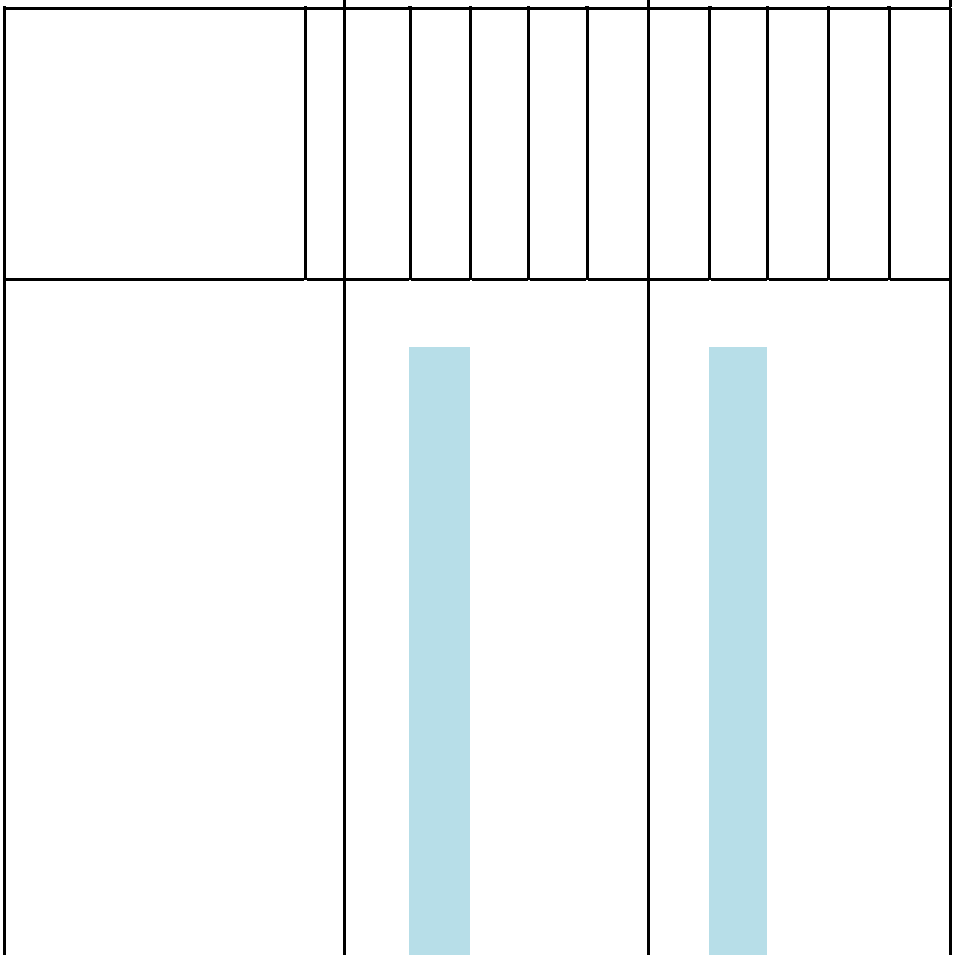
| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | *Description* | | | | *Description* | | | | |
| | **Project:** | | | | **Project:** | | | | |
| 83 | | | | | | | | | |
| 84 | Type: | | | | Type: | | | | |
| | Depr. Rate: (A) | 0.00% | | | Depr. Rate: (A) | 0.0000% | | | |
| 85 | | | | | | | | | |
| | TIER Adder (B) | - | | | TIER Adder (B) | - | | | |
| 86 | | | | | | | | | |
| | Avg. Interest Ra | #DIV/0 | Return Add | #DIV/ | Avg. Interest | #DIV/ | Return Add | #DIV/ | |

7 te ! er 0! Rate 0! er 0!

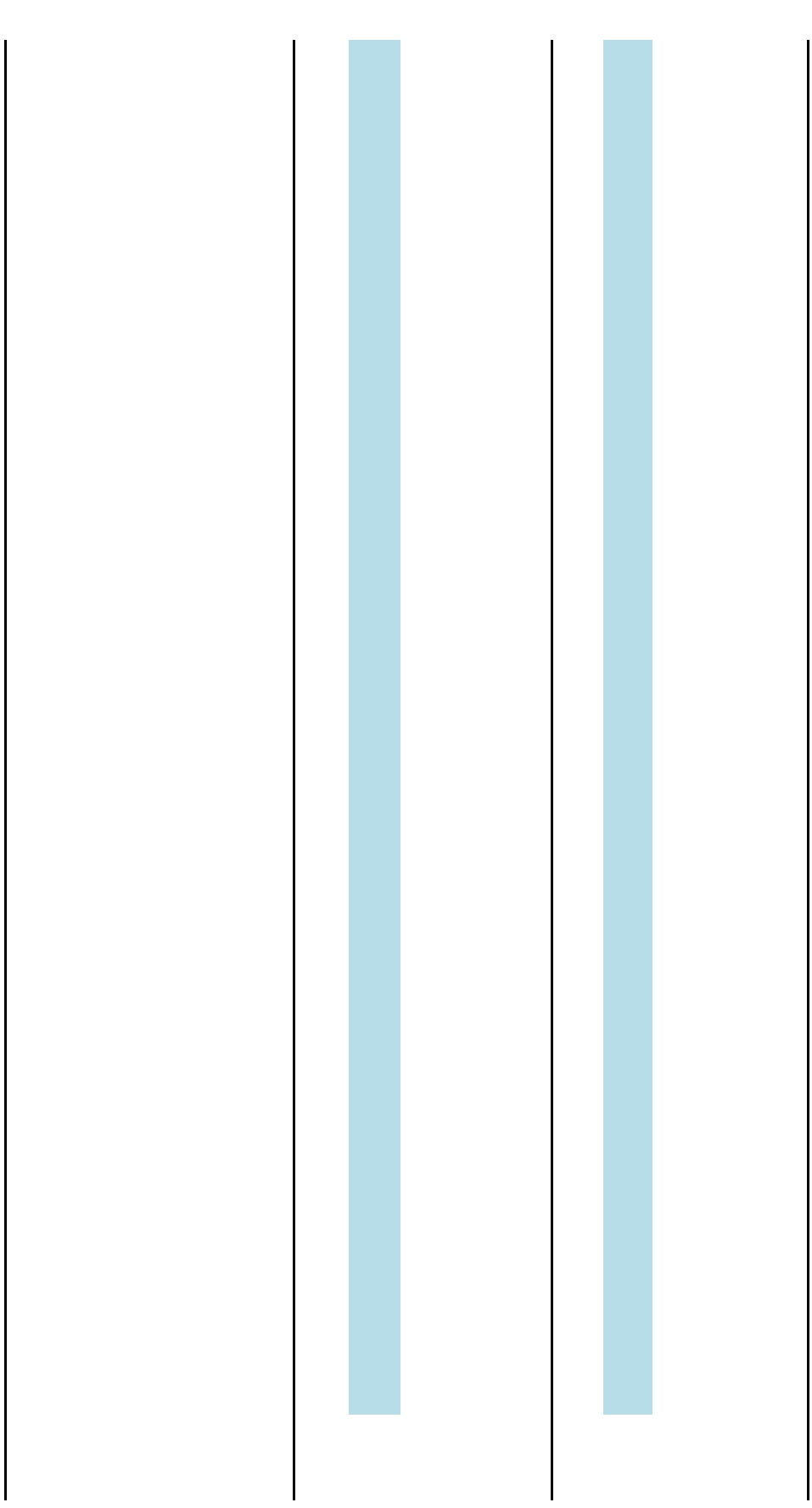


| | | | Begin. Plant Bal: | | | | Begin. Acc. Depr: | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | $ - | | | | | | | |
| | | | Begin. Year-Mo.: | | | | | | | |
| | **Mon** | **Year** | **Gross Plant** | **Depreciation** | **Accum Depr.** | **Net Plant** | **Gross Plant** | **Depreciation** | **Accum Depr.** | **Net Plant** |
| | | | $ - | | | | $ - | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Jan | 1 | | | | | | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Feb | 1 | | | | | | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Mar | 1 | | | | | | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Apr | 1 | | | | | | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | May | 1 | | | | | | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Jun | 1 | | | | | | | | |
| | | - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Jul | 1 | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | | - | $ | $ | $ | $ | | $ | $ | $ | $ |
| 11 | Aug | 1 | - | - | - | - | | - | - | - | - |



| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 102 | Sep | -1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 103 | Oct | -1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 104 | No | -1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 105 | Dec | -1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 106 | Jan | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 107 | Feb | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 108 | Mar | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 109 | Apr | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 110 | May | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 111 | Jun | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 112 | Jul | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 113 | Aug | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 114 | Sep | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 115 | Oct | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 116 | Nov | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 117 | Dec | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |



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|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | |
| 1 | | | | $ | | | | $ | | |
| 9 | Total | | | - | | | | - | | |
| 1 | | | | | | | | | | |
| 2 | | | | $ | $ | $ | | $ | $ | $ |
| 0 | 13 Mo. Avg. | | | - | - | - | | - | - | - |
| 1 | | | | | | | | | | |
| 2 | | | | | | | | | | |
| 1 | | | | | | | | | | |
| 1 | | | | | | | | | | |
| 2 | | | | | | | | | | |
| 2 | | | | | | | | | | |
| | | | **Return due to Incentive Adder** | # DIV/0! | | | **Return due to Incentive Adder** | # DIV/0! | | |
| 1 | | | | | | | | | | |
| 2 | | | | | | | | | | |
| 3 | | | | | | | | | | |





## Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Plant
## For the 12 months ended - December 31, 0
## Summary (Sunflower Owned Facilities)

**Total Incentive, Non-Incentive and SPP Plant**

**Total Plant Additions (Excluding Leases)**

**Projected New Non Incentive Plant**

**Plant Additions**

| **R** | **Spon so** | **T** | **Pl** | **Depreci** | **Accu** |
|---|---|---|---|---|---|

| | | T re hi an ati m<br>O d rd t on ul |
|---|---|---|
| | | |

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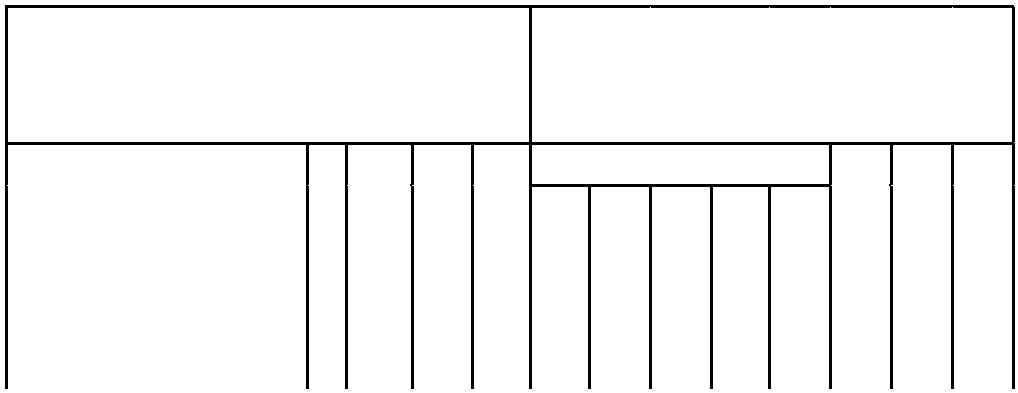

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | V/0! | V/0! | | | | | | | | V/0! | V/0! | |
| 13 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 14 | May | | 1 | - | | | | | | | | | | | | |
| 13 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 15 | Jun | | 1 | - | | | | | | | | | | | | |
| 13 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 16 | Jul | | 1 | - | | | | | | | | | | | | |
| 13 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 17 | Aug | | 1 | - | | | | | | | | | | | | |
| 13 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 18 | Sep | | 1 | - | | | | | | | | | | | | |
| 13 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 19 | Oct | | 1 | - | | | | | | | | | | | | |
| 14 | | | - | $ | #DIV/0! | $ - | $ - | $ - | | | | $ - | $ - | #DIV/0! | #DIV/0! | |
| 20 | Nov | | 1 | - | | | | | | | | | | | | |
| 1 | | | | | #DIV/0! | #DIV/0! | | | | | | | | #DIV/0! | #DIV/0! | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | | - | $ | V/ | /0 | $ | $ | $ | | $ | V/ | V/ |
| 1 | Dec | | 1 | - | 0! | ! | - | - | - | | - | 0! | 0! |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | #DIV/0! | |
| 142 | 50 | | Jan | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 143 | | | Feb | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 144 | | | Mar | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 145 | | | Apr | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 146 | | | May | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 147 | | | Jun | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 148 | | | Jul | 0 | $ | - | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| 149 | | | Aug | 0 | $ | - | #DIV/0! | |
| 150 | | | | | | | | |

| | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | #DIV/0! | #DIV/0! | | | | | | #DIV/0! | #DIV/0! | |
| 151 | | | | $ - | #DIV/0! | #DIV/0! | $ - | $ - | $ - | | $ - | #DIV/0! | #DIV/0! | |
| 152 | | Oct | 0 | | | | | | | | | | | |
| 153 | | Nov | 0 | $ - | #DIV/0! | #DIV/0! | $ - | $ - | $ - | | $ - | #DIV/0! | #DIV/0! | |
| 154 | | Dec | 0 | $ - | #DIV/0! | #DIV/0! | $ - | $ - | $ - | | $ - | #DIV/0! | #DIV/0! | |
| 155 | | | | | | | | | | | | | | |
| 156 | 12 Mon Tot | | | | #DIV/0! | | | | 12-Month Depreciation Expense | | | #DIV/0! | | |
| 157 | 13 Mon Avg | | | $ - | | #DIV/0! | | | 13-Month Aver. Balance | | $ - | | #DIV/0! | |

Notes:

(C) See WP P-4 (Proj. RTO Directed).
(D) See WP P-5 (Sponsored Projects).
(E) See WP P-6

| | | |
|---|---|---|
| | (Third Party Projects). | |

(F) Other transmission projects, not included in the Special Project categories.
(G) See WP A-5 (Act Depreciation Rate).

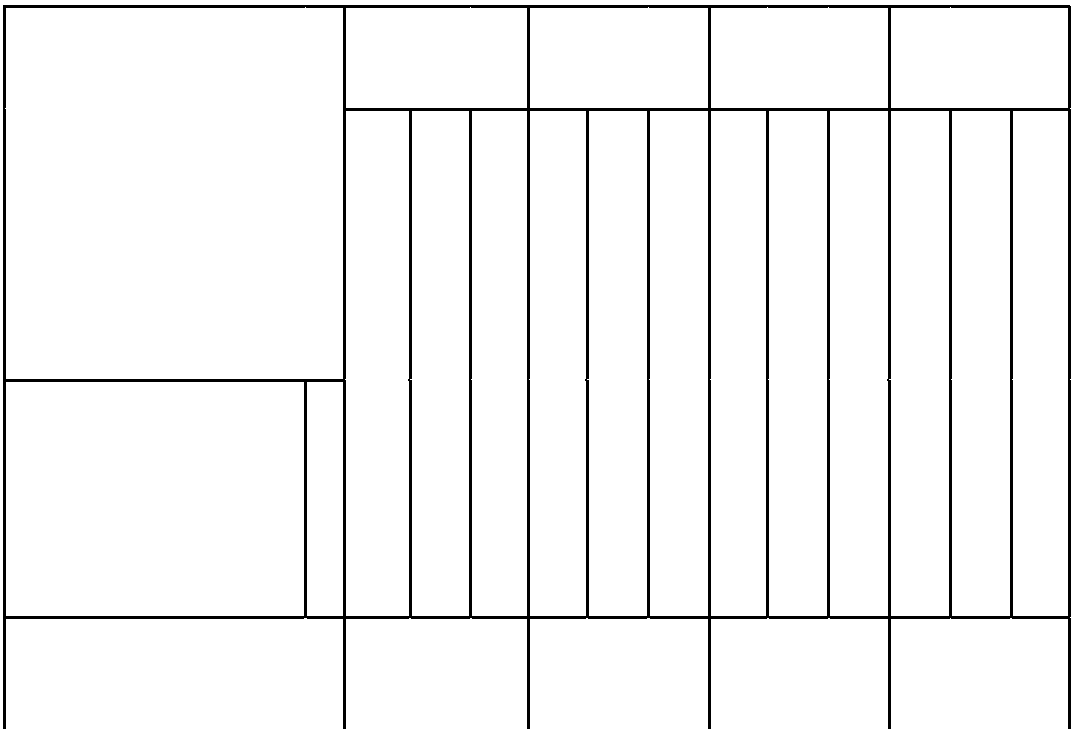
Workpaper P-1 Page 5 of 5



## Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Plant
## For the 12 months ended - December 31, 0
## Capital Leases

| 1 | | Plant-in-Service as of 12/31/-2 | | | New Non-RTO Facilities | | | New RTO Facilities | | | Total Capital Leases | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | | | | | |
| 7 | | | | | | | | | | | | | |
| | | Year | Plant | Equiv. Accum. Amortization | Net Plant | Gross Plant | Equiv. Accum. Amortization | Net Plant | Gross Plant | Equiv. Accum. Amortization | Net Plant | Gross Plant | Equiv. Accum. Amortization | Net Plant |
| 1 | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | |
| 9 | Mon. | | | | | | | | | | | | | |
| 1 | | (b | ( | (d | (e | | (g | (h | | (k | | m | (n | |
| 6 | | | | | | | | | | | | | | |

0 (a) ) c) ) ) (f) ) ) (i) (j) ) (l) ) )



| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 161 | | | | | | | | | | | |
| 162 | | | | | | | | | | | |
| 163 | | | | | | | | | | | |
| 164 | | | | | | | | | | | |
| 165 | | | | | | | | | | | |
| 166 | 177 | | - | Apr | $ - | $ - | $ - | $ - | $ - | $ - | |
| 167 | 178 | Jan | 1 | | - | - | - | - | - | - | |
| 168 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 169 | | Feb | 1 | | - | - | - | - | - | - | |
| 170 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 171 | | Mar | 1 | | - | - | - | - | - | - | |
| 172 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 173 | | Apr | 1 | | - | - | - | - | - | - | |
| 174 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 175 | | May | 1 | | - | - | - | - | - | - | |
| 176 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 177 | | Jun | 1 | | - | - | - | - | - | - | |
| 178 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 179 | | Jul | 1 | | - | - | - | - | - | - | |
| 180 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 181 | | Aug | 1 | | - | - | - | - | - | - | |
| 182 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 183 | | Sep | 1 | | - | - | - | - | - | - | |
| 184 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 185 | | Oct | 1 | | - | - | - | - | - | - | |
| 186 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 187 | | Nov | 1 | | - | - | - | - | - | - | |
| 188 | | | - | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 189 | | Dec | 1 | | - | - | - | - | - | - | |
| 190 | | | | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 191 | | Jan | 0 | | - | - | - | - | - | - | |
| 192 | | | | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 193 | | Feb | 0 | | - | - | - | - | - | - | |
| 194 | | | | | $ - | $ - | $ - | $ - | $ - | $ - | |
| 195 | | Mar | 0 | | - | - | - | - | - | - | |

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| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
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| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
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| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
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| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
| | | | | | | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 178 | May | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 179 | Jun | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 180 | Jul | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 181 | Aug | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 182 | Sep | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 183 | Oct | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 184 | Nov | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 185 | Dec | 0 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 186 | | | | | | | | | | | | | | | |
| 187 | 13 Mon Avg | | | | $ - | | | $ - | | | $ - | $ - | $ - | $ - | |

Note: Depreciation/amortization is not actually recorded for capital leased facilities. Instead, Plant-in-Service is reduced as a portion of the lease payments are used to reduce the principle amount. The above treatment is equivalent to the accounting treatment intended to develope the appropriate Net Plant values to use in allocating O&M and other expenses.

# Sunflower Electric Power Corporation (SEPC)
## Projected Expenses and Revenue Credits For the 12 months ended - December 31, 0

| Line | Description | Source | (3) -2 Actual Costs | (4) | (5) 0 Projected Costs (Ratio * Proj. Net Plant) |
|---|---|---|---|---|---|
| | (1) | (2) | | | |
| 1 | Net Plant in Service (Excludes Capital and Operating Leases) | Actual Gross Rev, Pg. 1, L22, Col 6 & Projected Gross Rev, Pg 1, L21, Col. 6 | $ - | | #DIV/0! |
| 2 | Plus: Net Plant Equivalent for Capital Leases (Note B) | A-12 , Pg. 1, L23 & P-1, Pg. 5, L187 | - | | - |
| 3 | Less: Net Plant Excluded for O&M, Other Taxes and Gen. Plant | | - | | |
| 4 | Adjusted Net Plant for O&M and Other Taxes | L1 + L2 - L3 | $ - | | #DIV/0! |
| 5 | Ratio Projected Net Plant to Actual Net Plant | | | CALC RATIO = | #DIV/0! |
| 6 | | | | CAP = | 1.3000 |
| 7 | | | | CAPPED RATIO | #DIV/0! |
| 8 | **Operation and Maintenance Expenses** | | | | |
| 9 | Transmission | Actual Gross Rev, Pg. 2, L60 | $ - | x CAPPED RATIO | #DIV/0! |
| 10 | Less: Account 565 | Actual Gross Rev, Pg. 2, L61 | - | x CAPPED RATIO | #DIV/0! |
| 11 | Less: Transmission Leases & Facility Charges | Actual Gross Rev, Pg. 2, L62 | - | x CAPPED RATIO | #DIV/0! |
| 12 | Less Schedule 1 Rev. Req. | Actual Gross Rev, Pg. 2, L63 | - | x CAPPED RATIO | #DIV/0! |
| 13 | Plus: Projected Transmission Leases & Facility Charges | See Note A | | | - |

| | | | | | |
|---|---|---|---|---|---|
| | | | | x | |
| 14 | A&G -Adjusted per WP A-11 | Actual Gross Rev, Pg. 2, L65 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 15 | Plus: Safety Advertising | Actual Gross Rev, Pg. 2, L66 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 16 | Plus Association Dues Directly Related to Transmission | Actual Gross Rev, Pg. 2, L67 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 17 | Plus: Advertising - Transmission | Actual Gross Rev, Pg. 2, L68 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 18 | Plus: Research -Transmission | Actual Gross Rev, Pg. 2, L69 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 19 | Plus: Regulatory Exp - Transmission | Actual Gross Rev, Pg. 2, L70 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 20 | Plus: Corporate Visibility - Transmission | Actual Gross Rev, Pg. 2, L71 | - | CAPPED RATIO | #DIV/0! |
| | Projected O&M | L9 - Sum(L10:L12) + L13 + L14 + Sum(L15:L20) | $ - | | #DIV/0! |
| 21 | | | | | |
| 22 | **Other Taxes** | | | | |
| 23 | LABOR RELATED | | | | |
| | | | | x | |
| 24 | Payroll | Actual Gross Rev, Pg. 2, L87 | $ - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 25 | Highway and vehicle | Actual Gross Rev, Pg. 2, L88 | - | CAPPED RATIO | #DIV/0! |
| 26 | PLANT RELATED | | | | |
| | | | | x | |
| 27 | Property (Note P) | Actual Gross Rev, Pg. 2, L90 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 28 | Gross Receipts | Actual Gross Rev, Pg. 2, L91 | - | CAPPED RATIO | #DIV/0! |
| | | | | x | |
| 29 | Other | Actual Gross Rev, Pg. 2, L92 | - | CAPPED RATIO | #DIV/0! |
| 30 | Projected Other Taxes | Sum (L24:L29) | $ - | | #DIV/0! |
| 31 | | | | | |
| 32 | **Revenue Credits** | | | | |
| | | A-1 (Act. Rev | | | $ |

| | | | |
|---|---|---|---|
| 33 | Total Revenue Credits | Credit), L91 (Note C) | - |

| | | | |
|---|---|---|---|
| | Net Sch. 11 Revenue to be Applied as a Credit to Base Plan ATRR in -2 | A-1 (Act. Rev Credit), L89 | $ - |
| 34 | | | |
| 35 | Revenue Credits applied to Zonal ATRR | L33 - L34 | $ - |
| 36 | | | |

Notes:

A Lease payments for -2 (actual) and 0 (projected) are shown below:

| | Annualized -2 | 0 |
|---|---|---|
| | $ | $ |
| Midwest Energy | - | - |
| Pioneer | - | - |
| Western | - | - |
| Wheatland | - | - |
| Total | $ - | $ - |

B Capital Leases are only to be included here if Sunflower is responsible for the O&M expense

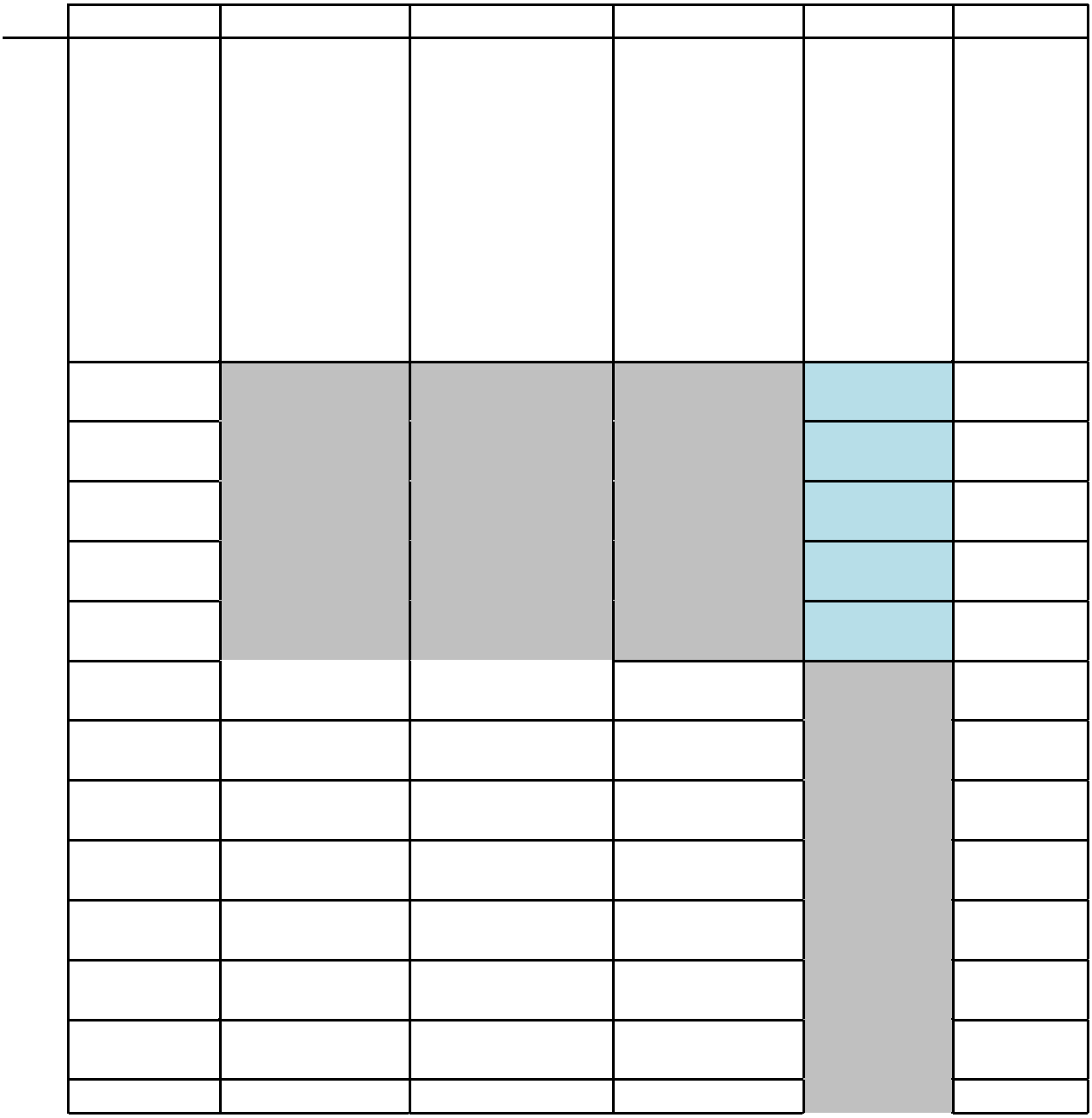
C Adjusted revenue credits for known changes in upgrade revenue. In the event total revenue credits are adjusted, Sunflower will provide a separate workpaper supporting the adjustment.

Worksheet P-3
Page 1 of 1

# Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Network Load For the 12 months ended - December 31, -1

| Line No. | a | b | c | d | e | f |
|---|---|---|---|---|---|---|
| | **Month** | **Monthly Transmission Network Load as Percentage of the Average Total Network Load of January thru May (Worksheet A-2)** | **Average Monthly Transmission Network Load for January thru May (col e, line 2 thru line 9)** | **Estimated Monthly Transmission Network Load for June thru December ( b X c)** | **Actual Load for January through May** | **Projected Transmission Network Load** |
| 1 | January | | | | - | - |
| 3 | February | | | | - | - |
| 4 | March | | | | - | - |
| 5 | April | | | | - | - |
| 6 | May | | | | - | - |
| 7 | June | #DIV/0! | - | #DIV/0! | | #DIV/0! |
| 8 | July | #DIV/0! | - | #DIV/0! | | #DIV/0! |
| 9 | August | #DIV/0! | - | #DIV/0! | | #DIV/0! |
| 10 | September | #DIV/0! | - | #DIV/0! | | #DIV/0! |
| 11 | October | #DIV/0! | - | #DIV/0! | | #DIV/0! |
| 12 | November | #DIV/0! | - | #DIV/0! | | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| 13 | December | #DIV/0! | - | #DIV/0! | | #DIV/0! |
| 14 | Total | | | | | #DIV/0! |



| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |

| | | | |
|---|---|---|---|
| 15 | 12-CP | | #DIV/0! |

Note: **Column b** is the monthly transmission network load for June thru December as a percentage of the average of the monthly transmission network load values for January through May, based on monthly load values in Worksheet A-2.
**Column c** is average (January thru May) of monthly transmission network load in column e.
**Column f** contains actual load values for January-May and projected load values for June - December.

# Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Plant Related Projects -RTO Directed Projects (B & C)
## For the 12 months ended - December 31, 0

**Total Base Plan Projects (*Sunflower Owned*)**

| | | | | | | Project: | 1 | | Project: | 2 | | Project: | 3 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | | | | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | |
| 3 | | | | | | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) |
| 4 | | | | | | Begin Plant in Serv. | $ - | | Begin Plant in Serv. | $ - | | Begin Plant in Serv. | $ - | |
| 5 | | | | | | Begin. Acc. Depr: | $ - | | Begin. Acc. Depr: | $ - | | Begin. Acc. Depr: | $ - | |
| 6 | | | | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | |
| 7 | Mon | Year | Gross Plant | Total Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant |
| 8 | | | | | | $ - | | | $ - | | | $ - | | |
| 9 | Jan | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 10 | Feb | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 11 | Mar | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | A | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 2 | pr | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | M | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 3 | ay | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | Ju | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 4 | n | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | Ju | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 5 | l | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | A | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 6 | ug | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | Se | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 7 | p | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | O | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 8 | ct | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 1 | N | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 9 | o | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | D | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 0 | ec | 1 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | Ja | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 1 | n | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | Fe | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 2 | b | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | M | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 3 | ar | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | A | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 4 | pr | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | M | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 5 | ay | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | Ju | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 6 | n | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |
| 2 | Ju | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 7 | l | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | | | | #DI | | | | | | #DI | | | | #DI |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | Aug | 0 | $ - | #DIV/0! | ! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | ! | $ - | #DIV/0! | ! |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | Sep | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 30 | Oct | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 31 | Nov | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 32 | Dec | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 33 | | | | | | | | | | | | | | |
| 34 | 13 Mon Avg | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 35 | 12 Mon Depr Exp | | | #DIV/0! | | 12 Mon Depr Exp | #DIV/0! | | 12 Mon Depr Exp | #DIV/0! | | 12 Mon Depr Exp | #DIV/0! | |

**Notes:**

(A) See WP A-5 (Act Depreciation.Rate).

(B) P-4 projects should be included in total projected transmission projects for P-1

(C) Projects should not be listed until the first year they are expected to be in service. Do not duplicate projects listed in A-7 (Act.RTO Directed Proj).



## Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Plant Related Projects -RTO Directed Projects (B & C)
## For the 12 months ended - December 31, 0

## Base Plan Projects

**(*Sunflower Owned*) (cont'd)**

**Project:** SPP Proj. ID 4

Depr. Rate: #DIV/0! (A)

Begin Plant in Serv. $ -

Begin. Acc. Depr: $ -

Begin. Year-Mo.:

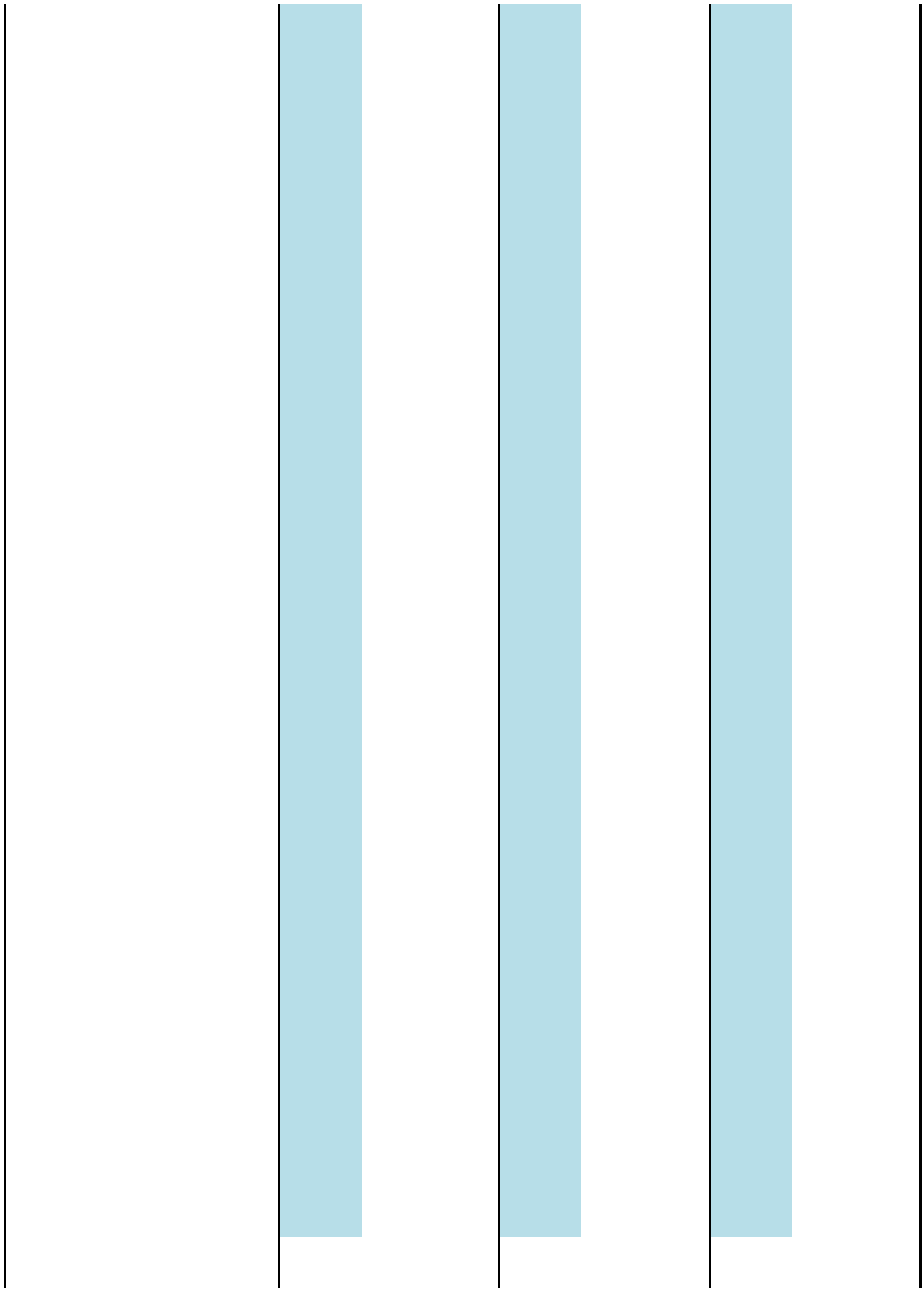
| Month | Year | Gross Plant | Accm. Depr. | Net Plant |
|---|---|---|---|---|
| | | $ - | | |
| Jan | -1 | $ - | #DIV/0! | #DIV/0! |
| Feb | -1 | $ - | #DIV/0! | #DIV/0! |
| Mar | -1 | $ - | #DIV/0! | #DIV/0! |
| Apr | -1 | $ - | #DIV/0! | #DIV/0! |
| May | -1 | $ - | #DIV/0! | #DIV/0! |
| Jun | -1 | $ - | #DIV/0! | #DIV/0! |
| Jul | -1 | $ - | #DIV/0! | #DIV/0! |

$ #DI
#DI
- V/0!
V/0!

| **Project:** | **5** | | | **Project:** | **6** | | | Mo.: | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | | | SPP Proj. ID | | | | | | | | | |
| Depr. Rate: | #DI V/0! | (A) | | Depr. Rate: | #DI V/0! | (A) | | | | | | | |
| Begin Plant in Serv. | $ - | | | Begin Plant in Serv. | $ - | | | | | | | | |
| Begin. Acc. Depr: | $ - | | | Begin. Acc. Depr: | $ - | | | | | | | | |
| Begin. Year-Mo.: | | | | Begin. Year-Mo.: | | | | | | | | | |
| **Gross Plant** | | **Accm. Depr.** | **Net Plant** | **Gross Plant** | | **Accm. Depr.** | **Net Plant** | **Gross Plant** | | **Accm. Depr.** | **Net Plant** | | |
| $ - | | | #DI V/0! | $ - | | | #DI V/0! | $ - | | #DI V/0! | #DI V/0! | | |
| $ - | | #DI V/0! | #DI V/0! | $ - | | #DI V/0!

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | Sep | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Oct | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Nov | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Dec | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Jan | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Feb | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Mar | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 5 | Apr | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | May | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Jun | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Jul | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Aug | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Sep | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Oct | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Nov | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 6 | Dec | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |

6
8



| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | 13 | | | | | | #DI | | | | #DI |
| 6 | Mon | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 | |
| 9 | Avg | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! | |
| | | 12 | | | 12 | | | 12 | | | |
| | | Mon | | | Mon | | | Mon | | | |
| 7 | 12 Mon Depr | Depr | #DI | | Depr | #DI | | Depr | #DI | | |
| 0 | Exp | Exp | V/0! | | Exp | V/0! | | Exp | V/0! | | |

**Notes:**

(A) See WP A-5 (Act Depreciation.Rate).

(B) P-4 projects should be included in total projected transmission projects for P-1

(C) Projects should not be listed until the first year they are expected to be in service unless there is a CWIP return incentive. Do not duplicate projects listed in A-7 (Act. RTO Proj).



$0.00

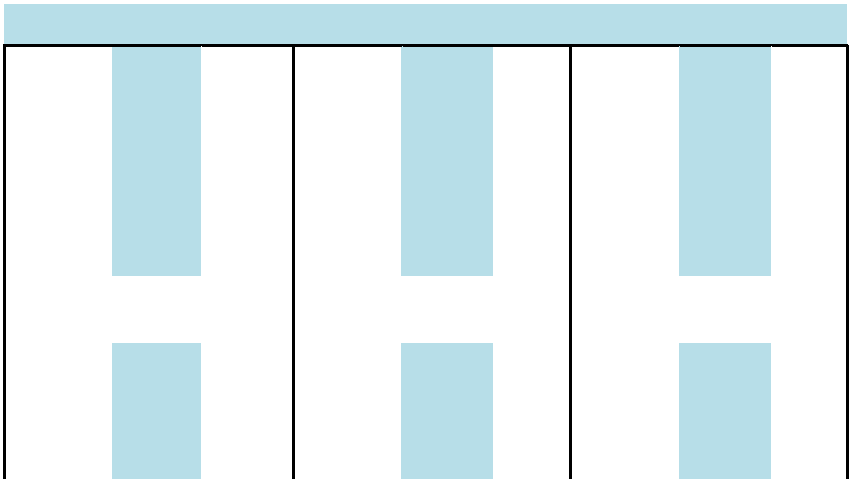


# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant Related Projects -RTO Directed Projects (B & C)
# For the 12 months ended - December 31, 0

## Base Plan Projects (*Sunflower Owned*)

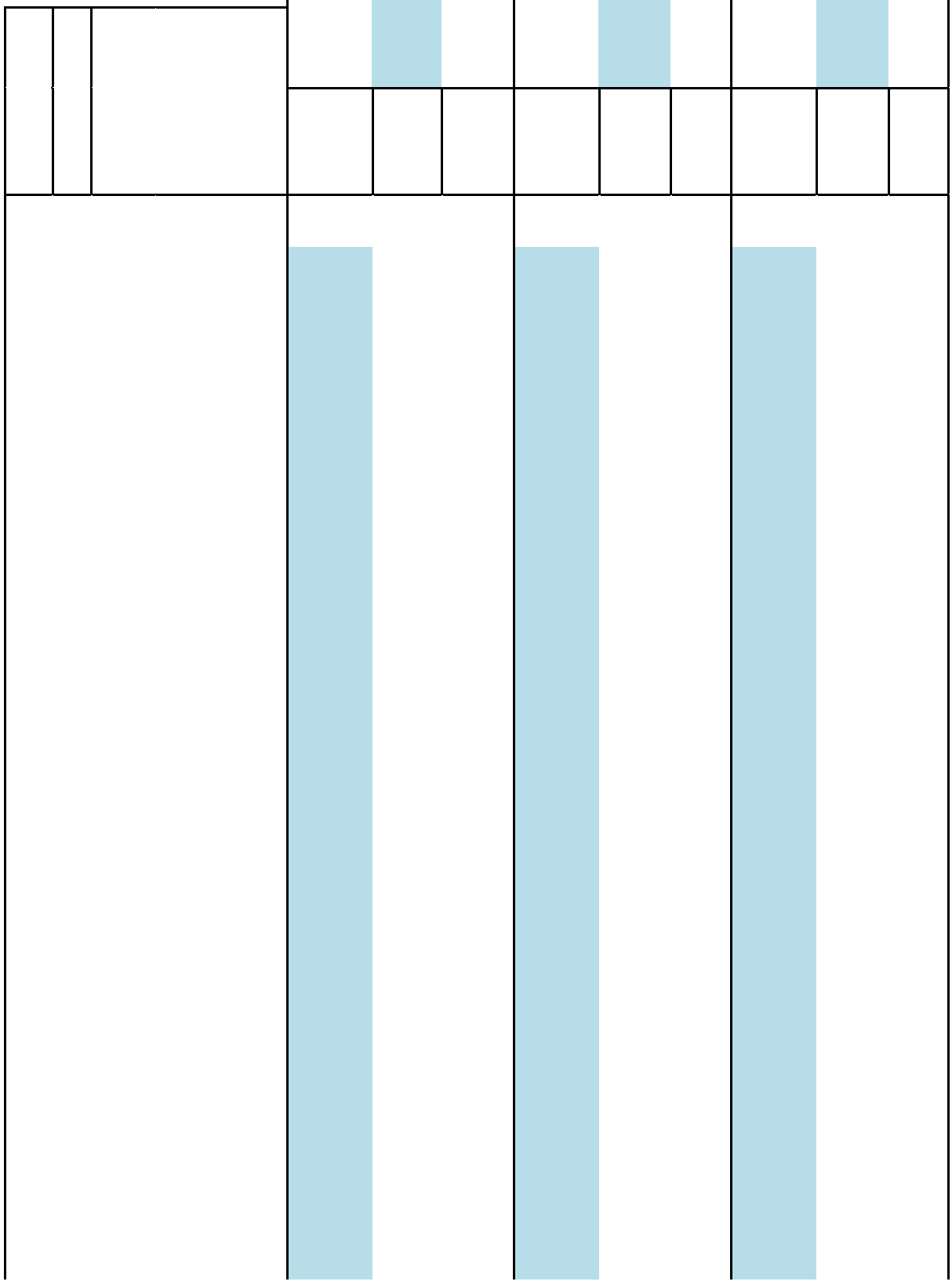
| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **(cont'd)** | **Project:** | **7** | | **Project:** | | | **Project:** | | | |
| | | SPP Proj. | | | SPP Proj. | | | SPP Proj. | | | |
| 2 | | ID | | | ID | | | ID | | | |
| | | Depr. | #DI | | Depr. | #DI | | Depr. | #DI | | |
| 3 | | Rate: | V/0! | (A) | Rate: | V/0! | (A) | Rate: | V/0! | (A) | |
| | | Begin Plant | | | Begin Plant | | | Begin Plant | | | |
| | | in | $ | | in | $ | | in | $ | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 4 | Serv. | - | Serv. | - | Serv. | - | |



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | | | Begin. Acc. Depr: | $ - | | Begin. Acc. Depr: | $ - | | Begin. Acc. Depr: | $ - | | |
| 6 | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | | |
| 7 | **Month** | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| 8 | | | $ - | | | $ - | | | $ - | | |
| 9 | Jan | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 10 | Feb | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 11 | Mar | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 12 | Apr | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 13 | May | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 14 | Jun | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 15 | Jul | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 16 | Aug | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 17 | Sep | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 18 | Oct | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 19 | No | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 20 | Dec | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Ja | | | $ | #DI | #DI | | $ | #DI | #DI | | $ | #DI | #DI |
| 1 | n | 0 | | - | V/0! | V/0! | | - | V/0! | V/0! | | - | V/0! | V/0! |



| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Feb | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | Mar | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | Apr | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | May | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | Jun | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | Jul | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | Aug | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 2 | Sep | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | Oct | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | Nov | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | Dec | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | | | | | | | | | | | |
| 3 | | | | | | | | | | | |
| 3 | 13 Mon Avg | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 3 | 12 Mon Depr Exp | | 12 Mon Depr Exp | #DIV/0! | | 12 Mon Depr Exp | #DIV/0! | | 12 Mon Depr Exp | #DIV/0! | |

**Notes:**

| | | | | |
|---|---|---|---|---|
| (A) See WP A-5 (Act Depreciation.Rate). | | | | |

(B) P-4 projects should be included in total projected transmission projects for P-1

(C) Projects should not be listed until the first year they are expected to be in service unless there is a CWIP return incentive. Do not duplicate projects listed in A-7 (Act. RTO Proj).



# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant Related Projects -RTO Directed Projects (B & C)
# For the 12 months ended - December 31, 0

## Total Base Plan

**Projects (*Capital Leases*)**

| | | |

| **Project:** | **8** | **Project:** | **9** | Year-Mo.: | | | |
|---|---|---|---|---|---|---|---|
| SPP Proj. ID | | SPP Proj. ID | | | **Gross Plant** | **Accm. Amort.** | **Net Plant** |
| Sum of Monthly Lease Payments 0 Begin Plant in Serv. | $ - | Sum of Monthly Lease Payments 0 Begin Plant in Serv. | $ - | | | | |
| Begin. Acc. Amort: | $ - | Begin. Acc. Amort: | $ - | | | | |
| Begin. Year-Mo.: | | | | | | | |

| **Gross Plant** | **Accm. Amort. Net Plant** |
|---|---|
| $ - | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | Ja | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | n | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | Fe | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | b | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | M | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | ar | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | A | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | pr | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | M | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | ay | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | Ju | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | n | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | Ju | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | l | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | A | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | ug | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | Se | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | p | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | O | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | ct | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | N | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | o | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | D | - | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | ec | 1 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Ja | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | n | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Fe | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 2 | b | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | M | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 3 | ar | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | A | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 4 | pr | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | M | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 5 | ay | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Ju | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 6 | n | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Ju | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 7 | l | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | A | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 8 | ug | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Se | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 9 | p | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | | | | | | | | | | | | | |
| 0 | O | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 0 | ct | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | | | | | | | | | | | | | |
| 0 | N | | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |
| 1 | ov | 0 | - | - | - | - | - | - | - | - | - | - | - | - |
| 1 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | D | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ | | $ | $ | $ |
| 2 | ec | 0 | - | - | - | | - | - | - | | - | - | - | | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 103 | | | | | | | | | | | | | | |
| 104 | 13 Mon Avg | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 105 | 12 Mon Depr Exp | $ - | | | 12 Mon Depr Exp | $ - | | 12 Mon Depr Exp | $ - | | 12 Mon Depr Exp | $ - | | |

**Notes:**

(B) P-4 projects should be included in total projected transmission projects for P-1

(C) Projects should not be listed until the first year they are expected to be in service. Do not duplicate projects listed in A-7 (Act.RTO Directed Proj).



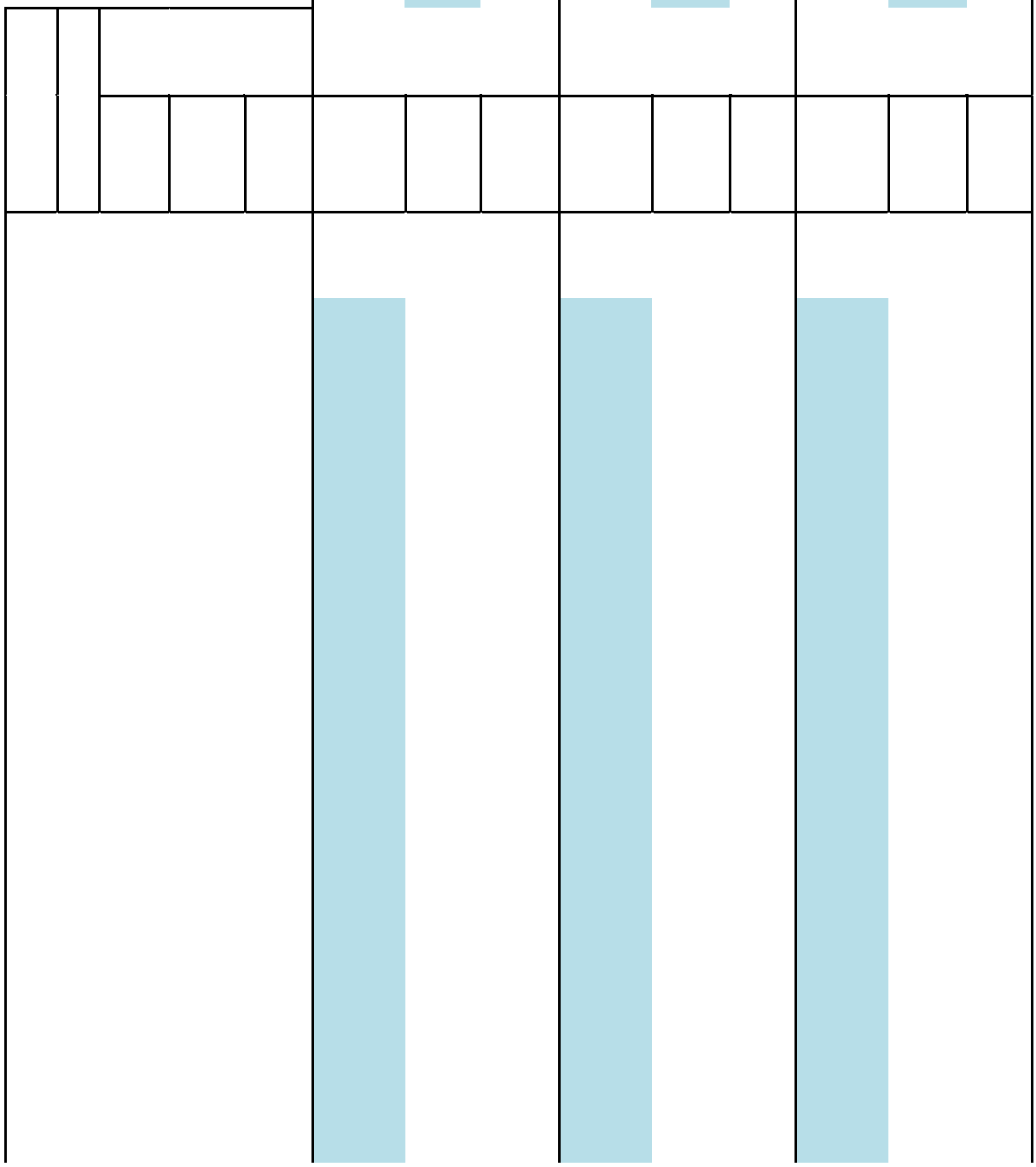


## Sunflower Electric Power Corporation (SEPC)
## Projected Transmission Plant Related Projects -RTO Directed Projects (B & C)
## For the 12 months ended - December 31, 0

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 106 | **Total Balanced Portfolio Projects** | *Description* | | | *Description* | | | *Description* | | |
| 107 | | **Project:** SPP Proj. ID | **1** | | **Project:** SPP Proj. ID | **2** | | **Project:** SPP Proj. ID | **3** | |
| 108 | | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) |

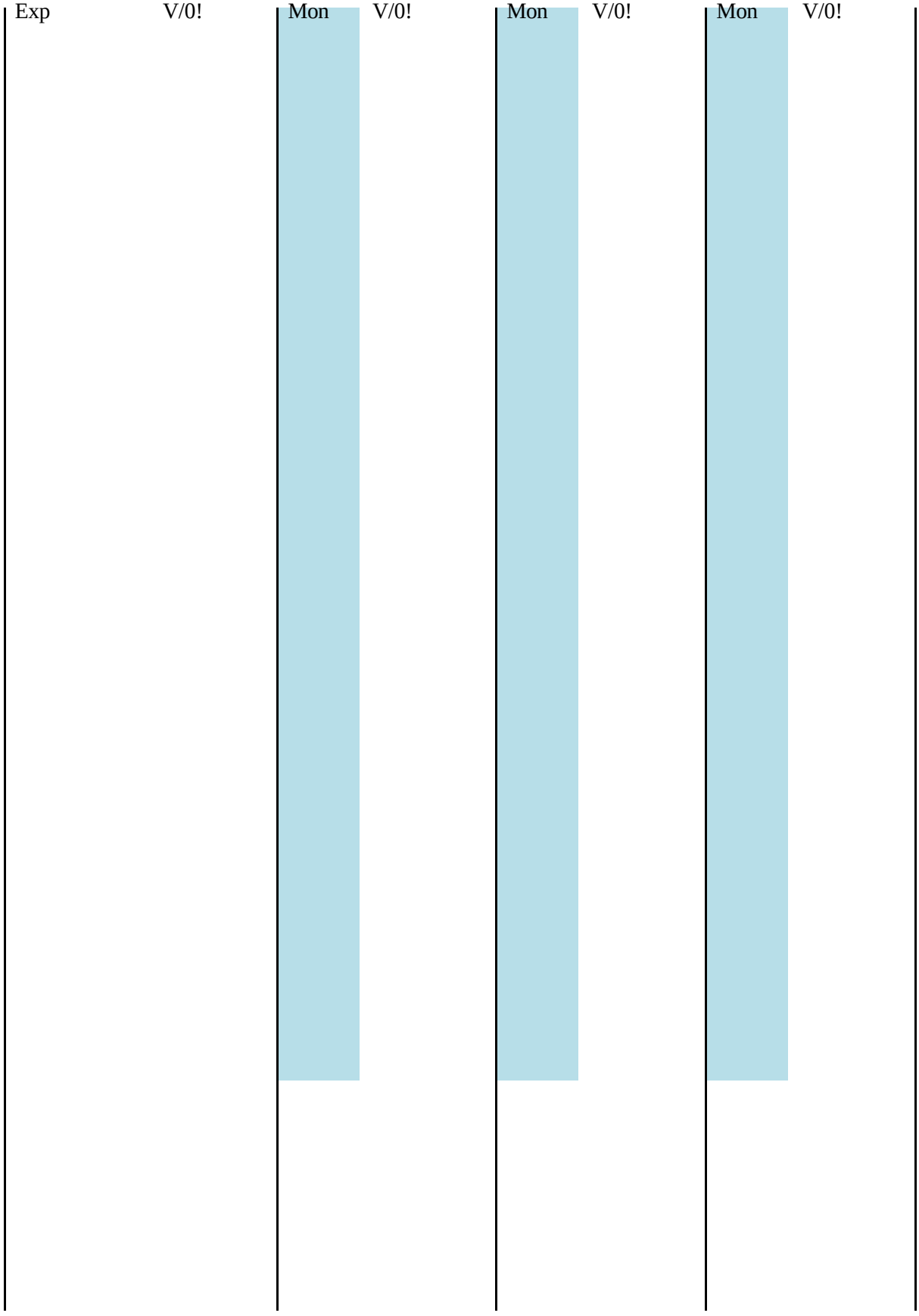
| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 109 | | | | | | Begin Plant in Serv. Begin. | $ - | | Begin Plant in Serv. Begin. | $ - | | Begin Plant in Serv. Begin. | $ - | | |
| 110 | | | | | | Acc. Depr: Begin. Year-Mo.: | $ - | | Acc. Depr: Begin. Year-Mo.: | $ - | | Acc. Depr: Begin. Year-Mo.: | $ - | | |
| 111 | | | | | | | | | | | | | | | |
| 112 | **Month** | **Year** | **Gross Plant** | **Total Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| 113 | | | | | | $ | | | $ | | | $ | | |
| 114 | | | | | | - | | | - | | | - | | |
| 115 | Jan | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 116 | Feb | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 117 | Mar | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 118 | Apr | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 119 | May | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 120 | Jun | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 121 | Jul | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 122 | Aug | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 123 | Sep | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 124 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | O | - | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 4 | ct | 1 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |



| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI |
| 2 | N | - | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 5 | o | 1 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 2 | D | - | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 6 | ec | 1 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 2 | Ja | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 7 | n | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 2 | Fe | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 8 | b | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 2 | M | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 9 | ar | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | A | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 0 | pr | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | M | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 1 | ay | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | Ju | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 2 | n | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | Ju | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 3 | l | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | A | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 4 | ug | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | Se | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 5 | p | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | O | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 6 | ct | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | N | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 7 | o | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | #DI | | | | | | | #DI | | | | #DI | |
| 3 | D | | $ | #DI | V/0 | | $ | #DI | #DI | | $ | #DI | V/0 | | $ | #DI | V/0 |
| 8 | ec | 0 | - | V/0! | ! | | - | V/0! | V/0! | | - | V/0! | ! | | - | V/0! | ! |
| 1 | | | | | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | | | |
| 1 | 13 | | | | #DI | | | | | | | #DI | | | | #DI | |
| 4 | Mon | | $ | #DI | V/0 | $ | | #DI | #DI | $ | | #DI | V/0 | $ | | #DI | V/0 |
| 0 | Avg | | - | V/0! | ! | - | | V/0! | V/0! | - | | V/0! | ! | - | | V/0! | ! |
| 1 | | | | | | | | | | | | | | | | | |

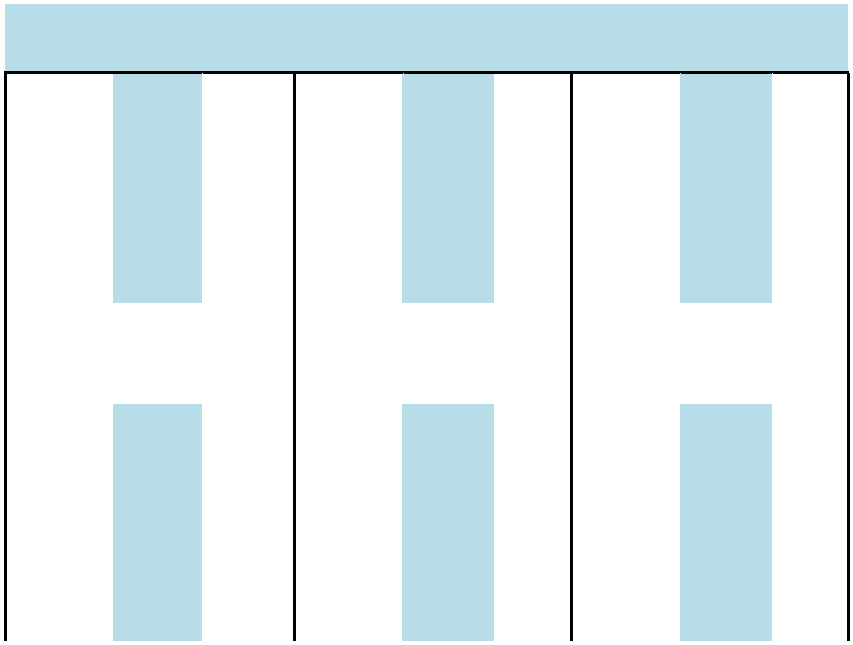
| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 4 1 | 12 Mon Depr Exp | #DIV/0! | 12 Mon | #DIV/0! | 12 Mon | #DIV/0! | 12 Mon | #DIV/0! |



| | | |

| *Description* | *Description* | *Begin. Acc. Depr:* |
|---|---|---|
| **Project:** SPP Proj. ID | **2** | |
| Depr. Rate: (A) | #DIV/0! | |
| Begin Plant in Serv. | | |
| Begin. Acc. Depr: | | |

| | | |
|---|---|---|
| **Project:** SPP Proj. ID | **3** | |
| Depr. Rate: (A) | #DIV/0! | |
| Begin Plant in Serv. | | |
| Begin. Acc. Depr: | | |



| | | | | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Month** | **Year** | **Gross Plant** | **Total Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** |
| | | | | | $ - | | | $ - | | | $ - | | |
| Jan | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Feb | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Mar | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Apr | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| May | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Jun | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Jul | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Aug | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Sep | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| Oct | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| No | - 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| D | - | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 |

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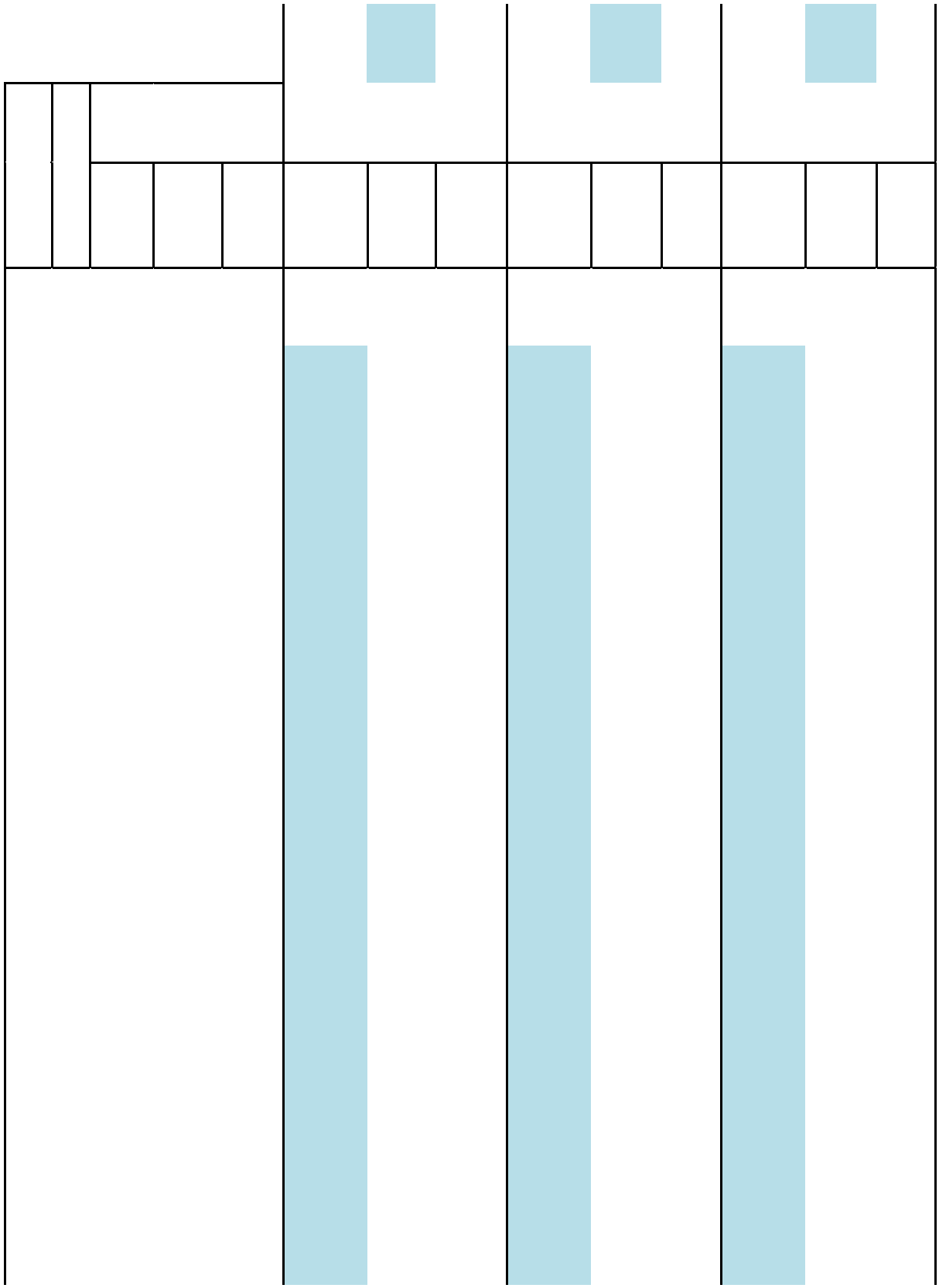

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| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 63 | Jan | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 64 | Feb | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 65 | Mar | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 66 | Apr | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 67 | May | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 68 | Jun | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 116 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 69 | Jul | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 117 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 70 | Aug | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 117 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 71 | Sep | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 117 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 72 | Oct | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 117 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 73 | Nov | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 117 | | | | | #DIV/0! | | | | | | | #DIV/0! | | | | #DIV/0! |
| 74 | Dec | 0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | | | |
| 175 | | | | | | | | | | | | | | | | |
| 176 | | | | | | | | | | | | | | | | |
| 177 | | | | | | | | | | | | | | | | |
| 115 | 13 Mon Avg | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | | |
| 116 | | | | | | 12 Mon Depr Exp | | | 12 Mon Depr Exp | | | 12 Mon Depr Exp | | | | |
| 117 | 12 Mon Depr Exp | | | #DIV/0! | | | #DIV/0! | | | #DIV/0! | | | #DIV/0! | | | |

| | | | | |
|---|---|---|---|---|
| **Notes:** | | | | |

(A) See WP A-5 (Act Depreciation.Rate).
(B) P-4 projects should be included in total projected transmission projects for P-1
(C) Projects should not be listed until the first year they are expected to be in service unless there is a CWIP return incentive. Do not duplicate projects listed in A-7 (Act. RTO Proj).





# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant Related Projects -RTO Directed Projects (B & C)
# For the 12 months ended - December 31, 0 4

| | | | |
|---|---|---|---|
| | | **Total** | *Description* |
| 17 | **Total ITP / Priority Projects-2** | | |
| 178 | | | **Project:** **1** |
| 179 | | | SPP Proj. ID |
| 180 | | | Depr. Rate: #DIV/0! (A) |
| 181 | | | Begin Plant in Serv. |
| 182 | | | Begin. Acc. Depr: |
| 183 | | | Begin. Year-Mo.: |
| 18 | | | |

*Description*

**Project:** 2

SPP Proj. ID

Depr. Rate: #DIV/0! (A)

Begin Plant in Serv. Begin. Acc. Depr: Begin. Year-Mo.:

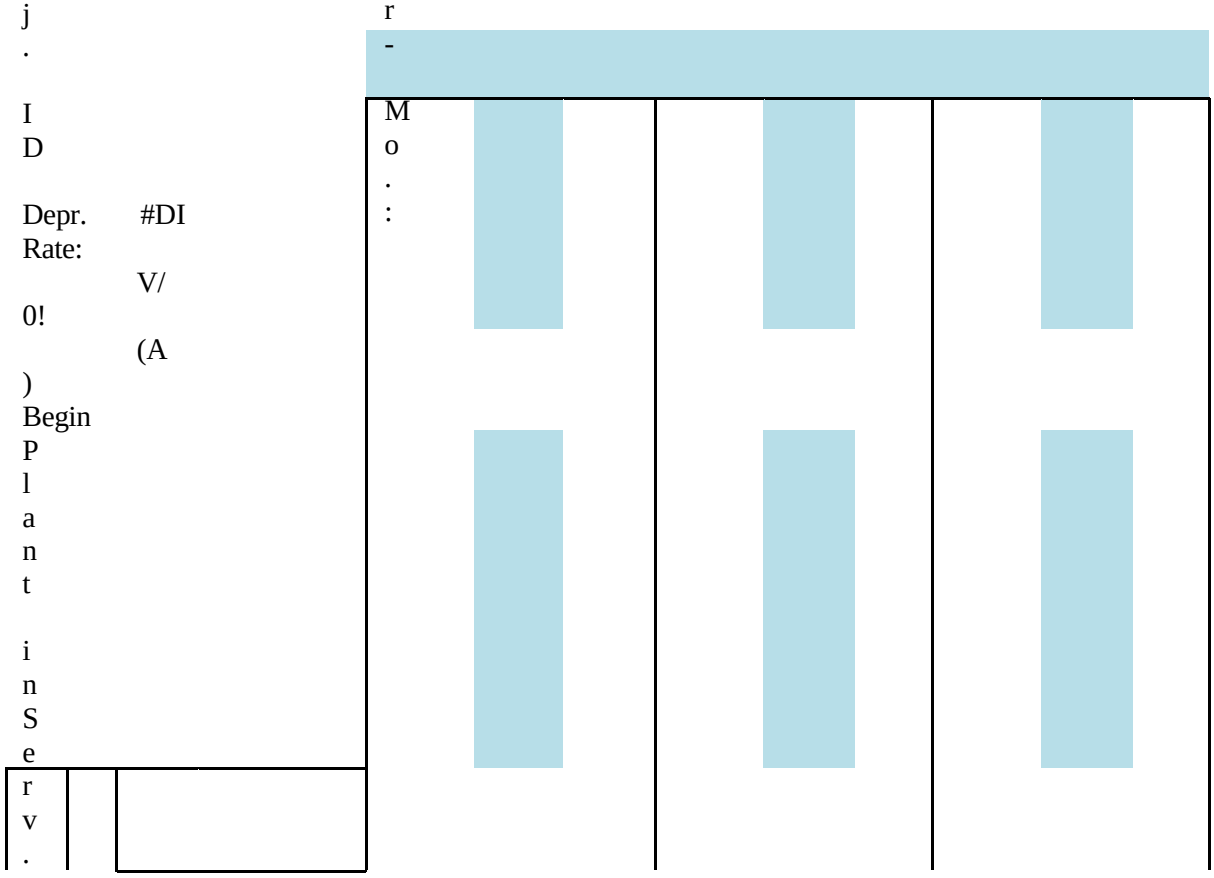
*Description*

**Project:** 3

SPP Proj. ID

Depr. Rate: #DIV/0! (A)

Begin Plant in Serv. Begin. Year-Mo.:



| 1 | Month | Year | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant | Gross Plant | Accm. Depr. | Net Plant |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 185 | | | | | | $ | | | $ | | | $ | | |
| 186 | | | | | | - | | | - | | | - | | |
| 187 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 188 | Jan | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 189 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 188 | Feb | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 191 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 188 | Mar | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 192 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 190 | Apr | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 193 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 191 | May | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 194 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 192 | Jun | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 195 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 193 | Jul | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 196 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 194 | Aug | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 197 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 195 | Sep | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 198 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 196 | Oct | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 199 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 197 | Nov | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 200 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 198 | Dec | -1 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 201 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 199 | Jan | -0 | $ - | #DIV/0! | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | | $ - | #DIV/0! | |
| 202 | | | | | #DIV/0! | | | | | | #DIV/0! | | | #DIV/0! |
| 200 | Feb | | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! | $ | #DIV/0! | #DIV/0! |

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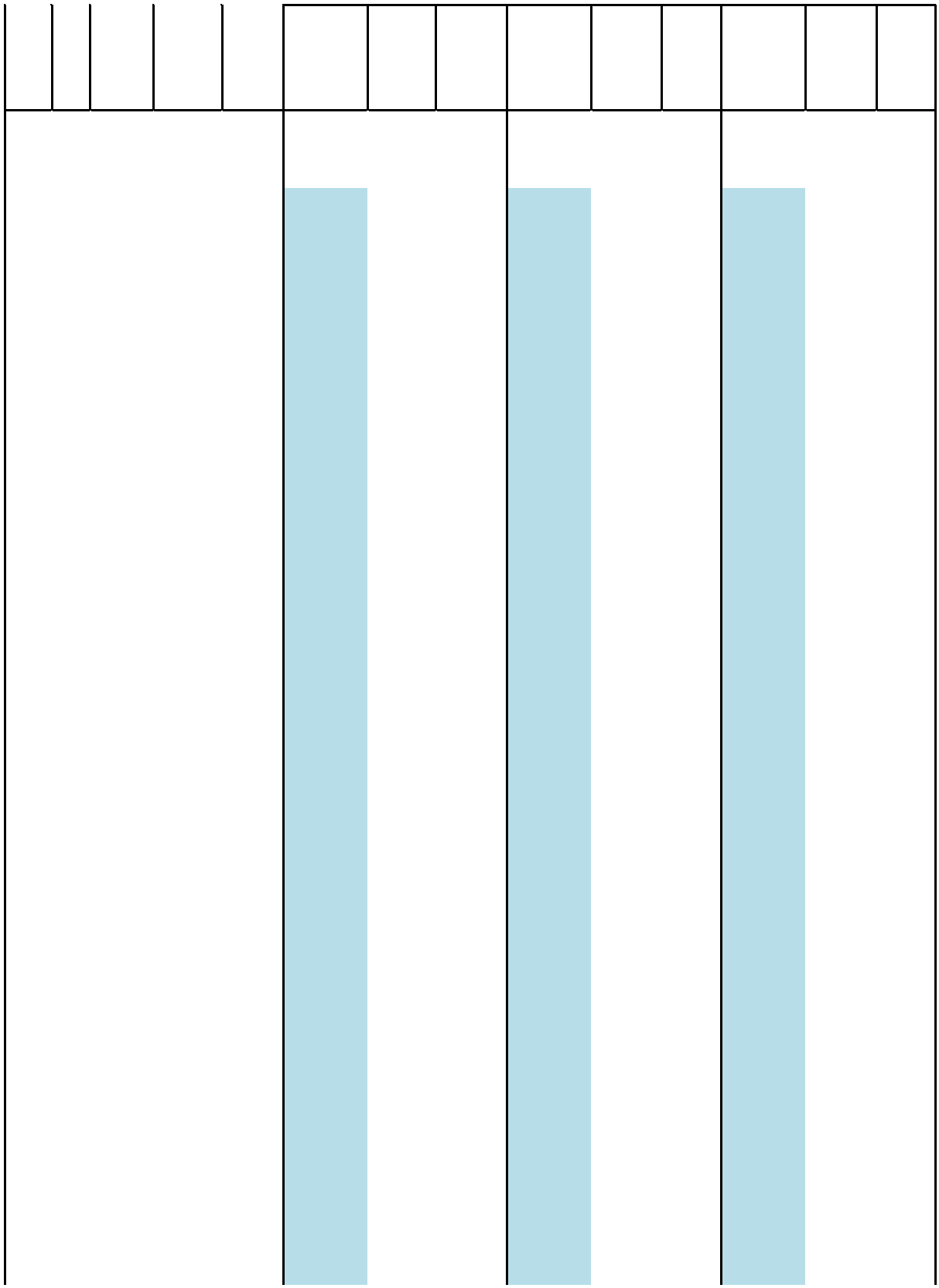

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| 2 | | | | | #DI | | | | | | | #DI | | | #DI |
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| 1 | ar | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! |
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| 0 | A | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 |
| 2 | pr | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! |
| 2 | | | | | #DI | | | | | | #DI | | | #DI |
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| 4 | n | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! |
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| 7 | p | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! |
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| 8 | ct | 0 | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! |
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| 2 | 13 | | | | #DI | | | | | | #DI | | | #DI |
| 1 | Mon | | $ | #DI | V/0 | $ | #DI | #DI | $ | #DI | V/0 | $ | #DI | V/0 |
| 2 | Avg | | - | V/0! | ! | - | V/0! | V/0! | - | V/0! | ! | - | V/0! | ! |
| 2 | 12 Mon Depr Exp | | | #DI V/0! | | 12 Mon Depr Exp | #DI V/0! | | 12 Mon Depr Exp | #DI V/0! | | 12 Mon Depr Exp | #DI V/0! | |

**Notes:**

(A) See WP A-5 (Act Depreciation.Rate).

| | | | |
|---|---|---|---|
| (B) P-4 projects should be included in total projected transmission projects for P-1 | | | |

(C) Projects should not be listed until the first year they are expected to be in service unless there is a CWIP return incentive. Do not duplicate projects listed in A-7 (Act. RTO Proj).

# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant Related to Sponsored Projects
# For the 12 months ended - December 31, 0

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | *Description* | | | *Description* | | | *Description* | | | | |
| 1 | **Total Sponsor Funded Projects (B & C)** | | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | | | |
| 2 | | | | | | Begin. Year-Mo.: | | | SPP Proj. ID | | | SPP Proj. ID | | | | |
| 3 | | | | | | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) | | |
| 4 | | | | | | Begin Plant in Serv. | | | Begin Plant in Serv. | | | Begin Plant in Serv. | | | | |
| 5 | | | | | | Begin. Acc. Depr: | | | Begin. Acc. Depr: | | | Beg Acc. Depr: | | | | |
| 6 | | | | | | Begin. Year-Mo.: | | | Begin. Year-Mo.: | | | Beg Year-Mo.: | | | | |
| 7 | **Mon.** | **Year** | **Gross Plant** | **Total Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Deprec.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | | |
| 8 | | | | | | $ | | | $ | | | $ | | | | |
| 9 | | | | | | - | | | - | | | - | | | | |
| 10 | Jan | - | $ | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | | |
| 11 | Feb | - | $ | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | | |
| 12 | Mar | - | $ | #DIV/ | #DIV/ | $ | #DIV | #DIV/ | $ | #DIV | #DIV/ | $ | #DIV | #DIV | | |

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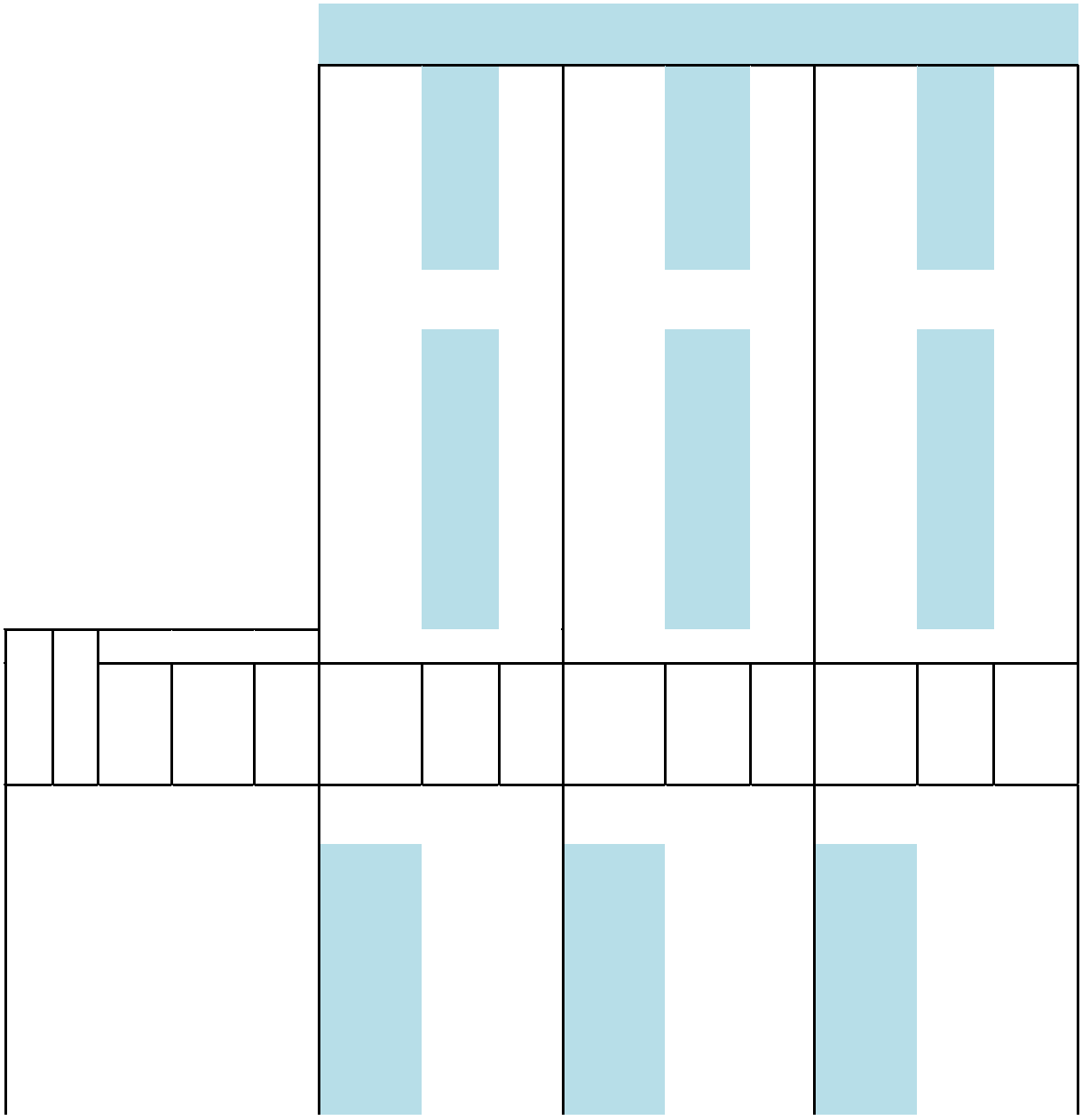

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| 3 | r | 1 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | M | | | | #D | | | #D | | | #D | | | | |
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| 4 | y | 1 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | J | | | | #D | | | #D | | | #D | | | | |
| 1 | u | - | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 5 | n | 1 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | | | | | #D | | | #D | | | #D | | | | |
| 1 | J | - | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 6 | ul | 1 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
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| 0 | o | 1 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | D | | | | #D | | | #D | | | #D | | | | |
| 2 | e | - | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 1 | c | 1 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | J | | | | #D | | | #D | | | #D | | | | |
| 2 | a | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 2 | n | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | F | | | | #D | | | #D | | | #D | | | | |
| 2 | e | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 3 | b | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | | | | | #D | | | #D | | | #D | | | | |
| 2 | M | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 4 | ar | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | A | | | | #D | | | #D | | | #D | | | | |
| 2 | p | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 5 | r | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | M | | | | #D | | | #D | | | #D | | | | |
| 2 | a | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 6 | y | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | J | | | | #D | | | #D | | | #D | | | | |
| 2 | u | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 7 | n | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | | | | | #D | | | #D | | | #D | | | | |
| 2 | J | | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DIV | IV/ | $ | #DI | #DI | |
| 8 | ul | 0 | - | V/0! | 0! | - | V/0! | 0! | - | /0! | 0! | - | V/0! | V/0! | |
| | A | | | | #D | | | #D | | | #D | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | Sug | 0 | $ - | #DIV/0! | IV/0! | $ - | #DIV/0! | IV/0! | $ - | #DIV/0! | IV/0! | $ - | #DIV/0! | #DIV/0! | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | Sep | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 31 | Oct | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 32 | Nov | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 33 | Dec | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 34 | | | | | | | | | | | | | | |
| 35 | 13 Mon Avg | | $ - | #DIV/0! | #DIV/0! | $ - 12 Mon Depr Exp | #DIV/0! | #DIV/0! | $ - 12 Mon Depr Exp | #DIV/0! | #DIV/0! | $ - 12 Mon Depr Exp | #DIV/0! | #DIV/0! |
| 36 | 12 Mon Depr Exp | | | #DIV/0! | | | #DIV/0! | | | #DIV/0! | | | #DIV/0! | |

Notes:

(A) See WP A-5 (Act Depreciation.Rate).

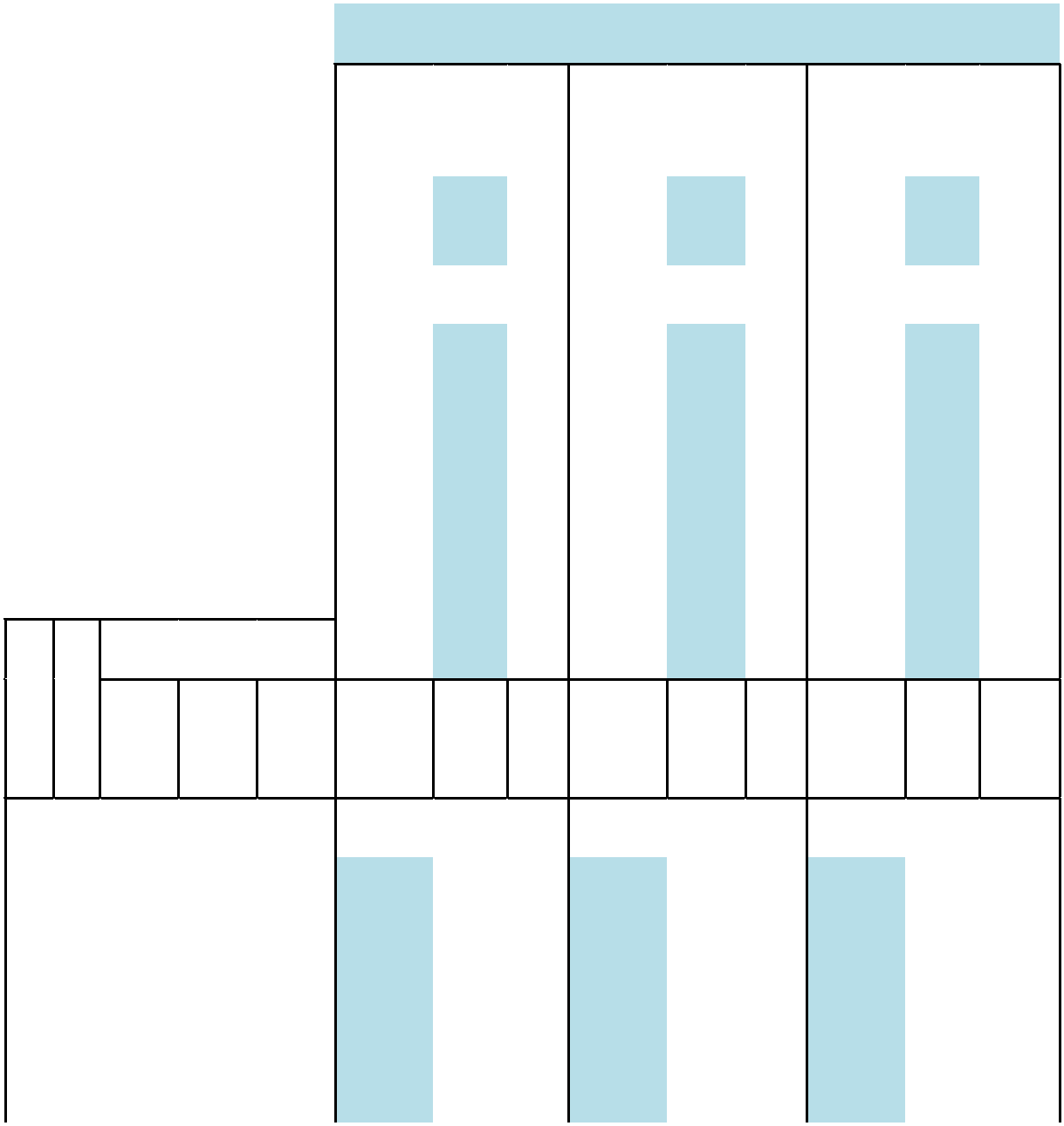
(B) P-5 projects should be included in total projected transmission projects for P-1

(C) Projects should not be listed until the first year they are expected to be in service. Do not duplicate projects listed in A-8 (Act. Sponsor).

# Sunflower Electric Power Corporation (SEPC)
# Projected Transmission Plant Related to Third Party Projects
# For the 12 months ended - December 31, 0

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | *Description* | | | *Description* | | | *Description* | | | |
| 1 | **Total Projects Funded for Third Parties (B & C)** | | | | | **Project:** | **1** | | **Project:** | **2** | | **Project:** | **3** | | |
| 2 | | | | | | SPP Proj. ID | | | SPP Proj. ID | | | SPP Proj. ID | | | |
| 3 | | | | | | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) | Depr. Rate: | #DIV/0! | (A) | |
| 4 | | | | | | Begin Plant in Serv. | $ - | | Begin Plant in Serv. | $ - | | Begin Plant in Serv. | | | |
| 5 | | | | | | Begin. Acc. Depr: | - | | Begin. Acc. Depr: | - | | Begin. Acc. Depr: | | | |
| 6 | | | | | | Year-Mo.: | | | Year-Mo.: | | | Year-Mo.: | | | |
| 7 | | | | **Total** | | Third Party: | | | Third Party: | | | Third Party: | | | |
| 8 | **Mon.** | **Year** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | **Gross Plant** | **Accm. Depr.** | **Net Plant** | |
| 9 | | | | | | $ - | | | $ - | | | $ - | | | |
| 10 | Jan | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |
| 11 | Feb | -1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | M | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 2 | ar | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | #D | | | #D | | | |
| 1 | A | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 3 | pr | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | M | | | | | | | #D | | | #D | | | |
| 1 | a | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 4 | y | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 1 | Ju | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 5 | n | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 1 | Ju | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 6 | l | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | A | | | | | | | #D | | | #D | | | |
| 1 | u | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 7 | g | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | S | | | | | | | #D | | | #D | | | |
| 1 | e | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 8 | p | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 1 | O | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 9 | ct | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | N | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 0 | o | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | D | - | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 1 | ec | 1 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | Ja | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 2 | n | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | F | | | | | | | #D | | | #D | | | |
| 2 | e | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 3 | b | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | M | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 4 | ar | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | A | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 5 | pr | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | M | | | | | | | #D | | | #D | | | |
| 2 | a | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 6 | y | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | Ju | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 7 | n | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | | | | | | | | #D | | | #D | | | |
| 2 | Ju | | $ | #DI | #DI | $ | #DI | IV/ | $ | #DI | IV/ | $ | #DI | #DI |
| 8 | l | 0 | - | V/0! | V/0! | - | V/0! | 0! | - | V/0! | 0! | - | V/0! | V/0! |
| | A | | | | | | | #D | | | #D | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 29 | Sug | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | IV/0! | $ - | #DIV/0! | IV/0! | $ - | #DIV/0! | #DIV/0! | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 30 | Sep | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 31 | Oct | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 32 | Nov | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 33 | Dec | 0 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! |
| 34 | | | | | | | | | | | | | | |
| 35 | 13 Mon Avg | | $ - | #DIV/0! | #DIV/0! | $ - 12 | #DIV/0! | #DIV/0! | $ - 12 | #DIV/0! | #DIV/0! | $ - 12 | #DIV/0! | #DIV/0! |
| 36 | 12 Mon Depr Exp | | | #DIV/0! | | Mon Depr Exp | #DIV/0! | | Mon Depr Exp | #DIV/0! | | Mon Depr Exp | #DIV/0! | |

Notes:
(A) See WP A-5 (Act Depreciation.Rate).
(B) P-6 (Third Party Projects) should be included in total projected transmission projects on Worksheet P-1
(C) Projects should not be listed until the first year they are expected to be in service. Do not duplicate projects listed in A-10 (Act. Third Party Proj).

Workpaper P-7 Page 1 of 1

# Sunflower Electric Power Corporation (SEPC)
# ATRR Calculation for Projected Year Competitively Bid Projects (Notes D, E & F)

Project:

| Line | Traditional ATRR for Competitive Bid Project: Description | Source | Amount | As Bid ATRR for Competitive Bid Project (Note A): Description | Source | Amount | Actual ATRR for Competitive Bid Project (Notes A & B): Description | Source | Amount |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Plant in Service | | | Plant in Service | | | Plant in Service | | |
| 2 | Accumulated Reserves for Depreciation | | | Accumulated Reserves for Depreciation | | | Accumulated Reserves for Depreciation | | |
| 3 | Net Plant | | $ - | Net Plant | | $ - | Net Plant | | $ - |
| 4 | | | | | | | | | |
| 5 | Return Based on Target TIER | | | Return Based on Target TIER | | | Return Based on Target TIER | | |
| 6 | Interest Rate | Actual Gross Rev Req L158 | #DIV/0! | Interest Rate | | | Interest Rate | | |
| 7 | Target TIER | Actual Gross Rev Req L150 | 2.030 | Target TIER | | | Target TIER | | |
| | Rate of Return | | #D | Rate of Return | | 0.000 | Rate of Return | | 0.0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | New Projects | IV/ 0! | New Projects | 0 % | New Projects | 00 0% |



| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 9 | | | | | | | | | | |
| 10 | O&M and A&G | A-7 (Act. RTO Directed Proj) L7 | #DIV/0! | O&M and A&G | | | O&M and A&G | | |
| 11 | | | | | | | | | | |
| 12 | Other Taxes | A-7 (Act. RTO Directed Proj) L9 | #DIV/0! | Other Taxes | | | Other Taxes | | |
| 13 | | | | | | | | | | |
| 14 | General Plant | A-7 (Act. RTO Directed Proj) L14 | #DIV/0! | General Plant | | | General Plant | | |
| 15 | | | | | | | | | | |
| 16 | Carrying Charge Rate Based on Net Plant | L8 + L10 + L12 + L14 | #DIV/0! | Carrying Charge Rate Based on Net Plant | L8 + L10 + L12 + L14 | 0.000% | Carrying Charge Rate Based on Net Plant | L8 + L10 + L12 + L14 | 0.000% |
| 17 | Carrying Charges Based on Net Plant | L3 * L16 | #DIV/0! | Carrying Charges Based on Net Plant | L3 * L16 | $0.00 | Carrying Charges Based on Net Plant | L3 * L16 | $0.00 |
| 18 | | | | | | | | | | |
| 19 | Depreciation | | | Depreciation | | | Depreciation | | |
| 20 | Average System Depreciation Rate | A-5 (Act Depreciation Rate) L30 | #DIV/0! | Depreciation Rate | | | Depreciation Rate | | |
| 21 | Depreciation Expense | L1 * L20 | #DIV/0! | Depreciation Expense | L1 * L20 | $ - | Depreciation Expense | L1 * L20 | $ - |

2

2

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Total ATRR Traditional | L17 + | #D IV/ | Total ATRR | L17 + | $ | Total Actual | L17 + | $ |
| 3 | Calculation | L21 | 0! | As Bid | L21 | - | ATRR | L21 | - |
| 2 4 | | | | | | | Total ATRR as Bid | L23 As Bid | $ - |
| 2 5 | | | | | | | Non-Transmission ATRR (Note C) | L23 - L24 | $ - |

**Note**

A Unless fixed or capped or discounted in the bid, project costs will use the formula rate allocated cost (Col (d)).

B Costs from column (j) to be reflected on RTO Project Smry in columns (e) through (n).

C Amount entered on tab RTO Project Smry cannot be greater than zero.

D Blue shaded cells represent input cells and are not derived from a formula.

E Tab P-7 will only be used when Sunflower has a competitively bid project in which Sunflower has made commitments in its bid for any of the adjustable line items. If Sunflower has a competitively bid project in which no commitments where made, tab P-7 shall be left blank and the project costs will appear the same as other RTO projects on tab RTO Project Smry. Only the following items may be adjusted from the Traditional values (Col. d) in developing a Competititive Bid: financing costs, target TIER, depreciation expense, and other cash taxes.

# Sunflower Electric Power Corporation

# Transmission Formula Rate Protocols

The formula rate template ("Formula Rate Template") and these implementation protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Sunflower Electric Power Corporation ("Sunflower") for transmission revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("Tariff"). Sunflower shall follow annually the instructions specified in the Formula Rate to calculate its annual transmission revenue requirement. Recovery of the costs associated with existing facilities and new facilities shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the Tariff.

The initial annual transmission revenue requirement will be in effect on January 1, 2020. The Formula Rate shall be recalculated each year with the resulting rates to become effective on and after January 1 of the following year through December 31 of such year ("Rate Year"). The resulting rates implemented each January 1 will be subject to review and true-up as further provided in the Protocols. The Formula Rate shall become effective for recovery of Sunflower's annual transmission revenue requirement upon the effective date authorized by the Federal Energy Regulatory Commission ("FERC") under Section 205 of the Federal Power Act ("FPA").

## I. Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

A. "Accounting Change(s)" means any change in Sunflower's accounting policies or practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the calculations in the Annual Update. Accounting Changes include:

1. initial implementation of an accounting standard or policy;
2. revisions to Sunflower's Annual Report data or the requirement to report certain values within it;
3. correction of errors and prior periods adjustments;
4. the implementation of new or different estimation methods or policies;
5. changes to any tax requirements for Sunflower;
6. changes to accounting practices or policies mandated by a regulatory authority that Sunflower adopts that could impact the Formula Rate or calculations under the Formula Rate;
7. implementation of accounting practices for unusual or unconventional items;
8. items included in the Formula Rate at an amount other than a historic cost basis (e.g., fair value adjustments);
9. changes in Sunflower's inter-corporate cost allocation policies or

practices from those policies and/or practices in effect in the Prior Rate Year; or

10. new requirements or changes related to any reorganization or merger transaction with the exception of the merger which was consummated pursuant to KCC Docket 19-SEPE-054-MER.

B. "Annual Meeting" means the meeting hosted by Sunflower for the purpose of exchanging information with Interested Parties regarding the Annual Update.

C. "Annual Report" means the Electric Cooperative Utility Annual Report that is filed by Sunflower with the Kansas Corporation Commission, or any equivalent thereof. Data provided in the Annual Report will reflect the independently-audited books and records of Sunflower.

D. "ATRR" means Sunflower's net annual revenue requirement for the transmission services in a Rate Year calculated in accordance with the Formula Rate.

E. "Annual Update" means Sunflower's annual posting of its populated Formula Rate Template, as defined in Section II.

F. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and federal holidays.

G. "Calendar Year" means January 1 through December 31 of a given year.

H. "Current Calendar Year" means the Calendar Year in which the Annual Update is posted (e.g., if the Annual Update is posted on July 1, 2018, the Current Calendar Year is 2018).

I. "Customer(s)" means the customers taking Network Integration Transmission Service, service under Grandfathered Agreements, or Point-To-Point Service, pursuant to the Tariff.

J. "FERC" means the Federal Energy Regulatory Commission.

K. "Final Posting" means the Annual Update information posted to the SPP Member Related Postings Website with changes agreed to during the Informal Challenge procedures.

L. "Formal Challenge" means a challenge filed by an Interested Party with FERC to an aspect of the Annual Update, and served on Sunflower by electronic service on the date of such filing.

M. "Formula Rate" means the Sunflower Protocols together with the Formula Rate Template.

N. "Formula Rate Template" means the Sunflower transmission formula rate template set forth in Attachment H of the SPP Tariff.

O. "FPA" means the Federal Power Act, 16 U.S.C. § 791a *et seq*.

P. "Informal Challenge" means written notification by an Interested Party to

Sunflower, during the Review Period, of a specific challenge to the Annual Update.

Q. “Information Request” means a written request submitted by an Interested Party to Sunflower during the Review Period, and which may include a reasonable request for explanations, documents, or other materials, subject to Section IV.A of these Protocols.

R. “Informational Filing” means Sunflower’s annual filing at FERC as described in Section IV.E.

S. “Interest” means the amount of interest calculated consistent with 18 C.F.R. § 35.19a(a)(2)(iii).

T. “Interest Rate” means the interest rate produced by the calculation set forth in 18 C.F.R. § 35.19a(a)(2)(iii).

U. “Interested Party” includes, but is not limited to, Customers, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

V. “Member Related Postings Website” shall mean such publicly available website as established by SPP for SPP Member postings.

W. “Prior Rate Year” means the Rate Year prior to the Current Calendar Year (e.g., if the Current Calendar Year is January 1, 2018 through December 31, 2018, then the Prior Rate Year is January 1, 2017 through December 31, 2017).

X. “Protective Agreement and Non-Disclosure Certificate” means the agreement and certificate to be executed by parties and their representatives in order to obtain access to material that Sunflower deems confidential or that contains Critical Energy Infrastructure Information as that term is defined in 18 C.F.R. § 388.113(c)(1).

Y. “Protocols” means these Sunflower transmission Formula Rate implementation protocols.

Z. “Publication Date” means the date on which SPP posts the Sunflower Annual Update to the SPP Member Related Postings Website. The Publication Date for each year shall be no later than June 24 (or the first Business Day after June 24 if June 24 is not a Business Day).

AA. “Rate Year” means January 1 of a given Calendar Year through December 31 of the same Calendar Year.

BB. “Review Period” means, unless otherwise extended in writing by Sunflower, the period commencing on the Publication Date and ending November 1 of the same Calendar Year or, if November 1 is not a Business Day, the next Business Day.

CC. “Service List” shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be

added to the Service List through the "Exploder List" link on the SPP website.[1]

DD. "SPP" means Southwest Power Pool, Inc. or its successor organization.

EE. "Stated Values" means values that are fixed and not subject to change in an Annual Update including (i) the times interest earned ratio ("TIER"); (ii) depreciation and amortization rates; (iii) the cap on projected expenses and (iv) other similar fixed values. Stated Values may be changed only pursuant to FPA Section 205 or 206.

FF. "Sunflower" means Sunflower Electric Power Corporation.

GG. "Tariff" means SPP's Open Access Transmission Tariff.

HH. "True-Up Adjustment" means Sunflower's calculated difference between the projected ATRR and actual ATRR collected for a Rate Year, calculated in accordance with the Formula Rate.

II. "Upcoming Rate Year" means the Rate Year after the Current Calendar Year.

## II. Annual Update

A. On or before the Publication Date (i) Sunflower shall provide its Annual Update, the non-confidential version of the applicable Annual Report(s), and Protective Agreement and Non-Disclosure Certificate to SPP and (ii) SPP shall post the Sunflower Annual Update, the non-confidential version of the applicable Annual Report(s), and Protective Agreement and Non-Disclosure Certificate on the SPP Member Related Postings Website. The Annual Update shall:

1. Calculate the projected ATRR for the Upcoming Rate Year in accordance with the Formula Rate;

2. Calculate the True-up Adjustment for the Prior Rate Year as described in Section III below;

3. Sum the projected ATRR for the Upcoming Rate Year and the True-up Adjustment for the Prior Rate Year, including Interest, as explained in Section III below.

B. Concurrent with the posting of the Annual Update, the non-confidential version of the applicable Annual Report(s), and Protective Agreement and Non-Disclosure Certificate Sunflower shall provide notice of the posting to the Service List.

C. The Annual Update shall:

1. Include a populated Formula Rate Template with fully functional spreadsheets with links and formulas intact, showing the calculation of the Annual Update and underlying, detailed work papers in

[1] As of February 2019, the Exploder List was titled "Formula Rate Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/.

native format with links and formulas intact, and supporting documentation for data;

2. Be based on the Annual Report and the independently-audited books and records of Sunflower for the most recent fiscal year, and provide information necessary to trace the data and information in the populated Formula Rate Template to the Annual Report;

3. Provide sufficient information to enable Interested Parties to replicate the calculations of the formula results from the Formula Rate;

4. Identify any Accounting Change(s), and explain the individual impact of such Accounting Change(s) on charges billed under the Formula Rate;

5. Not seek to modify the Formula Rate; and

6. Include an affidavit from the Manager of Regulatory Relations of Sunflower (or a similar successor position, if applicable) attesting to the accuracy of the cost and revenue data.

## III. True-Up Adjustment

A. The True-Up Adjustment shall be the sum of components 1 and 2, determined in the following manner:

1. *Difference between the projected ATRR and the actual ATRR:* Sunflower's projected ATRR for the Prior Rate Year will be compared to Sunflower's actual ATRR for the Prior Rate Year calculated in accordance with the Sunflower Formula Rate and based upon:

   a. the Stated Values and the data from the Annual Report applicable to the Prior Rate Year;

   b. any Sunflower filings and FERC orders specifically applicable to Sunflower's calculation of its ATRR;

   c. accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates;

   d. any aspects of the Tariff or SPP Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates; and

2. *Interest:* Interest on any over- or under-recovery.

B. The True-Up Adjustment will include a variance analysis of, at minimum, actual revenue requirement components of the zonal ATRR, base plan ATRR, operating and maintenance expenses, depreciation expense,

taxes, return, and revenue credits as compared to the corresponding components in the projected ATRR that was calculated for the Prior Rate

Year with an explanation of material variances in each revenue requirement component listed above.

*True-Up Transition Formula*

C. For the ATRR to be recovered in Rate Year 2020, the True-Up Adjustment shall be determined using 2018 data, combined for both Sunflower and Mid-Kansas Electric Company, Inc., and applied to the 2020 projection, as filed with and approved by FERC. Similarly, for the ATRR to be recovered in Rate Year 2021, the ATRR shall be determined using 2019 data, combined for both Sunflower and Mid-Kansas Electric Company, Inc., and applied to the 2021 projection, as filed with and approved by FERC.

D. For the 2018 and 2019 True-Up Adjustments included in the 2020 and 2021 projection, respectively, Sunflower will calculate the applicable charge or refund for each of its zonal transmission customers in accordance with the transition formula agreed to in the Unanimous Settlement Agreement in Docket 19-SEPE-054-MER on file with the Kansas Corporation Commission and included as *Attachment 1* to these Protocols.

## IV. Review of Annual Update

No sooner than seven (7) calendar days and no later than twenty (20) calendar days after the Publication Date of Sunflower's Annual Update, Sunflower will host its Annual Meeting. Concurrent with the posting of the Annual Update on the SPP Member Related Postings Website, Sunflower shall provide notice of the Annual Meeting by providing such notice to SPP, which SPP shall post on the SPP Member Related Postings Website and by providing such notice to Interested Parties via email to the Service List. The notice shall include the date, time and location of the Annual Meeting, and shall also include instructions for (i) execution of a Protective Agreement and Non-Disclosure Certificate and (ii) if applicable, accessing Sunflower's external sharing site. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the SPP Member Related Postings Website.

A. Information Exchange

1. Interested Parties may submit Information Requests to Sunflower immediately on the Publication Date through the end of the Review Period. Such Information Requests shall be limited to seeking information, documents, and other materials that are necessary to determine:

   a. The extent, effect, or impact of an Accounting Change;

   b. Whether the Annual Update fails to include data in accordance with the Protocols;

   c. The proper application of the Formula Rate, including the

accuracy of data, consistency with the Formula Rate, and/or correctness of calculations shown in the Annual Update;

d. The prudence of actual costs and expenditures, including prudence of Sunflower's procurement methods and cost control methodologies;

e. The effect of any change to the Formula Rate Template; or

f. Any other information that may reasonably have an effect on the calculation of the charges pursuant to the Formula Rate.

The Information Requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. Sunflower will not claim that Sunflower's own information that is responsive to Information Requests pursuant to the Protocols is subject to any settlement confidentiality provision. However, Sunflower may require that Interested Parties and their representative(s) execute a Protective Agreement and Non-Disclosure Certificate, respectively. Sunflower shall provide to SPP the Protective Agreement and Non-Disclosure Certificate, which SPP shall post it on the SPP Member Related Postings Website concurrent with the Publication Date.

2. Sunflower shall use best efforts to respond fully to Information Requests pertaining to the Annual Update within ten (10) Business Days of receipt. Sunflower shall use best efforts to timely notify the proponent of an Information Request if all or any part of an Information Request is unclear or the subject matter is outside the scope of Section IV.A.1.

3. Sunflower shall provide copies of all Information Requests from Interested Parties and Sunflower's response(s) to such requests, to the Service List by email, or by creating an external sharing site. If an external sharing site is used, Sunflower shall provide to the Service List instructions for accessing the site. If responses to Information Requests contain information deemed by Sunflower to be confidential, such information will only be provided to requesting parties pursuant to a Protective Agreement executed by the requesting party and Sunflower.

B. Informal Challenge Procedures

1. Interested Parties shall have until the end of the Review Period to notify Sunflower in writing (which may be transmitted by e-mail) of any Informal Challenges. The Informal Challenge is to specify (to the extent such information has been made available) the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects, and provide an appropriate explanation and documents to support its Informal Challenge. Sunflower will make a good faith effort to respond to any Informal Challenge within fifteen (15) Business Days of notification of such Informal Challenge. If Sunflower disagrees with an Informal

Challenge, Sunflower's response shall provide an explanation of the basis for Sunflower's disagreement. Sunflower shall provide the

Interested Party with the name of the representative(s) assigned to work with the Interested Party to resolve the Informal Challenge.

2. Sunflower will provide to SPP and SPP shall then post on the Member Related Postings Website all Informal Challenges from Interested Parties and Sunflower's responses to the Informal Challenges. If responses to Informal Challenges contain information deemed by Sunflower to be confidential, such information will only be made available to Interested Parties pursuant to a Protective Agreement executed by the requesting Interested Party and Sunflower.

3. Sunflower will provide to SPP and SPP will then post the Final Posting on the Member Related Postings Website no later than November 30 of each year (or the next Business Day if November 30 is not a Business Day).

4. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by Sunflower and resolved not less than 10 Business Days prior to the Final Posting shall be reported in the Final Posting. Any changes or adjustments agreed to by Sunflower after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges

1. Interested Parties shall have until February 1 (or the next Business Day if February 1 is not a Business Day) to file a Formal Challenge.

2. A Formal Challenge shall:

a. Identify the action or inaction that is alleged to violate the Formula Rate;

b. Explain how the action or inaction violates the Formula Rate;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including if applicable:

i. The extent, effect or impact of an Accounting Change;

ii. The proper application of the Formula Rate, including the accuracy of data, consistency with the Formula Rate and/or correctness of calculations shown in the Annual Update;

iii. The prudence of actual costs and expenditures;

iv. The effect of any change to the Formula Rate Template; or

v. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing proceeding in any forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include relevant documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

3. There is no requirement to raise an issue in an Informal Challenge prior to filing a Formal Challenge on that issue. The filing party may state whether it used the Informal Challenge procedures.

4. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or in a separate docket established for FPA Section 206 complaint procedures, and shall be served upon Sunflower. Service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), by express delivery or messenger to the individual listed as the contact in Sunflower's Informational Filing.

5. Sunflower will provide a response to the Formal Challenge within the time period prescribed by FERC.

6. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Sunflower shall bear the burden, consistent with FPA Section 205, of proving that it has correctly applied the terms of the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Modification of the Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Informal or Formal Challenge procedures set forth in these Protocols. Any modifications to the Formula Rate will require an FPA Section 205 or 206 filing, as applicable. Nothing herein shall be deemed to limit in any way the right of Sunflower to file unilaterally, pursuant to FPA

Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, or the right of any party to request such

changes pursuant to Section 206 of the FPA and the regulations thereunder.

2. In the event that Sunflower identifies an error in the True-Up Adjustment (or its Annual Report or successor form which is used as an input to the Formula), or is required by applicable law or a court or regulatory body to correct an error, Sunflower shall correct such error in good faith and without regard to whether the correction increases or decreases Sunflower's revenue requirements. Nothing in these protocols should or may be construed as preventing Interested Parties or the Commission from protesting such correction as inappropriate. If, in the normal course of business, Sunflower identifies and error in a prior True-Up Adjustment (or its Annual Report or successor form which is used as an input to the Formula), Sunflower will provide notice to the service list of the error identified.

3. .Any changes to the data inputs or any changes as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the Upcoming Rate Year. Interest shall be calculated on any over- or under-recovery.

E. FERC Informational Filing

1. By December 15 of each year (or the next Business Day if December 15 is not a Business Day), Sunflower shall submit to FERC its Informational Filing.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   a. That input data is properly recorded in the populated Formula Rate Template and any underlying work papers;

   b. That Sunflower has properly applied the Formula Rate;

   c. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   d. The effect of Accounting Changes that affect Formula Rate inputs.

3. The Informational Filing must also describe (i) each error, correction, and/or adjustment resolved after the Final Posting, for inclusion in the next Annual Update, and (ii) all aspects of the Formula Rate or its inputs that are subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Sunflower shall provide to SPP and SPP shall then post the

Informational Filing to the SPP Member Related Postings Website and Sunflower will provide notice of the Informational Filing and the

docket number assigned to the Informational Filing to Interested Parties via the Service List.

## V. Joint SPP Transmission Owner's Meeting

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, Sunflower intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP Member Related Postings Website and distributed by Sunflower to Interested Parties via the Service List maintained by SPP no less than seven (7) calendar days prior to such meetings.

| | |
|---|---|
| **VI. Sunflower Example Schedule (Nominal Last Dates)** | |
| **Action** | **Date** |
| Rate Year | January 1 - December 31 |
| Protective Agreement | Concurrent with Publication Date |
| Publication Date; Information Request Period Opens | June 24 |
| Annual Meeting of Interested Parties | July 14 |
| Information Request Period Ends | November 1 |
| Informal Challenges Due | November 1 |
| Informal Challenges Response Due Date | November 23 |
| Final Posting | November 30 |
| Informational Filing | December 15 |
| Formal Challenge Due Date | February 1 |

**Attachment 1 to Protocols**

**EXHIBIT SA-1 to Unanimous Settlement Agreement in**

**Docket No. 19-SEPE-054-MER**

**Per paragraph 17(d.)(i)., Transition Method for Convergence of Transmission Zones:**

The Transition Method is as set forth herein and as reflected in the supporting example calculations:

a. **Transition Period.** The "Transition Period" shall begin on the effective date of any subsequent Converged TFR approved or accepted by FERC that will supersede the separate Sunflower and Mid-Kansas Legacy TFRs and continue for two years. For example, if Joint Applicants, in the SPP filing at FERC that will seek to consolidate the Sunflower and Mid-Kansas transmission zones and converge the transmission rates, request, and FERC permits, the filing and rates to become effective January 1, 2020, the Transition Period will run from January 1, 2020 until December 31, 2021, inclusive.

b. **Legacy True-Up Adjustments.** During the Transition Period, the Legacy True-Up Adjustments shall be the Annual True-Up Adjustments for Sunflower and Mid-Kansas determined separately for each transmission zone using the Legacy TFR formulas. For example, if the Converged TFR becomes effective January 1, 2020, Legacy True-Up Adjustments will be determined separately for Sunflower and Mid-Kansas for the 2018 and 2019 Rate Years in accordance with the Legacy TFR Protocols. For clarity, only the calculation of the Legacy True-up Adjustments will follow the Legacy TFR protocols. The procedural schedule will be in accordance with any newly approved protocols.

c. **Corrections during the Transition Period.** Legacy True-Up Adjustments shall be

limited to the adjustments, including interest at the applicable FERC-authorized interest rate (Applicable Rate), to reflect any under-collection or over-collection of ATRRs in the final two Rate Years of the Sunflower and Mid-Kansas Legacy TFRs,

plus any corrections to Annual True-Up Adjustment calculations under the Legacy TFRs to be applied during the Transition Period, for errors discovered before the effective date established by FERC for the convergence of the TFRs (*i.e.*, True-Up Adjustments for the 2018 and 2019 Rate Years plus any corrections during the Transition Period).

d. **Corrections after the Transition Period.** Corrections discovered by the Combined Company or wholesale transmission customers after the Transition Period that would impact prior Annual True-Up Adjustments shall be included in the annual true-up adjustments proposed under the Converged TFR. For example, if an error discovered after the end of the Transition Period resulted in an overstatement of the actual ATRR determined for an Annual True-Up Adjustment under a Legacy TFR, the correction necessary for that error shall be included with the Converged TFR's True-Up Adjustment for the Converged TFR. The parties acknowledge that this treatment of corrections is intended solely to provide the Combined Company with the benefit of administrative convenience.

e. **Load Ratio Share.** Annually, the Joint Applicants submit zonal load ratio share (LRS) information to SPP. During the Transition Period, Joint Applicants shall also prepare LRS information for (i) the Converged TFR, (ii) the standalone Sunflower zone, and (iii) the standalone Mid-Kansas zone. The standalone LRS information shall reflect the zonal LRS information that would have existed had the Joint Applicants not caused to be established a Converged TFR. The standalone LRS information will be used to calculate the Transition Adjustment. Parties acknowledge, for example, the 2019 load ratio shares are used to allocate transmission revenue requirements billed in 2020.

f. **Adjustments to Load Ratio Share.** The Combined Company shall be allowed to

propose a reasonable adjustment to the allocation of any relevant Legacy True-Up Adjustments to address customer migration, subject to the condition that complete supporting documentation for any such adjustments shall be provided to the impacted wholesale transmission customers. Approval shall not be unreasonably withheld.

g. **Transition Method applies to WPA.** The parties agree that, during 2020, under the Wholesale Power Agreement (WPA) between Sunflower and KEPCo, the Transmission Charge that Sunflower shall assess KEPCo shall reflect the ATRR including the Sunflower LRS of the Sunflower Legacy True-Up Adjustment. As the WPA is KCC jurisdictional and not FERC jurisdictional, information regarding the WPA calculations will not be included with the information filed at FERC. At KEPCo's request, Sunflower shall provide to KEPCo workpapers supporting the Sunflower Legacy True-Up Adjustment applied for the calculation of the Transmission Charge under the WPA.

h. **Allocation of Base Plan Legacy True-Up to Projects.** The parties recognize that in the Legacy TFR, the base plan true-up in the FBR requires allocation to eligible individual base plan projects in order to be allocated properly in the SPP RRR file, including to the Sunflower and Mid-Kansas zones. The Converged TFR will calculate the projected revenue requirement by project. During the Transition Period, the Converged TFR projected revenue requirement by project will be used to allocate the Sunflower base plan true-up to the eligible Sunflower projects and the Mid-Kansas base plan true-up to the eligible Mid-Kansas projects. For this purpose, 'Sunflower projects' and 'Mid-Kansas projects' pertain to

projects as they appear in the Annual Projections in the standalone Sunflower and Mid-Kansas Legacy TFRs, respectively.

i. A**llocation of Base-Plan Legacy True-Up to Zones**. After the base plan Legacy True-up Adjustment is allocated to each qualifying project, the base plan Legacy True-up is allocated to the various SPP zones and to the SPP regional charges in accordance with the SPP parameters for each project. Following this process, Sunflower will calculate the percent of the Base Plan True-Ups allocated to the Sunflower zone on a stand-alone basis, the Mid-Kansas zone on a stand-alone basis, and to the Converged zone on a converged basis (Base Plan Zonal Percent).

j. **Zonal True-Up Adjustment.** During the Transition Period, Sunflower will calculate a Zonal True-Up Transition Adjustment for each zonal customer. The Zonal Legacy True-up Adjustment (see section b. and section c.) for Sunflower will be allocated to each zonal customer using the stand-alone LRS information for the Sunflower zone (see section e.). The Zonal Legacy True-up Adjustment (see section b. and section c.) for Mid-Kansas will be allocated to each zonal customer using the stand-alone LRS information for the Mid-Kansas zone (see section e.). The Sunflower and Mid-Kansas Zonal Legacy True-Up Adjustments will be added together and allocated to each Zonal Customer using the LRS information for the Converged TFR (see section e.). The Zonal True-Up Transition Adjustment for each zonal customer is the difference between the sum of the Sunflower and Mid-Kansas stand-alone Zonal Legacy True-up Adjustments allocated to that customer and the Converged Zonal Legacy Trueup Adjustment allocated to that customer.

k. **Base Plan True-Up Adjustment**. During the Transition Period, Sunflower will

calculate a Base Plan True-Up Transition Adjustment for each zonal customer.

The zonal impact of the base plan Legacy True-up Adjustment is calculated by

multiplying the base plan Legacy True-up Adjustment (see section b. and section c.) by the Base Plan Zonal Percent (see section i.) for each of Sunflower, MidKansas, and the Converged zone. The base plan True-up Transition Adjustment is then calculated for each zonal customer following the same process as described for the Zonal True-Up Adjustment.

l. **Reallocation of Imbalance.** The base plan True-up Adjustment, for the zone as a whole, can result in an imbalance from the calculated net cost shift to or from the SPP region. To the extent this cost shift occur, the result of the Transition Adjustment would be an imbalance, which could result in the Combined Company either over- or under-collecting costs associated with the Legacy TrueUp Adjustments. To eliminate this imbalance, the imbalance shall be reallocated to each zonal customer based on their LRS in the Converged zone.

m. **Net Transition Adjustment.** The net Transition Adjustment for each zonal customer will be the sum of the Zonal True-Up Adjustment (see section j.), the Base Plan True-Up Adjustment (see section k.), and the Reallocation of Imbalance (see section l.)

n. **Settlement and Timing.** The Transition Adjustment calculation is dependent on LRS data that will not be finalized until after the end of the calendar year (see section e.). For example, 2018 Legacy True-Up Adjustments distributed in 2020 rely on LRS data for 2019 that will not be available until after the end of 2019. The stand-alone LRS data will be prepared concurrently with the Converged LRS information that is required to be submitted to SPP for the Converged TFR in January. The Allocation of Base Plan Legacy True-Up to Projects relies on data

from the Converged TFR and the SPP RRR file. Complete RRR file data may not be available until as late as February ( for example February of 2020 for the

2020 distribution of the 2018 Legacy True-Up Adjustments). Note that some data will be available with the posting of the Converged TFR projected rate for Sunflower. Zonal Customers shall be notified when data is available to complete the calculations. Interested parties may request and review the calculation prior to settlement. Settlement (payments or invoices) will be issued to zonal customers in 12 equal monthly amounts beginning after all interested parties have completed their review.

**[EXAMPLE CALCULATIONS TO FOLLOW]**

Transition Adjustment (worksheet)

| | | |
|---|---|---|
| 1 | **RESULTS** | **True-up Adj** |
| 2 | | **(Pay)/Receive** |
| 3 | Members | (318,962) |
| 4 | KEPCo | 327,384 |
| 5 | KMEA | (15,499) |
| 6 | KPP | 47,465 |
| 7 | MWE | (46,648) |
| 8 | WR | 6,259 |
| 9 | Total | 0 |
| 10 | | |
| 11 | KEPCo WPA | (146,112) |

| | | | | |
|---|---|---|---|---|
| 12 | | | | |
| 13 | **Inputs - 2017/2019 True-ups; 2018 LRS** | | | |
| 14 | | Sunflower | Mid-Kansas | Merged |
| 15 | Zonal Legacy True-Up* | 920,135 | (3,349,995) | (2,429,860) |
| 16 | Base Plan Legacy True-Up | (185,337) | 1,063,347 | 878,010 |
| 17 | Total | 734,798 | (2,286,648) | (1,551,850) |
| 18 | | | | |
| 19 | Load Ratio Share (LRS) | Sunflower | Mid-Kansas | Merged |
| 20 | Members | 82.48% | 64.73% | 72.56% |
| 21 | KEPCo | 1.08% | 19.38% | 11.37% |

| | | | | |
|---|---|---|---|---|
| | | | | |
| | | | | |
| 22 | KMEA | 13.69% | 12.92% | 13.34% |
| 23 | KPP | 0.00% | 2.70% | 1.56% |
| 24 | MWE | 2.73% | 0.00% | 1.09% |
| 25 | WR | 0.02% | 0.27% | 0.08% |
| 26 | Total | 100.00% | 100.00% | 100.00% |
| 27 | | | | |
| 28 | KEPCo WPA | 8.39% | 0.00% | 3.57% |
| 29 | | | | |
| 30 | Base Plan Zonal Percent | 36.56% | 33.49% | 38.73% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 31 | | | | | | | | | |
| 32 | Zonal True-ups (000s) | | | | | | | | Merged |
| 33 | | Sunflower | 920 | Mid-Kansas | (3,350) | | Merged | (2,430) | Cost/(Benefit) |
| 34 | Zonal Customer | LRS | Sunflower | LRS | Mid-Kansas | Combined | LRS | Merged | Diff |
| 35 | Members | 82.48% | 759 | 64.73% | (2,168) | (1,409) | 72.56% | (1,763) | (354) |
| 36 | KEPCo | 1.08% | 10 | 19.38% | (649) | (639) | 11.37% | (276) | 363 |
| 37 | KMEA | 13.69% | 126 | 12.92% | (433) | (307) | 13.34% | (324) | (17) |
| 38 | KPP | 0.00% | - | 2.70% | (90) | (90) | 1.56% | (38) | 53 |
| 39 | MWE | 2.73% | 25 | 0.00% | - | 25 | 1.09% | (27) | (52) |
| 40 | WR | 0.02% | 0 | 0.27% | (9) | (9) | 0.08% | (2) | 7 |
| 41 | Total | 100.00% | 920 | 100.00% | (3,350) | (2,430) | 100.00% | (2,430) | - |
| 42 | | | | | | | | | |
| 43 | KEPCo-WPA | 8.39% | 77 | 0.00% | - | 77 | 3.57% | (87) | (164) |
| 44 | | | | | | | | | |
| 45 | | | | | | | | | |
| 46 | Base Plan True-ups (000s) | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 47 | | | (185) | | 1,063 | | | 878 | | |
| 48 | Zonal % | | 36.56% | | 33.49% | | | 38.73% | Merged | ReAlloc |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 49 | | Sunflower | (68) | Mid-Kansas | 356 | | Merged | 340 | Cost/(Benefit) | Imbalance |
| 50 | Zonal Customer | LRS | Sunflower | LRS | Mid-Kansas | Combined | LRS | Merged | Diff | |
| 51 | Members | 82.48% | (56) | 64.73% | 231 | 175 | 72.56% | 247 | 72 | (37) |
| 52 | KEPCo | 1.08% | (1) | 19.38% | 69 | 68 | 11.37% | 39 | (30) | (6) |
| 53 | KMEA | 13.69% | (9) | 12.92% | 46 | 37 | 13.34% | 45 | 9 | (7) |
| 54 | KPP | 0.00% | - | 2.70% | 10 | 10 | 1.56% | 5 | (4) | (1) |
| 55 | MWE | 2.73% | (2) | 0.00% | - | (2) | 1.09% | 4 | 6 | (1) |
| 56 | WR | 0.02% | (0) | 0.27% | 1 | 1 | 0.08% | 0 | (1) | (0) |
| 57 | Total | 100.00% | (68) | 100.00% | 356 | 288 | 100.00% | 340 | 52 | (52) |
| 58 | | | | | | | | | | |
| 59 | KEPCo-WPA | 8.39% | (6) | 0.00% | - | (6) | 3.57% | 12.13 | 18 | |
| 60 | | | | | | | | | | |

61 * Undercollection/(Overcollection/Refund)

62 Note: Allocations applicable to the KEPCo WPA in lines 43 and 59 shall be consistent with the allocations used in the WPA billings.

# BP Zonal Detail (worksheet)

Supporting Calculation of Zonal Percent of Base Plan Funding True-up

BPF True-up

(Projects and project revenue requirement amounts from Converged Formula Rate, excludes new projects in projection, includes all TU allocation eligible projects)

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | **Sunflower** | **Mid-Kansas** | | | **Merged** | |
| | | **BP True-up Zonal Percents** | | | | | | | | | **36.6%** | **33.5%** | | | **38.73%** | |
| | 1 | 2 | 4 | 5 | 6 | 8 | 10 | 11 | 12 | 13 | 14 | 18 | 19 | 20 | 25 | |
| | | Facility Description | Each Project's Revenue Requirement | Notes | Region-Wide Revenue Requirement Amount | Total Zonal Revenue Requirement to be allocated to zones Amount | | Sunflower Allocated Base Plan TU to Projects | Mid-Kansas Allocated Base Plan TU to Projects | Sunflower Zonal Alloc | Mid-Kansas Zonal Alloc | | Merged Allocated Base Plan TU to Projects | Merged Zonal Alloc | | |
| | | Sunflower Base Plan funded Projects | | | | | | | | | | | | | | |
| | | Base Plan projects with NTCs issued ***prior*** *to June 19, 2010* | | | | | | | | | | | | | | |
| | 10336 | Johnson - Pioneer 115kV Line | 558,491 | (3) | 184,302 | 374,189 | | (16,270) | | (9,560) | (251) | | 18,325 | 11,050 | | |
| | 50246 | Johnson Corner Capacitor Bank #1 | 67,052 | (3) | 22,127 | 44,925 | | (1,953) | | (1,309) | - | | 2,200 | 1,474 | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 16 | 50247 | Johnson Corner Capacitor Bank #2 | | 48,686 | (3) | 16,066 | 32,620 | | (1,418) | | (950) | - | | 1,598 | 1,070 | |
| 17 | 11215 | Holcomb - Plymell 115KV CKT 1 | | 707,811 | (3) | 233,578 | 474,233 | | (20,621) | | (11,939) | - | | 23,225 | 13,446 | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18 | 10480 | Pioneer Tap - Plymell 115KV CKT 1 | | 899,537 | (3) | 296,847 | 602,690 | | (26,206) | | (15,325) | (2,233) | | 29,516 | 19,776 | |
| 19 | | | | | | | | | | | | | | | | |
| 20 | | Balance Portfolio projects & Base Plan projects with NTCs issued after June 19, 2010 | | | | | | | | | | | | | | |
| 21 | 11195 | Fletcher - Holcomb 115KV CKT 1 #2 (Wheatland) | | 819,898 | (11) | 270,566 | 549,332 | | (23,886) | | (16,004) | - | | 26,903 | 18,025 | |
| 22 | 50520 | Mingo 345/115 kV Ckt 2 Transformer | | 1,677,095 | (11) | 553,441 | 1,123,654 | | (48,858) | | (32,735) | - | | 55,029 | 36,870 | |
| 23 | 51180 | Mingo 345 kV Terminal Upgrades | | 845,066 | (10) | 845,066 | (0) | | (24,619) | | 0 | - | | 27,729 | (0) | |
| 24 | 51209 | Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades | | 738,162 | (10) | 738,162 | 0 | | (21,505) | | (0) | - | | 24,221 | 0 | |
| 25 | 51326 | Walkemeyer Tap - Walkemeyer 345/115 kV | | | (11) | - | - | * | - | | | | | | | |
| 26 | | | | | | | | | | | | | | | | |
| 27 | | NEED DATE OF 10/1/2015 or AFTER | | | | | | | | | | | | | | |
| 28 | 51271 | Ellsworth 115 kV Cap Bank | | - | (20),(11) | - | - | | - | | | | | - | | |
| 29 | 51332 | Ingalls 115 kV Cap Bank | | | (20),(11) | - | - | * | - | | | | | | | |
| 30 | 51333 | Device - Lane Scott 115 kV Cap Bank | | | (20),(11) | - | - | * | - | | | | | | | |
| 31 | | | | | | | | | | | | | | | | |
| 32 | | **Total Sunflower** | | **6,361,799** | | | | | **(185,337)** | **-** | **(87,822)** | **(2,484)** | | **208,745** | **101,711** | |
| 33 | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | | MKEC Bas Plan Funded Projects | | | | | | | | | | |
| 35 | | Base Plan projects with NTCs issued *prior to June 19, 2010* | | | | | | | | | | |
| 36 | 50067 | Pratt Capacitor Bank 115 kV | 451,443 | (3) | 148,976 | 302,467 | 23,535.12 | - | 15,769 | 14,813 | 9,925 |
| 37 | 50068 | Harper Capacitor Bank 115 kV | 296,595 | (3) | 97,876 | 198,719 | 15,462.39 | - | 10,360 | 9,732 | 6,520 |
| 38 | 10213 | WEPL-Cimarron Plant 115 kV Line | 354,086 | (3) | 116,848 | 237,238 | 18,459.57 | 12,368 | - | 11,618 | 7,784 |
| 39 | 10858 | Pratt - St. John 115kV Line Rebuild | 2,603,780 | (3) | 859,247 | 1,744,533 | 135,742.96 | - | 79,929 | 85,436 | 50,307 |
| 40 | 50104 | Plainville Capacitor Bank 115 kV | 208,334 | (3) | 68,750 | 139,584 | 10,861.09 | - | 7,277 | 6,836 | 4,580 |
| 41 | 11200 | Clifton - Greenleaf 115KV CKT 1 | 458,976 | (6) | 458,976 | 0 | 23,927.83 | - | 0 | 15,060 | 0 |
| 42 | 11323 | Heizer-Mullergren 115 kV Line | 145,401 | (3) | 47,982 | 97,419 | 7,580.22 | 2,327 | 2,752 | 4,771 | 3,197 |
| 43 | 10994 | XFR Medicine Lodge 138/115 kV Transformer Upgrade | 1,318,408 | (6) | 1,147,015 | 171,393 | 68,732.65 | 2,397 | 3,467 | 43,260 | 3,691 |
| 44 | 11201 | Flatridge - Medicine Lodge 138kV CKT 1 | 478,942 | (6) | 158,051 | 320,891 | 24,968.69 | 2,930 | 3,492 | 15,715 | 4,042 |
| 45 | 11202 | Line - Flatridge - Harper 138 kV | 1,070,153 | (6) | 1,070,153 | (0) | 55,790.33 | (0) | (0) | 35,114 | (0) |
| 46 | 11203 | Line - Medicine Lodge - Pratt 115 kV | 1,189,940 | (6) | 1,167,332 | 22,608 | 62,035.22 | 33 | 765 | 39,045 | 503 |
| 47 | | | | | | | | | | | |
| 48 | | Balance Portfolio projects & Base Plan projects with NTCs issued after June 19, 2010 | | | | | | | | | |
| 49 | 10993 | Harper - Milan Tap 138 kV Ckt 1 | - | (11) | - | - | - | | | - | |
| 50 | 50409 | Ellsworth - Bushton 115kV | 3,916,919 | (11) | 1,292,583 | 2,624,336 | 204,200.91 | - | 136,815 | 128,523 | 86,110 |
| 51 | 50410 | Ellsworth Tap 115kV Ring Bus | - | (11) | - | - | - | | | - | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 52 | 50449 | Ellsworth Substation 115kV | | - | (11) | - | - | | | - | | | | - | |
| 53 | 30299 | Jewell - Smith Center 115kV | | | (20) | - | - | | | - | | | | - | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 54 | 30447 | Haggard - Gray County - West Dodge | - | (11) | - | - | | | - | | | - | |
| 55 | 30523 | Cudahy - Kismet 115kV | - | (11) | - | - | | | - | | | - | |
| 56 | 50828 | Harper-Rago 138kV ckt1 | 2,113,712 | (11) | 697,525 | 1,416,187 | ** | | 110,194.25 | - | 73,830 | 69,356 | 46,468 |
| 57 | 50991 | Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1 | | (11) | - | - | * | | - | | | - | |
| 58 | | | | | | | | | | | | | |
| 59 | | NEED DATE OF 10/1/2015 or AFTER | | | | | | | | | | | |
| 60 | 30299 | Jewell - Smith Center 115kV | 23,842 | (20),(11) | 7,868 | 15,974 | | | 1,242.94 | - | 833 | 782 | 524 |
| 61 | 50426A | Elm Creek-Summit 345/230kV Transformer 49% | 463,803 | (20),(11) | 153,055 | 310,748 | | | 24,179.45 | - | 16,200 | 15,218 | 10,196 |
| 62 | 50427A | Elm Creek-Summit 345kV Upgrades 49% | 1,143,848 | (20),(10) | 1,143,848 | (0) | | | 59,632.26 | - | (0) | 37,532 | (0) |
| 63 | 50428A | Elm Creek-Summit 230kV Upgrades 49% | 203,761 | (20),(11) | 67,241 | 136,520 | | | 10,622.68 | - | 7,117 | 6,686 | 4,480 |
| 64 | 50425A | Elm Creek-Summit 345kV Upgrades 49% (ITCGP) | 3,954,852 | (20),(10) | 3,954,852 | (0) | | | 206,178.46 | - | (0) | 129,768 | (0) |
| 65 | 50827 | Anthony - Harper 138 kV Ckt 1 | | (20),(11) | - | - | * | | - | | | - | |
| 66 | 51271 | Device - Ellsworth 115 kV Cap Bank | | (20),(11) | - | - | * | | - | | | - | |
| 67 | | | | | | | | | | | | | |
| 68 | | **Total Mid-Kansas** | **20,396,794** | | | | | | **1,063,347** | **20,055** | **358,604** | **669,265** | **238,326** |
| 69 | | **Combined** | **26,758,592** | | | | | **(185,337)** | **1,063,347** | **(67,767)** | **356,120** | **878,010** | **340,037** |
| 70 | | | | | | | | | | | | | |

71 * Excluded Projects (not eligible for allocation of Base Plan True-up)

72 ** Partially Excluded Projects (a portion not eligible for allocation of Base Plan True-up)

| 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | 39 | 40 | 41 | 42 | 43 | 44 | 45 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RRR Allocation % from "Base Plan Rev. Req. Alloc" and "Base Plan Project Alloc Factors" and "Brightline10-1-15 Base PlanATRR" | | | | | | | | | | | | | | | | | | | |
| | | AEP | SPRM | EDE | GRDA | KCPL | OGE | MIDW | KCPL-GMO | SPA | SPS | SECI | WFEC | WR | MKEC | LES | NPPD | OPPD | UMZ |
| UID | Facility | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone | Zone |
| Sunflower Electric Cooperative, Inc | | | | | | | | | | | | | | | | | | | |
| Base Plan projects with NTCs issued *prior to June 19, 2010* | | | | | | | | | | | | | | | | | | | |
| 10336 | Johnson - Pioneer 115kV Line | | | | | | | | | | 4.10% | 87.70% | 1.30% | | 2.30% | | 4.60% | | |
| 50246 | Johnson Corner Capacitor Bank #1 | | | | | | | | | | | 100.0% | | | | | | | |
| 50247 | Johnson Corner Capacitor Bank #2 | | | | | | | | | | | 100.0% | | | | | | | |
| 11215 | Holcomb - Plymell 115KV CKT 1 | | | | | | | | | | | 86.41% | | 13.59% | | | | | |
| 10480 | Pioneer Tap - Plymell 115KV CKT 1 | | | | | | | | | | | 87.28% | | | 12.72% | | | | |
| Balance Portfolio projects & Base Plan projects with NTCs issued after June 19, 2010 | | | | | | | | | | | | | | | | | | | |
| 11195 | Fletcher - Holcomb 115KV CKT 1 #2 (Wheatland) | | | | | | | | | | | 100.0% | | | | | | | |
| 50520 | Mingo 345/115 kV Ckt 2 Transformer | | | | | | | | | | | 100.0% | | | | | | | |
| 51180 | Mingo 345 kV Terminal Upgrades | | | | | | | | | | | 100.0% | | | | | | | |

| | | |
|---|---|---|
| | Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades | 100.0% |
| 51209 | | |
| 51326 | Walkemeyer Tap - Walkemeyer 345/115 kV | 100.0% |

NEED DATE OF 10/1/2015 or AFTER

| | | |
|---|---|---|
| 51271 | Ellsworth 115 kV Cap Bank | 100.0% |
| 51332 | Ingalls 115 kV Cap Bank | 100.0% |
| 51333 | Device - Lane Scott 115 kV Cap Bank | 100.0% |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Mid-Kansas Electric Company | | | | | | | | | | | | | | | | | | |
| Base Plan projects with NTCs issued *prior to June 19, 2010* | | | | | | | | | | | | | | | | | | |
| 50067 | Pratt Capacitor Bank 115 kV | | | | | | | | | | | | | 100.0% | | | | |
| 50068 | Harper Capacitor Bank 115 kV | | | | | | | | | | | | | 100.0% | | | | |
| 10213 | WEPL-Cimarron Plant 115 kV Line | | | | | | | | | | 100.0% | | | | | | | |
| 10858 | Pratt - St. John 115kV Line Rebuild | | | | | | | | | | | | 12.12% | 87.88% | | | | |
| 50104 | Plainville Capacitor Bank 115 kV | | | | | | | | | | | | | 100.0% | | | | |
| 11200 | Clifton - Greenleaf 115KV CKT 1 | | | | | 4.90% | | | | | | | 37.48% | 22.02% | | 30.14% | 5.46% | |
| 11323 | Heizer-Mullergren 115 kV Line | | | | | | | | | | 45.82% | | | 54.18% | | | | |
| 10994 | XFR Medicine Lodge 138/115 kV Transformer Upgrade | | | | | 10.88% | | 5.03% | | | 26.83% | | 18.47% | 38.80% | | | | |
| 11201 | Flatridge - Medicine Lodge 138kV CKT 1 | 4.69% | | | | 6.17% | 5.92% | 12.64% | | 8.44% | 17.51% | | 16.94% | 20.87% | | 6.82% | | |
| 11202 | Line - Flatridge - Harper 138 kV | | | | | 1.67% | | 11.51% | | 8.30% | 7.87% | | 33.17% | 34.67% | | 2.80% | | |
| 11203 | Line - Medicine Lodge - Pratt 115 kV | | | | | | | | | | 2.83% | | 32.24% | 64.92% | | | | |
| | | | | | | | | | | | | | | | | | | |
| Balance Portfolio projects & Base Plan projects with NTCs issued after June 19, 2010 | | | | | | | | | | | | | | | | | | |
| 10993 | Harper - Milan Tap 138 kV Ckt 1 | | | | | | | | | | | | | 100.0% | | | | |
| 50409 | Ellsworth - Bushton 115kV | | | | | | | | | | | | | 100.0% | | | | |
| 50410 | Ellsworth Tap 115kV Ring Bus | | | | | | | | | | | | | 100.0% | | | | |
| 50449 | Ellsworth Substation 115kV | | | | | | | | | | | | | 100.0% | | | | |
| 30299 | Jewell - Smith Center 115kV | | | | | | | | | | | | | 100.0% | | | | |
| 30447 | Haggard - Gray County - West Dodge | | | | | | | | | | | | | 100.0% | | | | |
| 30523 | Cudahy - Kismet 115kV | | | | | | | | | | | | | 100.0% | | | | |
| 50828 | Harper-Rago 138kV ckt1 | | | | | | | | | | | | | 100.0% | | | | |
| 50991 | Multi - Anthony - Bluff City - Caldwell - Mayfield - Milan - Viola 138 kV Ckt 1 | | | | | | | | | | | | | 100.0% | | | | |

NEED DATE OF 10/1/2015 or AFTER

| | | |
|---|---|---|
| 30299 | Jewell - Smith Center 115kV | 100.0% |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | |
| 50426A | Elm Creek-Summit 345/230kV Transformer 49% | | | | | | | | | | | | | | | 100.0% | | | | |
| 50427A | Elm Creek-Summit 345kV Upgrades 49% | | | | | | | | | | | | | | | 100.0% | | | | |
| 50428A | Elm Creek-Summit 230kV Upgrades 49% | | | | | | | | | | | | | | | 100.0% | | | | |
| 50425A | Elm Creek-Summit 345kV Upgrades 49% (ITCGP) | | | | | | | | | | | | | | | 100.0% | | | | |
| 50827 | Anthony - Harper 138 kV Ckt 1 | | | | | | | | | | | | | | | 100.0% | | | | |
| | | | | | | | | | | | | | | | | | | | | |
| 51271 | Device - Ellsworth 115 kV Cap Bank | | | | | | | | | | | | | | | 100.0% | | | | |
| | | | | | | | | | | | | | | | | | | | | |

# ADDENDUM 21 TO ATTACHMENT H

# Appendix A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

**Transource Missouri, LLC**

Projected Annual Transmission Revenue Requirement
For the 12 months ended 12/31/____

| Line No. | | | (1) | (2) | (3) |
|---|---|---|---|---|---|
| | | | | | Allocated Amount |
| 1 | GROSS REVENUE REQUIREMENT | (line 73) | | 12 months | $ - |
| | REVENUE CREDITS | | Total | Allocator | |
| 2 | Total Revenue Credits | Attachment 1, line 6 | - | TP 1.0000 | - |
| 3 | True-up Adjustment | Attachment 7 | - | DA 1.00000 | - |
| 4 | NET REVENUE REQUIREMENT | (line 1 minus line 2 plus line 3) | | | $ - |

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

**Transource Missouri, LLC**

| Line No. | (1) | (2) Form No. 1 Page, Line, Col. | (3) Company Total | (4) Allocator | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|
| | **RATE BASE:** | | | | |
| | GROSS PLANT IN SERVICE | | | | |
| 5 | Production | (Attachment 2) | - | NA | - |
| 6 | Transmission | (Attachment 2) | - | TP | 1.0000 - |
| 7 | Distribution | (Attachment 2) | - | NA | - |
| 8 | General & Intangible | (Attachment 2) | - | W/S | - |
| 9 | TOTAL GROSS PLANT (sum lines 5-8) | (GP=1 if plant =0) | - | GP= | - |
| 10 | ACCUMULATED DEPRECIATION & AMORTIZATION | | | | |
| 11 | Production | (Attachment 2) | - | NA | - |
| 12 | Transmission | (Attachment 2) | - | TP | 1.0000 - |
| 13 | Distribution | (Attachment 2) | - | NA | - |
| 14 | General & Intangible | (Attachment 2) | - | W/S | - |
| 15 | TOTAL ACCUM. DEPRECIATION (sum lines 11-14) | | - | | - |
| 16 | NET PLANT IN SERVICE | | | | |
| 17 | Production | (line 5- line 11) | - | | - |
| 18 | Transmission | (line 6- line 12) | - | | - |
| 19 | Distribution | (line 7- line 13) | - | | - |
| 20 | General & Intangible | (line 8- line 14) | - | | - |
| 21 | TOTAL NET PLANT (sum lines 17-20) | (NP=1 if plant =0) | - | NP= | - |
| 22 | ADJUSTMENTS TO RATE BASE (Note A) | | | | |
| 23 | ADIT | (Attachment 6a) | - | TP | 1.0000 - |
| 24 | Account No. 255 (enter negative) (Note F) | (Attachment 2) | - | NP | - |
| 25 | CWIP | (Attachment 2) (Note J) | - | DA | - |
| 26 | Reserves (enter negative) | (Attachment 2) | - | DA | 1.0000 - |
| 27 | Unamortized Regulatory Assets | (Attachment 2) | - | DA | 1.0000 - |
| 28 | Unamortized Abandoned Plant | (Attachment 2) (Note K) | - | DA | 1.0000 - |
| 29 | TOTAL ADJUSTMENTS (sum lines 23-28) | | - | | - |
| 30 | LAND HELD FOR FUTURE USE | (Attachment 2) | - | TP | 1.0000 - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 31 | WORKING CAPITAL (Note C) | | | | | |
| 32 | CWC | calculated (1/8 * Line 44) | - | | | - |
| 33 | Materials & Supplies (Note B) | (Attachment 2) | - | TP | 1.0000 | - |
| 34 | Prepayments (Account 165 - Note C) | (Attachment 2) | - | GP | - | - |
| 35 | TOTAL WORKING CAPITAL (sum lines 32-34) | | - | | | - |
| 36 | RATE BASE (sum lines 21, 29, 30, & 35) | | - | | | - |

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

**Transource Missouri, LLC**

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | **Form No. 1** | | | **Transmission** (Col 3 times Col 4) |
| | | **Page, Line, Col.** | **Company Total** | **Allocator** | |
| 37 | O&M | | | | |
| 38 | Transmission | 321.112.b | - | TP= 1.0000 | - |
| 39 | Less Accounts 565, 561 and 561.1 to 561.8 | 321.84.b to 92.b | - | TP= 1.0000 | - |
| 40 | A&G | 323.197.b | - | W/S - | - |
| 41 | Less EPRI & Reg. Comm. Exp. & Other Ad. | (Note D & Attach 2) | - | DA - | - |
| 42 | Plus Transmission Related Reg. Comm. Exp. | (Note D & Attach 2) | - | TP= 1.0000 | - |
| 43 | PBOP expense adjustment | (Attachment 2) | - | TP= 1.0000 | - |
| 44 | TOTAL O&M (sum lines 38, 40, 42, 43 less lines 39 & 41) | | - | | - |
| 45 | DEPRECIATION EXPENSE | | | | |
| 46 | Transmission | 336.7.b & c | - | TP 1.0000 | - |
| 47 | General and Intangible | 336.1.d&e + 336.10.b&c | - | W/S - | - |
| 48 | Amortization of Abandoned Plant | (Attachment 2) (Note K) | - | DA 1.0000 | - |
| 49 | TOTAL DEPRECIATION (Sum lines 46-48) | | - | | - |
| 50 | TAXES OTHER THAN INCOME TAXES (Note E) | | | | |
| 51 | LABOR RELATED | | | | |
| 52 | Payroll | 263._.i (enter FN1 line #) | - | W/S - | - |
| 53 | Highway and vehicle | 263._.i (enter FN1 line #) | - | W/S - | - |
| 54 | PLANT RELATED | | | | |
| 55 | Property | 263._.i (enter FN1 line #) | - | GP - | - |
| 56 | Gross Receipts | 263._.i (enter FN1 line #) | - | NA - | - |
| 57 | Other | 263._.i (enter FN1 line #) | - | GP - | - |
| 58 | TOTAL OTHER TAXES (sum lines 52-57) | | - | | - |
| 59 | INCOME TAXES<br>T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} | (Note F) | | | |
| 60 | = | | - | | |
| 61 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | - | | |
| 62 | where WCLTD=(line 90) and R= (line 93) | | | | |
| 63 | and FIT, SIT & p are as given in footnote F. | | | | |
| 64 | 1 / (1 - T) = (T from line 60) | | - | | |
| 65 | Amortized Investment Tax Credit (266.8f) (enter negative) | | - | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 66 | Income Tax Calculation = line 61 * line 70 | | - | NA | | | - |
| 67 | ITC adjustment (line 64 * line 65) | | - | NP | - | | - |
| 68 | Total Income Taxes | (line 66 plus line 67) | - | | | | - |
| 69 | RETURN | | | | | | |
| 70 | [ Rate Base (line 36) * Rate of Return (line 93)] | | - | NA | | | - |
| 71 | Rev Requirement before 60/40 Projects (sum lines 44, 49, 58, 68, 70) | | - | | | | - |
| 72 | Return and Income Tax on 60/40 Projects | (Attachment 3) | - | DA | 100% | | - |
| 73 | Total Revenue Requirement (sum lines 71 & 72) | | - | | | | - |

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

**Transource Missouri, LLC**
**SUPPORTING CALCULATIONS AND NOTES**

| | | | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN | | |
| 74 | RTO RATES | | |
| 75 | Total transmission plant (line 6, column 3) | | - |
| 76 | Less transmission plant excluded from RTO rates (Note H) | | - |
| 77 | Less transmission plant included in OATT Ancillary Services (Note H) | | - |
| 78 | Transmission plant included in RTO rates (line 75 less lines 76 & 77) | | - |
| 79 | Percentage of transmission plant included in RTO Rates (line 78 divided by line 75) [If line 75 equal zero, enter 1) | TP= | 1.0000 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 80 | WAGES & SALARY ALLOCATOR (W&S) (Note I) | | | | | | | | |
| 81 | | Form 1 Reference | $ | TP | Allocation | | | | |
| 82 | Production | 354.20.b | - | | | | | | |
| 83 | Transmission | 354.21.b | - | 1.00 | - | | | | |
| 84 | Distribution | 354.23.b | - | | | | W&S Allocator | | |
| 85 | Other | 354.24,25,26.b | - | | | | ($ / Allocation) | | |
| 86 | Total (sum lines 82-85) [TP equals 1 if there are no wages & salaries] | | - | | - | = | - | = | WS |
| 87 | RETURN (R) (Note J) | | | | | | | | |
| 88 | | | | | | | | | |
| 89 | | | $ | % | Cost | | Weighted | | |
| 90 | Long Term Debt (Note G) | (Attachments 2 and 5) | - | - | - | | - | =WCLTD | |
| 91 | Preferred Stock | (Attachment 2) | - | - | - | | - | | |
| 92 | Common Stock | (Attachment 2) | - | - | 10.30% | | - | | |
| 93 | Total (sum lines 90-92) | | - | | | | - | =R | |

| | (a) | (b) |
|---|---|---|
| Sum Of Net Plant, CWIP, Regulatory Asset and Abandoned Plant | Non 60/40 Projects | 60/40 Projects |

| | | | | | |
|---|---|---|---|---|---|
| 94 | Net Transmission Plant in Service | (Line 18) | - | | |
| 95 | CWIP | (Line 25) | - | - | |
| 96 | Unamortized Abandoned Plant | (Line 28) | - | | |
| 96 | Regulatory Assets | (Line 27) | - | | |
| 97 | Sum Of Net Plant, CWIP, Regulatory Asset and Abandoned Plant | | - | - | For use on Attachment 3 Line 24 and Attachment 4, line 4 |

**SUPPORTING CALCULATIONS AND NOTES**

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/____

**Transource Missouri, LLC**

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

| Note Letter | |
|---|---|
| A | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated. |
| B | Identified in Form 1 as being only transmission related. |
| C | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission<br>Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1. |
| D | Line 41 removes EPRI Annual Membership Dues listed in Form 1 at 353._.f (enter FN1 line #),<br>any EPRI Lobbying expenses included in line 44 of the template and all Regulatory Commission Expenses itemized at 351.h<br>Line 41 removes all advertising included in Account 930.1, except safety, education or out-reach related advertising<br>Line 41 removes EEI and EPRI research, development and demonstration expenses associated with projects in which transmission customers can voluntarily participate to the extent such expenses exceed a maximum annual aggregate amount of $100,000<br>Line 42 reflects all Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized at 351.h |
| E | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.<br>Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| F | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) . |

Inputs Required:

FIT = -

SIT= - (State Income Tax Rate or Composite SIT from Attachment 3)

p = - (percent of federal income tax deductible for state purposes)

For each Rate Year (including both Annual Projections and True-Up Adjustments) the statutory income tax rates utilized in the Formula Rate shall reflect the weighted average rates actually in effect during the Rate Year. For example, if the statutory tax rate is 10% from January 1 through June 30, and 5% from July 1 through December 31, such rates would be weighted 181/365 and 184/365, respectively, for a non-leap year.

G The cost of debt is determined using the internal rate of return methodology shown on Attachment 5 until the Actual Capital Structure Date, and is determined using the methodology in Attachment 2 thereafter. Attachment 5 contains a hypothetical example of the internal rate of return methodology; the methodology will be applied to actual amounts for use in Appendix A.

H Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

I Enter dollar amounts

J ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC under FPA Section 205 or 206.

The capital structure will be 60% equity and 40% debt for the CWIP associated with the projects listed below (60/40 Projects), and the return on such projects will be calculated on Attachments 3 and 4 and input on line 71. The CWIP associated with the 60/40 Projects will not be included in rate base (line 25). The capital structure shown on lines 89-92 will be 60% equity and 40% debt until the first of the 60/40 Projects is placed into service. After the first 60/40 project is placed in service, the capital structure on lines 89-92 will reflect the actual capital structure, and will be capped at 55% equity. If the actual equity ratio exceeds 55%, the common stock ratio will be reset to 55% and the debt ratio will be equal to 1 minus sum of the preferred stock ratio and common stock ratio. Any remaining 60/40 projects will continue to earn a return predicated on a 60% equity capital structure until such time as they are placed into commercial operation.

| Projects for which the Comission has authorized a 60/40 proxy capital structure during construction: | Docket Number |
|---|---|
| Iatan – Nashua 345 kV line Project | ER12-2554 |
| Nebraska City – Sibley 345 kV line Project | ER12-2554 |
| … | |
| … | |

K

Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Company must submit a Section 205 filing to recover the cost of abandoned plant. Any such filing to recover the cost of an abandoned plant item shall be made no later than 730 days after the date that Company formally declares such plant item abandoned.

# 1 – Revenue Credits

# Attachment 1 - Revenue Credit Workpaper*

## Transource Missouri, LLC

| | | | |
|---|---|---|---|
| | **Account 454 - Rent from Electric Property** | Notes 1 & 3 | |
| 1 | Rent from FERC Form No. 1 | | - |
| | **Account 456 and 456.1** | Notes 1 & 3 | |
| 2 | Other Electric Revenues (Note 2) | | - |
| 3 | Professional Services | | - |
| 4 | Revenues from Directly Assigned Transmission Facility Charges (Note 2) | | - |
| 5 | Rent or Attachment Fees associated with Transmission Facilities | | - |
| 6 | Total Revenue Credits | Sum lines 2-5 + line 1 | - |

Note 1

All revenues booked to Account 454 that are derived from cost items classified as transmission-related will be included as a revenue credit. All revenues booked to Account 456 that are derived from cost items classified as transmission-related, and are not derived from rates under this transmission formula rate will be included as a revenue credit. Work papers will be included to properly classify revenues booked to these accounts to the transmission function. A breakdown of all Account 454 revenues by subaccount will be provided below, and will be used to derive the proper calculation of revenue credits. A breakdown of all Account 456 revenues by subaccount and customer will be provided and tabulated below, and will be used to develop the proper calculation of revenue credits.

Note 2

If the facilities associated with the revenues are not included in the formula, the revenue is shown below, but not included in the total above and explained in the Attachment 3.

Note 3 All Account 454 and 456 Revenues must be itemized below

| Line No. | | | TOTAL | SPP | Other 1 | Other 2 |
|---|---|---|---|---|---|---|
| 1 | Account 456 | | | | | |
| 1a | Transmission Service | $ | - | $ - | $ - | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1x | Trans. Fac. Charge | | | - | | - | - | | - | |
| 2 | Trans Studies | | | - | | - | - | | - | |
| 3 | Total | $ | | - | $ | - | $ | - | $ | - |
| 4 | Less: | | | | | | | | | |
| 5 | Revenue for Demands in Divisor | | | - | | - | - | | - | |
| 6 | **Sub Total Revenue Credit** | $ | | - | $ | - | $ | - | $ | - |
| 7 | Prior Period Adjustments | | | - | | - | - | | - | |
| 8 | Total | | | | | | | | | |
| 9 | Account 454 | | $ | | | | | | | |
| 9a | Joint pole attachments - telephone | | | - | | | | | | |
| 9b | Joint pole attachments - cable | | | - | | | | | | |
| 9c | Underground rentals | | | - | | | | | | |
| 9d | Transmission tower wireless rentals | | | - | | | | | | |
| 9e | Other rentals | | | - | | | | | | |
| 9f | Corporate headquarters sublease | | | - | | | | | | |
| 9g | Misc non-transmission rentals | | | - | | | | | | |
| 9x | xxxx | | | - | | | | | | |
| 10 | Total | | | - | | | | | | |

# 2 – Cost Support

# Attachment 2 - Cost Support

## Transource Missouri, LLC

**Plant in Service Worksheet**

| | | | | |
|---|---|---|---|---|
| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | |
| 1 | **Calculation of Transmission Plant In Service** | Source | Year | Balance |
| 2 | December | p206.58.b | - | - |
| 3 | January | company records | - | - |
| 4 | February | company records | - | - |
| 5 | March | company records | - | - |
| 6 | April | company records | - | - |
| 7 | May | company records | - | - |
| 8 | June | company records | - | - |
| 9 | July | company records | - | - |
| 10 | August | company records | - | - |
| 11 | September | company records | - | - |
| 12 | October | company records | - | - |
| 13 | November | company records | - | - |
| 14 | December | p207.58.g | - | - |
| 15 | **Transmission Plant In Service** | (sum lines 2-14) /13 | | - |
| 16 | **Calculation of Distribution Plant In Service** | Source | | |
| 17 | December | p206.75.b | - | - |
| 18 | January | company records | - | - |
| 19 | February | company records | - | - |
| 20 | March | company records | - | - |

| | | | | |
|---|---|---|---|---|
| 20 | | | | |
| 21 | April | company records | - | - |
| 22 | May | company records | - | - |
| 23 | June | company records | - | - |
| 24 | July | company records | - | - |
| 25 | August | company records | - | - |
| 26 | September | company records | - | - |
| 27 | October | company records | - | - |
| 28 | November | company records | - | - |
| 29 | December | p207.75.g | - | - |
| 30 | **Distribution Plant In Service** | (sum lines 17-29) /13 | | - |

| | | | | |
|---|---|---|---|---|
| 31 | **Calculation of Intangible Plant In Service** | Source | | |
| 32 | December | p204.5.b | - | - |
| 33 | January | company records | - | - |
| 34 | February | company records | - | - |
| 35 | March | company records | - | - |
| 36 | April | company records | - | - |
| 37 | May | company records | - | - |
| 38 | June | company records | - | - |
| 39 | July | company records | - | - |
| 40 | August | company records | - | - |
| 41 | September | company records | - | - |
| 42 | October | company records | - | - |
| 43 | November | company records | - | - |
| 44 | December | p205.5.g | - | - |
| 45 | **Intangible Plant In Service** | (sum lines 32 & 44) /2 | | - |
| | | | | |
| 46 | **Calculation of General Plant In Service** | Source | | |
| 47 | December | p206.99.b | - | - |
| 48 | January | company records | - | - |
| 49 | February | company records | - | - |
| 50 | March | company records | - | - |
| 51 | April | company records | - | - |
| 52 | May | company records | - | - |
| 53 | June | company records | - | - |
| 54 | July | company records | - | - |
| 55 | August | company records | - | - |
| 56 | September | company records | - | - |
| 57 | October | company records | - | - |
| 58 | November | company records | - | - |
| 59 | December | p207.99.g | - | - |
| 60 | **General Plant In Service** | (sum lines 47 & 59) /2 | | - |

| | | | | |
|---|---|---|---|---|
| 61 | **Calculation of Production Plant In Service** | Source | | |
| 62 | December | p204.46b | - | - |
| 63 | January | company records | - | - |
| 64 | February | company records | - | - |
| 65 | March | company records | - | - |
| 66 | April | company records | - | - |
| 67 | May | company records | - | - |
| 68 | June | company records | - | - |
| 69 | July | company records | - | - |
| 70 | August | company records | - | - |
| 71 | September | company records | - | - |
| 72 | October | company records | - | - |
| 73 | November | company records | - | - |
| 74 | December | p205.46.g | - | - |
| 75 | **Production Plant In Service** | (sum lines 62-74) /13 | | - |
| 76 | **Total Plant In Service** | (sum lines 15, 30, 45, 60, & 75) | | - |

**Accumulated Depreciation Worksheet**

Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions

| | | | | |
|---|---|---|---|---|
| 77 | **Calculation of Transmission Accumulated Depreciation** | Source | Year | Balance |
| 78 | December | Prior year p219.25.b | - | - |
| 79 | January | company records | - | - |
| 80 | February | company records | - | - |
| 81 | March | company records | - | - |
| 82 | April | company records | - | - |
| 83 | May | company records | - | - |
| 84 | June | company records | - | - |
| 85 | July | company records | - | - |
| 86 | August | company records | - | - |
| 87 | September | company records | - | - |
| 88 | October | company records | - | - |
| 89 | November | company records | - | - |
| 90 | December | p219.25.b | - | - |

| | | | |
|---|---|---|---|
| 91 | **Transmission Accumulated Depreciation** | (sum lines 78-90) /13 | - |

| | | | | |
|---|---|---|---|---|
| 92 | **Calculation of Distribution Accumulated Depreciation** | Source | | |
| 93 | December | Prior year p219.26.b | - | - |
| 94 | January | company records | - | - |
| 95 | February | company records | - | - |
| 96 | March | company records | - | - |
| 97 | April | company records | - | - |
| 98 | May | company records | - | - |
| 99 | June | company records | - | - |
| 100 | July | company records | - | - |
| 101 | August | company records | - | - |
| 102 | September | company records | - | - |
| 103 | October | company records | - | - |
| 104 | November | company records | - | - |
| 105 | December | p219.26.b | - | - |
| 106 | **Distribution Accumulated Depreciation** | (sum lines 93-105) /13 | | - |
| | | | | |
| 107 | **Calculation of Intangible Accumulated Depreciation** | Source | | |
| 108 | December | Prior year p200.21.c | - | - |
| 109 | January | company records | - | - |
| 110 | February | company records | - | - |
| 111 | March | company records | - | - |
| 112 | April | company records | - | - |
| 113 | May | company records | - | - |
| 114 | June | company records | - | - |
| 115 | July | company records | - | - |
| 116 | August | company records | - | - |
| 117 | September | company records | - | - |
| 118 | October | company records | - | - |
| 119 | November | company records | - | - |
| 120 | December | p200.21.c | - | - |
| 121 | **Accumulated Intangible Depreciation** | (sum lines 108 & 120) /2 | | - |

| | | | | |
|---|---|---|---|---|
| 122 | **Calculation of General Accumulated Depreciation** | Source | | |
| 123 | December | Prior year p219.28.b | - | - |
| 124 | January | company records | - | - |
| 125 | February | company records | - | - |
| 126 | March | company records | - | - |
| 127 | April | company records | - | - |
| 128 | May | company records | - | - |
| 129 | June | company records | - | - |
| 130 | July | company records | - | - |
| 131 | August | company records | - | - |
| 132 | September | company records | - | - |
| 133 | October | company records | - | - |
| 134 | November | company records | - | - |
| 135 | December | p219.28.b | - | - |
| 136 | **Accumulated General Depreciation** | (sum lines 123 & 135) /2 | | - |
| 137 | **Calculation of Production Accumulated Depreciation** | Source | | |
| 138 | December | p219.20:24.b (prior year) | - | - |
| 139 | January | company records | - | - |
| 140 | February | company records | - | - |
| 141 | March | company records | - | - |
| 142 | April | company records | - | - |
| 143 | May | company records | - | - |
| 144 | June | company records | - | - |
| 145 | July | company records | - | - |
| 146 | August | company records | - | - |
| 147 | September | company records | - | - |
| 148 | October | company records | - | - |
| 149 | November | company records | - | - |
| 150 | December | p219.20 thru 219.24.b | - | - |
| 151 | **Production Accumulated Depreciation** | (sum lines 138-150) /13 | | - |
| 152 | **Total Accumulated Depreciation** | (sum lines 91, 106, 121, 136, & 151) | | - |

# 2a – Cost Support

**ADJUSTMENTS TO RATE BASE (Note A)**

Attachment 2 - Cost Support

| Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | | | Details |
|---|---|---|---|---|---|
| | | | Beginning of Year | End of Year | Average Balance |
| 153 | Account No. 255 (enter negative) | 267.8.h | - | - | - |
| 154 | Unamortized Abandoned Plant (recovery of abandoned plant requires a FERC order approving the amount and recovery period) | Per FERC Order | - | - | - |
| 155 | Amortization of Abandoned Plant | | | - | |
| 156 | Prepayments (Account 165) (Prepayments exclude Prepaid Pension Assets) | | Year | | Balance |
| 157 | December | 111.57.d | - | | - |
| 158 | January | company records | - | | - |
| 159 | February | company records | - | | - |
| 160 | March | company records | - | | - |
| 161 | April | company records | - | | - |
| 162 | May | company records | - | | - |
| 163 | June | company records | - | | - |
| 164 | July | company records | - | | - |
| 165 | August | company records | - | | - |
| 166 | September | company records | - | | - |
| 167 | October | company records | - | | - |
| 168 | November | company records | - | | - |
| 169 | December | 111.57.c | - | | - |
| 170 | **Prepayments** | (sum lines 157-169) /13 | | | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 171 | **Calculation of Transmission CWIP** | Source | Year | Non 60/40 Projects | 60/40 Projects | Total |
| 172 | December | 216.b (prior Year) | - | - | - | - |
| 173 | January | company records | - | - | - | - |
| 174 | February | company records | - | - | - | - |
| 175 | March | company records | - | - | - | - |
| 176 | April | company records | - | - | - | - |
| 177 | May | company records | - | - | - | - |
| 178 | June | company records | - | - | - | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | - |
| 179 | July | company records | - | - | - | - | |
| 180 | August | company records | - | - | - | - | |
| 181 | September | company records | - | - | - | - | |
| 182 | October | company records | - | - | - | - | |
| 183 | November | company records | - | - | - | - | |
| 184 | December | 216.b | - | - | - | - | |
| 185 | **Transmission CWIP** | (sum lines 172-184) /13 | | - | | - | - |

## LAND HELD FOR FUTURE USE

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Beg of year | End of Year | Average | Details |
|---|---|---|---|---|---|---|---|
| 186 | **LAND HELD FOR FUTURE USE** | p214 | Total | - | - | - | |
| | | | Non-transmission Related | - | - | | |
| | | | Transmission Related | - | - | - | |

## Reserves

| | | | Amount | Enter 1 if Customer Funded, O if not | Allocation (Plant or Labor Allocator) | Amount Allocated | |
|---|---|---|---|---|---|---|---|
| 187 | List of all reserves: | | | | | | |
| | | Reserve 1 | - | - | | - | |
| | | Reserve 2 | - | - | | - | |
| | | Reserve 3 | | | | | |
| | | Reserve 4 | | | | | |
| | | … | | | | | |
| | | … | - | - | | - | |
| | | Total | - | | | - | |

The Formula Rate shall include a credit to rate base for all funded and unfunded reserves (*i.e.*, those for which the funds collected have not been set aside in escrow and the earnings thereon included in the reserve fund) that are funded by customers and for which the associated accrued costs are recoverable under the Formula Rate. Company will include a spreadsheet (to be included in the Formula Rate template) each year as part of the Annual Update that lists the reserves and indicates which ones meet the test for crediting to rate base.

## EPRI Dues Cost Support

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Details |
|---|---|---|---|---|
| | **Allocated General & Common Expenses** | | | |
| | | | EPRI Dues | EPRI Dues |
| 188 | EPRI Dues | p353._.f (enter FN1 line #) | | |

## Regulatory Expense Related to Transmission Cost Support

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | Form 1 Amount | Transmission Related | Non-transmission Related | Details* |
|---|---|---|---|---|---|---|
| | **Directly Assigned A&G** | | | | | |
| 189 | Regulatory Commission Exp Account 928 | p323.189.b | | | - | |

| | |
|---|---|
| | * insert case specific detail and associated assignments here |

**Multi-state Workpaper**

| Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | State 1 | State 2 | State 3 | State 4 | State 5 | Weighed Average |
|---|---|---|---|---|---|---|
| **Income Tax Rates** | | | | | | |
| 190 SIT=State Income Tax Rate or Composite | | | | | | - |
| Multiple state rates are weighted based on the state apportionment factors on the state income tax returns | 0 | | | | | |

**Safety Related and Education and Out Reach Cost Support**

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | Form 1 Amount | Safety Related, Education, Siting & Outreach Related | Other | Details |
|---|---|---|---|---|---|---|
| | **Directly Assigned A&G** | | | | | |
| 191 | General Advertising Exp Account 930.1 | p323.191.b | | | - | |

**Excluded Plant Cost Support**

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | Excluded Transmission Facilities | Description of the Facilities |
|---|---|---|---|
| | **Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities** | | |
| 192 | Excluded Transmission Facilities | - | **General Description of the Facilities** |
| | | | **Add more lines if necessary** |

**Materials & Supplies**

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | Stores Expense Undistributed | Transmission Materials & Supplies | Construction Materials & Supplies | Total |
|---|---|---|---|---|---|---|
| | Note: for the projection, the prior year's actual balances will be used | | | | | |
| | Form No.1 page | | p227.16 | p227.8 | p227.5 | |
| 193 | December | Column b | - | - | - | - |
| 194 | January | | - | - | - | - |
| 195 | February | | - | - | - | - |
| 196 | March | | - | - | - | - |
| 197 | April | | - | - | - | - |
| 198 | May | | - | - | - | - |
| 199 | June | | - | - | - | - |
| 200 | July | | - | - | - | - |
| 201 | August | | - | - | - | - |
| 202 | September | | - | - | - | - |
| 203 | October | | - | - | - | - |
| 204 | November | | - | - | - | - |
| 205 | December | Column c | - | - | - | - |

| | | |
|---|---|---|
| 206 | Average | - |

**Regulatory Asset**

**Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions**

| | | | Project Name | Project Name | Project Name | **Total** | |
|---|---|---|---|---|---|---|---|
| 207 | Beginning Balance of Regulatory Asset | | | - | - | | Uncapitalized costs as of date the rates become effective |
| 208 | Months remaining in Amortization Period | | | - | - | | As approved by FERC |
| 209 | Monthly Amortization to Account 566 | (line 207 / line 208) | - | - | - | - | All amortizations of the Regulatory Asset are to be booked to Account 566 over a 5 year period beginning on the first month that the revenue requirement for the project is assessed |
| 210 | Months in Year to be amortized | | | - | - | | Number of months rates are in effect during the calendar year |
| 211 | Ending Balance of Regulatory Asset | (line 207 - line 209 * 210) | - | - | - | | Enter docket nos. for orders authorizing recovery here: |
| 212 | Average Balance of Regulatory Asset | (line 207 + line 211)/2 | - | - | - | - | |

| Docket Number | Amortization period |
|---|---|
| ER12-2554 | 60 Months |
| | |
| | |

## Capital Structure

**Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions**

| | Monthly Balances for Capital Structure | Year | Debt | Preferred Stock | Common Stock | Total Capitalization |
|---|---|---|---|---|---|---|
| 214 | December (prior year) | - | - | - | - | - |
| 215 | January | - | - | - | - | - |
| 216 | February | - | - | - | - | - |
| 217 | March | - | - | - | - | - |
| 218 | April | - | - | - | - | - |
| 219 | May | - | - | - | - | - |
| 220 | June | - | - | - | - | - |
| 221 | July | - | - | - | - | - |
| 222 | August | - | - | - | - | - |
| 223 | September | - | - | - | - | - |
| 224 | October | - | - | - | - | - |
| 225 | November | - | - | - | - | - |
| 226 | December | - | - | - | - | - |
| 227 | Average | | - | - | - | - |

Debt is equal to 112.18c less 112.19c plus 112.20c plus 112.21c, recognizing that 112.19c is entered into the Form 1 as a negative number and shall remain negative (i.e., it is not a double minus in the formula that mathematically would lead to adding in line 112.19c) so that Reacquired Bonds (Account 222) are subtracted from other long term debt outstanding and that Line 112.20c may contain both short term and long term indebtedness to affiliates and therefore any short term affiliate debt shall be removed from 112.20c before adding it into the above long term debt balance formula in the formula rate.

Preferred Stock is equal to 112.3c less any Preferred Treasury Stock plus any Preferred Additional Paid-in-Capital, recognizing that if there is any Preferred Treasury Stock or Preferred Additional Paid-in-Capital, then the respective amounts shall be appropriately disclosed in a footnote to the capital structure cost support in the formula rate template.

Common Equity is equal to 112.16c less 112.3c less 112.12c less 112.15c, recognizing that line 112.15c may be a positive or negative number and if it is positive, it shall be subtracted in the formula, and if it is entered as a negative in the Form 1, it shall be added (a double minus sign when subtracting a negative number) in the formula.

The cost of long-term debt for a Rate Year will be the sum of the interest expense and cost of issuances divided by the 13-month average long-term debt balance for the Rate Year. The cost of long-term debt issuances shall include long-term interest expense amounts recorded in the following FERC accounts:

| | | | | Amount |
|---|---|---|---|---|
| 228 | | Account 427 | Interest on Long-Term Debt (limited solely to interest expense for long-term debt reported in Accounts 221-224) (FF1, 117/62/c) | - |
| 229 | plus: | Account 428 | Amortization of Debt Discount and Expense (FF1, 117/63/c) | - |
| 230 | plus: | Account 428.1 | Amortization of Loss on Reacquired Debt (FF1, 117/64/c) | - |
| 231 | less: | Account 429 | Amortization of Premium on Debt (FF1, 117/65/c) | - |
| 232 | less: | Account 429.1 | Amortization of Gain on Reacquired Debt (FF1, 117/66/c) | - |
| 233 | plus: | Account 430 | Interest on Debt to Associated Companies but limited solely to the expense associated with long-term debt recorded in Account 223. | - |
| 234 | Total | | | - |

Interest expenses not directly related to the long-term bond issuances included in the capital structure will be excluded.

The cost of preferred stock will be preferred stock dividends (booked in FERC Account 437) divided by the average preferred stock balance for the rate year.

| | | |
|---|---|---|
| 235 | Preferred Dividends in Account 437 | - |
| 236 | 13 Month average balance of Preferred Stock | - |
| 237 | Cost of Preferred Stock | - |

**PBOPs**

| | Appendix A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions | | | Details |
|---|---|---|---|---|
| 238 | **Calculation of PBOP Expenses** | | | |
| 239 | **AEP Employees** | | | |
| 240 | Total PBOP expenses | | $72,293,585 | |
| 241 | Labor dollars | | 1,181,809,072 | |
| 242 | Cost per labor dollar | | $0.061 | |
| 243 | labor (labor not capitalized) current year | | - | |
| 244 | PBOP Expense for current year | | - | |
| 245 | PBOP Expense in Account 926 for current year | | - | |
| 246 | PBOP Adjustment for Appendix A, Line 54 | | - | |
| 247 | Lines 240-242 cannot change absent approval or acceptance by FERC in a separate proceeding. | | | |
| 247 | **KCP&L Employees** | | | |
| 248 | Total PBOP expenses | | $10,853,189 | |
| 249 | Labor dollars | | 145,384,684 | |
| 250 | Cost per labor dollar | | $0.075 | |
| 251 | labor (labor not capitalized) current year | | - | |
| 252 | PBOP Expense for current year | | - | |
| 253 | PBOP Expense in Account 926 for current year | | - | |
| 254 | PBOP Adjustment for Appendix A, Line 54 | | - | |
| 255 | Lines 248-250 cannot change absent approval or acceptance by FERC in a separate proceeding. | | | |
| 256 | PBOP expense adjustment | (sum lines 246 & 254) | - | |

# 3 - Incentives

Incentive ROE and 60/40 Project
Worksheet

Attachment 3

Rate Formula Template
Utilizing Attachment O
Data

Transource Missouri, LLC

For the 12 months ended 12/31/2012

**Incentive ROE**

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Rate Base | | | | | - |
| 2 | 100 Basis Point Incentive Return | | | | $ | |
| | | $ | % | Cost (Note P) | Weighted | |
| 3 | Long Term Debt | - | - | - | - | |
| 4 | Preferred Stock | - | - | - | - | |
| 5 | Common Stock Including 100 basis points | - | - | - | - | |
| 6 | Total (sum lines 3-5) | - | | | - | |
| 7 | 100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6) | | | | | - |
| 8 | INCOME TAXES | | | | | |
| 9 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | - | | | | |
| 10 | CIT=(T/1-T) * (1-(WCLTD/R)) = | - | | | | |
| 11 | where WCLTD=(line 3) and R= (line 6) | | | | | |
| 12 | and FIT, SIT & p are as given in footnote F on Appendix A. | | | | | |
| 13 | 1 / (1 - T) = (T from line 9) | - | | | | |
| 14 | Amortized Investment Tax Credit (266.8f) (enter negative) | - | | | | |
| 15 | | | | | | |
| 16 | Income Tax Calculation = line 10 * line 7 | | | | | - |
| 17 | ITC adjustment (line 13 * line 14) and line 17 allocated on NP allocator | - | | NP | - | - |
| 18 | Total Income Taxes (line 16 plus line 17) | - | | | | - |

| | | | |
|---|---|---|---|
| 19 | Return and Income Taxes with 100 basis point increase in ROE | Sum lines 7 and 18 | - |
| 20 | Return (Appendix A line 70 col 5) | | - |
| 21 | Income Tax (Appendix A line 68 col 5) | | - |
| 22 | Return and Income Taxes without 100 basis point increase in ROE | Sum lines 20 and 21 | - |
| 23 | Incremental Return and Income Taxes for 100 basis point increase in ROE | Line 19 less line 22 | - |
| 24 | Sum Of Net Plant, CWIP, Abandoned Plant And Regulatory Assets | Appendix A, line 97a | - |
| 25 | Carrying Charge Difference for 100 Basis point of ROE | (Line 23 divided by line 24) | - |

**Incentive ROE associated with 60/40 Projects**

Attachment 3

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 26 | Rate Base | | | | | | - |
| 27 | 100 Basis Point Incentive Return | | | | | $ | |
| | | | $ | % | Cost (Note P) | Weighted | |
| 28 | Long Term Debt | | - | - | - | - | |
| 29 | Preferred Stock | | - | - | - | - | |
| 30 | Common Stock Including 100 basis points | | - | - | - | - | |
| 31 | Total (sum lines 28-30) | | - | | | - | |
| 32 | 100 Basis Point Incentive Return multiplied by Rate Base (line 26 * line 31) | | | | | | - |
| 33 | INCOME TAXES | | | | | | |
| 34 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | - | | | | |
| 35 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | - | | | | |
| 36 | where WCLTD=(line 28) and R= (line 31) | | | | | | |
| 37 | and FIT, SIT & p are as given in footnote on Appendix A. | | | | | | |
| 38 | 1 / (1 - T) = (T from line 34) | | - | | | | |
| 39 | Amortized Investment Tax Credit (266.8f) (enter negative) | | - | | | | |
| 40 | Income Tax Calculation = line 35 * line 32 | | | | | | - |
| 41 | ITC adjustment (line 38 * line 39) and line 41 allocated on NP allocator | - | | NP | - | - | |
| 42 | Total Income Taxes | (line 40 plus line 41) | - | | | | - |
| 43 | Return and Income Taxes with 100 basis point increase in ROE | | | Sum lines 32and 42 | | | - |
| 44 | Return (Appendix A line 70 col 5) | | | | | | - |
| 45 | Income Tax (Appendix A line 68 col 5) | | | | | | - |
| 46 | Return and Income Taxes without 100 basis point increase in ROE | | | Sum lines 44 and 45 | | | - |
| 47 | Incremental Return and Income Taxes for 100 basis point increase in ROE | | | Line 43 less line 46 | | | - |
| 48 | Sum Of Net Plant, CWIP, Abandoned Plant And Regulatory Assets | | | Appendix A, line 97a | | | - |
| 49 | Carrying Charge Difference for 100 Basis point of ROE | | | (Line 47 divided by line 48) | | | - |

**Base FCR for 60/40 Projects**

Attachment 3

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 50 | 60/40 Projects | (Appendix A, line 97b) | | | | | - |
| | | | | | | $ | |
| | | | $ | % | Cost (Note P) | Weighted | |
| 51 | Long Term Debt | | - | - | - | - | |
| 52 | Preferred Stock | | - | - | - | - | |
| 53 | Common Stock Including 100 basis points | | - | - | - | - | |
| 54 | Total (sum lines 28-30) | | - | | | - | |
| 55 | 100 Basis Point Incentive Return multiplied by Rate Base (line 26 * line 31) | | | | | | - |
| 56 | INCOME TAXES | | | | | | |
| 57 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | - | | | | |
| 58 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | - | | | | |
| 59 | where WCLTD=(line 51) and R= (line 54) | | | | | | |
| 60 | and FIT, SIT & p are as given in footnote on Appendix A. | | | | | | |
| 61 | 1 / (1 - T) = (T from line 57) | | - | | | | |
| 62 | Amortized Investment Tax Credit (266.8f) (enter negative) | | - | | | | |
| 63 | Income Tax Calculation = line 58 * line 55 | | | | | - | |
| 64 | ITC adjustment (line 61 * line 62) and line 64 allocated on NP allocator | | - | NP | - | - | |
| 65 | Total Income Taxes | (line 63 plus line 64) | - | | | | - |
| 66 | Return and Income Taxes without 100 basis point increase in ROE | | | | Sum lines 55 and 65 | | - |
| 67 | 60/40 Projects | | | | Appendix A, line 97b | | - |
| 68 | Base FCR for 60/40 Projects | | | | Line 66 / line 67 | | - |

# 4 – Cap Adds

Attachment 4 - Transmission Enhancement Charge Worksheet

Transource Missouri, LLC

| | | | For all but 60/40 Projects | For 60/40 Projects only (Attachment 3) | Total |
|---|---|---|---|---|---|
| 1 | Rev Requirement | (Appendix A, line 71 & 72) | - | - | - |
| 2 | Less Transmission Depreciation Expense plus Abandoned Plant and Regulatory Asset Amortization Expense | (Appendix A, line 97a & b) | - | | - |
| 3 | Net Rev Req less Depreciation expense | (Line 1 minus line 2) | - | - | |
| 4 | Sum Of Net Plant, Regulatory Asset and Abandoned Plant (Attachment A, line 97a) | | - | - | |
| 5 | Base Fixed Charge Rate (Base FCR) | (Line 3 / line 4) | - | - | |
| 6 | Carrying Charge Difference for 100 Basis point of ROE | (Attachment 3, line 25 and 49) | - | - | |

| | **Column A** | **Column B** | **Column C** | **Column D** | **Column E** | **Column F** | **Column G** | **Column H** | **Column I** |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | 2014 | | | |
| | Project Name and SPP Identification | Useful life of project/Amort period | Input the allowed ROE Incentive Increased ROE (Basis Points) | Line 5 Base FCR | Line 6 times Col C divided by 100 basis points plus Col D FCR for This Project | Actual Rev Req at Base FCR | | | Actual Rev Req at Increased ROE |
| | | | | | | 13 Month Balance Net Plant; | Depreciation or Amortization Expense | Revenue Requirement [Col D x Col F + Col G] | Revenue Requirement (Col E x Col F + Col G) |
| 7a | | | | | - | | | - | - |
| 7b | | | | | - | | | - | - |
| 7c | | | | | - | | | - | - |
| 7d | | | | | - | | | - | - |
| 7e | | | | | - | | | - | - |
| 7f | | | | | - | | | - | - |
| 7g | | | | | - | | | - | - |
| 7h | | | | | - | | | - | - |
| 7i | | | | | - | | | - | - |
| 18 | **Total** | | | | | | | | |

| | | | |
|---|---|---|---|
| - | - | - | - |
| 19 Line 18 must tie to the lines above as shown | Total of Col F ties to Line 4 | Total of Col G ties to Line 2 Total | Total of Col H ties to Line 1 Total | Total Amount to be Charged |

Note 1: Add additional lines after line 7i for additional projects
Note 2: Regulatory Assets, CWIP, and plant in-service shall be listed on separate lines for each project

# 5 – LTD

**Attachment 5 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology**
Transource Missouri, LLC
HYPOTHETICAL EXAMPLE

Assumes financing will be a 5 year loan with Origination Fees of $2.1 million and a Commitments Fee of 0.3% on the undrawn principal.
Consistent with GAAP, the Origination Fees and Commitments Fees will be amortized using the standard Internal Rate of Return formula below.
Each year, the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount will be updated on this attachment
The IRR calculation will use the Excel Worksheet Function XIRR.

| | |
|---|---|
| **Total Loan Amount** | **$ 200,000,000** |

| | |
|---|---|
| **Internal Rate of Return[1]** | **4.902%** |

**Based on following Financial Formula[2]:**

$$\text{NPV} = 0 = \sum_{t=1}^{N} Ct/(1+IRR)^{pwr(t)}$$

| | |
|---|---|
| **Origination Fees** | |
| Underwriting Discount | - |
| Arrangement Fee | 400,000 |
| Upfront Fee | 700,000 |
| Rating Agency Fee | - |
| Legal Fees | 1,000,000 |
| Total Issuance Expense | **2,100,000** |
| **Annual Rating Agency Fee** | 160,000 |
| **Annual Bank Agency Fee** | 50,000 |
| **Revolving Credit Commitment Fee** | 0.300% |

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|---|---|
| LIBOR Rate | 0.6360% | 1.0340% | 1.6000% | 2.1300% | 2.1300% | 2.1300% | 2.1300% |
| Spread | 2.25% | 2.25% | 2.25% | 2.25% | 2.25% | 2.25% | 2.25% |
| **Interest Rate** | 2.89% | 3.28% | 3.85% | 4.38% | 4.38% | 4.38% | 4.38% |

| (A) Year | (B) | ( C) Capital Expenditures ($000's) | (D) Principal Drawn In Quarter ($000's) | (E) Principal Drawn To Date ($000's) | (F) Interest & Principal ($000's) | (G) Origination Fees ($000's) | (H) Commitment & Utilization Fee ($000's) | (I) Net Cash Flows ($000's) (D-F-G-H) |
|---|---|---|---|---|---|---|---|---|
| 1/1/2014 | Prior Periods | 81,200 | | | | | | 1 |
| 3/31/2014 | Q3 | 19,350 | 40,220 | 40,220 | | 2,100 | | 38,120 |
| 6/30/2014 | Q4 | 19,350 | 7,740 | 47,960 | 289 | | 329.84 | 7,121 |
| 9/30/2014 | Q1 | 19,350 | 7,740 | 55,700 | 349 | | 114 | 7,277 |
| 12/31/2014 | Q2 | 19,350 | 7,740 | 63,440 | 405 | | 108 | 7,227 |
| 3/31/2015 | Q3 | 24,775 | 9,910 | 73,350 | 451 | | 102 | 9,356 |
| 6/30/2015 | Q4 | 24,775 | 9,910 | 83,260 | 601 | | 305 | 9,004 |
| 9/30/2015 | Q1 | 24,775 | 9,910 | | | | | 9,133 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | 93,170 | 689 | 88 | |
| 12/31/2015 | Q2 | 24,775 | 9,910 | 103,080 | 771 | 80 | 9,059 |
| 3/31/2016 | Q3 | 23,950 | 9,580 | 112,660 | 844 | 73 | 8,663 |
| 6/30/2016 | Q4 | 23,950 | 9,580 | 122,240 | 1,081 | 276 | 8,223 |
| 9/30/2016 | Q1 | 23,950 | 9,580 | 131,820 | 1,186 | 58 | 8,335 |
| 12/31/2016 | Q2 | 23,950 | 9,580 | 141,400 | 1,279 | 51 | 8,250 |
| 3/31/2017 | Q3 | 23,575 | 9,430 | 150,830 | 1,342 | 44 | 8,044 |
| 6/30/2017 | Q4 | 23,575 | 9,430 | 160,260 | 1,647 | 247 | 7,536 |
| 9/30/2017 | Q1 | 23,575 | 9,430 | 169,690 | 1,769 | 30 | 7,631 |
| 12/31/2017 | Q2 | 23,575 | 9,430 | 179,120 | 1,873 | 23 | 7,534 |
| 3/31/2018 | Q3 | - | - | 179,120 | 181,054.50 | 16 | (181,070) |
| 6/30/2018 | Q4 | - | - | - | - | - | - |
| 9/30/2018 | Q1 | - | - | - | - | - | - |

1 The IRR is the Debt Cost shown on Line 88 of Appendix A.

2 The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e., NPV function with goal seek in a spreadsheet program).

# 6a – ADIT

**Transource Missouri, LLC**

**Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)**

**Beginning of Year**

| Item | Transmission Related | Plant Related | Labor Related | Total Plant & Labor Related | |
|---|---|---|---|---|---|
| ADIT- 282 | - | - | - | | From Acct. 282 total, below |
| ADIT-283 | - | - | - | | From Acct. 283 total, below |
| ADIT-190 | - | - | - | | From Acct. 190 total, below |
| Subtotal | - | - | - | | |
| Wages & Salary Allocator | | | - | | |
| NP | | - | | | |
| Beginning of Year | - | - | - | - | |
| End of year from Attachment 6b, line 7 | - | - | - | - | |
| Average of Beginning of Year and End of Year ((7 +8)/2) | - | - | - | - | Enter as negative Appendix A, line 23. |

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately. For ADIT directly related to project depreciation or CWIP, the balance must shown in a separate column for each project.

| A | B | C | D | F | G | H |
|---|---|---|---|---|---|---|
| ADIT-190 | Total | Gas, Prod Or Other Related | Transmission Related | Plant Related | Labor Related | Justification |
| | | | | | | |
| | | | | | | |
| | | | | | | |
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| | | | | | | |
| Subtotal - p234 | - | - | - | - | - | |
| Less FASB 109 Above if not separately removed | | | | | | |
| Less FASB 106 Above if not separately removed | | | | | | |
| Total | - | - | - | - | - | |

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Transource Missouri, LLC**

**Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)**

**Beginning of Year**

| A | B | C | D | F | G | H |
|---|---|---|---|---|---|---|
| ADIT- 282 | Total | Gas, Prod Or Other Related | Transmission Related | Plant Related | Labor Related | Justification |
| | | | | | | |
| | | | | | | |
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| | | | | | | |
| Subtotal - p275 | - | - | - | - | - | |
| Less FASB 109 Above if not separately removed | | | | - | | |
| Less FASB 106 Above if not separately removed | | | | | | |
| Total | - | - | - | - | - | |

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Transource Missouri, LLC**

**Attachment 6a - Accumulated Deferred Income Taxes (ADIT) Worksheet (Beginning of Year)**

**Beginning of Year**

| A | B | C | D | F | G | H |
|---|---|---|---|---|---|---|
| ADIT- 283 | Total | Gas, Prod Or Other Related | Transmission Related | Plant Related | Labor Related | |
| | | | | | | |
| | | | | | | |
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| | | | | | | |
| | | | | | | |
| Subtotal - p277 | - | - | - | - | - | |
| Less FASB 109 Above if not separately removed | - | | | - | | |
| Less FASB 106 Above if not separately removed | - | | | | | |
| Total | - | - | - | - | - | |

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

# 6b ADIT

**Transource Missouri, LLC**

**Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)**

**End of Year**

| Line | | Transmission Related | Plant Related | Labor Related | Total Plant & Labor Related | |
|---|---|---|---|---|---|---|
| 1 | ADIT- 282 | - | - | - | | From Acct. 282 total, below |
| 2 | ADIT-283 | - | - | - | | From Acct. 283 total, below |
| 3 | ADIT-190 | - | - | - | | From Acct. 190 total, below |
| 4 | Subtotal | - | - | - | | |
| 5 | Wages & Salary Allocator | | | - | | |
| 6 | NP | | - | | | |
| 7 | End of Year ADIT | - | - | - | - | |

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed,
dissimilar items with amounts exceeding
$100,000 will be listed separately.

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| ADIT-190 | Total | Gas, Prod Or Other Related | Transmission Related | Plant Related | Labor Related | Justification |
| | | | | | | |
| | | | | | | |
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| | | | | | | |
| Subtotal - p234 | - | - | - | - | - | |
| Less FASB 109 Above if not separately removed | | | | | | |
| Less FASB 106 Above if not separately removed | | | | | | |
| Total | - | - | - | - | - | |

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Transource Missouri, LLC**

**Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)**

**End of Year**

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| ADIT- 282 | Total | Gas, Prod Or Other Related | Transmission Related | Plant Related | Labor Related | Justification |
| | | | | | | |
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| Subtotal - p275 | - | - | - | - | - | |
| Less FASB 109 Above if not separately removed | | | | - | | |
| Less FASB 106 Above if not separately removed | | | | | | |
| Total | - | - | - | - | - | |

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

**Transource Missouri, LLC**

**Attachment 6b - Accumulated Deferred Income Taxes (ADIT) Worksheet (End of Year)**

**End of Year**

| A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|
| | Total | Gas, Prod | | | | |
| ADIT- 283 | | Or Other | Transmission | Plant | Labor | |
| | | Related | Related | Related | Related | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| Subtotal - p277 | - | - | - | - | - | |
| Less FASB 109 Above if not separately removed | - | | | - | | |
| Less FASB 106 Above if not separately removed | - | | | | | |
| Total | - | - | - | - | - | |

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

2. ADIT items related only to Transmission are directly assigned to Column D

3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

# 7 – True Up

# Attachment 7 - Example of True-Up Calculation
## Transource Missouri, LLC

| 2013 | | 2013 | | Over (Under) Recovery |
|---|---|---|---|---|
| Revenue Requirement Billed | **Less** | Actual Revenue Requirement | **Equals** | |
| $2,000,000 | | $2,000,000 | | $0 |

| Interest Rate on Amount of Refunds or Surcharges | Over (Under) Recovery Plus Interest | Monthly Interest Rate on Attachment 7a | Months | Calculated Interest | Amortization | Surcharge (Refund) Owed |
|---|---|---|---|---|---|---|
| | | 0.5500% | | | | |

**An over or under collection will be recovered prorata over year collected, held for one year and returned prorata over next year**

**Calculation of Interest** — **Monthly**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| January | Year 2013 | - | 0.5500% | 12 | - | | - |
| February | Year 2013 | - | 0.5500% | 11 | - | | - |
| March | Year 2013 | - | 0.5500% | 10 | - | | - |
| April | Year 2013 | - | 0.5500% | 9 | - | | - |
| May | Year 2013 | - | 0.5500% | 8 | - | | - |
| June | Year 2013 | - | 0.5500% | 7 | - | | - |
| July | Year 2013 | - | 0.5500% | 6 | - | | - |
| August | Year 2013 | - | 0.5500% | 5 | - | | - |
| September | Year 2013 | - | 0.5500% | 4 | - | | - |
| October | Year 2013 | - | 0.5500% | 3 | - | | - |
| November | Year 2013 | - | 0.5500% | 2 | - | | - |
| December | Year 2013 | - | 0.5500% | 1 | - | | - |
| | | | | | - | | - |

**Annual**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| January through December | Year 2014 | - | 0.5500% | 12 | - | | - |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** — **Monthly**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| January | Year 2015 | - | 0.5500% | | - | - | - |
| February | Year 2015 | - | 0.5500% | | - | - | - |
| March | Year 2015 | - | 0.5500% | | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| April | Year 2015 | - | 0.5500% | - | - | - |
| May | Year 2015 | - | 0.5500% | - | - | - |
| June | Year 2015 | - | 0.5500% | - | - | - |
| July | Year 2015 | - | 0.5500% | - | - | - |
| August | Year 2015 | - | 0.5500% | - | - | - |
| September | Year 2015 | - | 0.5500% | - | - | - |
| October | Year 2015 | - | 0.5500% | - | - | - |
| November | Year 2015 | - | 0.5500% | - | - | - |
| December | Year 2015 | - | 0.5500% | - | - | - |
| | | | | - | | |

| | | |
|---|---|---|
| Total Amount of True-Up Adjustment | $ | - |
| Less Over (Under) Recovery | $ | - |
| Total Interest | $ | - |

# 7a – Interest Rate

Attachment 7

**True-Up Interest Calculation**



| | | | Avg. Ann Short Term Interest |
|---|---|---|---|
| | **Short term Interest Rate (Notes A & C)** | | |
| 1 | Other Interest Exp.(Notes, p.117) | (Note A) | - |
| 2 | Notes Payable (Acct. 231-daily balances wksht.) | (Note A) | - |
| 3 | No. of Months | | - |
| 4 | Annual Short-term Int Rate | (line 1 / line 2 ) | - |

| | | | Purusant to 35.19 (a) |
|---|---|---|---|
| | **FERC Quarterly Interest Rate** | | |
| 5 | Qtr 3 (Previous Year) | | - |
| 6 | Qtr 4 (Previous Year) | | - |
| 7 | Qtr 1 (Current Year) | | - |
| 8 | Qtr 2 (Current Year) | | - |
| 9 | Average of the last 4 quarters | (Lines 5-8 / 4) | - |
| 10 | Interest Rate Used for True-up adjustment (Note B) | | - |
| 11 | Monthly Interest Rate | (Line 10 / 12) | - |

**Note:**

A The short term interest rate is based on a 12 month rate ending June of the year in which the Annual Update is prepared, with denominator calculated using daily balances and the numerator based on Form 3Q.

B If the True-up amount on Attachment 7 is a surcharge to customers use the lower of line 4 and line 9, however, if line 4 is zero, then use line 9. Use line 9 if the True-up amount is a refund to customers.

C The numerator and denominator of the short-term interest rate calculation will reflect consistent debt components.

# 8 - Const Loan True-up

# Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
## Transource Missouri, LLC

**SUMMARY**

| YEAR | | Estimated Effective cost of debt used in true up | Final Effective cost of debt for the construction loan: | Revenue Requirement: Based on Estimated Effective cost of debt | Revenue Requirement: Based on Actual Effective cost of debt | Over (Under) Recovery | Monthly Interest Rate applicable over the ATRR period | Total Amount of Construction Loan Related True-Up included in rates effective Jan 2017 (Refund)/Owed |
|---|---|---|---|---|---|---|---|---|
| 2012 | | 7.18% | 6.50% | $ 2,500,000.00 | $ 2,400,000.00 | $ 100,000.00 | 0.550% | $ (148,288.33) |
| 2013 | | 6.8% | 6.50% | $5,000,000.00 | $5,150,000.00 | $ (150,000.00) | 0.560% | $ 209,670.43 |
| 2014 | | 7.2% | 6.50% | $8,300,000.00 | $8,200,000.00 | $ 100,000.00 | 0.540% | $ (131,109.09) |
| 2015 | | 7.3% | 6.50% | $12,300,000.00 | $12,000,000.00 | $ 300,000.00 | 0.580% | $ (368,656.73) |
| 2016 | * | 7.1% | 6.50% | $18,000,000.00 | $17,900,000.00 | $ 100,000.00 | 0.570% | $ (114,946.28) |
| | * | | | | | | | |
| 2016 | * | 6.50% | 6.50% | $25,000,000.00 | $25,000,000.00 | $ - | | |
| | | | | | | | | $ (553,329.99) |

***The Hypothetical Example:***
**** Assumes that the construction loan is retired on Sept 1, 2016***
***** Assumes permanent debt structure is put in place on Sept 1, 2016 with effective rate of 6.5%***

**Calculation of Applicable Interest Expense for each ATRR period**

| Interest Rate on Amount of Refunds or Surcharges from 35.19a | Over (Under) Recovery Plus Interest | Hypothetical Monthly Interest Rate | Months | Calculated Interest | Amortization | Surcharge (Refund) Owed |
|---|---|---|---|---|---|---|
| **Calculation of Interest for 2011 True-Up Period** | | | | | | |
| **An over or under collection will be recovered prorata over 2011, held for 2012, 2013, 2014, 2013, 2016 and returned prorate over 2017** | | | | **Monthly** | | |
| - | | | | | | |
| January | Year 2012 | 0.5500% | 12.00 | - | | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | - | | | | | |
| February | Year 2012 | - | 0.5500% | 11.00 | - | | - |
| March | Year 2012 | 10,000 | 0.5500% | 10.00 | (550) | | (10,550) |
| April | Year 2012 | 10,000 | 0.5500% | 9.00 | (495) | | (10,495) |
| May | Year 2012 | 10,000 | 0.5500% | 8.00 | (440) | | (10,440) |
| June | Year 2012 | 10,000 | 0.5500% | 7.00 | (385) | | (10,385) |
| July | Year 2012 | 10,000 | 0.5500% | 6.00 | (330) | | (10,330) |
| August | Year 2012 | 10,000 | 0.5500% | 5.00 | (275) | | (10,275) |
| September | Year 2012 | 10,000 | 0.5500% | 4.00 | (220) | | (10,220) |
| October | Year 2012 | 10,000 | 0.5500% | 3.00 | (165) | | (10,165) |
| November | Year 2012 | 10,000 | 0.5500% | 2.00 | (110) | | (10,110) |
| December | Year 2012 | 10,000 | 0.5500% | 1.00 | (55) | | (10,055) |
| | | | | | (3,025) | | **(103,025)** |
| | | | | | **Annual** | | |
| January through December | Year 2013 | (103,025) | 0.5600% | 12.00 | (6,923) | | **(109,948)** |
| January through December | Year 2014 | (109,948) | 0.5400% | 12.00 | (7,125) | | **(117,073)** |
| January through December | Year 2015 | (117,073) | 0.5800% | 12.00 | (8,148) | | **(125,221)** |
| January through December | Year 2016 | (125,221) | 0.5700% | 12.00 | (8,565) | | **(133,786)** |
| January through December | Year 2017 | (133,786) | 0.5700% | 12.00 | (9,151) | | **(142,937)** |
| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | **Monthly** | | |
| January | Year 2018 | **142,937** | 0.5700% | | (815) | (12,357) | (131,395) |
| February | Year 2018 | 131,395 | 0.5700% | | (749) | (12,357) | (119,786) |
| March | Year 2018 | 119,786 | 0.5700% | | (683) | (12,357) | (108,112) |
| April | Year 2018 | 108,112 | 0.5700% | | (616) | (12,357) | (96,371) |
| May | Year 2018 | | 0.5700% | | (549) | (12,357) | (84,563) |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | 96,371 | | | | |
| June | Year 2018 | 84,563 | 0.5700% | (482) | (12,357) | (72,687) |
| July | Year 2018 | 72,687 | 0.5700% | (414) | (12,357) | (60,744) |
| August | Year 2018 | 60,744 | 0.5700% | (346) | (12,357) | (48,733) |
| September | Year 2018 | 48,733 | 0.5700% | (278) | (12,357) | (36,653) |
| October | Year 2018 | 36,653 | 0.5700% | (209) | (12,357) | (24,505) |
| November | Year 2018 | 24,505 | 0.5700% | (140) | (12,357) | (12,287) |
| December | Year 2018 | 12,287 | 0.5700% | (70) | (12,357) | 0 |
| | | | | (5,351) | | |

| | | |
|---|---|---|
| Total Amount of True-Up Adjustment for 2012 ATRR | $ | (148,288) |
| Less Over (Under) Recovery | $ | 100,000 |
| Total Interest | $ | (48,288) |

# Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan
# Transource Missouri, LLC

## Calculation of Interest for 2012 True-Up Period

**An over or under collection will be recovered prorata over 2012, held for 2013, 2014, 2013, 2016 and returned prorate over 2017**

**Monthly**

| - | | | | | | | |
|---|---|---|---|---|---|---|---|
| January | Year 2013 | (12,500) | | 0.5600% | 12.00 | 840 | 13,340 |
| February | Year 2013 | (12,500) | | 0.5600% | 11.00 | 770 | 13,270 |
| March | Year 2013 | (12,500) | | 0.5600% | 10.00 | 700 | 13,200 |
| April | Year 2013 | (12,500) | | 0.5600% | 9.00 | 630 | 13,130 |
| May | Year 2013 | (12,500) | | 0.5600% | 8.00 | 560 | 13,060 |
| June | Year 2013 | (12,500) | | 0.5600% | 7.00 | 490 | 12,990 |
| July | Year 2013 | (12,500) | | 0.5600% | 6.00 | 420 | 12,920 |
| August | Year 2013 | (12,500) | | 0.5600% | 5.00 | 350 | 12,850 |
| September | Year 2013 | (12,500) | | 0.5600% | 4.00 | 280 | 12,780 |
| October | Year 2013 | (12,500) | | 0.5600% | 3.00 | 210 | 12,710 |
| November | Year 2013 | (12,500) | | 0.5600% | 2.00 | 140 | 12,640 |
| December | Year 2013 | (12,500) | | 0.5600% | 1.00 | 70 | 12,570 |
| | | | | | | 5,460 | **155,460** |

**Annual**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| January through December | Year 2014 | | 155,460 | 0.5400% | 12.00 | 10,074 | **165,534** |
| January through December | Year 2015 | | 165,534 | 0.5800% | 12.00 | 11,521 | **177,055** |
| January through December | Year 2016 | | 177,055 | 0.5700% | 12.00 | 12,111 | **189,166** |
| January through December | Year 2017 | | 189,166 | 0.5700% | 12.00 | 12,939 | **202,104** |

| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | **Monthly** | | |
|---|---|---|---|---|---|---|
| January | Year 2018 | **(202,104)** | 0.5700% | 1,152 | 17,473 | 185,784 |
| February | Year 2018 | (185,784) | 0.5700% | 1,059 | 17,473 | 169,370 |
| March | Year 2018 | (169,370) | 0.5700% | 965 | 17,473 | 152,863 |
| April | Year 2018 | (152,863) | 0.5700% | 871 | 17,473 | 136,262 |
| May | Year 2018 | (136,262) | 0.5700% | 777 | 17,473 | 119,566 |
| June | Year 2018 | (119,566) | 0.5700% | 682 | 17,473 | 102,775 |
| July | Year 2018 | (102,775) | 0.5700% | 586 | 17,473 | 85,888 |
| August | Year 2018 | (85,888) | 0.5700% | 490 | 17,473 | 68,905 |
| September | Year 2018 | (68,905) | 0.5700% | 393 | 17,473 | 51,826 |
| October | Year 2018 | (51,826) | 0.5700% | 295 | 17,473 | 34,649 |
| November | Year 2018 | (34,649) | 0.5700% | 197 | 17,473 | 17,374 |
| December | Year 2018 | (17,374) | 0.5700% | 99 | 17,473 | (0) |
| | | | | 7,566 | | |

| | | |
|---|---|---|
| Total Amount of True-Up Adjustment for 2013 | | |
| ATRR | $ | 209,670 |
| Less Over (Under) Recovery | $ | (150,000) |
| Total Interest | $ | 59,670 |

## Calculation of Interest for 2013 True-Up Period

**An over or under collection will be recovered prorata over 2013, held for 2014, 2013, 2016 and returned prorate over 2017**

| - | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| January | Year 2014 | 8,333 | 0.5400% | 12.00 | (540) | (8,873) |
| February | Year 2014 | 8,333 | 0.5400% | 11.00 | (495) | (8,828) |
| March | Year 2014 | 8,333 | 0.5400% | 10.00 | (450) | (8,783) |
| April | Year 2014 | 8,333 | 0.5400% | 9.00 | (405) | (8,738) |
| May | Year 2014 | 8,333 | 0.5400% | 8.00 | (360) | (8,693) |
| June | Year 2014 | 8,333 | 0.5400% | 7.00 | (315) | (8,648) |

| | | | | | | |
|---|---|---|---|---|---|---|
| July | Year 2014 | 8,333 | 0.5400% | 6.00 | (270) | (8,603) |
| August | Year 2014 | 8,333 | 0.5400% | 5.00 | (225) | (8,558) |
| September | Year 2014 | 8,333 | 0.5400% | 4.00 | (180) | (8,513) |
| October | Year 2014 | 8,333 | 0.5400% | 3.00 | (135) | (8,468) |
| November | Year 2014 | 8,333 | 0.5400% | 2.00 | (90) | (8,423) |
| December | Year 2014 | 8,333 | 0.5400% | 1.00 | (45) | (8,378) |
| | | | | | (3,510) | **(103,510)** |
| | | | | | **Annual** | |
| January through December | Year 2015 | (103,510) | 0.5800% | 12.00 | (7,204) | **(110,714)** |
| January through December | Year 2016 | (110,714) | 0.5700% | 12.00 | (7,573) | **(118,287)** |
| January through December | Year 2017 | (118,287) | 0.5700% | 12.00 | (8,091) | **(126,378)** |

| **Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months** | | | | | **Monthly** | |
|---|---|---|---|---|---|---|
| January | Year 2018 | **126,378** | 0.5700% | (720) | (10,926) | (116,173) |
| February | Year 2018 | 116,173 | 0.5700% | (662) | (10,926) | (105,909) |
| March | Year 2018 | 105,909 | 0.5700% | (604) | (10,926) | (95,587) |
| April | Year 2018 | 95,587 | 0.5700% | (545) | (10,926) | (85,206) |
| May | Year 2018 | 85,206 | 0.5700% | (486) | (10,926) | (74,766) |
| June | Year 2018 | 74,766 | 0.5700% | (426) | (10,926) | (64,266) |
| July | Year 2018 | 64,266 | 0.5700% | (366) | (10,926) | (53,707) |
| August | Year 2018 | 53,707 | 0.5700% | (306) | (10,926) | (43,087) |
| September | Year 2018 | 43,087 | 0.5700% | (246) | (10,926) | (32,407) |
| October | Year 2018 | 32,407 | 0.5700% | (185) | (10,926) | (21,666) |
| November | Year 2018 | 21,666 | 0.5700% | (123) | (10,926) | (10,864) |
| December | Year 2018 | 10,864 | 0.5700% | | (10,926) | |

| | | | | |
|---|---|---|---|---|
| | (62) | | | 0 |
| | (4,731) | | | |
| Total Amount of True-Up Adjustment for 2014 | | | | |
| ATRR | | $ | (131,109) | |
| Less Over (Under) Recovery | | $ | 100,000 | |
| Total Interest | | $ | (31,109) | |

**Attachment 8 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan**
**Transource Missouri, LLC**

**Calculation of Interest for 2014 True-Up Period**

**An over or under collection will be recovered prorata over 2014, held for 2013, 2016 and returned prorate over 2017**

| | | | | Monthly | | |
|---|---|---|---|---|---|---|
| January | Year 2015 | 25,000 | 0.5800% | (1,740) | | (26,740) |
| February | Year 2015 | 25,000 | 0.5800% | (1,595) | | (26,595) |
| March | Year 2015 | 25,000 | 0.5800% | (1,450) | | (26,450) |
| April | Year 2015 | 25,000 | 0.5800% | (1,305) | | (26,305) |
| May | Year 2015 | 25,000 | 0.5800% | (1,160) | | (26,160) |
| June | Year 2015 | 25,000 | 0.5800% | (1,015) | | (26,015) |
| July | Year 2015 | 25,000 | 0.5800% | (870) | | (25,870) |
| August | Year 2015 | 25,000 | 0.5800% | (725) | | (25,725) |
| September | Year 2015 | 25,000 | 0.5800% | (580) | | (25,580) |
| October | Year 2015 | 25,000 | 0.5800% | (435) | | (25,435) |
| November | Year 2015 | 25,000 | 0.5800% | (290) | | (25,290) |
| December | Year 2015 | 25,000 | 0.5800% | (145) | | (25,145) |
| | | | | (11,310) | | **(311,310)** |

| | | | | Annual | | |
|---|---|---|---|---|---|---|
| January through December | Year 2016 | (311,310) | 0.5700% | (21,294) | | **(332,604)** |
| January through December | Year 2017 | (332,604) | 0.5700% | (22,750) | | **(355,354)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | Monthly | | |
|---|---|---|---|---|---|---|
| January | Year 2018 | **355,354** | 0.5700% | (2,026) | (30,721) | (326,658) |
| February | Year 2018 | 326,658 | 0.5700% | (1,862) | (30,721) | (297,798) |
| March | Year 2018 | 297,798 | 0.5700% | (1,697) | (30,721) | (268,774) |
| April | Year 2018 | 268,774 | 0.5700% | (1,532) | (30,721) | (239,585) |
| May | Year 2018 | 239,585 | 0.5700% | (1,366) | (30,721) | (210,229) |
| June | Year 2018 | 210,229 | 0.5700% | (1,198) | (30,721) | (180,706) |
| July | Year 2018 | 180,706 | 0.5700% | (1,030) | (30,721) | (151,015) |
| August | Year 2018 | 151,015 | 0.5700% | (861) | (30,721) | (121,154) |
| September | Year 2018 | 121,154 | 0.5700% | (691) | (30,721) | (91,123) |
| October | Year 2018 | 91,123 | 0.5700% | (519) | (30,721) | (60,921) |
| November | Year 2018 | 60,921 | 0.5700% | (347) | (30,721) | (30,547) |
| December | Year 2018 | 30,547 | 0.5700% | (174) | (30,721) | 0 |
| | | | | (13,303) | | |

| | | |
|---|---|---|
| Total Amount of True-Up Adjustment for 2015 ATRR | $ (368,657) | |
| Less Over (Under) Recovery | | $ 300,000 |
| Total Interest | | $ (68,657) |

**Calculation of Interest for 2013 True-Up Period**

**An over or under collection will be recovered prorata over 2013, held for 2016 and returned prorate over 2017**

| | | | | **Monthly** | | |
|---|---|---|---|---|---|---|
| January | Year 2016 | 8,333 | 0.5700% | (570) | | (8,903) |
| February | Year 2016 | 8,333 | 0.5700% | (523) | | (8,856) |
| March | Year 2016 | 8,333 | 0.5700% | (475) | | (8,808) |
| April | Year 2016 | 8,333 | 0.5700% | (428) | | (8,761) |
| May | Year 2016 | 8,333 | 0.5700% | (380) | | (8,713) |
| June | Year 2016 | 8,333 | 0.5700% | (333) | | (8,666) |
| July | Year 2016 | 8,333 | 0.5700% | (285) | | (8,618) |
| August | Year 2016 | 8,333 | 0.5700% | (238) | | (8,571) |
| September | Year 2016 | 8,333 | 0.5700% | (190) | | (8,523) |
| October | Year 2016 | 8,333 | 0.5700% | (143) | | (8,476) |
| November | Year 2016 | 8,333 | 0.5700% | (95) | | (8,428) |
| December | Year 2016 | 8,333 | 0.5700% | (48) | | (8,381) |
| | | | | (3,705) | | **(103,705)** |
| | | | | **Annual** | | |
| January through December | Year 2017 | (103,705) | 0.5700% | (7,093) | | **(110,798)** |

**Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months**

| | | | | **Monthly** | | |
|---|---|---|---|---|---|---|
| January | Year 2018 | **110,798** | 0.5700% | (632) | (9,579) | (101,851) |
| February | Year 2018 | 101,851 | 0.5700% | (581) | (9,579) | (92,853) |
| March | Year 2018 | 92,853 | 0.5700% | (529) | (9,579) | (83,803) |
| April | Year 2018 | 83,803 | 0.5700% | (478) | (9,579) | (74,702) |
| May | Year 2018 | 74,702 | 0.5700% | (426) | (9,579) | (65,549) |
| June | Year 2018 | 65,549 | 0.5700% | (374) | (9,579) | (56,344) |
| July | Year 2018 | 56,344 | 0.5700% | (321) | (9,579) | (47,086) |
| August | Year 2018 | 47,086 | 0.5700% | (268) | (9,579) | (37,776) |
| September | Year 2018 | 37,776 | 0.5700% | (215) | (9,579) | (28,412) |
| October | Year 2018 | 28,412 | 0.5700% | (162) | (9,579) | (18,995) |
| November | Year 2018 | 18,995 | 0.5700% | (108) | (9,579) | (9,525) |
| December | Year 2018 | 9,525 | 0.5700% | (54) | (9,579) | 0 |

| | | | |
|---|---|---|---|
| | (4,148) | | |
| Total Amount of True-Up Adjustment for 2016 ATRR | | $ | (114,946) |
| Less Over (Under) Recovery | | $ | 100,000 |
| Total Interest | | $ | (14,946) |

# 9 – Depreciation Rates

# Attachment 9 - Depreciation and Amortization Rates

**Transource Missouri, LLC**

| | Account Number | FERC Account | Rate (Annual) Percent |
|---|---|---|---|
| | **TRANSMISSION PLANT** | | |
| 1 | 350.1 | Land Rights | 1.33 |
| 2 | 352 | Structures and Improvements | 2.05 |
| 3 | 353 | Station Equipment | 1.73 |
| 4 | 354 | Towers and Fixtures | 1.33 |
| 5 | 355 | Poles and Fixtures | 2.85 |
| 6 | 356 | Overhead Conductor and Devices | 1.97 |
| 7 | 358 | Underground Conductor and Devices | 2.50 |
| | **GENERAL PLANT** | | |
| 8 | 390 | Structures & Improvements | 1.63 |
| 9 | 391 | Office Furniture & Equipment | 4.13 |
| 10 | 391.1 | Computers | 20.00 |
| 11 | 392 | Transportation Equipment | 6.67 |
| 12 | 393 | Stores Equipment | 3.43 |
| 13 | 394 | Tools, Shop & Garage Equipment | 4.00 |
| 14 | 395 | Laboratory Equipment | 3.54 |
| 15 | 396 | Power Operated Equipment | 4.04 |
| 16 | 397 | Communication Equipment | 5.42 |
| 17 | 398 | Miscellaneous Equipment | 5.00 |
| | **INTANGIBLE PLANT** | | |
| 18 | 303 | Miscellaneous Intangible Plant | 20.00 |
| | | Transmission facility Contributions in Aid of Construction | Note 1 |

These depreciation rates will not change absent the appropriate filing at FERC.

Note 1: In the event a Contribution in Aid of Construction (CIAC) is made for a transmission facility, the transmission depreciation rates above will be weighted based on the relative amount of underlying plant booked to the accounts shown in lines 1-7 above and the weighted average depreciation rate will be used to amortize the CIAC.

# FORMULA RATE IMPLEMENTATION PROTOCOLS

The formula rate template ("Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Transource Missouri, LLC ("Transource Missouri") for transmission revenue requirement determinations under the Southwest Power Pool ("SPP") Open Access Transmission Tariff ("OATT"). Transource Missouri shall follow the instructions specified in the Formula Rate to calculate annually its net revenue requirement, as set forth at page 1, line 4 of the Template ("Net Revenue Requirement"). The project-specific net revenue requirements determined under the Formula Rate are "up to" rates, i.e., ceiling rates, and permit Transource Missouri to discount the revenue requirement for a future project to the extent necessary to reflect the result of any competitive bidding on such a project. The Net Revenue Requirement (page 1, line 4 of the Template) shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of Transource Missouri's Net Revenue Requirement upon the effective date for incorporation into the SPP OATT through an appropriate filing with the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205 of the Federal Power Act ("FPA").

## Section 1. Annual Projection

a. No later than September 30 preceding the first Rate Year, and each subsequent Rate Year, Transource Missouri shall determine its projected Net Revenue Requirement for the upcoming Rate Year in accordance with Transource Missouri's Formula Rate ("Annual Projection"). The Annual Projection shall include the True-up Adjustment described and defined in Section 2 below, if applicable. Transource Missouri shall cause an electronic version of the Annual Projection to be posted in both a Portable Document Format and fully-functioning Excel file at a publicly accessible location on SPP's internet website. Such posting shall include (i) all inputs in sufficient detail to identify the components of Transource Missouri's projected Net Revenue Requirement, and (ii) explanations of the bases for the projections and input data. If the date for making such posting of the Annual Projection should fall on a weekend or a holiday recognized by FERC, then the posting shall be made no later than the next business day. Transource Missouri shall electronically serve each Annual Projection upon the Service List.[1]

[1] As used in these protocols, "Service List" shall mean (i) the email list of SPP OATT Transmission Customers maintained by the SPP; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility, provided such consumer advocate agency requests to be placed on the Service List and provides an e-mail address to Transource Missouri.

b. To the extent Transource Missouri agrees to make changes in the Annual Projection for a given Rate Year, such revised Annual Projection shall be promptly posted at a publicly accessible location on SPP's internet website and a link to the website shall be electronically served upon the Service List. Changes posted prior to November 30 of the preceding Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under SPP's billing practices), shall be reflected in the Annual Projection for the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-up Adjustment for the Rate Year.

c. The Annual Projection, including the True-Up Adjustment, for each Rate Year shall be subject to review, challenge, true-up and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

**Section 2. <u>True-up Adjustment</u>**

Transource Missouri will calculate the amount of under- or over-collection of its actual Net Revenue Requirement during the preceding Rate Year ("True-up Adjustment") after the FERC Form No. 1 data for that Rate Year has been filed with the Commission. The True-up Adjustment shall be the sum of components a and b, determined in the following manner:

a. Transource Missouri's projected Net Revenue Requirement collected during the previous Rate Year[2] will be compared to Transource Missouri's actual Net Revenue Requirement for the previous Rate Year calculated in accordance with Transource Missouri's Formula Rate and based upon (i) Transource Missouri's FERC Form No. 1 for that same Rate Year, (ii) any FERC orders specifically applicable to Transource Missouri's calculation of its annual revenue requirement, (iii) the books and records of Transource Missouri (which shall be maintained consistent with the FERC Uniform System of Accounts ("USoA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the SPP OATT Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates, [3] to determine any over- or under-recovery ("True-up Adjustment Over/Under Recovery").

[2] If the initial year of this rate schedule is a partial year, the initial projected Net Revenue Requirement will be divided by the number of months the Formula Rate is in effect to calculate the monthly projected cost of service to be collected each month of the first year. Similarly, the actual Net Revenue Requirement will be divided by the number of months the rate is in effect to calculate the actual cost of service to be collected each month of the first year. The first True-up Adjustment will compare the projected Net Revenue Requirement billed and the actual Net Revenue Requirement for that initial Rate Year.

[3] SPP OATT Governing Documents include the SPP OATT, Bylaws, Criteria, and Membership Agreements.

Transource Missouri will include a variance analysis of, at minimum, actual revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as compared to the corresponding components in the projected revenue requirement that was calculated for the prior Rate Year with an explanation of material changes.

b. Interest on any True-up Adjustment Over/Under Recovery of the actual Net Revenue Requirement shall be calculated in accordance with the Formula Rate true-up worksheet.

**Section 3. <u>Annual Update</u>**

a. On or before June 30 following each Rate Year, Transource Missouri shall calculate its actual Net Revenue Requirement and the True-up Adjustment as described in Section 2 ("Annual Update") for such Rate Year, and shall cause such Annual Update to be posted, in both a Portable Document Format and fully-functioning Excel format containing the populated template for that year's update, at a publicly accessible location on SPP's internet website, and electronically serve a link to the website on the Service List. In addition, the Annual Update shall be contemporaneously submitted as an informational filing with the FERC.

b. If the date for making the Annual Update posting should fall on a weekend or a holiday recognized by the FERC, then the posting shall be due on the next business day.

c. The date on which the last of the events listed in Section 3.a or 3.b occurs shall be that year's "Publication Date."

d. Together with the posting of the Annual Update, Transource Missouri shall cause to be posted on the SPP website the time, date and location for a stakeholder meeting with (i) any Eligible Customer under the SPP OATT; (ii) any regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility, or (iv) any party with standing under FPA Section 205 or 206 (collectively, "Interested Persons") in order for Transource Missouri to explain its Annual Update and to provide Interested Persons an opportunity to seek information and clarifications regarding the Annual Update ("Stakeholder Meeting"). The Stakeholder Meeting shall be held no less than twenty (20) business days and no more than thirty (30) business days after June 30.

e. The Annual Update for the Rate Year:

(i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[4]

(ii) Shall provide notice of changes in Transource Missouri's accounting policies and practices from those in effect for the calendar year upon which the immediately preceding Annual Update was based that affect the Formula Rate or calculation of the Annual Update ("Accounting Change(s)"). Such notice shall include (i) those changes that, in Transource Missouri's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next three years; (ii) any changes in the SPP OATT from the provisions of the SPP OATT in effect during the calendar year upon which the most recent ATRR was based and that, in Transource Missouri's reasonable judgment, could impact the Formula Rate or the calculations under the Formula Rate within the next three years; and (iii) any change, and the dollar value of the change, in the classification of any transmission facility under Attachment AI of the SPP OATT (including the costs of any reclassified facility) that Transource Missouri has made in the applicable True-Up Adjustment or Annual Update.

(iii) Shall be subject to review and challenge in accordance with the procedures set forth in Sections 4, 5, and 6 of these Protocols.

(iv) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual Update; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of going forward or burden of proof under formula rates in such prudence challenges; and

(v) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Person seeking to modify the Formula Rate. *(i.e.*, any modifications to the Formula Rate will require, as applicable, an FPA Section 205 or Section 206 filing or

[4] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

initiation of a Section 206 investigation).

f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA Section 205 or 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) "Post-Employment Benefits other than Pensions" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges; and (iii) the depreciation and/or amortization rates as set forth in Attachment 9 to the Formula Rate template.

g. **Example – Timeline for 2015 Annual Update**:

On or before September 30, 2013, Transource Missouri will determine the projected Net Revenue Requirement for the 2014 Rate Year, which is expected to be the first year that costs are recovered from SPP customers under the Formula Rate. Transource Missouri will post the Annual Projection for the 2014 Rate Year in accordance with Section 1 above. Transource Missouri will not determine a True-up Adjustment or post an Annual Update on August 1, 2014 if no costs have been recovered under the Formula Rate during 2013. On or before September 30, 2014, Transource Missouri will post the Annual Projection for the 2015 Rate Year. On or before August 1, 2015, Transource Missouri will post its first Annual Update, consisting of the True-up Adjustment for the 2014 Rate Year determined pursuant to Section 2 above. Such True-up Adjustment will be reflected in the Annual Projection of the Net Revenue Requirement for the 2016 Rate Year posted on or before September 30, 2015. The Annual Update posted August 1, 2015 will be subject to the customer review and challenge procedures described in Sections 4, 5, and 6 of these Protocols.

## Section 4. Annual Review Procedures

Each Annual Update shall be subject to the following review procedures ("Annual Review Procedures"):

a. Interested Persons shall have up to the latest of one hundred fifty (150) calendar days after the Publication Date, thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of Transource Missouri), or thirty (30) calendar days after resolution of a dispute that does not result in the production of additional information ("Review Period"), to review the calculations and to notify Transource Missouri in writing of any specific challenges, including challenges related to

Accounting Changes, to the Annual Update ("Preliminary Challenge"). Transource Missouri shall promptly cause to be posted all Preliminary Challenges at a publicly accessible location on SPP's internet website and a link to the website will be electronically served upon the Service List.

Transource Missouri shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which Transource Missouri agrees or disagrees with the challenge. If Transource Missouri disagrees with the Preliminary Challenge, its response shall include supporting documentation. Transource Missouri shall promptly cause to be posted responses to all Preliminary Challenges at a publicly accessible location on SPP's internet website and a link to the website will be electronically served upon the Service List.

b. Interested Persons shall have up to one hundred twenty (120) calendar days after each annual Publication Date (unless such period is extended with the written consent of Transource Missouri) to serve reasonable information requests on Transource Missouri. Information requests shall be limited to what is necessary to determine if: (i) Transource Missouri has properly calculated the Annual Update under review (including any corrections pursuant to Section 6); (ii) the costs included in the Annual Update are properly recordable and recorded, prudently incurred, and otherwise consistent with Transource Missouri's accounting policies, practices and procedures consistent with the USoA; (iii) the input data used in the Annual Update are accurate and correctly used in the Formula Rate; and (iv) the Formula Rate has been applied according to its terms, including the procedures in these Protocols. Information requests shall not solicit information concerning costs or allocations where the costs or allocation methods have been determined to be appropriate by FERC in the context of prior Transource Missouri Annual Updates, except that such information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances, (ii) are in connection with corrections pursuant to Section 6, or (iii) relate to costs or allocations that have not previously been challenged and adjudicated by FERC. Information requests received will be posted at a publicly accessible location on SPP's internet website and a link to the website will be electronically served upon the Service List.

c. Transource Missouri shall make a good faith effort to respond to information requests pertaining to the Annual Update within ten (10) business days of receipt of such requests.

To the extent Transource Missouri and any Interested Person(s) are unable to resolve disputes related to information requests submitted in accordance with these Annual Review Procedures,

Transource Missouri or any Interested Person may petition the FERC to appoint an Administrative Law Judge as a discovery master to resolve the discovery dispute(s) in accordance with these Protocols and consistent with the FERC's discovery rules.

d. Preliminary Challenges, or Formal Challenges as described in Section 5 below, related to Accounting Changes shall be treated in the same manner under these Protocols as other challenges to the Annual Update. Failure to make a Preliminary Challenge with respect to an Accounting Change in an Annual Update shall not act as a bar with respect to a Formal Challenge with respect to that Annual Update, nor shall such failure bar a subsequent Preliminary Challenge related to a subsequent Annual Update to the extent such Accounting Change affects the subsequent Annual Update.

e. If a change made by Transource Missouri to its accounting policies, practices or procedures, or the application of the Formula Rate, is found by the FERC to be unjust, unreasonable, and/or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-up Adjustments, shall not include such change, but shall include any remedy that may be prescribed by FERC in the exercise of its discretion as of the effective date of such remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential.

**Section 5. Resolution of Challenges**

a. If Transource Missouri and any Interested Person have not resolved any Preliminary Challenge to the Annual Update within sixty (60) calendar days after the end of the Review Period (unless such period is extended with the written consent of Transource Missouri to continue efforts to resolve the Preliminary Challenge), such Interested Person may, within thirty (30) calendar days thereafter, file a challenge with the FERC, pursuant to 18 C.F.R. § 385.206 ("Formal Challenge"), which shall be served on Transource Missouri by electronic service on the date of such filing. Subject to any applicable confidentiality and Critical Energy Infrastructure Information restrictions, all information and correspondence produced by Transource Missouri pursuant to these Protocols may be included in any Formal Challenge or other FERC proceeding relating to the Formula Rate.

b. Any response by Transource Missouri to a Formal Challenge must be submitted to the FERC within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be

served on the filing party(ies) and the Service List by electronic service on the date of such filing.

c. In any proceeding concerning a given year's Annual Update (including corrections) or Accounting Change(s), Transource Missouri shall demonstrate the justness and reasonableness of the rate resulting from its application of the Formula Rate by demonstrating that it has reasonably and accurately calculated the Annual Update and/or reasonably adopted and applied the Accounting Change.

d. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Transource Missouri to file unilaterally, pursuant to Section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a Section 205 filing under these Protocols (including, but not limited to, ROE, depreciation and amortization rates, and PBOPs), or the right of any other party or the Commission to seek such changes pursuant to Section 206 of the FPA and the regulations thereunder.

e. Transource Missouri may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for amortization and depreciation rates, or PBOP rates. The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.

**Section 6. Changes to Annual Updates**

If Transource Missouri determines or concedes that corrections to the Annual Update are required, whether under Sections 4 or 5 of these Protocols, including but not limited to those requiring corrections to its FERC Form No. 1, or input data used for a Rate Year that would have affected the Annual Update for that Rate Year, Transource Missouri shall promptly notify the Service List, file a correction to the Annual Update with the FERC as an amended informational filing, and cause such information to be posted at a publicly accessible location on SPP's internet website. Such corrections shall be subject to review at the time they are made and shall be reflected in the next Annual Update, with interest. A corrected posting shall reset the deadlines under Section 4 and 5 of the Protocols for Interested Person review and the revised dates shall run from the posting date(s) for each of the corrections. The scope of review shall be limited to the aspects of the Formula Rate affected by the corrections. Interest on any over- or under-recovery due to corrections for preceding True-up Adjustments shall be calculated monthly on such over- or under-recovery from January 1 of

the corrected Rate Year through December 31 of the Rate Year in which such over- or under-recovery is reflected ("Correction Period"). That is equivalent to two years interest applied to over- or under- collection. The applicable monthly interest rates for the Correction Period for an over-recovery shall be determined in accordance with the Formula Rate true-up worksheet divided by twelve (12) for each month from the beginning of the Correction Period through December 31 of the Rate Year immediately preceding the Rate Year in which such over-recovery is reflected. The applicable monthly interest rates for the Correction Period for an under-recovery shall be the annual interest rate determined in accordance 18 C.F.R § 35.19a divided by twelve (12) for each month from the beginning of the Correction Period through December 31 of the Rate Year immediately preceding the Rate Year in which such under-recovery is reflected.

**Section 7. Construction Work in Progress**

a. *Accounting.* For each transmission project for which Transource Missouri has been authorized by a Commission order to include 100 percent of Construction Work in Progress ("CWIP") in transmission rate base ("CWIP Incentive Project"), Transource Missouri shall use the following accounting procedures to ensure that it does not recover an Allowance for Funds Used During Construction ("AFUDC") for such project.

(i) Transource Missouri shall assign each CWIP Incentive Project a unique Funding Project Number ("FPN") for internal cost tracking purposes.

(ii) Transource Missouri shall record actual construction costs to each FPN through work orders that are coded to correspond to the FPN for each CWIP Incentive project. Such work orders shall be segregated from work orders for transmission projects for which the Commission has not authorized Transource Missouri to include CWIP in rate base.

(iii) For each CWIP Incentive Project, Transource Missouri shall prepare monthly work order summaries of costs incurred under the associated FPN. These summaries shall show monthly additions to CWIP and plant in service and shall correspond to amounts recorded in Transource Missouri's FERC Form No. 1. Transource Missouri shall use these summaries as data inputs into the Annual Update calculated pursuant to Section 3. Transource Missouri shall make such work order summaries available upon request under the review procedures of Section 4.

(iv) When a CWIP Incentive Project, or portion thereof, is placed into service, Transource Missouri shall deduct from total CWIP the accumulated charges for work orders under the FPN for that project, or portion thereof. The purpose of this control process is to

ensure that expenditures are not double counted as both CWIP and as additions to plant.

(v) For transmission projects for which the Commission has not authorized Transource Missouri to include CWIP in rate base, Transource Missouri shall record AFUDC to be applied to CWIP and capitalized when the project is placed into service.

b. *Annual Reporting.* For each CWIP Incentive Project, Transource Missouri shall file a report with the Commission at the time of Transource Missouri's Annual Update that shall include the following information concerning each such project:

(i) the actual amount of CWIP recorded for each project;

(ii) any amounts recorded in related FERC accounts or subaccounts, such as AFUDC and regulatory liability;

(iii) the resulting effect of CWIP on the revenue requirement;

(iv) a statement of the current status of each project; and

(v) the estimated in-service date for each project.

# Addendum 22 to Attachment H
# Basin Electric Power Cooperative

## BASIN ELECTRIC POWER COOPERATIVE

**Descriptions - Schedules, Worksheets and Work Papers**

| | |
|---|---|
| **Schedule 1** | **Calculates ATRR based on either Projected or Actual Costs (including the True-Up Adjustment)** |
| **Schedule 2** | **Revenue Requirement by Project** |
| **Schedule 3** | **Calculation of Incentive ROE** |
| **Schedule 4** | **True-Up Adjustment with Interest** |
| **Schedule 5** | **Shows actual ATRR used as the baseline for making Projections** |
| **Schedule 6** | **Loads for Rate Divisor** |
| **Schedule 7** | **Depreciation Rates** |
| | |
| **Worksheets #1** | **List of Projected SPP Facilities** |
| **Worksheets #2** | **List of Facilities Currently in SPP** |
| **Worksheets #3** | **Load Dispatching / LSE** |
| **Worksheets #4** | **Summary of Annual Depreciation & Amortization Expense** |
| **Worksheets #5** | **Basin Electric Share of MBPP Costs; Calcuation of Percent Share MBPP Transmission** |
| **Worksheets #6** | **Regulatory Assets and Abandoned Plant** |
| **Worksheets #7** | **Construction Work in Progress (CWIP)** |
| **Worksheets #8** | **Tax Reclassification** |
| | |
| **Workpapers #1** | **SPP New Facilities** |
| **Workpapers #2** | **SPP Base Plan Upgrades (BPU) - New Facilities** |
| **Workpapers #3** | **MBPP New Facilities** |

**Workpapers #4** **RUS Form 12a Sections A & B and Calculation: LTD & Equity**

**Workpapers #5** **RUS Form 12h Sections A, B & H and Adjustment to Gross Plant and Accumulated Depreciation**

**Workpapers #6** RUS Form 12i Data, O&M Expense Detail and Annual Member Lease Expense
**Workpapers #7** Intangibles
**Workpapers #8** General Plant Detail
**Workpapers #9** Wages & Salaries
**Workpapers #10** Gross Receipts Tax, Revenue Credits and Working Capital
**Workpapers #11** Transmission Facilities - Detail
**Workpapers #12** MBPP Facilities
**Workpapers #13** Long Term Debt - Detail

# BASIN ELECTRIC POWER COOPERATIVE
## Formula Rate Template
## Schedule 1 - ATRR

**FOR RATES EFFECTIVE:** **Projected YE 20XX**



| Line No. | | Source | | | | Transmission Amount |
|---|---|---|---|---|---|---|
| 1 | Gross Revenue Requirement | Schedule 1 pg 2, ln 3 | | | | #DIV/0! |
| 2 | Revenue Credits | | | | | |
| 3 | Base Plan Upgrades (w/o incentives) | Schedule 2, sum of Base Plan Upgrades | | | | #VALUE! |
| 4 | Other transmission revenue | Schedule 4, pg 3, ln 7 | | | | - |
| 5 | Net Third Party Receipts / (Payments) | Workpaper #10 | $ - | DA 100 | 100.000 % | - |
| 6 | Total Revenue Credits | (Lines 2 + 3 + 4 + 5) | | | | #VALUE! |
| 7 | Zonal ATRR before true up | | | | | #DIV/0! |
| 8 | Zonal True-up applicable to forecast rate year | Schedule 4, pg 1, ln 1 | | | | #DIV/0! |

| | | | |
|---|---|---|---|
| 9 | **SPP Zonal Revenue Requirement** | **Line 1 - 6 - 8** | **#DIV/0!** |
| 10 | **Schedule 1 Revenue Requirement** | Worksheet #3 | **-** |

## BASIN ELECTRIC POWER COOPERATIVE
## Formula Rate Template
## Schedule 1 - ATRR

**FOR RATES EFFECTIVE:** **Projected YE 20XX**



| Line No. | | | Total Transmission | (1) Zone 19 (UMZ) Transmission | (2) MBPP Transmission | (3) Other Transmission |
|---|---|---|---|---|---|---|
| 1 | **BEPC GROSS REVENUE REQUIREMENT (page 4, line 27)** | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 1a | **Less: MBPP - Transmission West** | | | | #DIV/0! | |
| 2 | **BEPC REVENUE REQUIREMENT** | (line 1+ line 1a ) | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 3 | **BEPC SPP GROSS REVENUE REQUIREMENT** | (line 2 col (1) + line 2 col (2) | | **#DIV/0!** | | |

## BASIN ELECTRIC POWER COOPERATIVE
## FORMULA RATE TEMPLATE
## Schedule 1 - ATRR

**FOR RATES**

| | (1) | (2) | (3) | (4) | | (5) | (6) | | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Source | Total | Allocator A (Note O) | | Direct Assigned Transmission | Allocator B (Note O) | | Zone 19 (UMZ) Transmission | MBPP Transmission | Other Transmission |
| | **GROSS PLANT IN SERVICE (Note L)** | | | | | | | | | | |
| 1 | Production (Note A) | Work Paper #5 | - | | | - | | | - | - | - |
| 2 | Transmission (Note B) | Work Paper #5, #11 & Worksheet #1 | - | | | - | | | - | - | - |
| 3 | Distribution | Work Paper #5 | - | | NA | - | NA | | - | - | - |
| 4 | General & RTO/ISO Plant | Work Paper #5 | - | | | | | | | | |
| 4a | Direct Assign - Transmission (Note C) | Work Paper #8 | | | | - | | | - | - | - |
| 4b | Direct Assign - Production | Work Paper #8 | - | | NA | | NA | 0.000 % Gross Plant | - | - | - |
| 4c | Other | Work Paper #8 | - | WS1 | #DIV/0! | #DIV/0! | GP1 | | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Intangible | Work Paper #7 | - | WP7 | | - | | | - | - | - |
| 6 | **TOTAL GROSS PLANT** | (Sum lines 1, 2, 4, 5) | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **ACCUMULATED DEPRECIATION (Note L)** | | | | | | | | | | |
| 7 | Production | Work Paper #5 | - | | | - | | | - | - | - |
| | | Work Paper #5 | | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | Transmission | & Worksheet #1 | - | - | - | - | - | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | Distribution | Work Paper #5 | - | | | - | | NA | | - | - | - |
| 10 | General | Work Paper #5 | - | | | | | | | | | |
| 10a | Direct Assign - Transmission | Work Paper #8 | | | | - | | | | - | - | - |
| 10b | Direct Assign - Production | Work Paper #8 | - | | NA | | | NA | | - | - | - |
| 10c | Other | Work Paper #8 | - | WS1 | #DIV/0! | #DIV/0! | | GP1 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | Intangible | Work Paper #7 | - | WP7 | | - | | | | - | - | - |
| 12 | **TOTAL ACCUM. DEPR** | (Sum Lines 7, 8, 10, 11) | **$ -** | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **NET PLANT IN SERVICE** | | | | | | | | | | | |
| 13 | Production | (line 1- line 7) | - | | | - | | AUTO | | - | - | - |
| 14 | Transmission | (line 2- line 8) | - | | | - | | AUTO | | - | - | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - | | AUTO | | - | - | - |
| 16 | General | (line 4 - line 10) | - | | | - | | AUTO | | - | - | - |
| 16a | Direct Assign - Transmission | (line 4a - line 10a) | | | | - | | AUTO | | - | - | - |
| 16b | Direct Assign - Production | (line 4b - line 10b) | - | | NA | - | | | | - | - | - |
| 16c | Other | (line 4c - line 10c) | - | | | #DIV/0! | | AUTO | | #DIV/0! | #DIV/0! | #DIV/0! |
| 17 | Intangible | (line 5 - line 11) | - | | | - | | AUTO | | - | - | - |
| 18 | **TOTAL NET PLANT** | (Sum lines 13, 14, 15, 16, 17) | **$ -** | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |

**ADJUSTMENTS**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | CWIP (Note P) | Worksheet #7 | - | DA 100 | 100.000% | - | DA 100 | 100.00% | - | - | - | |
| 20 | Regulatory Asset (Note N) | Worksheet #6 | - | DA 100 | 100.000% | - | DA 100 | 100.00% | - | - | - | |
| 21 | Abandoned Plant (Note M) | | - | DA 100 | 100.000% | - | DA 100 | 100.00% | - | - | - | |
| 22 | | | | | | | | | | | | |
| 1a | **Total Adjustments** | (Sum lines 19, 20, 21) | **$ -** | | | **$ -** | | | **$ -** | **$ -** | **$ -** | |
| | **WORKING CAPITAL** | | | | | | | | | | | |
| 22 | CWC (Note D) | one eighth of page 4, line 9 less line 17b | - | AUTO | | #DIV/0! | AUTO | | #DIV/0! | #DIV/0! | #DIV/0! | |
| 23 | Materials & Supplies Transmission | Work Paper #10 | - | DA 100 | 100.000% | - | GP1 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! | |
| 24 | Prepayments (Note D) | Work Paper #4 | - | WS1 | #DIV/0! | #DIV/0! | GP1 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! | |
| 25 | **TOTAL WORKING CAPITAL** | (Sum lines 22, 23, 24) | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |
| 26 | **Rate Base** | | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |

**BASIN ELECTRIC POWER COOPERATIVE**
**FORMULA RATE TEMPLATE**
**Schedule 1 - ATRR**

**FOR RATES EFFECTIVE:** **Projected YE 20XX**

| n<br>e | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|---|

| No. | | Source | | Total | Allocator A | | Transmission | Allocator B | | Zone 19 (UMZ) Transmission | MBPP Transmission | Other Transmission |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **O&M** | | | | | | | | | | | |
| 1 | Transmission | Work Paper #6 | - | | | | | | | | | |
| 2 | Direct Assignment (Note E) | Work Paper #6 | | | 0 | | - | | | - | - | - |
| 2a | Less Account 561 and LSE related costs | Worksheet #3 | - | | | | - | GP2 | Gross Plant | #DIV/0! | - | #DIV/0! |
| 3 | Other | Line 1 minus line 2 & 2a | | | 0 | | - | GP2 | 100.000% | #DIV/0! | - | #DIV/0! |
| 4 | A&G | Worksheet #5 | - | | | | | | | | | |
| 4a | PBOP Expense (Note Q) | Worksheet #5 | - | | WS1 | #DIV/0! | #DIV/0! | GP2 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! |
| 4b | Authorized PBOP Expense (Note Q) | Worksheet #5 | - | | WS1 | #DIV/0! | #DIV/0! | GP2 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Regulatory Expense (Note F) | Worksheet #5 | | | | | - | DA 100 | 100.000% | - | - | - |
| 6 | Production | Worksheet #5 | | #DIV/0! | | | - | 0 | | - | - | - |
| 7 | Transmission (Note G) | Worksheet #5 | | | | | ~~#DIV/0!~~ | DA 100 | 100.000% | - | #DIV/0! | - |
| 8 | Headquarters | Worksheet #5 | | #DIV/0! | WS2 | #DIV/0! | #DIV/0! | GP2 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | **TOTAL O&M** | (Sum lines 1 and 4) | - | | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **DEPRECIATION & AMORTIZATION EXPENSE (Note L)** | | | | | | | | | | | |
| 10 | Depreciation and Amortization Expense | Worksheet #4 | - | | | | | | | | | |
| 11 | Transmission | Work Paper #11 & Worksheet #4 | | | | - | | DA 100 | 100.00% | - | - | - |
| 12 | Production | Worksheet #4 | - | | | | | | | - | - | - |
| 13 | General Plant | Work Paper 8 | - | | | - | | NA 0 | 0.000% | - | - | - |
| 14 | Transmission | Worksheet #4 | | | | - | | | | - | - | - |
| 15 | Production | Worksheet #4 | - | | - | - | | | | - | - | - |
| 16 | Hdqtrs General Plant | Worksheet #4 | - | WS1 | #DIV/0! | #DIV/0! | | GP1 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! |
| 17 | Intangible | Work Paper #7 | - | WP7 | | - | | DA 100 | 0.000% | - | - | - |
| 17a | Amortization of Abandoned Plant (Note M) | Worksheet #6 | | | | - | | | | - | - | - |
| 17b | Amortization of Regulatory Assets | Worksheet #6 | | | | - | | | | - | - | - |
| 18 | **TOTAL DEPRECIATION** | (Sum Lines 11, 12, 13, 17, 17a & 17b) | **$ -** | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **TAXES OTHER THAN INCOME TAXES** | | | | | | | | | | | |
| 19 | PLANT RELATED | | | | | | | | | | | |
| 20 | Property total | Work Paper #10 | - | | | | | | | | | |
| 22 | Tax | | | | | | | | 0.000% | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Reclassification | Worksheet #8 | - | | NA 0 | 0.000% | - | | NA 0 | % | - | - | - | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22 | Gross Receipts (Note I) | Work Paper #10 | - | DA 100 | 100.000% | - | DA 100 | 100.00% | - | - | - | |
| 23 | Production | | - | NA 0 | 0.000% | - | NA 0 | 0.000% | - | - | - | |
| 24 | **TOTAL OTHER TAXES** | (Sum Lines 21 - 23) | **$ -** | | | **$ -** | | | **$ -** | **$ -** | **$ -** | |
| 25 | **TOTAL OPERATING EXPENSES (Sum 9+18+24)** | | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |
| 26 | **Return** | Rate Base times Weighted Cost of Capital | **$ -** | WCC | Rate Base | **#DIV/0!** | WCC | Rate Base | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |
| 27 | **REV. REQUIREMENT (sum lines 25+26)** | | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |

## BASIN ELECTRIC POWER COOPERATIVE
## FORMULA RATE TEMPLATE
## Schedule 1 - ATRR

**FOR RATES EFFECTIVE:** **Projected YE 20XX** 

| **Line #** | **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | (4a) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|---|
| | **From Accounting Report** | | **TOTAL** | | **Percent** | | **Zone 19 (UMZ) Transmission** | **MBPP Transmission** | **Other Transmission** |
| 1 | Production | Work Paper #9 | - | | | | | | |
| 2 | Transmission-Shops/Warehouses | Work Paper #9 | - | Trans % | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Transmission-MBPP | Work Paper #9 | - | | **WS1** | of total wages | #DIV/0! | | GP 1 | #DIV/0 ! | #DIV/0 ! | #DIV/0 ! |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Transmission-Transmisssion System Maintenance (TSM) | Work Paper #9 | - | | | | | | | | | |
| 5 | Distribution | Work Paper #9 | - | | **WS2** | Trans % excluding MBPP | #DIV/0! | | Note H | GP 2 | #DIV/0! | 0.000 % | #DIV/0! |
| 6 | Other Transmission | Work Paper #9 | - | | | | | | | | | |
| 7 | Total Wages and Salaries (sum lines 1-6) (exclude adm) | | **$ -** | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 8 | | Notes J & K | **Estimated Weighted Cost of Capital** | | | | |
| 9 | | | | | **Percent** | **Rate** | **cost** |
| 10 | | Work Paper #4 (R21 / R72) | LTD | - | 63.70% | 0.00% | 0.00% |
| 11 | | Work Paper #4 (R26 / R77) | Equity | - | 36.30% | 10.10% | 3.67% |
| 12 | | | | - | 100.00% | | 3.67% |

Notes

A FERC Form No. 1 plus new investment EOY / BOY average.

B Transmission capital leases are excluded from transmission plant investment.
General Plant directly assigned to transmission includes

the transmission maintenance buildings and microwave

C assigned to transmission.

Cash working capital (CWC) assigned to transmission is one eighth of O&M allocated to transmission on
D Schedule 1, page 4 , line 9, columns 7-9.
Prepayments are the electric related prepayments booked to Account No. 165 and reported on the FERC Form No. 1, page 111, line 57.
Includes estimated lease payments for member facilities in the SPP system and O&M that is charged to specific
E lines or substations.
Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or
F transmission siting.
A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission G
based on MBPP gross plant investment.
MBPP plant investment on page 3, line 2, column 7 is excluded in the percentage calculations on page 5, GP2, columns 6-8 for
H A&G and transmission O&M allocation
as these are directly allocated to MBPP through the project billing.
SD Gross receipts taxes paid in lieu of property tax with a portion directly assigned to Common Use System
I (CUS).
Payroll taxes, property taxes and the North Dakota transmission line tax are included in Account 408.1
Equity and long term debt balances are from Work paper #4. Cost of long debt is long term interest divided by
J long term debt balance .
K ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by
L FERC.
M Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
N Recovery of Regulatory Asset permitted only for pre-commercial and formation expenses related to

projects and is subject to FERC approval before any Regulatory Asset amounts are included in rates.
Recovery of any other Regulatory Assets requires authorization from the Commission. A carrying

charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rates becoming effective.

O DA in the allocator Column means that the cost is directly assigned to transmission consistent with the attached workpapers.

P AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization

Q The dollar amount will be N/A absent specific FERC approval.

At which time, Basin Electric will add an additional worksheet showing the derivation of Postretirement Benefits Other Than Pensions (PBOP) expense/authorized PBOP expense.

**Basin Electric Power Cooperative**

**Formula Rate Template**

**Schedule 2: Revenue Requirement by Project**

**Projected YE 20XX**

**Schedule 2 Page 1 of 5**

| Line No | Description | Source | Total Transmission (3) |
|---|---|---|---|
| | (1) | (2) | |

| | | | |
|---|---|---|---|
| | Gross Transmission Plant - Total | Schedule 1, p 3, line 2 col (7) | - |
| 1a | Transmission Accumulated Depreciation | Schedule 1, p 3, line 8 col (7) | - |
| 1b | CWIP, Regulatory Assets, and Abandoned Plant | Schedule 1, p 3, line 21a col (7) | - |
| 2 | Net Transmission Plant - Total | Line 1 minus Line 1a | - |
| | O&M TRANSMISSION EXPENSE | | |
| | Total O&M Allocated to Transmis | Schedule 1, p 4, line 9 | # DIV/ |

3 sion col (7) 0!

| | | | |
|---|---|---|---|
| 3a | Transmission O&M | Schedule 1, p 4, line 1 col (7) | - |
| 3c | Less Account 565 (trans of elec by others) | Schedule 1, p 4, line 2b col (7) | #DIV/0! |
| 3e | Adjusted Transmission O&M | Line 3a minus Lines 3b thru 3d | #DIV/0! |
| 4 | **Annual Allocation Factor for Transmission O&M** | **(Line 3e divided by line 1, col 3)** | **0.00%** |
| | OTHER O&M EXPENSE | | |
| 4 | Other O&M Allocate | Line 3 minus | #DIV/ |

a d to Line 3e 0!

| | | | |
|---|---|---|---|
| 4b | Transmission Annual Allocation Factor for Other O&M | Line 4a divided by Line 1, col 3 | **0.00 %** |
| | GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE | | |
| 5 | Total G, I & C Depreciation Expense | Schedule 1, p 4, lines 14, 16 & 17, col (6) (Note A) | #DIV/0! |
| | Annual Allocation Factor for G&C Depreciation | (line 5 divided by line 1 | **0.00** |

| | | | | |
|---|---|---|---|---|
| 6 | Expense | | col 3) | **%** |

| | | | |
|---|---|---|---|
| | TAXES OTHER THAN INCOME TAXES | | |
| 7 | Total Other Taxes | Schedule 1, p 4, line 24 col (6) | - |
| 8 | Annual Allocation Factor for Other Taxes | (line 7 divided by line 1 col 3) | **0.00 %** |
| **9** | **Annual Allocation Factor for Other Expense** | **Sum of line 4b, 6, and 8** | **0.00 %** |
| | RETURN | | |
| 10 | Return on Rate Base | Schedule 1, p 4, line 26 col (6) | #DIV/0! |
| 11 | Annual Allocation | (line 10 | **0.00** |

| | | | |
|---|---|---|---|
| 1 | n Factor | divide | **%** |

| | | | |
|---|---|---|---|
| | for Return on Rate Base | d by line 2 col 3) | |
| | **Annual Allocation Factor for Return** | | |
| 1 | **for** | **Line** | **0.00** |
| 2 | **Return** | **11** | **%** |

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 2: Revenue Requirement by Project**
**Projected YE 20XX**

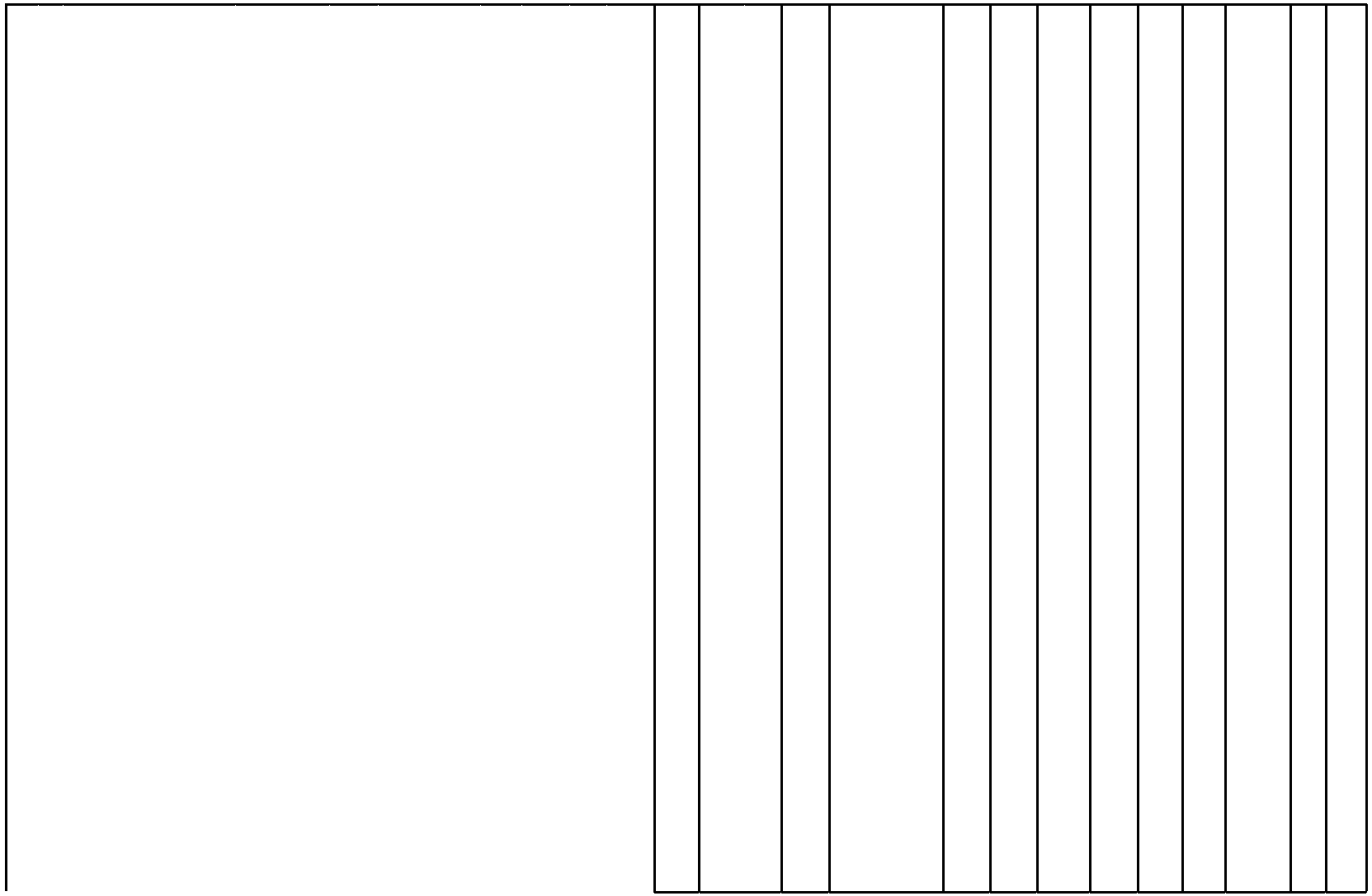
**Schedule 2 Page 2 of 5**

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 2: Revenue Requirement by Project**
**Projected YE 20XX**

**Schedule 2 Page 3 of 5**

| | (1) | | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (16a) | (17) | (18) | (19) | (20) | (21) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Project Name | UI | Type (Base Plan, Economic, etc) and Docket | Project Gross Plant | Project Accumulated Depreciation | Transmission O&M Annual Allocation Factors | Annual Allocation for Transmission O&M | Other Expenses Annual Allocation Factors | Annual Allocation for Other Expenses | Annual Allocation for Project Net Plant | Project Net Plant Carrying Charge | Annual Allocation for Project Net Plant | Annual Return Carrying Charge | Project Depreciation/Amortization | Annual Revenue Requirement | Incentive Return | Incentive Basis Point | Ceiling Rate | Competitive Bid Cost | Total Annual Revenue Requirement | True-Up Adjustment | Sch 11 TPR Credit | Net Rev Req |
| | | | | | | | | | | | | | | | | | | | | | | | |

**and ID # D # nt ation c e c e e t n ge Expense nt s rn e n t nt t t**



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A) 4 .5 9 .7 8 B) 2 1 n) 3 D) 10 6 e) 7 F) ) 0 u



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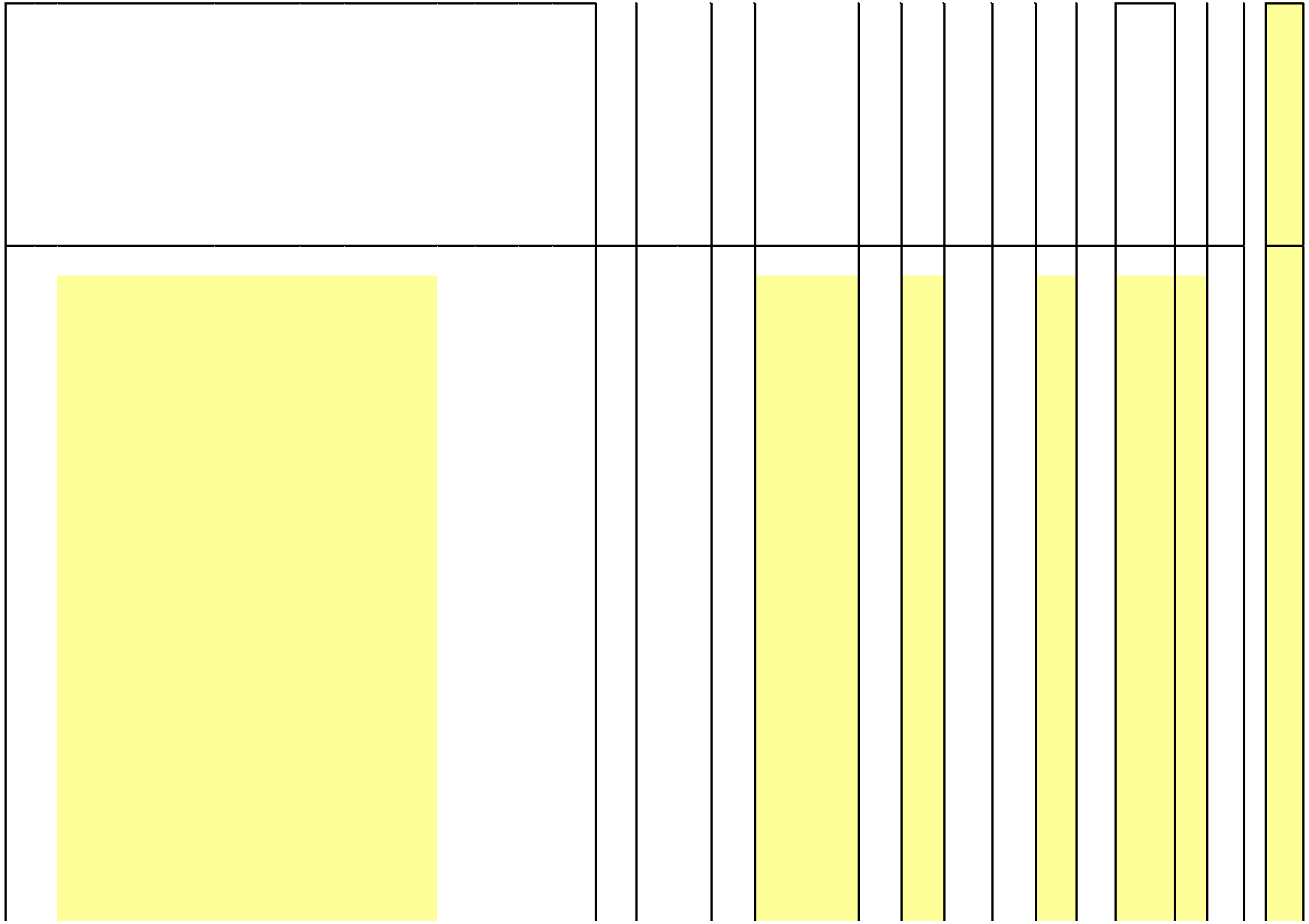

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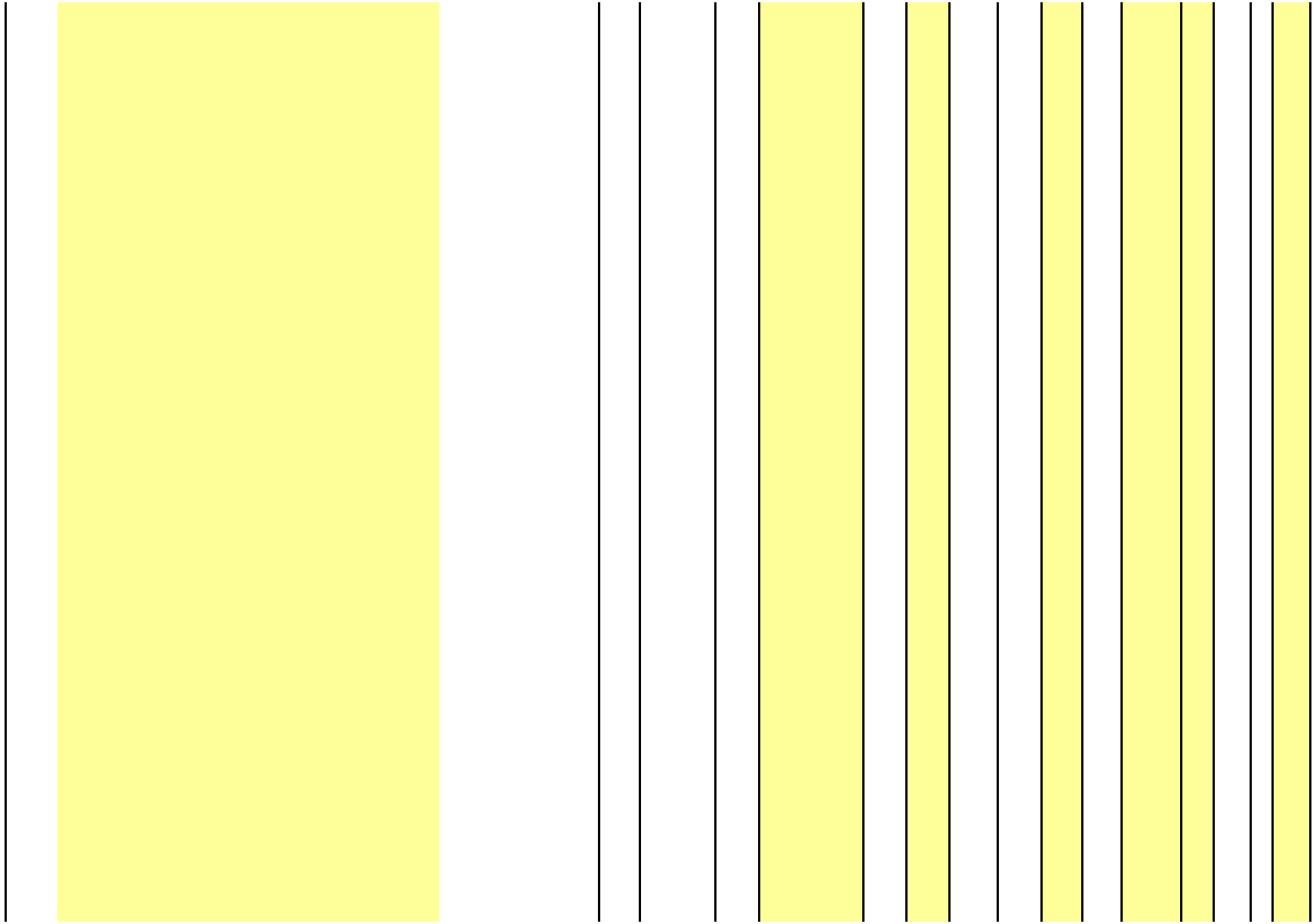

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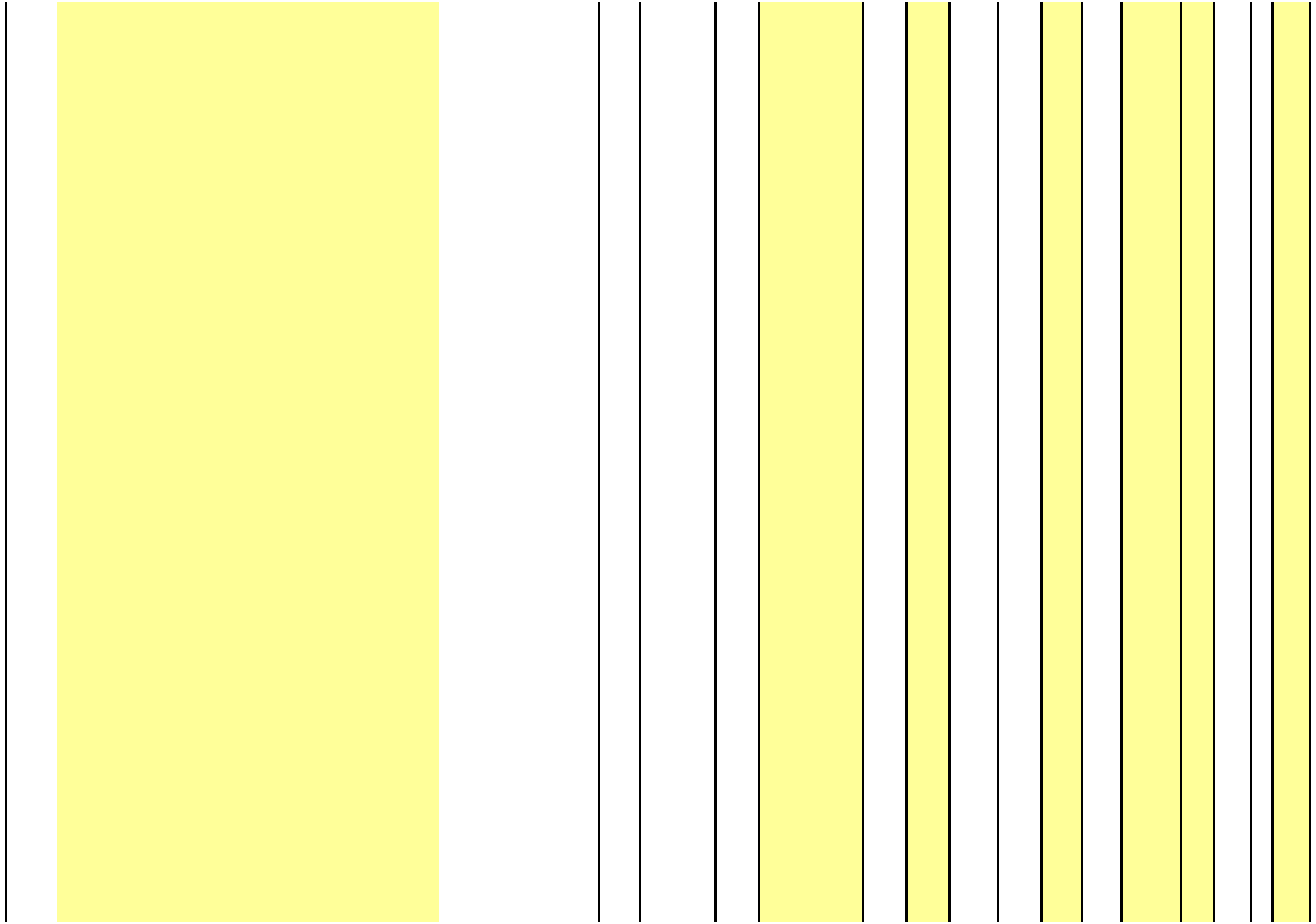
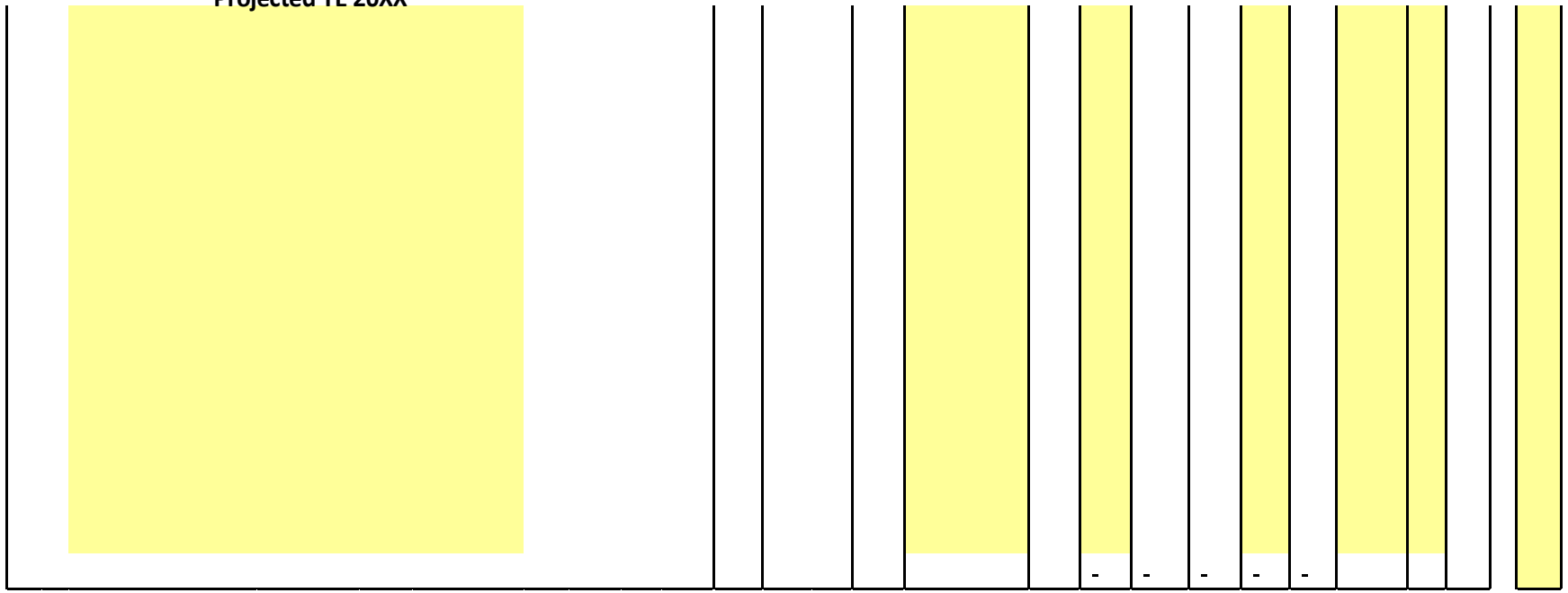


| | | |

**Schedule 2: Revenue Requirement by Project**

**Projected YE 20XX**



**Schedule 2 Page 4 of 5**

| Line No | Description | UID | 20XX | 20XX (4) | 20XX | 20XX (6) | 20XX (7) |
|---|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | | (5) | | |
| 1a | | | | | | | |
| 1b | | | | | | | |
| 1c | | | | | | | |

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**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 2: Revenue Requirement by Project**
**Projected YE 20XX**

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A Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in page 1, line 1 . This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

B Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation in page 2, column 4. Net Plant includes CWIP, Unamortized Abandoned Plant and any FERC approved Regulatory Asset.

C Project Depreciation Expense is the amount in Schedule 1, Page 4, line 11 that is associated with the specified project. Project Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved

Regulatory Asset.

However, if FERC

| | |
|---|---|
| | grants accelerated depreciation for a project the depreciation rate authorized by FERC will be used instead of the rates shown on Schedule 7 for all other projects. Requires approval by FERC of incentive return applicable to the specified |
| D | project(s) Competitive Bid Concession, if any, will reflect outcome of SPP competitive developer selection process and |
| E | will be computed on a workpaper that will be provided as supporting documentation for each Annual Update and will be zero or a reduction to the revenue requirement. |

Additionally, the value and form of the rate reduction will be

| | |
|---|---|
| | reflected in a project sponsor agreement between BEPC and SPP. |
| F | True-Up Adjustment is calculated on the Schedule 4 - Project True-Up Template |
| G | Prior Year Sch 11 Point-to-Point Revenue as detailed on Sch 4 - True-up is allocated on a prorata basis to all Base Plan Projects. |
| H | The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Schedule with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act |

section 205 or 206 filing,
except to reflect the
addition of new lines

and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 3 - Calculation of Incentive ROE**

Projected YE 20XX

**Schedule 3 Page 1 of 1**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | Rate Base | Schedule 1, page 3, line 26, Col. 6 | | | | | | #DIV/0! |
| 2 | 100 Basis Point Incentive Return | | | | | | $ | |
| | | | | $ | % | Cost | Weighted | |
| 3 | Long Term Debt | (Schedule 1, Page 5) | | - | 63.70% | 0.0000 | 0.0000 | |
| 4 | Common Stock | (Schedule 1, Page 5) | Cost = Schedule 1, Page 5, Cost plus .01 | - | 36.30% | 11.10% | 0.0403 | |
| 5 | Total (sum lines 3-4) | | | - | | | 0.0403 | |
| 6 | 100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 5) | | | | | | | #DIV/0! |
| 7 | Return (Schedule 1, Page 4, line 26, col. 6) | | | | | | | #DIV/0! |
| 8 | Incremental Return for 100 basis point increase in ROE | | | (Line 6 less line 7) | | | | #DIV/0! |

#D

9 Rate Base (line 1) IV/0!

| | | | |
|---|---|---|---|
| 10 | Incremental Return for 100 basis point increase in ROE divided by Rate Base | (Line 8 / line 9) | #DIV/0! |

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual incentive is calculated on Attachment 1 and must be approved by the Commission. For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 1.37 on Schedule 2 column 16.

**Basin Electric Power Cooperative**

**Formula Rate Template**

**Schedule 4 -**

**True-Up**

**Adjustment**

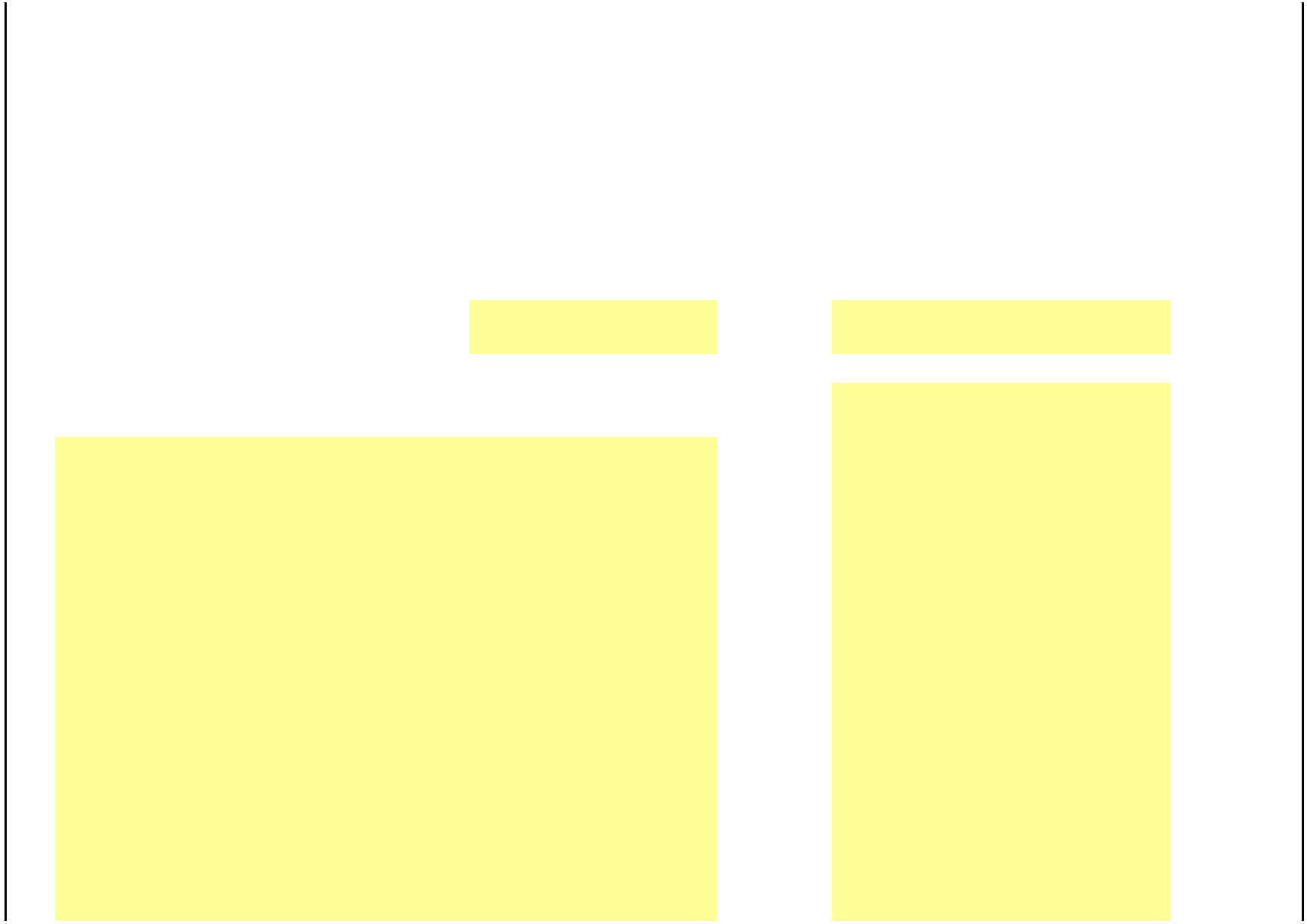
Projected YE 20XX



| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No | Project Name | UID | Actual Revenues Received From SPP | Revenue Requirement | True-Up Adjustment Principal Under/(Over) | Prior Period Adjustment (Note A) | Applicable Interest Rate on Under/(Over) | Date In Service | Number of Months in Service in Year | True-Up Adjustment Interest Under/(Over) | Total True-Up Adjustment 12/31/20XX |

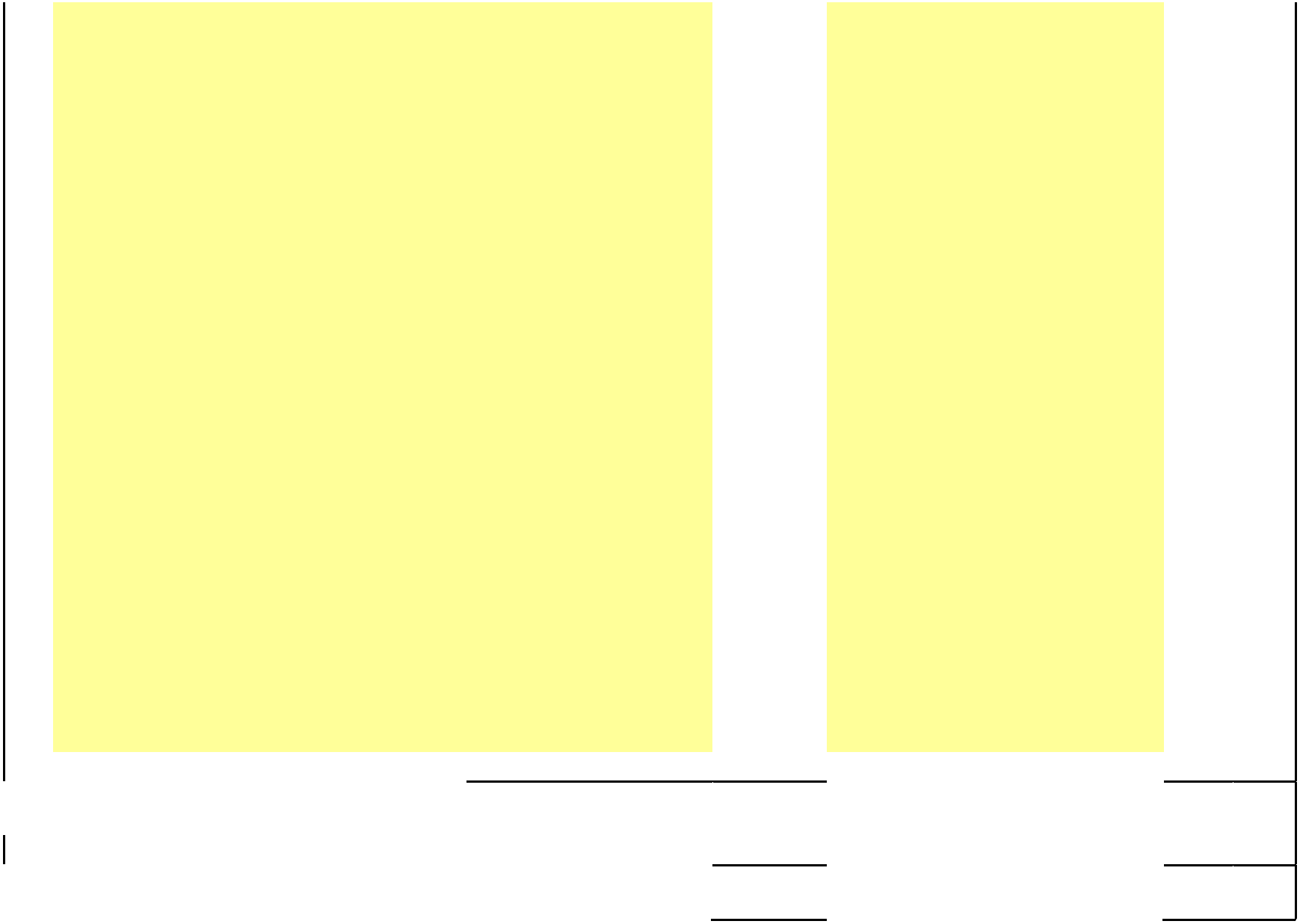
| | | Per Company book and records | Zonal ATRR from Sch 1 - actual/ Base Plan from Sch 2 - Actual **(Note A)** | Col. (e) - Col. (d) | Line 28x, Col. (e) | Line 26 | (Col. (f) + Col. (g)) xCol. (h) x ( 12 + Col. (i) ) | Col. (f) + Col. (g) + Col. (j) |
|---|---|---|---|---|---|---|---|---|
| 1 | **Zonal ATRR** | | | - | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 2 | **Base Plan Upgrade** | | | | | | | |
| 2.01 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.02 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.03 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.04 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.05 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.06 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.07 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.08 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.0 | | | | | | | | #N/ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | | #N/A | | #N/A | - | #DIV/0! | #N/A A |



| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2.10 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.11 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.12 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.13 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.14 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.15 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.16 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.17 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.18 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.19 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.20 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.21 | | #N/A | | #N/A | - | #DIV/0! | #N/A | #N/A |
| 2.22 | | | | | - | #DIV/0! | #DIV/0! | #DIV/0! |
| 2.23 | | | | | - | #DIV/0! | #DIV/0! | #N/A |
| 3 | Subtotal Base Plan Upgrades | #N/A | $0 | #N/A | | | #N/A | #N/A |

| | | | | |
|---|---|---|---|---|
| 4 | Total Under/(Over) Recovery | #N/A | /0! | V/0! |



Note A: Base Plan RR values from Schedule 2 Actuals.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 4 - True-Up Adjustment**
Projected YE
20XX



**FERC Refund Interest Rate**

| | | | Interest Rates under Section |
|---|---|---|---|
| 1 | Interest Rate (Note A): | Year | 35.19(a) |
| 2 | January | | |
| 3 | February | | |
| 4 | March | | |
| 5 | April | | |
| 6 | May | | |
| 7 | June | | |
| 8 | July | | |
| 9 | August | | |
| 10 | September | | |
| 11 | October | | |
| 12 | November | | |

13 December

14 January

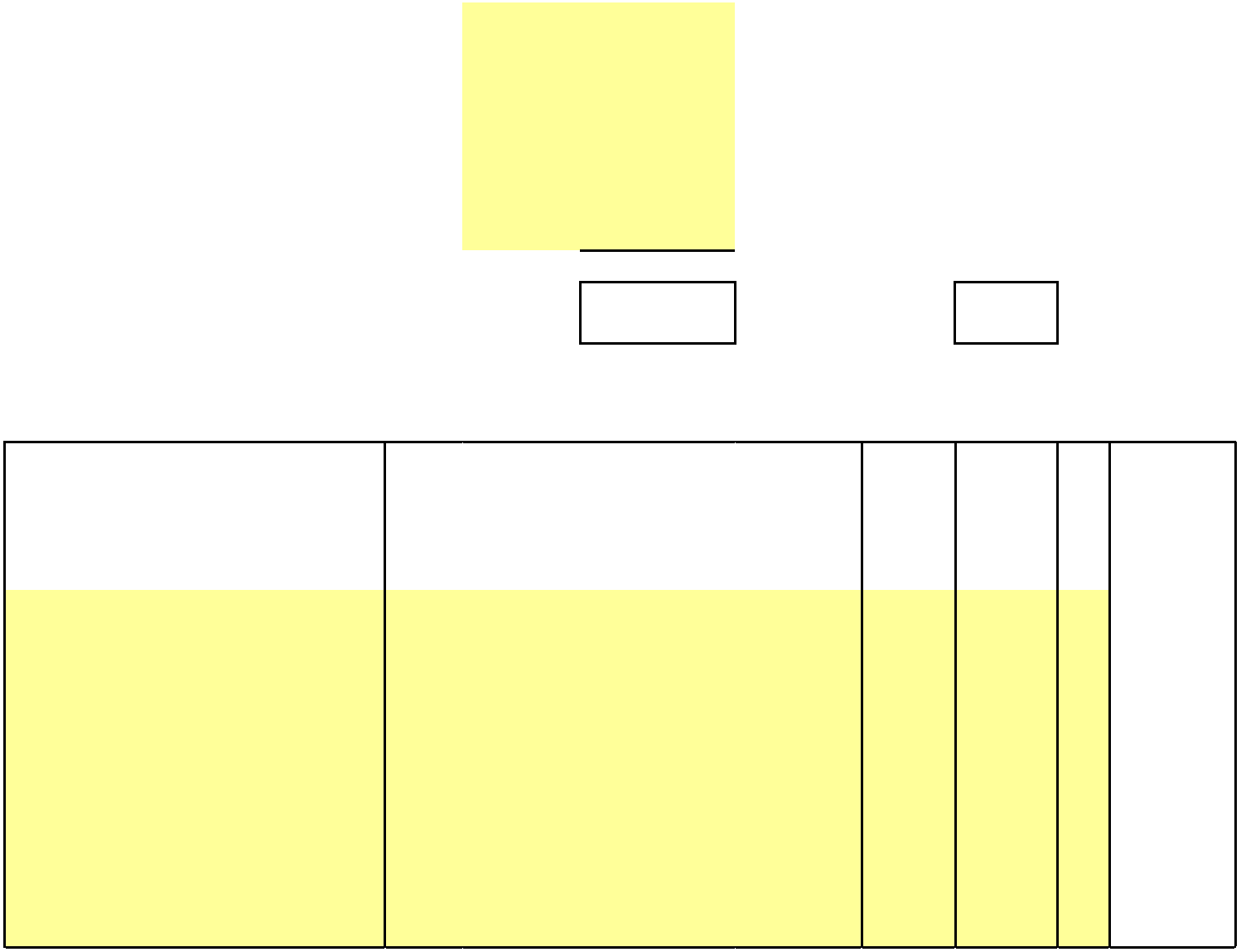
| | | |
|---|---|---|
| 15 | February | |
| 16 | March | |
| 17 | April | |
| 18 | May | |
| 19 | June | |
| 20 | July | |
| 21 | August | |
| 22 | September | |
| 23 | Avg. Monthly FERC Rate | **#DIV/0!** |

**#DIV/0!**

**Prior Period Adjustments**

| | (a) Project or Schedule 1 | (b) Adjustment A Description of the Adjustment | (c) Amount In Dollars | (d) Interest (Note A) | (e) Total Adjustment Col. (c) + Col. (d) |
|---|---|---|---|---|---|
| 24 | - | - | - | - | - |
| 24a | - | - | - | - | - |
| 24b | - | - | - | - | - |
| 24c | | | | | - |
| … | | | | | - |
| | | | | | - |

| | | |
|---|---|---|
| 25 | Total | - |



**Notes:**

A Prior Period Adjustments are when an error is discovered relating to a prior true-up or refunds/surcharges ordered by FERC. The interest on the Prior Period Adjustment excludes interest for the current true up period, because that interest is included in Rows 1-1x column (i).

B The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Schedule with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**

**Formula Rate Template**

**Schedule 4 - True-Up Adjustment**

Projected YE 20XX



2016 REVENUE CREDITS

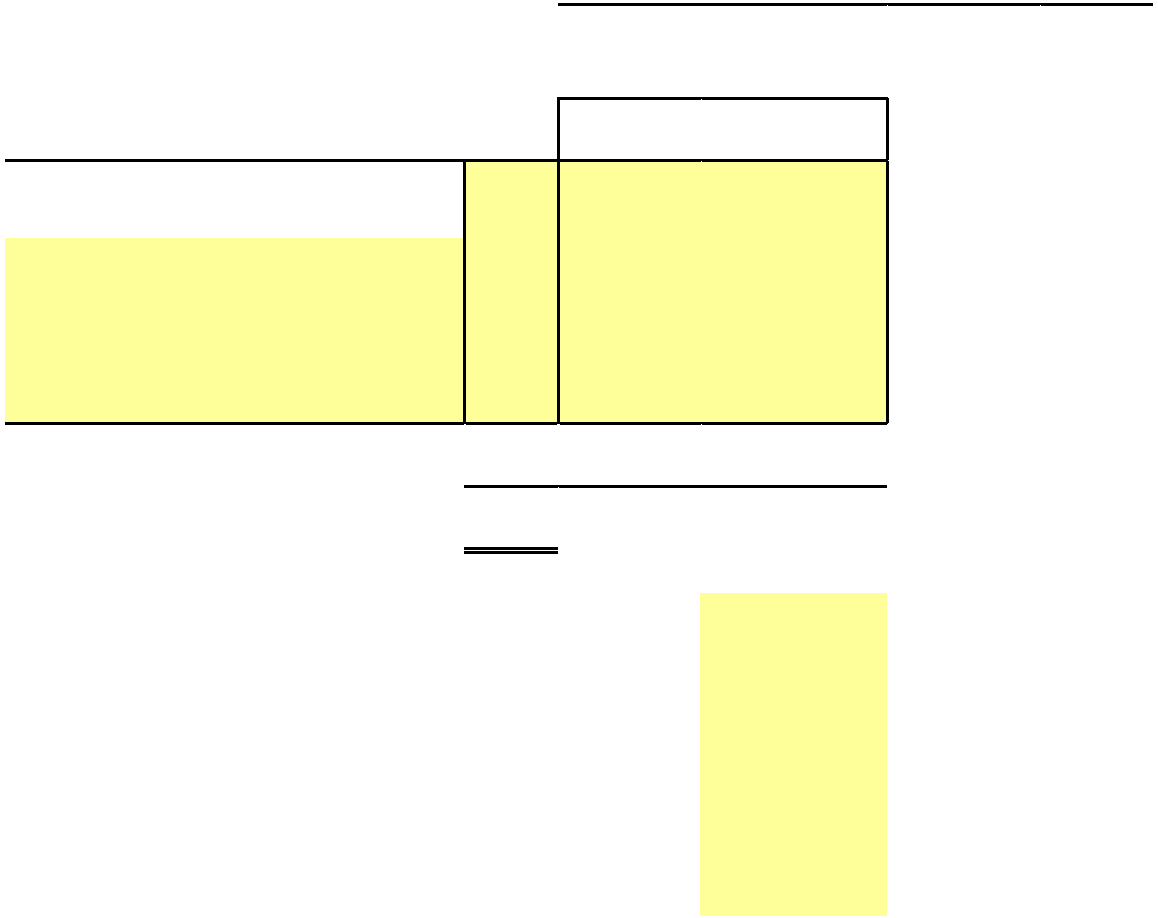
| Ln | A | B=C+D+E+F | C | D | E | F=G+H |
|---|---|---|---|---|---|---|
| 1 | Revenue - Rent From Electric Property | Revenue | Transmission | | General Plant | Other |
| 1a | 454000 - Total | - | | | | |
| 1b | 454100 - Distribution | - | | | | |
| 2 | Total | - | - | - | - | - |

| | | | Allocation Category | |
|---|---|---|---|---|
| 3 | Revenue - Other Electric Revenue | | Transmission Rev Credits | Other |
| 3a | 456.xxx: Sch 7 & 8 PTP | | | |
| 3b | 456.xxx: Sch 11 PTP | | | |
| 3c | Additional Items As Applicable | - | | |
| 3d | Additional Items As Applicable | - | | |
| 3e | Additional Items As Applicable | - | | |
| 4 | Total Acct 456 (Sum Ln 3 Subparts) | - | - | - |
| 5 | Total (Sum Ln 2 + Ln 4) | - | | |

| | | Projected 20XX for 20XX Rate Year | |
|---|---|---|---|
| | Less: | | |
| 6 | Schedule 11 PTP | $0 | Proated to each Base plan project on Sch 2, Col 20 |
| 7 | Other Transmission Revenue - Zonal ATRR Revenue Credit, Schedule 1 line 4 | $0 | |

| | |
|---|---|
| **Notes:** | A The addition of new lines and the removal of outdated lines necessary to populate or remove data in the Schedule with the changes in future years does not require a Federal Power Act section 205 |

or 206 filing. However, the addition or removal of columns and formulas contained within those



columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

# BASIN ELECTRIC POWER COOPERATIVE
## Formula Rate Template
## Schedule 5 - ATRR

**FOR RATES EFFECTIVE:** **Actual YE 20XX**



| Line No. | | Source | | | | Transmission Amount |
|---|---|---|---|---|---|---|
| 1 | Gross Revenue Requirement | Schedule 1 pg 2, ln 7 | | | | #DIV/0! |
| 2 | Revenue Credits | | | | | |
| 3 | Base Plan Upgrades (w/o incentives) | Schedule 2, sum of Base Plan Upgrades | | | | |
| 4 | Other tranmsmission revenue | Schedule 4, pg 3, ln 7 | | | | - |
| 5 | Net Thrird Party Receipts / (Payments) | Workpaper #10 | $ - | DA 100 | 100.000% | - |
| 6 | Total Revenue Credits | (Lines 2 -5) | | | | - |
| 7 | Zonal ATRR before true up | | | | | #DIV/0! |
| 8 | Zonal True-up applicable to forecast rate year | Schedule 4, pg 1, ln 1 | | | | - |
| 8 | Zonal True-up applicable to actual | True Up from applicable Rate | | | | |

a rate year Year formula

| | | | | |
|---|---|---|---|---|
| 9 | **SPP Zonal Revenue Requirement** | **Line 1 - 6 - 8** | **#DIV/0!** | **#DIV/0!** |

## BASIN ELECTRIC POWER COOPERATIVE
## Formula Rate Template
## Schedule 5 - ATRR

**FOR RATES EFFECTIVE:** **Actual YE 20XX**



| Line No. | | | | (1) Zone 19 (UMZ) Transmission | (2) MBPP Transmission | (3) Other Transmission |
|---|---|---|---|---|---|---|
| 1 | **BEPC GROSS REVENUE REQUIREMENT (page 4, line 27)** | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 1a | **Less: MBPP - Transmission West** | | | | #DIV/0! | |
| 2 | **BEPC REVENUE REQUIREMENT** | (line 1+ line 1a ) | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 3 | **BEPC SPP GROSS REVENUE REQUIREMENT** | (line 6 col (1) - line 6 col (2) | | **#DIV/0!** | | |

## BASIN ELECTRIC POWER COOPERATIVE
## FORMULA RATE TEMPLATE
## Schedule 5 - ATRR

**FOR RATES EFFECTIVE:** **Actual YE 20XX**



**Actual YE 20XX**

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) |
|---|---|---|---|---|---|---|---|---|

| | | Source | Total | Allocator A (Note O) | | Direct Assigned Transmission | Allocator B (Note O) | | Zone 19 (UMZ) Transmission | MBPP Transmission | Other Transmission |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **GROSS PLANT IN SERVICE (Note L)** | | | | | | | | | | |
| 1 | Production (Note A) | Work Paper #5 | - | | | - | | | - | - | - |
| 2 | Transmission (Note B) | Work Paper #5, #11 & Worksheet #1 | - | | | - | | | - | - | - |
| 3 | Distribution | Work Paper #5 | - | | NA | - | NA | | - | - | - |
| 4 | General & RTO/ISO Plant | Work Paper #5 | - | | | | | | | | |
| 4a | Direct Assign - Transmission (Note C) | Work Paper #8 | | | | - | | | - | - | - |
| 4b | Direct Assign - Production | Work Paper #8 | - | | NA | | NA | 0.000 % Gross Plant | - | - | - |
| 4c | Other | Work Paper #8 | - | WS 1 WP 7 | #DIV/0! | #DIV/0! | GP1 | | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Intangible | Work Paper #7 | - | | | - | | | - | - | - |
| 6 | **TOTAL GROSS PLANT** | (Sum lines 1, 2, 4, 5) | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **ACCUMULATED DEPRECIATION (Note L)** | | | | | | | | | | |
| 7 | Production | Work Paper #5 | - | | | - | | | - | - | - |
| 8 | Transmission | Work Paper #5 & Worksheet #1 | - | | | - | | | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 9 | Distribution | Work Paper #5 | - | - | NA | - | - | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | General | Work Paper #5 | - | | | | | | | - | - | - |
| 10a | Direct Assign - Transmission | Work Paper #8 | | | | - | | | | - | - | - |
| 10b | Direct Assign - Production | Work Paper #8 | - | | NA | | NA | | | - | - | - |
| 10c | Other | Work Paper #8 | - | WS 1 WP 7 | #DIV/0! | #DIV/0! | GP1 | Gross Plant | | #DIV/0! | #DIV/0! | #DIV/0! |
| 11 | Intangible | Work Paper #7 | - | | | - | | | | - | - | - |
| 12 | **TOTAL ACCUM. DEPR** | (Sum Lines 7, 8, 10, 11) | **$ -** | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **NET PLANT IN SERVICE** | | | | | | | | | | | |
| 13 | Production | (line 1- line 7) | - | | | - | AUTO | | | - | - | - |
| 14 | Transmission | (line 2- line 8) | - | | | - | AUTO | | | - | - | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - | AUTO | | | - | - | - |
| 16 | General | (line 4 - line 10) | - | | | - | AUTO | | | - | - | - |
| 16a | Direct Assign - Transmission | (line 4a - line 10a) | | | | - | AUTO | | | - | - | - |
| 16b | Direct Assign - Production | (line 4b - line 10b) | - | | NA | - | | | | - | - | - |
| 16c | Other | (line 4c - line 10c) | - | | | #DIV/0! | AUTO | | | #DIV/0! | #DIV/0! | #DIV/0! |
| 17 | Intangible | (line 5 - line 11) | - | | | - | AUTO | | | - | - | - |
| 18 | **TOTAL NET PLANT** | (Sum lines 13, 14, 15, 16, 17) | **$ -** | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **ADJUSTMENTS** | | | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19 | CWIP (Note P) | Worksheet #7 | - | DA 100 | 100.000% | - | DA 100 | 100.00 0% | - | - | - | |
| 20 | Regulatory Asset (Note N) | Worksheet #6 | - | DA 100 | 100.000% | - | DA 100 | 100.00 0% | - | - | - | |
| 21 | Abandoned Plant (Note M) | | - | DA 100 | 100.000% | - | DA 100 | 100.00 0% | - | - | - | |
| 22 | | | | | | | | | | | | |
| 1a | **Total Adjustments** | (Sum lines 19, 20, 21) | **$ -** | | | **$ -** | | | **$ -** | **$ -** | **$ -** | |
| | **WORKING CAPITAL** | | | | | | | | | | | |
| 22 | CWC (Note D) | one eighth of page 4, line 9 less line 17b | - | AUTO | | #DIV/0! | AUTO | | #DIV/0! | #DIV/0! | #DIV/0! | |
| 23 | Materials & Supplies Transmission | Work Paper #10 | - | DA 100 | 100.000% | - | GP1 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! | |
| 24 | Prepayments (Note D) | Work Paper #4 | - | WS 1 | #DIV/0! | #DIV/0! | GP1 | Gross Plant | #DIV/0! | #DIV/0! | #DIV/0! | |
| 25 | **TOTAL WORKING CAPITAL** | (Sum lines 22, 23, 24) | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |
| 26 | **Rate Base** | | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | |

**BASIN ELECTRIC POWER COOPERATIVE**
**FORMULA RATE TEMPLATE**
**Schedule 5 - ATRR**

**FOR RATES EFFECTIVE:** **Actual YE 20XX**

| Line No. | (1) | (2) Source | (3) Total | (4) Allocator A | | (5) Transmission | (6) Allocator B | | (7) Zone 19 (UMZ) Transmission | (8) MBPP Transmission | (9) Other Transmission |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **O&M** | | | | | | | | | | |
| 1 | Transmission | Work Paper #6 | - | | | | | | | | |
| 2 | Direct Assignment (Note E) | Work Paper #6 | | 0 | | - | | | - | - | - |
| 2a | Less Account 561 and LSE related costs | Worksheet #3 | - | | | - | GP2 | Gross Plant 100.000% | #DIV/0! | - | #DIV/0! |
| 3 | Other | Line 1 minus line 2 & 2a | | 0 | | - | GP2 | Gross Plant 100.000% | #DIV/0! | - | #DIV/0! |
| 4 | A&G | Worksheet #5 | - | | | | | | | | |
| 4a | PBOP Expense (Note Q) | Worksheet #5 | - | WS 1 | #DIV/0! | #DIV/0! | GP2 | Gross Plant 100.000% | #DIV/0! | #DIV/0! | #DIV/0! |
| 4b | Authorized PBOP Expense (Note Q) | Worksheet #5 | - | WS 1 | #DIV/0! | #DIV/0! | GP2 | Gross Plant 100.000% | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Regulatory Expense (Note F) | Worksheet #5 | | | | - | DA 100 | 0% | - | - | - |
| 6 | Production | Worksheet #5 | #DIV/0! | | | - | 0 | | - | - | - |
| 7 | Transmission (Note G) | Worksheet #5 | | | | **#DIV/0!** | DA 100 | 100.000% | - | #DIV/0! | - |
| | | | | W | | | | Gross | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 8 | Headquarters | Worksheet #5 | #DIV/0! | S 2 | #DIV/0! | #DIV/0! | GP2 | Pla nt | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | **TOTAL O&M** | (Sum lines 1 and 4) | **-** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **DEPRECIATION & AMORTIZATION EXPENSE (Note L)** | | | | | | | | | | | |
| 10 | Depreciation and Amortization Expense | Worksheet #4 | **-** | | | | | | | | | |
| 11 | Transmission | Work Paper #11 & Worksheet #4 | | | | **-** | | DA 100 | 100.00 0% | - | - | - |
| 12 | Production | Worksheet #4 | **-** | | | | | | | - | - | - |
| 13 | General Plant | Work Paper 8 | **-** | | | - | | NA 0 | 0.000 % | - | - | - |
| 14 | Transmission | Worksheet #4 | | | | **-** | | | | - | - | - |
| 15 | Production | Worksheet #4 | **-** | | - | - | | | | - | - | - |
| 16 | Hdqtrs General Plant | Worksheet #4 | **-** | WS 1 | #DIV/0! | #DIV/0! | | GP1 | Gross Plant 0.000 % | #DIV/0! | #DIV/0! | #DIV/0! |
| 17 | Intangible | Work Paper #7 | **-** | WP 7 | | **-** | | DA 100 | | - | - | - |
| 17a | Amortization of Abandoned Plant (Note M) | Worksheet #6 | | | | **-** | | | | - | - | - |
| 17b | Amortization of Regulatory Assets | Worksheet #6 | | | | **-** | | | | - | - | - |
| 18 | **TOTAL DEPRECIATION** | (Sum Lines 11, 12, 13, 17, 17a & 17b) | **$ -** | | | **#DIV/0!** | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | **TAXES OTHER THAN INCOME TAXES** | | | | | | | | | | | |
| 19 | PLANT RELATED | | | | | | | | | | | |
| 20 | | Work Paper | | | | | | | | | | |

| | | | |
|---|---|---|---|
| 0 | Property total | #10 | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21 | Tax Reclassification | Worksheet #8 | - | | NA 0 | 0.000% | - | | NA 0 | 0.000% | - | - | - |
| 22 | Gross Receipts (Note I) | Work Paper #10 | - | | DA 100 | 100.000% | - | | DA 100 | 100.000% | - | - | - |
| 23 | Production | | - | | NA 0 | 0.000% | - | | NA 0 | 0.000% | - | - | - |
| 24 | **TOTAL OTHER TAXES** | (Sum Lines 21 - 23) | **$ -** | | | | **$ -** | | | | **$ -** | **$ -** | **$ -** |
| 25 | **TOTAL OPERATING EXPENSES (Sum 9+18+24)** | | **$ -** | | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 26 | **Return** | Rate Base times Weighted Cost of Capital | | **#DIV/0!** | WCC | Rate Base | **#DIV/0!** | | WCC | Rate Base | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 27 | **REV. REQUIREMENT (sum lines 25+26)** | | | **#DIV/0!** | | | **#DIV/0!** | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |

## BASIN ELECTRIC POWER COOPERATIVE
## FORMULA RATE TEMPLATE
## Schedule 5 - ATRR

**FOR RATES EFFECTIVE:** **Actual YE 20XX**



| **Line #** | **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | (4a) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|---|
| | **From Accounting Report** | | **TOTAL** | | **Percent** | | **Zone 19 (UMZ) Transmission** | **MBPP Transmission** | **Other Transmission** |

| | | | |
|---|---|---|---|
| 1 | Production | Work Paper #9 | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Transmission-Shops/Warehouses | Work Paper #9 | - | | | | | | | | | |
| 3 | Transmission-MBPP | Work Paper #9 | - | **WS 1** | Trans % of total wages | #DIV/0! | | | GP 1 | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | Transmission-Transmisssion System Maintenance (TSM) | Work Paper #9 | - | | | | | | | | | |
| 5 | Distribution | Work Paper #9 | - | **WS 2** | Trans % excluding MBPP | #DIV/0! | | Note H | GP 2 | #DIV/0! | 0.000 % | #DIV/0! |
| 6 | Other Transmission | Work Paper #9 | - | | | | | | | | | |
| 7 | Total Wages and Salaries (sum lines 1-6) (exclude adm) | | **$ -** | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 8 | | Notes J & K | **Estimated Weighted Cost of Capital** | | | | |
| 9 | | | | | **Percent** | **Rate #** | **cost** |
| 10 | | Work Paper #4 (R21) | LTD | - | 63.70% | #DIV/0! | #DIV/0! |
| 11 | | Work Paper #4 (R26) | Equity | - | 36.30% | 10.10% | 3.67% |
| 12 | | | | - | 100.00% | | #DIV/0! |

Notes

FERC Form No. 1 plus new

A investment EOY / BOY average.

B Transmission capital leases are excluded from transmission plant investment.

C General Plant directly assigned to transmission includes the transmission maintenance buildings and microwave assigned to transmission.

D Cash working capital (CWC) assigned to transmission is one eighth of O&M allocated to transmission on Schedule 5, page 4 , line 9, columns 7-9.

Prepayments are the electric related prepayments booked to Account No. 165 and reported on the FERC Form No. 1, page 111, line 57.

E Includes estimated lease payments for member facilities in the SPP system and O&M that is charged to specific lines or substations.

F Line 5 - Regulatory Commission expenses directly related to transmission service, ISO filings, or transmission siting.

G A&G costs directly allocated to MBPP - Costs split between MBPP Production and MBPP Transmission based on MBPP gross plant investment.

H MBPP plant investment on page 3, line 2, column 7 is excluded in the percentage calculations on page 5, GP2, columns 6-8 for A&G and transmission O&M allocation as these are directly allocated to MBPP through the project billing.

I SD Gross receipts taxes paid in lieu of property tax with a portion directly assigned to Common Use System (CUS).

Payroll taxes, property taxes and the North Dakota transmission line tax are included in Account 408.1

J Equity and long term debt balances are from Work paper #4. Cost of long debt is long term interest divided by long term debt balance .

K ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.

L Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

M Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the

Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.

N Recovery of Regulatory Asset permitted only for pre-commercial and formation expenses related to projects and is subject to FERC approval before any Regulatory Asset amounts are included in rates. Recovery of any other Regulatory Assets requires authorization from the Commission. A carrying charge equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rates becoming effective.

O DA in the allocator Column means that the cost is directly assigned to transmission consistent with the attached workpapers.

P AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization

Q The dollar amount will be N/A absent specific FERC approval. At which time, Basin Electric will add an additional worksheet showing the derivation of Postretirement Benefits Other Than Pensions (PBOP) expense/authorized PBOP expense.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 6 - Transmission System Load, Adjusted**

FOR CALENDAR YEAR: **Projected YE 20XX**

Units: MW

**Schedule 6**
**Page 1 of 1**

| System Peak | Jan | Feb | Mar | Apr | May | Jun | July | Aug | Sept | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Day | | | | | | | | | | | | |
| Hour | | | | | | | | | | | | |
| **Total Network Load** | | | | | | | | | | | | |
| **Total L-T Firm Contracts** | | | | | | | | | | | | |
| **Less Short Term Firm and Non-Firm Loads Transmission System Rate Divisor (MW)** | - | - | - | - | - | - | - | - | - | - | - | - |
| (l 1 + l 2 - l 3) | | | | | | | | | | | | |

(average of Line 4)

**12 Coincident Peak ("CP") Average:** -

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Schedule 7 - Depreciation Rates**



**DEPRECIATION RATES FOR TRANSMISSION, GENERAL AND INTANGIBLE PLANT**

| Acct. No. | | Depreciation Rate (Note A) |
|---|---|---|
| **INTANGIBLES** | | |
| 303 | Intangible | 2.75% |
| **TRANSMISSION PLANT** | | |
| 352 | Structures & Improvements | 1.680% |
| 353 | Station Equipment | 1.680% |
| 354 | Towers & Fixtures | 1.680% |
| 355 | Poles & Fixtures | 1.680% |
| 356 | Overhead Conductors | 1.680% |
| 357 | Underground Conduit | 1.680% |
| 358 | Underground Conductors | 1.680% |
| 359 | Roads & Trails | 1.680% |
| **GENERAL PLANT** | | |
| 390 | Structures & Improvements | 5.00% |
| 391 | Office Furniture, Equipment | 7.00% |
| 392 | Transportation Equipment | 25.00% |
| 393 | Store Equipment | 5.00% |

| | | |
|---|---|---|
| 394 | Tool, Shop, Garage Equipment | 5.00% |
| 395 | Laboratory Equipment | 5.00% |

| | | |
|---|---|---|
| 396 | Power Operated Equipment | 10.00% |
| 397 | Communication Equipment | 5.00% |
| 398 | Miscellaneous | 5.00% |

**Notes:**

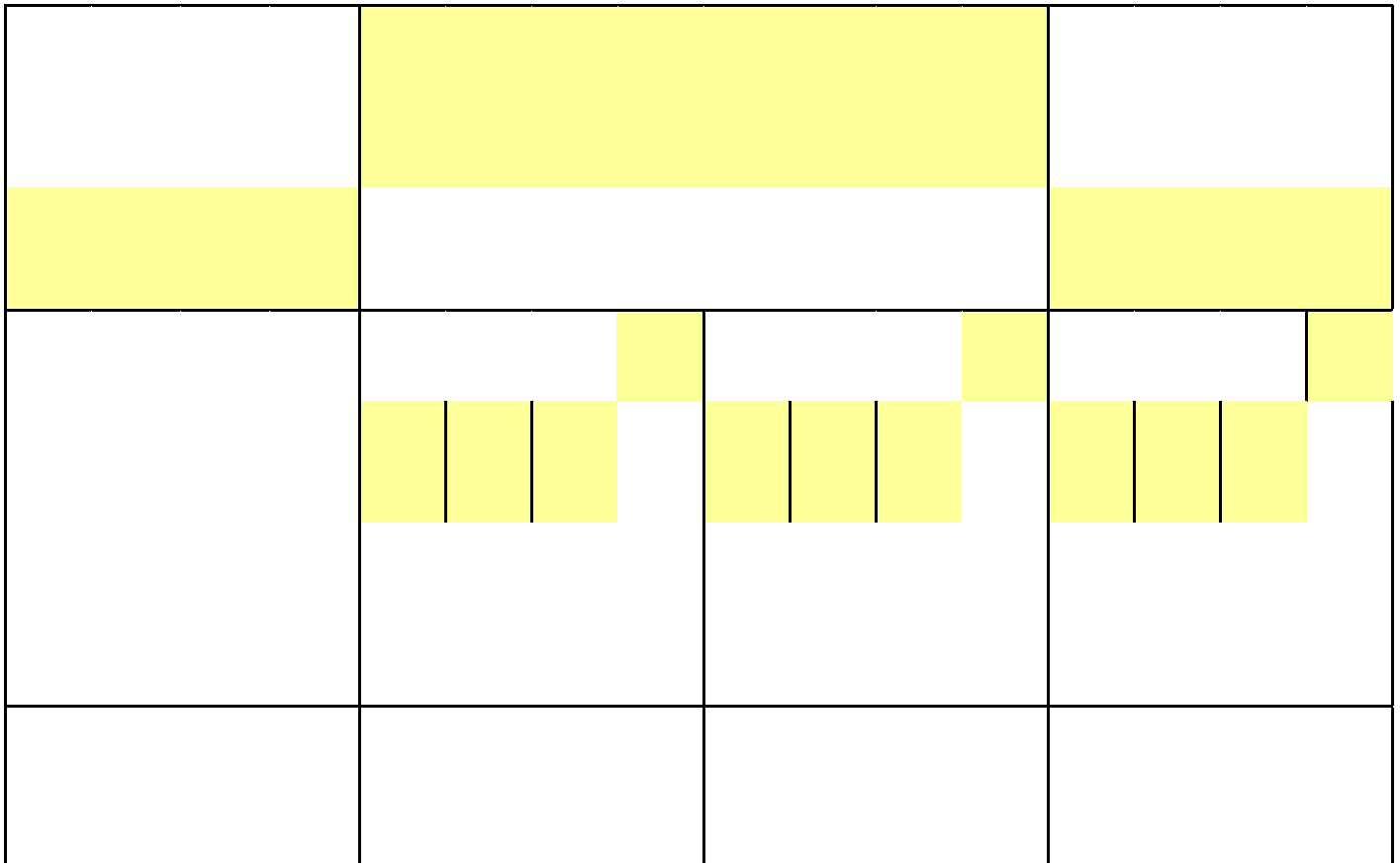
A These rates are fixed and cannot be changed absent a 205 or 206 filing with FERC.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Southwest Power Pool (SPP) Facilities**
**Worksheet #1 - FERC Account 350 - 356 Existing & New Projects (Gross Plant - Transmission)**



| | Assumed for SPP Rate Calcs | CAPX | BOY / EOY Ave. (Actuals - YE 12/31/20XX & YE 12/31/20XX) | | | | Updated Estimated 20XX | | | | Estimated 20XX | | | | BOY / EOY Ave. (20XX Estimate & 20XX Estimate) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Depreciation | 12/31/XX | 12/31/XX | 12/31/XX | 20XX Depreciation | 12/31/XX | 12/31/XX | 12/31/XX | 20XX Depreciation | 20XX/20XX | 20XX/20XX | 20XX/20XX | 20XX/20XX Depreciation |
| **FERC Account 350 - 356 Gross Plant Transmission** | | | Gross Plant | Accum Depr | Net Book Value | Expense | Gross Plant | Accum Depr | Net Book Value | Expense | Gross Plant | Accum Depr | Net Book Value | Expense | Gross Plant | Accum Depr | Net Book Value | Expense |
| **Lines** | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

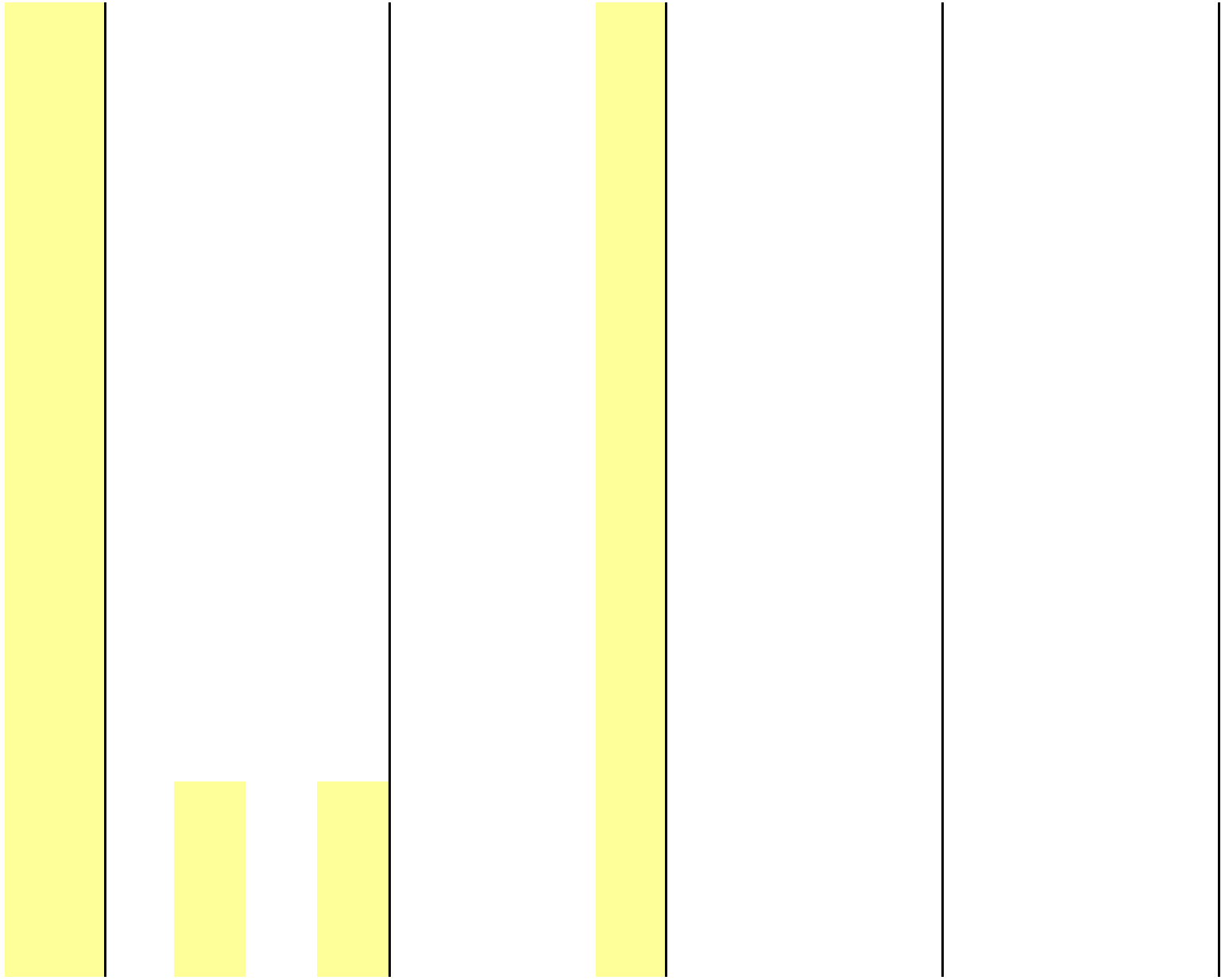
**Substations** - - - - - - - - - - - - - - - -



| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Subtotal** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Transmission Maintenance Buildings** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Microwave** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Existing SPP (Lines, Subs, TSM & Microwave)** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **New Gross Plant Transmission (BPU & Other)** | | | | | | | | | | | | | | | | |
| **Base Plan Upgrades (BPU)** | | | | | | | - | | | | | | | | | |
| | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - |
| | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - |
| **New Projects (Other Than BPU)** | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - |
| | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| James Rive Valley Flood Protection | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| TSM Shop Upgrade/Repl acements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Tongue River Sub Reactor Addition | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Line Easement LOS/Thomps on/Crow | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Watertown 345kV Equip Upgrades | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| LOS - Ft. Thompson Line Restore | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Broadland Sub 345kV Equip Upgrades | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| AVS - Broadland Line Equipment Upgrade | - | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Great Plains Sub Transformer Replacement | - | | | | - | - | - | - | - | - | - | - | - | - | - | - |
| Lonesome Creek Station- Clutch (RUS 350-356) | - | | - | | - | - | - | - | - | - | - | - | - | - | - | - |
| Pioneer Gen Station - Clutch (RUS | | | | | | | | | | | | | | | | |

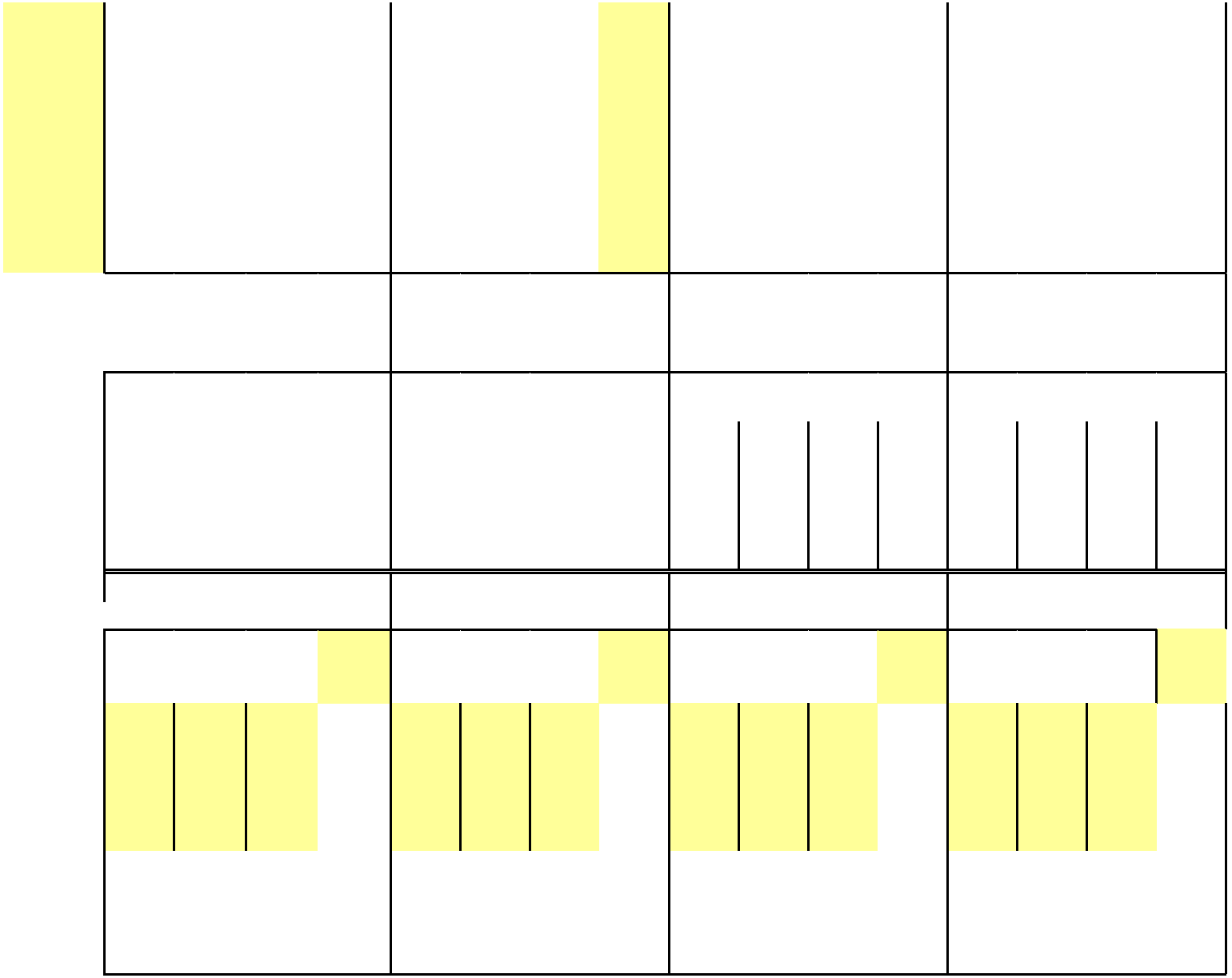
350-356) - - - - - - - - - - - - - -



| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Miles City - Baker 230kV Structure Replacement | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Dickinson Sub Service Feed | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - |
| | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - |
| **Subtotal New Projects Lines & Substation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | | | | | | - | | | | | | | | | | |
| **Grand Total - Gross Plant Transmission (FERC Account 350 - 356)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

| **MBPP Gross Plant Transmission - FERC Account 350 - 356** | **YE 20XX & 20XX Gross Plan** | **YE 20XX & 20XX Accum** | **YE 20XX & 20XX Net Book Valu** | **20XX Depreciation Exp** | **12/31/XX Gross Plan** | **12/31/XX Accum Dep** | **12/31/XX Net Book Valu** | **20XX Depreciation Expens** | **12/31/XX Gross Plan** | **12/31/XX Accum Dep** | **12/31/XX Net Book Valu** | **20XX Depreciation Expens** | **20XX/20XX Gross Plan** | **20XX/20XX Accum Dep** | **20XX/20XX Net Book Valu** | **20XX/20XX Depreciation Expens** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

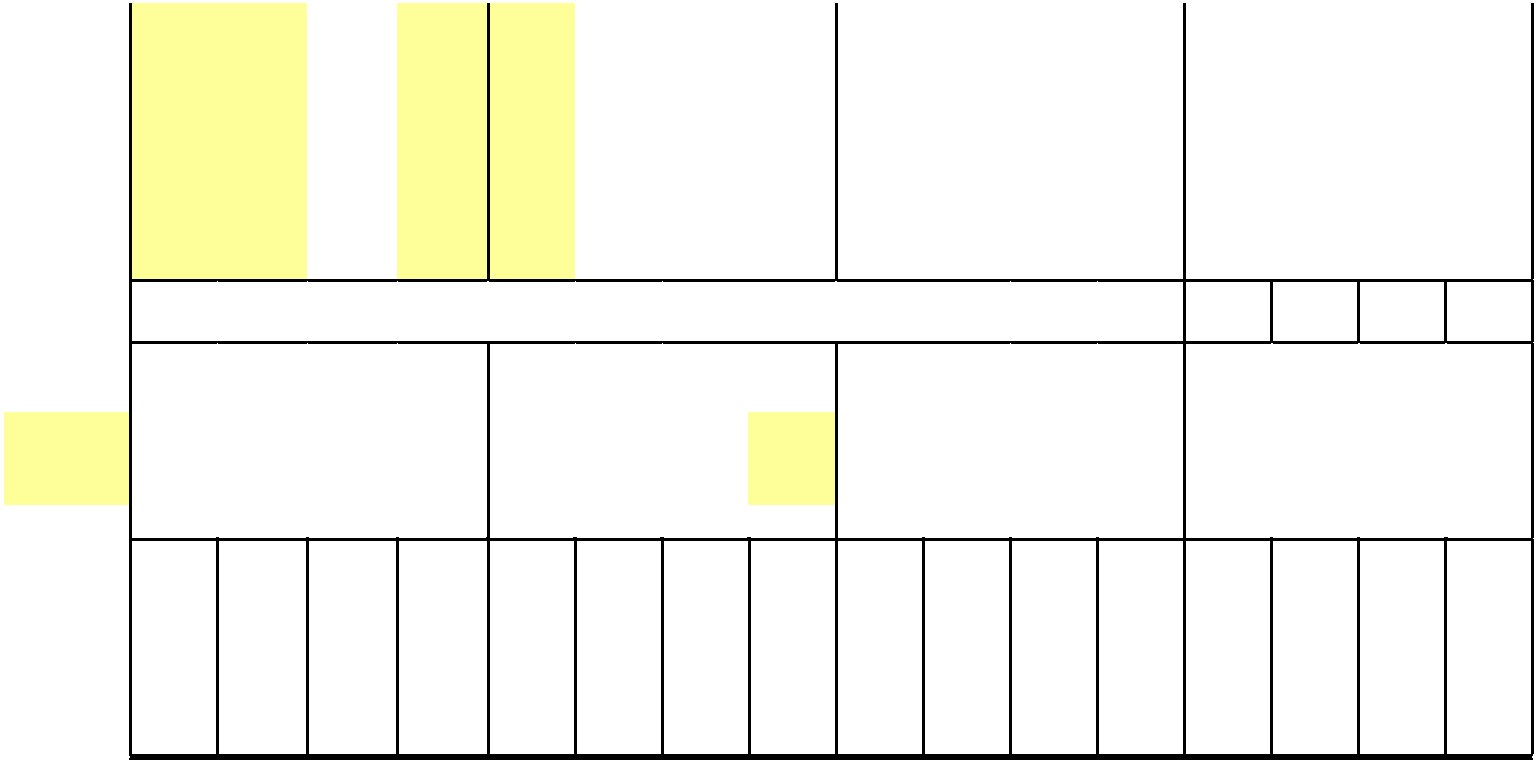
t Depr e ense t r e e t r e e t r e e



| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **MBPP Lines** | | | - | | | - | - | - | - | - | - | - | - | - | - | - |
| **MBPP Substations** | | | - | | | - | - | - | - | - | - | - | - | - | - | - |
| **MBPP Trans Mntnce Bldgs** | | | - | | | - | - | - | - | - | - | - | - | - | - | - |
| **MBPP Microwave** | | | - | | | - | - | - | - | - | - | - | - | - | - | - |
| **Subtotal** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Additional MBPP Facilities** | - | - | - | - | - | - | - | | - | - | - | - | - | - | - | - |
| **Grand Total MBPP - Gross Plant Transmission (FERC Account 350 - 356)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

Note:
The addition of new lines and the removal of outdated lines necessary to populate or remove data in the worksheet with the changes in

future years does not require a Federal Power



Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

# Basin Electric Power Cooperative
## Formula Rate Template
## Southwest Power Pool (SPP) Facilities
## Existing Facilities FERC Account 350 - 356 Transmission Plant



| | | | Facilities For Year Ending December 31, 20XX | | | | Facilities For Year Ending December 31, 20XX | | | | Facilities BOY / EOY Average | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| cpx | Type | Description | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt | Book Basis Amt | 1.68 % Depr Depr_YTD | Accum Depr | Net Book Amt | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt |
| 01202 | L | 230kv LO#1 DC Line to Washburn | | | | | | | | | - | - | - | - |
| 02102 | L | 345 kv line Stanton to SD Border | | | | | | | | | - | - | - | - |
| 02202 | L | 345 kv line - SD to Ft Thompson | | | | | | | | | - | - | - | - |
| 02302 | L | 345 kv line Stanton to SD Border | | | | | | | | | - | - | - | - |
| 02402 | L | 345 kv line SD to Watertown | | | | | | | | | - | - | - | - |
| 02 | | 230 kv line LOS#1 to | | | | | | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5 | L | **Logan** | | | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 0 | | | | | | | |
| 2 | | **230 kv line-230/115/69-** | | | | | |
| 6 | L | **sub (16)** | | | - | - | - | - |
| 0 | | | | | | | |
| 3 | | **115kV Line-Logan To** | | | | | |
| 1 | L | **Kenmare ND** | | | - | - | - | - |
| 0 | | **115kV Line-Logan To** | | | | | |
| 3 | | **Kenmare ND - 33%/67%** | | | | | |
| 1 | L | **Regional/Zonal** | | | - | - | - | - |
| 0 | | | | | | | |
| 3 | | **115 kv line Logan to** | | | | | |
| 2 | L | **Mallard** | | | - | - | - | - |
| 0 | | | | | | | |
| 3 | | **230 kv line Philip Tap-** | | | | | |
| 4 | L | **Philip Sub** | | | - | - | - | - |
| 1 | | | | | | | |
| 2 | | | | | | | |
| 7 | L | **345 kv N line #1 dbl circ** | | | - | - | - | - |
| 1 | | | | | | | |
| 2 | | | | | | | |
| 8 | L | **345 kv S line #2 dbl circ** | | | - | - | - | - |
| 1 | | | | | | | |
| 2 | | **500 kv AVS switchyd to** | | | | | |
| 9 | L | **SD bdr** | | | - | - | - | - |
| 1 | | | | | | | |
| 3 | | **500 kv SD bdr to** | | | | | |
| 0 | L | **Broadland sub** | | | - | - | - | - |
| 1 | | | | | | | |
| 3 | | | | | | | |
| 4 | L | **345 kv dbl circ line** | | | - | - | - | - |
| 1 | | | | | | | |
| 4 | | **230 kv line Broadland to** | | | | | |
| 1 | L | **Huron** | | | - | - | - | - |
| 1 | | | | | | | |
| 5 | | **230 kv line Estavan to** | | | | | |
| 0 | L | **Sask bdr** | | | - | - | - | - |
| 1 | | | | | | | |
| 5 | | **345 kv line AVS to** | | | | | |
| 2 | L | **Charlie Creek** | | | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 181 | L | **230 KV Line - Rhame to Belfield** | - | - | - | - |
| 212 | L | **115Kv Line-Char Ck-Sqw Gab Sub** | - | - | - | - |
| 225 | L | **115Kv Line-Sqw Gap-ND/MT Bordr** | - | - | - | - |
| 236 | L | **115Kv Line-ND/MT Brd-Richld Sb** | - | - | - | - |
| 288 | L | **230/115 kV Line - Judson Sub to Williston Sub** | - | - | - | - |
| 289 | L | **230Kv Line-Tande to Neset** | - | - | - | - |
| 291 | L | **344 kV Line - Judson Sub to Tande Sub** | - | - | - | - |
| 294 | L | **345 kV Line - AVS to Charlie Cr (North)** | - | - | - | - |
| 296 | L | **230 kv line - Williston to Tioga** | - | - | - | - |
| 298 | L | **345 kV Line - Charlie Creek Sub to Judson Sub** | - | - | - | - |
| 303 | L | **115Kv Line-Blaisdell to Bertho** | - | - | - | - |
| 306 | L | **BEPC Ovhd (384) Trans-Groton** | - | - | - | - |
| 311 | | **115 kv tie line to Groton** | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | L | **sub** | | | - | - | - | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 32 | | **115Kv Line LCS/West** | | | | | | | | | | | | | |
| 2 | L | **PatentGate** | | | | | | | | | - | - | - | - | |
| 33 | | **115Kv Line** | | | | | | | | | | | | | |
| 3 | L | **Patent/PatentGt Tie** | | | | | | | | | - | - | - | - | |
| 33 | | **115kV Line-Blaisdell** | | | | | | | | | | | | | |
| 7 | L | **Tap-Plaza** | | | | | | | | | - | - | - | - | |
| 33 | | **115kV Line-Blaisdell-** | | | | | | | | | | | | | |
| 9 | L | **Blaisdell** | | | | | | | | | - | - | - | - | |
| 35 | | **115kV LCS to** | | | | | | | | | | | | | |
| 1 | L | **PatentGate East** | | | | | | | | | - | - | - | - | |
| 36 | | | | | | | | | | | | | | | |
| 1 | L | **69KV Line Cornbelt** | | | | | | | | | - | - | - | - | |
| 36 | | **345Kv Line-Roundup to** | | | | | | | | | | | | | |
| 6 | L | **Kummer R** | | | | | | | | | - | - | - | - | |
| 41 | | **230 KV Line RC to New** | | | | | | | | | | | | | |
| 1 | L | **Underwood** | | | | | | | | | - | - | - | - | |
| 44 | | **230kV Ln - Crow Lk to** | | | | | | | | | | | | | |
| 4 | L | **Wess Spr** | | | | | | | | | - | - | - | - | |
| 48 | | **115kV Line Culbertson-** | | | | | | | | | | | | | |
| 6 | L | **WAPA** | | | | | | | | | - | - | - | - | |
| | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | |



**1.68** **1.68 % Depr after**

| | % Depr | 1/1/2016 | |
|---|---|---|---|
| | | | |
| | | | |
| | | | |

| cpx | Type | Description | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 01 | | | | | | | | | | | | | | |
| 13 | S | 230KV LO Washburn Substation | | | | | | | | | - | - | - | - |
| 01 | | | | | | | | | | | | | | |
| 16 | S | 230/115/69KV LO Substation | | | | | | | | | - | - | - | - |
| 03 | | | | | | | | | | | | | | |
| 36 | S | 345KV FT Thompson Substation | | | | | | | | | - | - | - | - |
| 03 | | | | | | | | | | | | | | |
| 37 | S | 230/115Kv Logan Substation | | | | | | | | | - | - | - | - |
| 03 | | | | | | | | | | | | | | |
| 39 | S | 230/115KV Storla, SD Substation | | | | | | | | | - | - | - | - |
| 04 | | | | | | | | | | | | | | |
| 00 | S | 230/115KV Philip, SD Substation | | | | | | | | | - | - | - | - |
| 04 | | | | | | | | | | | | | | |
| 02 | S | 230KV Philip,SD Tap Substation | | | | | | | | | - | - | - | - |
| 04 | | | | | | | | | | | | | | |
| 46 | S | Martin, SD USBR Sub Capacitor Installed | | | | | | | | | - | - | - | - |
| 04 | | | | | | | | | | | | | | |
| 47 | S | Armour, SD USBR Sub Capacitor Installed | | | | | | | | | - | - | - | - |
| 05 | | | | | | | | | | | | | | |
| 58 | S | 115KV Williston, ND Substation | | | | | | | | | - | - | - | - |
| 06 | | | | | | | | | | | | | | |
| 60 | S | 230/115KV Dickinson, ND Substation | | | | | | | | | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 0 | | | | | | | |
| 6 | | **115KV Spirit Mound** | | | | | |
| 1 | S | **Switchyard** | - | - | - | - | |
| 0 | | | | | | | |
| 6 | | **Static VAR Suppt-** | | | | | |
| 3 | S | **Victory Hill Sub-Sctbluff** | - | - | - | - | |
| 1 | | | | | | | |
| 1 | | **115kV Mobile Capacitor** | | | | | |
| 4 | S | **Banks** | - | - | - | - | |
| 1 | | | | | | | |
| 2 | | **500KV Broadland SD,** | | | | | |
| 6 | S | **Substation** | - | - | - | - | |
| 1 | | | | | | | |
| 4 | | **230KV USBR Huron** | | | | | |
| 2 | S | **Substation Addition** | - | - | - | - | |
| 1 | | | | | | | |
| 4 | | **Manning,ND Sub** | | | | | |
| 5 | S | **Capacitor Installed** | - | - | - | - | |
| 1 | | | | | | | |
| 5 | | **345/230/115kV Charlie** | | | | | |
| 3 | S | **Crk Sub** | - | - | - | - | |
| 1 | | **Charlie Crk Sub - 345KV** | | | | | |
| 5 | | **LN Add (Activity** | | | | | |
| 3 | S | **40782763, 40790110)** | - | - | - | - | |
| 1 | | **Little Missouri Tap** | | | | | |
| 7 | | **115 kv Capacitor** | | | | | |
| 9 | S | **Bank** | - | - | - | - | |
| 1 | | | | | | | |
| 8 | | **230 kv Belfield** | | | | | |
| 2 | S | **Substation** | - | - | - | - | |
| 1 | | | | | | | |
| 8 | | **230 kv Rhame** | | | | | |
| 3 | S | **Substation** | - | - | - | - | |
| 1 | | | | | | | |
| 9 | | **Bowman Sub -230 KV** | | | | | |
| 4 | S | **breakers** | - | - | - | - | |
| 1 | | | | | | | |
| 9 | | | | | | | |
| 5 | S | **Hettinger Capacitors** | - | - | - | - | |

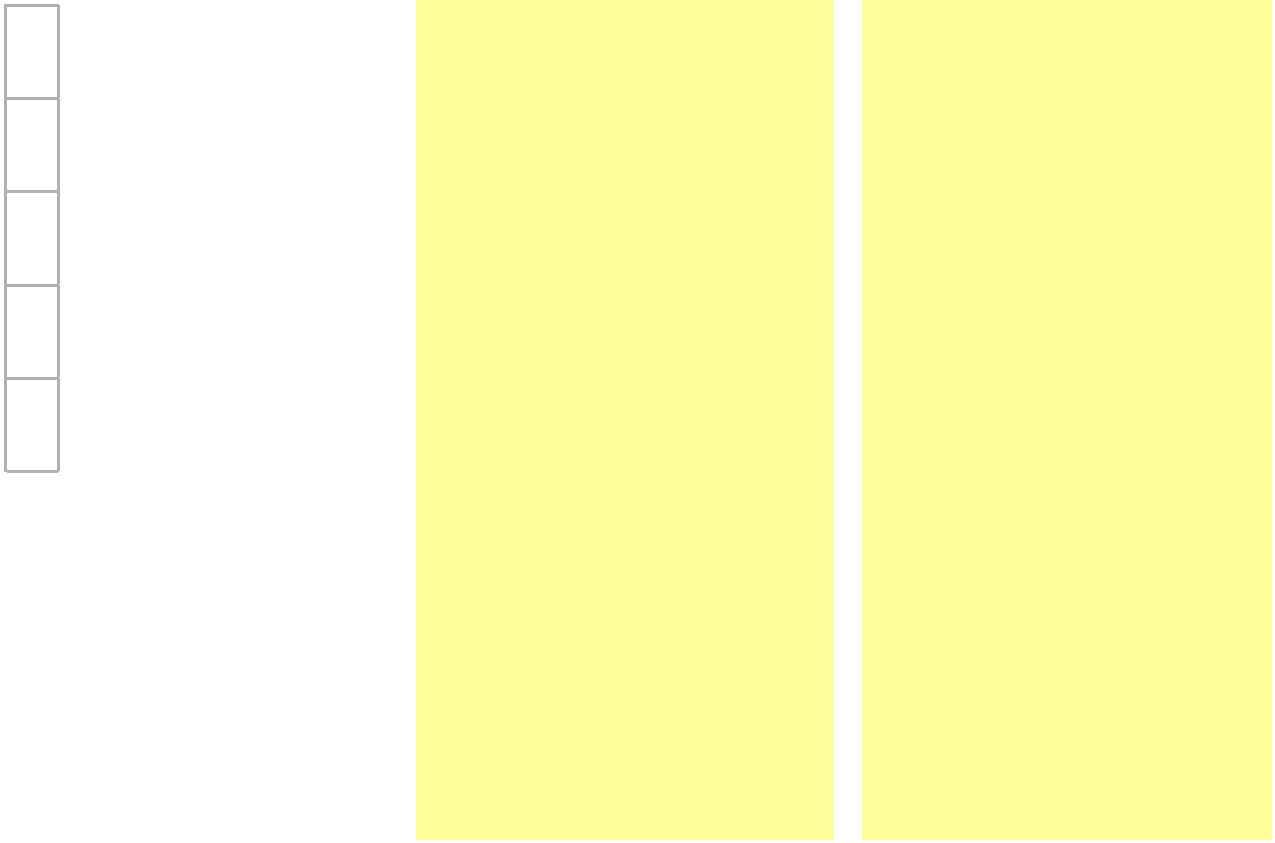
| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1196 | S | **Baker Capacitors** | | | - | - | - | - |
| 1198 | S | **230Kv Daglum Switchyard** | | | - | - | - | - |
| 1212 | S | **345kV Stegall Sub-BEPC Addtn** | | | - | - | - | - |
| 1213 | S | **115kV Shannon Substation** | | | - | - | - | - |
| 1237 | S | **Squaw Gap 115kV Substation** | | | - | - | - | - |
| 1238 | S | **Richland 115/69kV Substation** | | | - | - | - | - |
| 1239 | S | **Roughrider 115/24.9kV Tap** | | | - | - | - | - |
| 1240 | S | **Bicentennial 115/24.9kV Tap** | | | - | - | - | - |
| 1241 | S | **Koch Oil 115/12.47kV Tap** | | | - | - | - | - |
| 1243 | S | **East Sidney 115/12.47kV Tap** | | | - | - | - | - |
| 1278 | S | **230 kV Sully Butte Sub (Shunt)** | | | - | - | - | - |
| 1279 | S | **230 kV Glenham Sub (Shunt)*** | | | - | - | - | - |
| 1290 | S | **345/230Kv Tande Sub** | | | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 229 | S | 345/230kV Tande Sub - 33 % Regional / 67% Zonal | - | - | - | - |
| 229 | S | 345/230KV Judson Sub- 100% Regional | - | - | - | - |
| 229 | S | 345/230KV Judson Sub-33% Regional | - | - | - | - |
| 229 | S | 230/115kV Wheelock Substation | - | - | - | - |
| 229 | S | 230/115kV Blaisdell Substation | - | - | - | - |
| 229 | S | 230/115KV Neset (Tioga) Sub T3 | - | - | - | - |
| 229 | S | Neset Substation 230 kV Bus - 33 % Regional / 67% Zonal | - | - | - | - |
| 229 | S | 230Kv Willistn Sub Transformer | - | - | - | - |
| 230 | S | 345/115KV Groton Substation Addition | - | - | - | - |
| 230 | S | Groton 115kv Capacitor Banks | - | - | - | - |
| 232 | S | Witten | - | - | - | - |
| 232 | S | Watford | - | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | S | **Mission** | | | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 3 | | | | | | |
| 3 | | | | | | |
| 8 | S | **Blaisdell Tap Switches** | - | - | - | - |
| 3 | | | | | | |
| 6 | | **69KV Substation -** | | | | |
| 2 | S | **Cornbelt** | - | - | - | - |
| 3 | | | | | | |
| 6 | | **345/115kV Roundup** | | | | |
| 5 | S | **Sub** | - | - | - | - |
| 3 | | | | | | |
| 6 | | **345/115kV Roundup** | | | | |
| 5 | S | **Sub** | - | - | - | - |
| 3 | | **345/115 kV Pat** | | | | |
| 6 | | **Gate_Equip/Const/OH(C** | | | | |
| 9 | S | **omplex 369)** | - | - | - | - |
| 3 | | **345/115 kV Pat** | | | | |
| 6 | | **Gate_KU17A (Complex** | | | | |
| 9 | S | **369)** | - | - | - | - |
| 3 | | | | | | |
| 9 | | **Dry Creek 230/115/69kV** | | | | |
| 7 | S | **Sub** | - | - | - | - |
| 4 | | | | | | |
| 0 | | **RC Tie East** | | | | |
| 8 | S | **Interconnect** | - | - | - | - |
| 4 | | | | | | |
| 7 | | | | | | |
| 0 | S | **Groton Clutch** | - | - | - | - |
| 5 | | | | | | |
| 5 | | **115 kV Ordway** | | | | |
| 0 | S | **Substation** | - | - | - | - |
| 5 | | | | | | |
| 5 | | | | | | |
| 6 | S | **Berthold 115 kV Tap** | - | - | - | - |
| 5 | | | | | | |
| 5 | | **115 kV Kenaston Tap** | | | | |
| 7 | S | **Substation** | - | - | - | - |
| 5 | | | | | | |
| 5 | | **115kV PGS Switchyard -** | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 9 | S | **(Recip)** | | | - | - | - | - |



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 576 | S | 115Kv LCS Switchyard | | | | | | | | | - | - | - | - |
| 7111 | S | 230KV LO #1 Switchyard and AVS Addition | | | | | | | | | - | - | - | - |
| 7202 | S | 345/230KV LO#2 Switchyard and AVS Add | | | | | | | | | - | - | - | - |
| 7344 | S | Tioga substation - Capacitor bank | | | | | | | | | - | - | - | - |
| 7355 | S | 345/230KV Watertown Substation | | | | | | | | | - | - | - | - |
| 7373 | S | 230/115KV Logan Substation & Sask Addition | | | | | | | | | - | - | - | - |
| 7676 | S | 345Kv AVS Sub W ANG & Charlie-100% Regional | | | | | | | | | - | - | - | - |
| 7677 | S | 345Kv AVS Sub W ANG & Charlie | | | | | | | | | - | - | - | - |
| | | Subtotal Substation | - | - | - | - | - | - | - | - | - | - | - | - |



**FERC Account 350 - 356**

| cpx | Type | Description | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt | Book Basis Amt | Depr_YTD | Accum Depr | Net Book Amt |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 070 | T S M | Mandan Transmission Maint Bldg | | | | | | | | | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | T | | | | | | | | | | | | | |
| 7 | S | **Gettysburg Trans** | | | | | | | | | | | | |
| 1 | M | **Maint Bldg** | | | | | | | | - | - | - | - | |
| 0 | T | | | | | | | | | | | | | |
| 7 | S | **Groton Trans Maint** | | | | | | | | | | | | |
| 2 | M | **Bldg** | | | | | | | | - | - | - | - | |
| 1 | T | | | | | | | | | | | | | |
| 0 | S | **Logan Trans Maint** | | | | | | | | | | | | |
| 9 | M | **Bldg** | | | | | | | | - | - | - | - | |
| 1 | T | | | | | | | | | | | | | |
| 1 | S | **Broadland Trans** | | | | | | | | | | | | |
| 9 | M | **Maint Bldg** | | | | | | | | - | - | - | - | |
| 1 | T | | | | | | | | | | | | | |
| 2 | S | **AVS Plantsite Trans** | | | | | | | | | | | | |
| 0 | M | **Maint Bldg** | | | | | | | | - | - | - | - | |
| 2 | T | | | | | | | | | | | | | |
| 1 | S | **Huron Trans Maint** | | | | | | | | | | | | |
| 4 | M | **Bldg** | | | | | | | | - | - | - | - | |
| | | **Subtotal TSM** | - | - | - | - | - | - | - | - | - | - | - | - | |
| 0 | | | | | | | | | | | | | | |
| 4 | | **Microwave - North** | | | | | | | | | | | | |
| 3 | M | **Dakota** | | | | | | | | - | - | - | - | |
| 0 | | | | | | | | | | | | | | |
| 4 | | **Microwave -South** | | | | | | | | | | | | |
| 4 | M | **Dakota** | | | | | | | | - | - | - | - | |
| | | **xxxxxx** | | | | | | | | - | - | - | - | |
| | | **Subtotal Microwave** | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | **TOTAL SPP TRANSMISSION** | - | - | - | - | - | - | - | - | - | - | - | - | |

*** Excludes portion of Glenham Shunt included in "Other"**

N
o
t
e:

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Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a

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**Basin Electric Power Cooperative**
**Formula Rate Template**
**Load Dispatching & LSE Costs**

**Worksheet #3**
**Page 1 of 1**

| | | | | Schedule 1 (Per SPP Tariff) Revenue Requirement (Historical) | Schedule 1 (Per SPP Tariff) Revenue Requirement (Estimate) |
|---|---|---|---|---|---|
| 1 | Account 561 Load Dispatching | | | - | - |
| 2 | Less LSE Related Costs | | | - | - |
| 3 | | 0 | (Sum of lines 1 through 2 ) | $ - | $ - |

**Adjustments to Transmission Expense to Reflect TO's LSE Cost Responsibility in Accounts other than Account 561**

| | | | | | |
|---|---|---|---|---|---|
| 2 | Direct Assignment Charge | | | - | - |
| 3 | Sponsored (Requested or Economic) Upgrades Charge | | | - | - |

| | | | |
|---|---|---|---|
| 4 | Firm and Non-Firm Point-To-Point Charges | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 5 | Base Plan Charges | | | - | - |
| 6 | Schedule 9 Charges | | | - | - |
| 7 | SPP Schedule 1-A | | | - | - |
| 8 | SPP Annual Assessment | | | - | - |
| 9 | NERC Assessment | | | - | - |
| 10 | Ancillary Services Expenses | | | - | - |
| 11 | Other | | | - | - |
| 12 | Other | | | - | - |
| 13 | Other | | | - | - |
| 14 | | Total | (Sum of lines 2 through 13 ) | $ - | $ - |
| 15 | Total Adjustments to O&M | | (Sum line 1 and line 14) | - | - |

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# Basin Electric Power Cooperative
## Formula Rate Template
## Summary Depreciation & Amortization Expense
## Worksheet #4



**Annual Depreciation Expense**
**Actuals - Year Ending 12/31/20XX**

| Line No | Account No. | Description | Source | Total Annual Expense YTD Ending 12/20XX | UMZ Zone 19 Annual Expense YTD Ending 12/20XX | MBPP Annual Expense YTD Ending 12/20XX | Other Annual Expense YTD Ending 12/20XX |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | **Depreciation & Amortization Expense** | | | | | | |
| 1 | **303** | **Intangible** | Work Paper #7 | - | - | - | - |
| 2 | **310 - 316** | **Production Plant (Generation)** | Work Paper #7 | - | - | - | - |
| 3 | **340 - 346** | **Other Generation** | Work Paper #7 | - | - | - | - |
| 4 | **350 - 356** | **Transmission Plant** | Work Paper #11 | - | - | - | - |
| 5 | **380 - 398** | **General Plant & RTO / ISO** | | | | | |
| 6 | | Transmission Plant | Work Paper #8 | - | - | - | - |
| 7 | | Production Plant (Generation) | Work Paper #8 | - | - | - | - |
| | | Other - | Work | | | | |

| | | | | |
|---|---|---|---|---|
| 8 | Headquarters | Paper #8 | - | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | | Subtotal General Plant | - | - | - | - |
| 10 | | **Total Depreciation and Amortization** | **-** | **-** | **-** | **-** |

| Line No | Account No. | Description | Source | Annual Depreciation Expense Estimate - Rate Year 20XX: Total Annual Expense Estimated 20XX | UMZ Zone 19 Annual Expense Estimated 20XX | MBPP Annual Expense Estimated 20XX | Other Annual Expense Estimated 20XX |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) |
| | **Depreciation & Amortization Expense** | | | | | | |
| 1 | **303** | **Intangible** | Work Paper #7 | - | - | - | - |
| 2 | **310 - 316** | **Production Plant (Generation)** | Work Paper #7 | - | - | - | - |
| 3 | **340 - 346** | **Other Generation** | Work Paper #7 | - | - | - | - |
| 4 | **350 - 356** | **Transmission Plant** | Work Sheet #1 & Work Paper #11 | - | - | - | - |
| 5 | **380 - 398** | **General Plant & RTO / ISO** | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6 | Transmission Plant | Work Paper #8 | - | - | - | - |
| 7 | Production Plant (Generation) | Work Paper #8 | - | - | - | - |
| 8 | Other - Headquarters | Work Paper #8 | - | - | - | - |
| 9 | Subtotal General Plant | | - | - | - | - |
| 10 | **Total Depreciation and Amortization** | | **-** | **-** | **-** | **-** |

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**Basin Electric Power Cooperative**
**Formula Rate Template**
**Administrative & General Costs - MBPP**

**Worksheet #5**
**Page 1 of 2**

**Calculation: Administrative & General Costs - Basin Electric Share of MBPP**

| Line No. | Description | Source | A & G - Actuals - Year Ending 12/31/20XX Total<br>Annual Expense YTD Ending 12/20XX | UMZ Zone 19<br>Annual Expense YTD Ending 12/20XX | MBPP<br>Annual Expense YTD Ending 12/20XX | Other<br>Annual Expense YTD Ending 12/20XX |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | **Administrative & General** | **Work Paper #4** | - | - | - | - |
| 2 | **Less: PBOP Expense (Note A)** | N/A | - | - | - | - |
| 3 | **Plus: Authorized PBOP Exepnses (Note A)** | N/A | - | - | - | - |
| 4 | **Less: Regulatory Expense (Note B)** | Invoices | - | - | - | |
| 5 | | | | | | |
| 6 | **Production** | Line 19b * Line 22c | #DIV/0! | - | #DIV/0! | - |
| 7 | **Transmission (Note C)** | Line 19b * Line 23c | #DIV/0! | - | #DIV/0! | - |
| 8 | **Headquarters (Note D)** | (Line 1 less lines 4, 6 & 7) | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | Sum Lines 2 - | | | | |
| 9 | **Total A&G** | 9 | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | | | | | | |
| | | | **A & G - 20XX Estimate** | | | |
| | | | **Total** | **UMZ Zone 19** | **MBPP** | **Other** |
| **Line No.** | **Description** | **Source** | **Annual Expense YTD Ending 12/20XX** | **Annual Expense YTD Ending 12/20XX** | **Annual Expense YTD Ending 12/20XX** | **Annual Expense YTD Ending 12/20XX** |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 10 | **Administrative & General** | Financial Planning | | - | - | - |
| 11 | **Less: PBOP Expense (Note A)** | N/A | - | - | - | - |
| 12 | **Plus: Authorized PBOP Exepnses (Note A)** | N/A | - | - | - | - |
| 13 | **Less: Regulatory Expense (Note B)** | Invoices | - | - | - | |
| 14 | | | | | | |
| 15 | **Production *** | Line 19c * 21c | #DIV/0! | - | #DIV/0! | - |
| 16 | **Transmission (Note C) *** | Line 19c * 21c | #DIV/0! | - | #DIV/0! | - |
| 17 | **Headquarters (Note D)** | (Line 10 less lines 13, 15 & 16) | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| 18 | **Total A&G** | **Sum Lines 11 - 17** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |

**Worksheet #5**

*** Calculation: Basin Electric's Share of MBPP of A&G allocated to MBPP times MBPP production & transmission plant ratio.**



| Line No. | Description | 20XX Actuals | 20XX Estimate |
|---|---|---|---|
| | (a) | (b) | (c) |
| 19 | **Basin Electric Share of MBPP Costs** | | |
| 20 | **MBPP Transmission / Production Plant Ratio** | | |
| 21 | **Plant Expenses** | **20XX Actuals** | **Percent** |
| | | | **#DIV/0!** |
| 22 | **Generation** | - | |
| | | | **#DIV/0!** |
| 23 | **Transmission** | - | |
| | | | **#DIV/0!** |
| | | - | |

**Notes:**

A The dollar amount will be N/A absent specific FERC approval. At which time, Basin Electric will add an additional worksheet showing the derivation of Postretirement Benefits Other Than Pensions (PBOP) expense/authorized PBOP expense.

B Common Use System (CUS) exepenses.

C UMZ Zone 19 expenses include transmission legal expenses; MBPP expneses included A&G transmission. The remainder is allocated using GP2

D Allocator.

**Calculation: BEPC Gross Revenue Requirment - MBPP Transmission**

| Line | | MBPP | MBPP |
|---|---|---|---|

| e | Annual Expense | Annual Expense |
|---|---|---|
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

| No. | Description | | 20XX Act / 20XX Est | 20XX Actual |
|---|---|---|---|---|
| | (a) | (b) | (c) | |
| 1 | **BEPC GROSS REVENUE REQUIREMENT (page 4, line 27)** | | **#DIV/0!** | **#DIV/0!** |
| 2 | | | | |
| 3 | **MBPP - Generation West** | | **#DIV/0!** | **#DIV/0!** |
| 4 | **MBPP - Generation East** | | **#DIV/0!** | **#DIV/0!** |
| 5 | **Total Generation - MBPP** | **0** | **#DIV/0!** | **#DIV/0!** |
| 6 | | | | |
| 7 | **MBPP - Transmission West** | | **#DIV/0!** | **#DIV/0!** |
| 8 | **MBPP - Transmission East (included in Zone 19 - UMZ)** | | **#DIV/0!** | **#DIV/0!** |
| 9 | | | **#DIV/0!** | **#DIV/0!** |

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**Basin Electric Power Cooperative**
**Formula Rate Template**
**Regulatory Assets and Abandoned Plant**
**Worksheet #6**



**EOY/BOY Average Ending 12/31/XX**

| Line No | Project Description | Project ID | Pricing Zone (Note A) | Approval Docket No. | % Recovery Approved (Note B) | Total Project Amount (Note B) | Recovery Period (Months) (Note B) | Monthly Amort Expense (col. f / col. g) | Rate Year Amort. Periods (Months) | Rate Year Amort. Expense (col. e * col. h * col. i) |
|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| 1a | | | | | 0.00% | - | | - | | - |
| 1b | | | | | 0.00% | - | | - | | - |
| 1c | | | | | 0.00% | - | | - | | - |
| ... | | | | | 0.00% | - | | - | | - |
| ... | | | | | 0.00% | - | | - | | - |
| ... | | | | | 0.00% | - | | - | | - |

| | | | | |
|---|---|---|---|---|
| ... | 0.00% | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |
| ... | | 0.00% | - | - | | - |

Total Regulatory Asset and Abandoned Plant Amortization Expense for Rate Year: -

Notes:

A Amounts should be directly assigned to pricing zones on Schedule 1

B Regulatory Assets and/or Abandoned Plant cannot be included absent FERC approval.

Amounts, percentages includable, and amortization periods cannot be added or changed absent FERC approval.

C The addition of new lines and the removal of outdated lines necessary to populate or remove data in the worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Construction Work in Progress - BOY / EOY Average**
**Year Ending 12/31/xx**
**Worksheet #7**

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Construction Work in Progress - BOY / EOY Average**
**Year Ending 12/31/xx**
**Worksheet #7**





| Line No | Project Description | Docket No. | Approval % Recovery Approved (Note A) | Pricing Zone (Note B) | Project ID | Construction Start Date | In-Service Date (Estimated) | BOY/EOY Average Balance for Rate Year | | | | | | | | | | | | | | BOY/EOY Avg. Balance | Includable in Rate Base (Note C) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Dec. 20xx | Jan. 20xx | Feb. 20xx | Mar. 20xx | Apr. 20xx | May 20xx | Jun. 20xx | Jul 20xx | Aug. 20xx | Sep. 20xx | Oct. 20xx | Nov. 20xx | Dec. 20xx | | (col. h + t) /2 | (col. c * col. u) |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | | (u) | (v) |
| 1a1 | | | 0.00 % 0.00 | | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | | - | - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| b | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | 0.00 | | | | | | | | | | | | | | | |
| c | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | 0.00 | | | | | | | | | | | | | | | |
| … | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | Total CWIP Includable in Rate | | | | | | | | | | | | | | | | |
| 2 | Base | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:

Percentage recovery cannot be added or changed absent approval

A from FERC

CWIP amounts should be directly assigned to pricing zones on Schedule 1

B AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization.

C Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.

D The addition of new lines and the removal of outdated lines necessary to populate or remove data in the worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**

**Formula Rate Template**

**Tax Reclassification**

**12 Months Ending 12/31/xx**

**Worksheet #8**



| Line No. | Account # (if applicable) (a) | Decription (b) | Pricing Zone (if applicable) (Note A) (c) | Source/Reference (d) | Total Company Amount (e) |
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Notes:

Amounts should be directly assigned to pricing zones on

A Schedule 1

B The addition of new lines and the removal of outdated lines necessary to populate or remove data in the worksheet with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP New Facilities**
**Work Paper #1**



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**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP Facilities - Projected**
**Work Paper #1**



| Service Yr Service Mo In-Service | End of M | 1.6800% |
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Page 2 of 2

| Service Yr Service Mo In-Service | End of M | 1.6800% |
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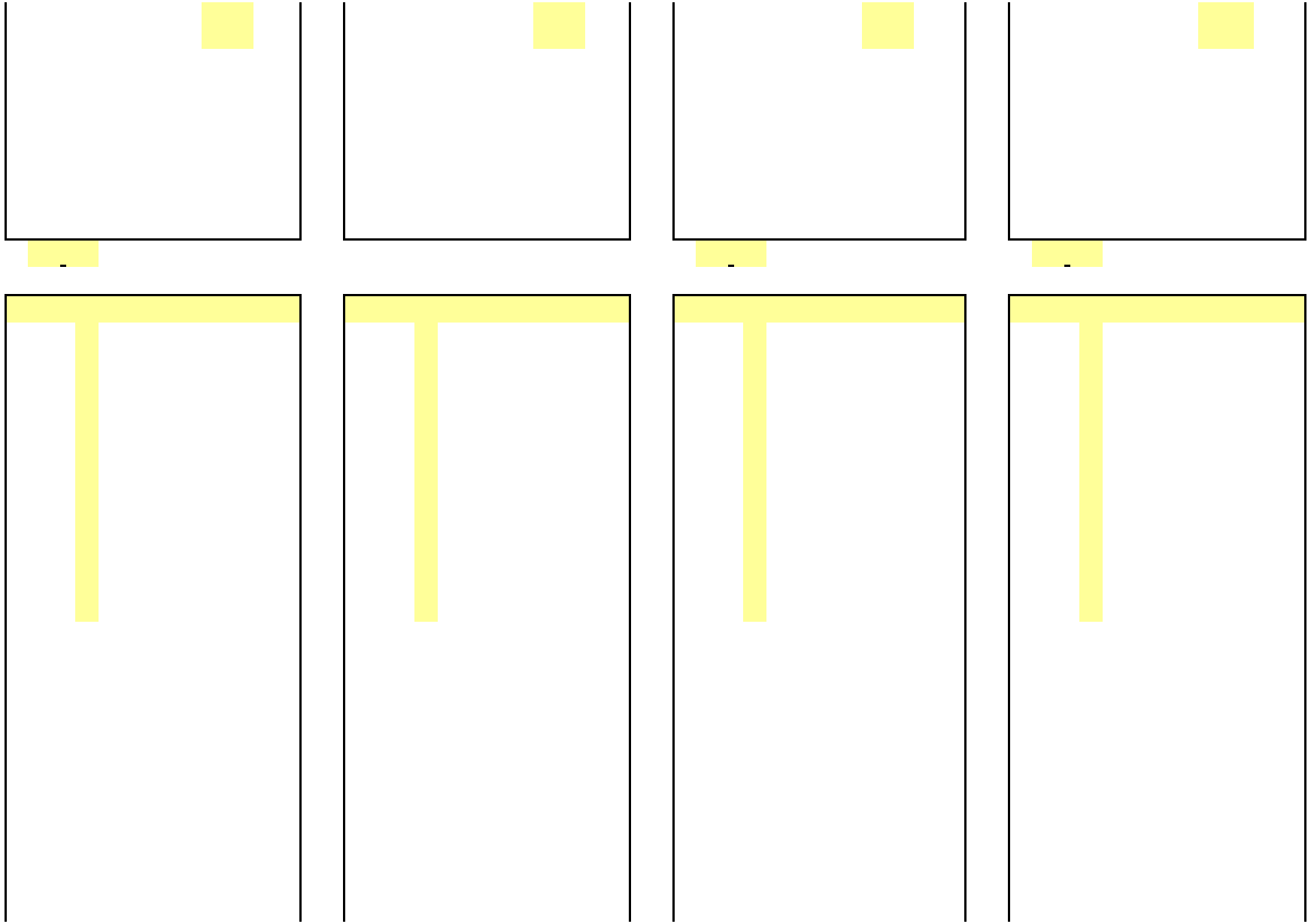

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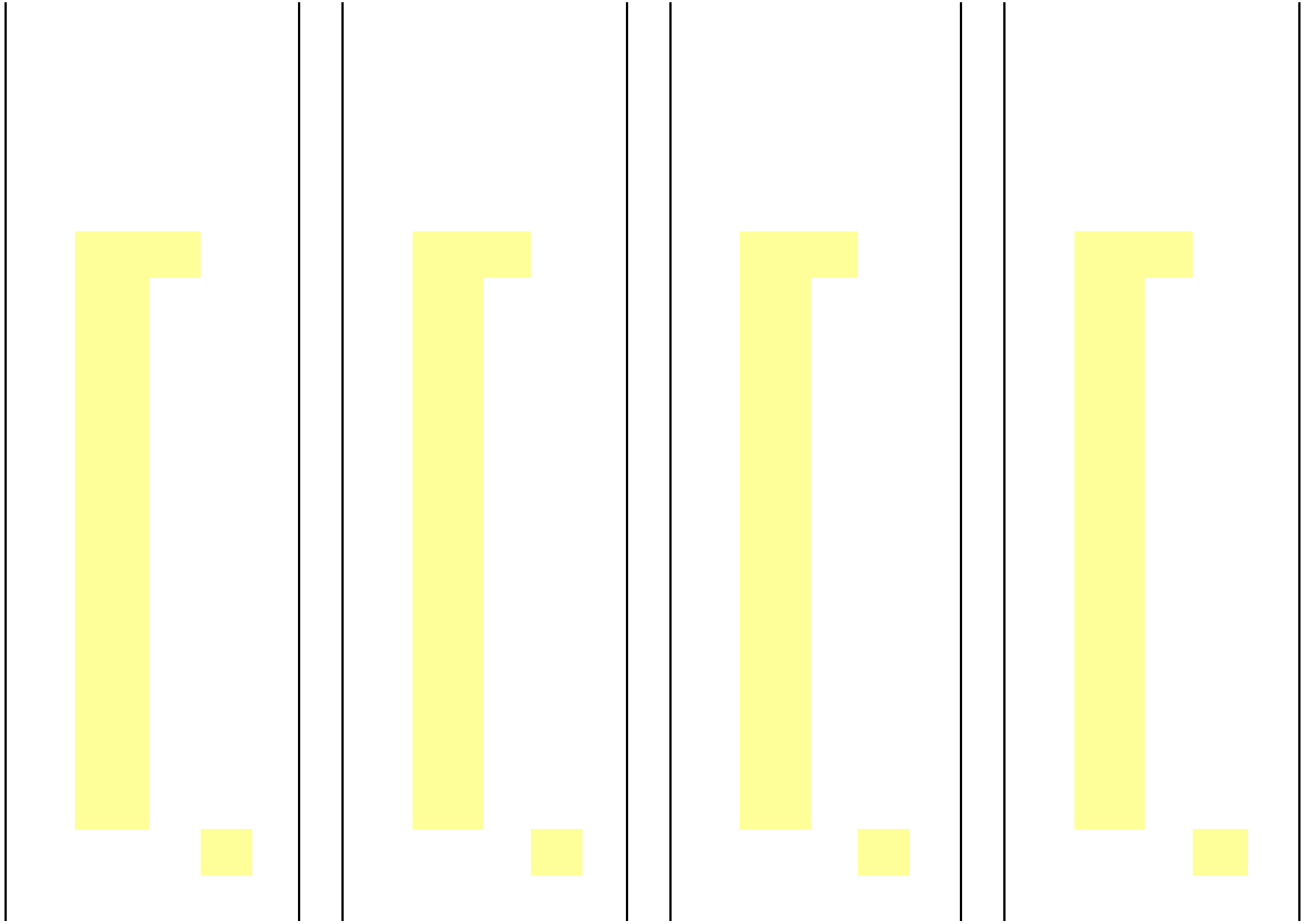

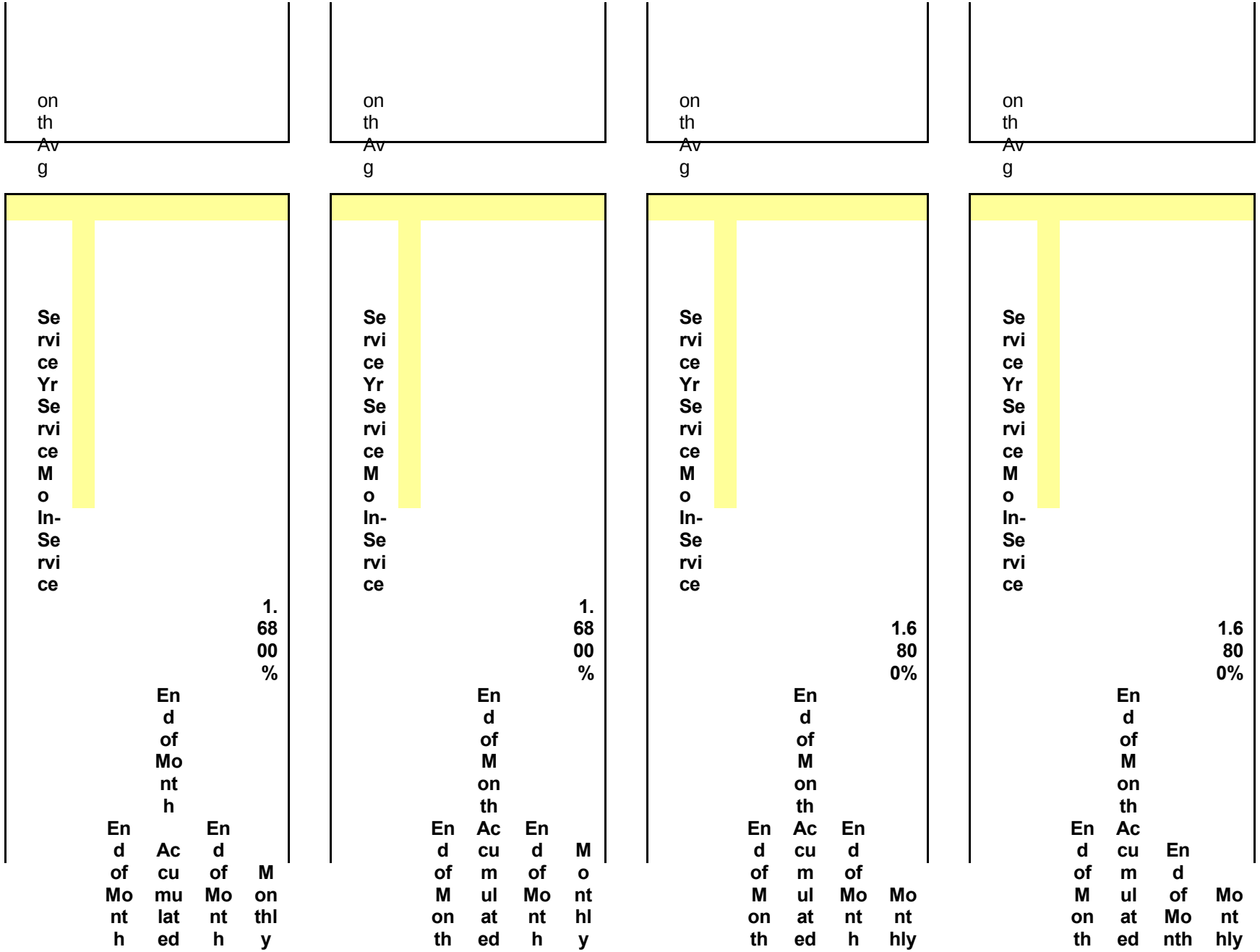
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Note
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**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP Base Plan Upgrades (BPU)**
**- New Facilities**

**Work Paper #2**

**Page 1 of 6**

**Service Year**
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**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP Base Plan Upgrades (BPU)**
**- New Facilities**

**Work Paper #2**

**Page 1 of 6**

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**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP Base Plan Upgrades (BPU)**
**- New Facilities**

**Work Paper #2**

**Page 4 of 6**

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**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP Base Plan Upgrades (BPU)**
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**Work Paper #2**

**Page 4 of 6**

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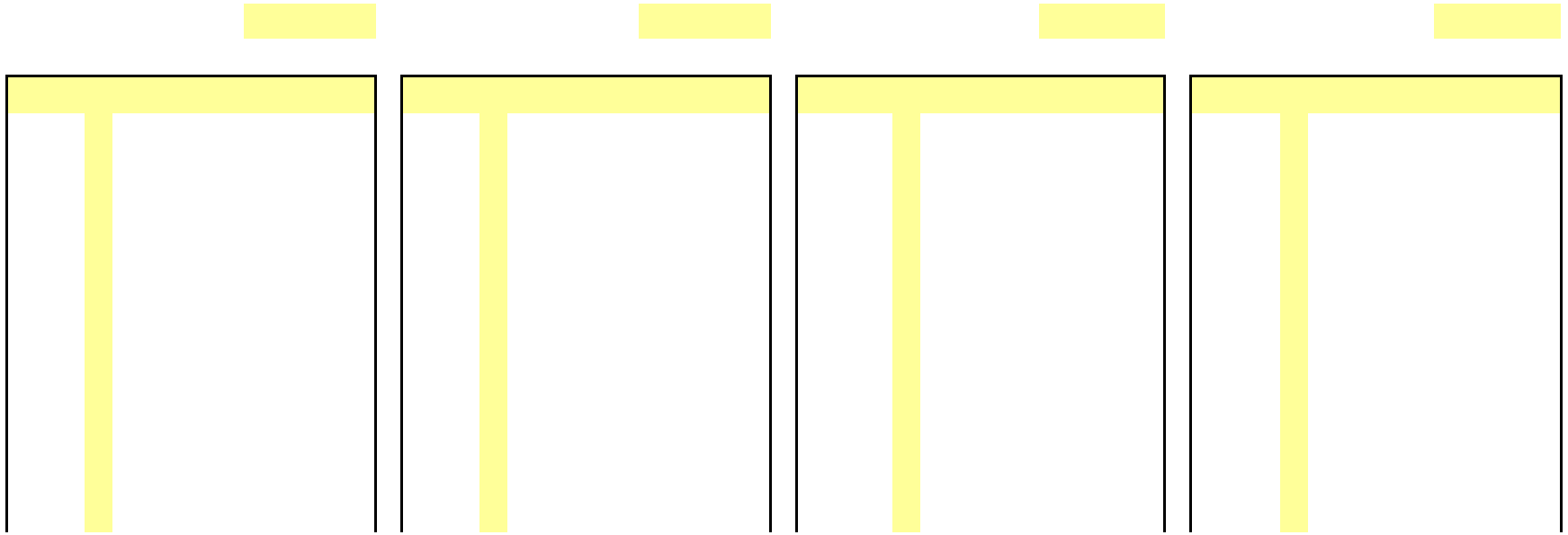

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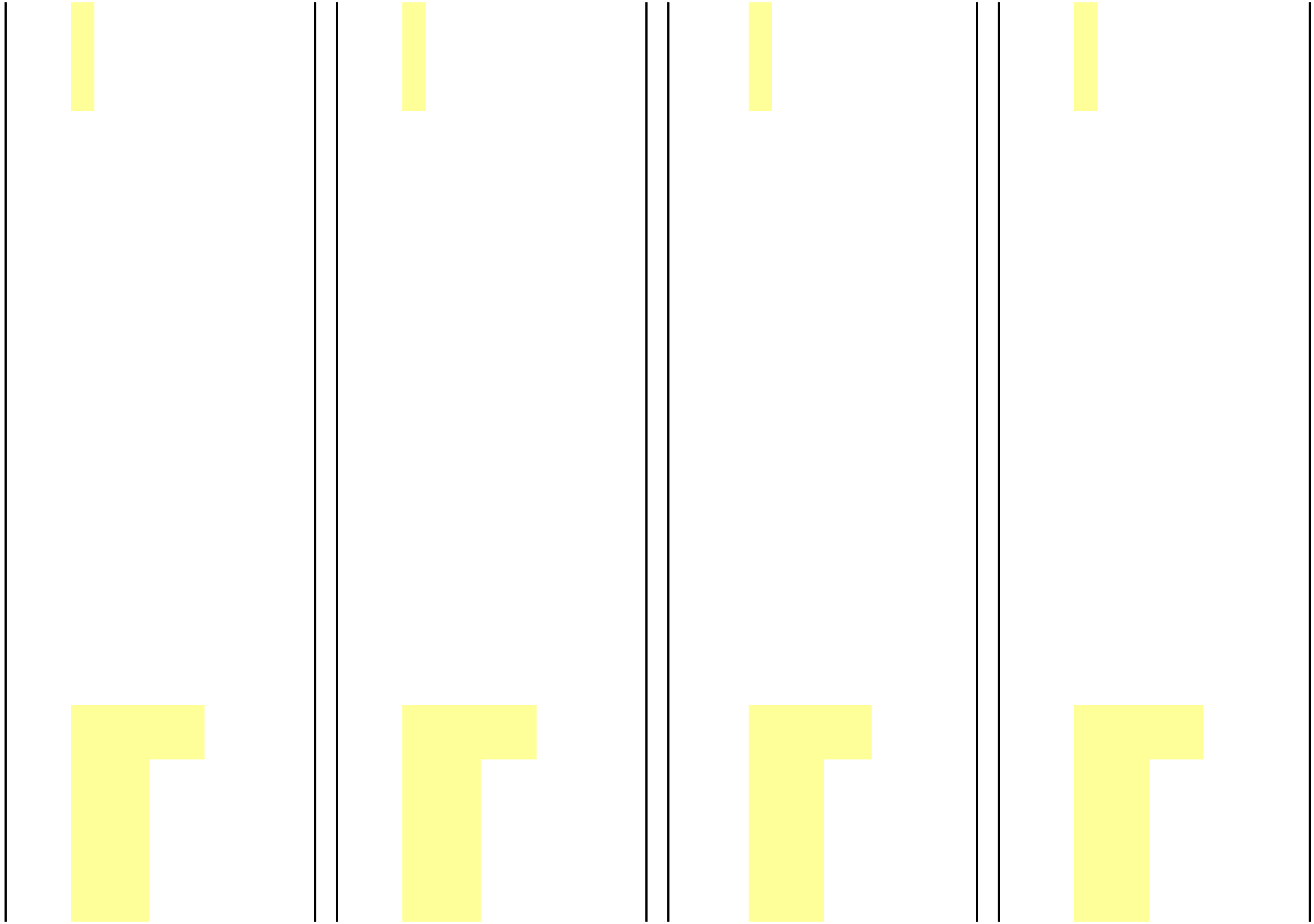

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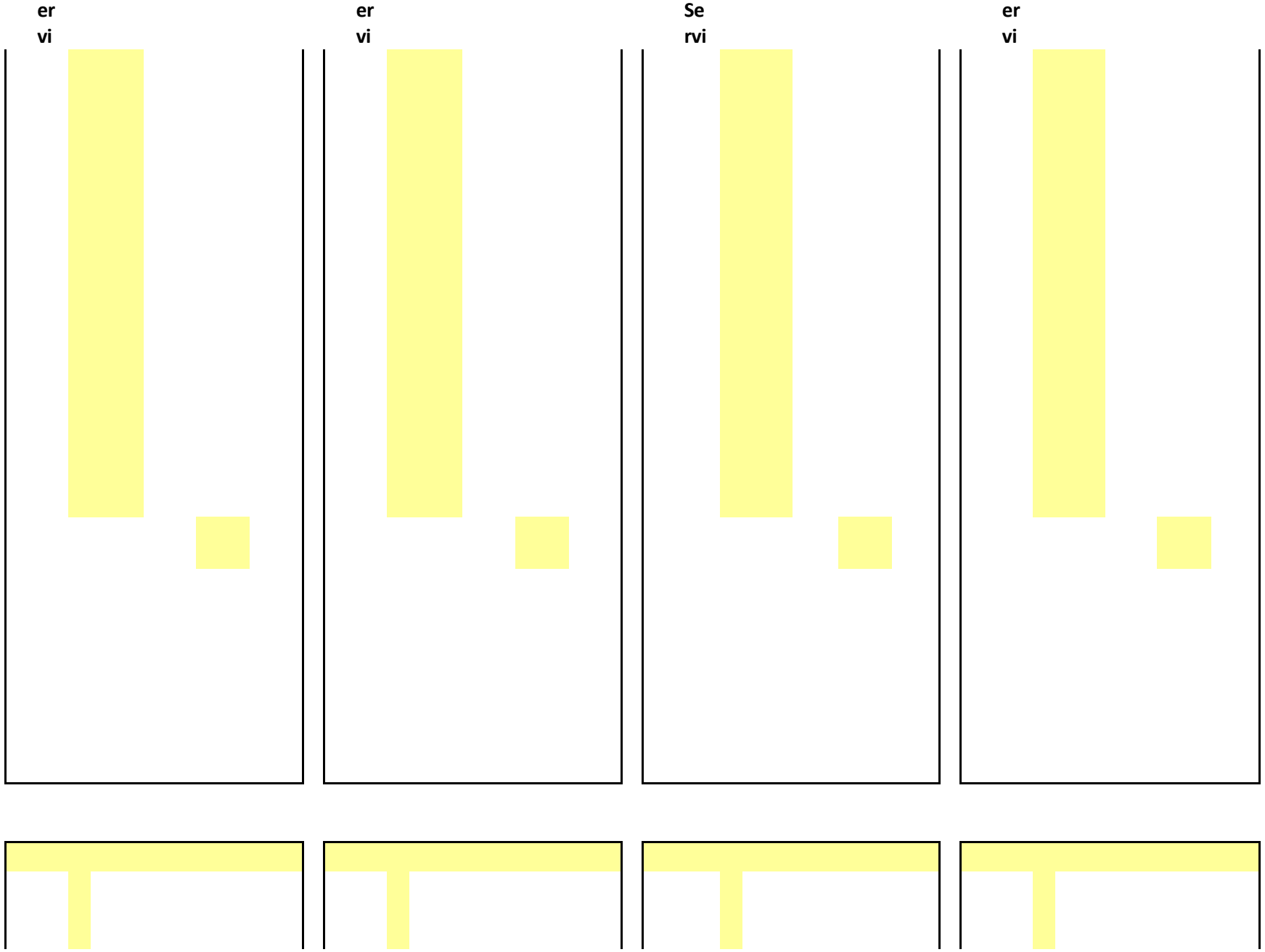
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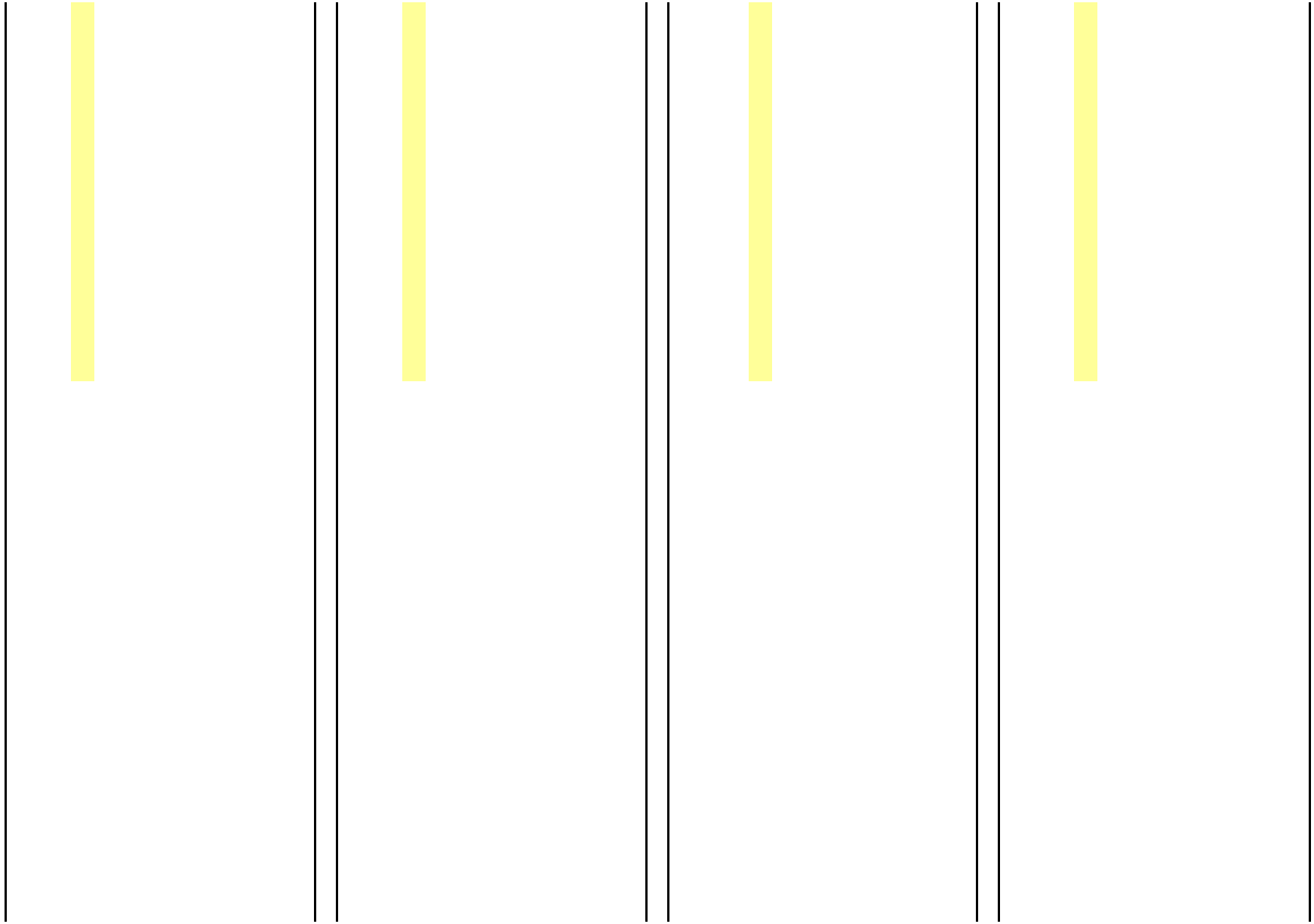

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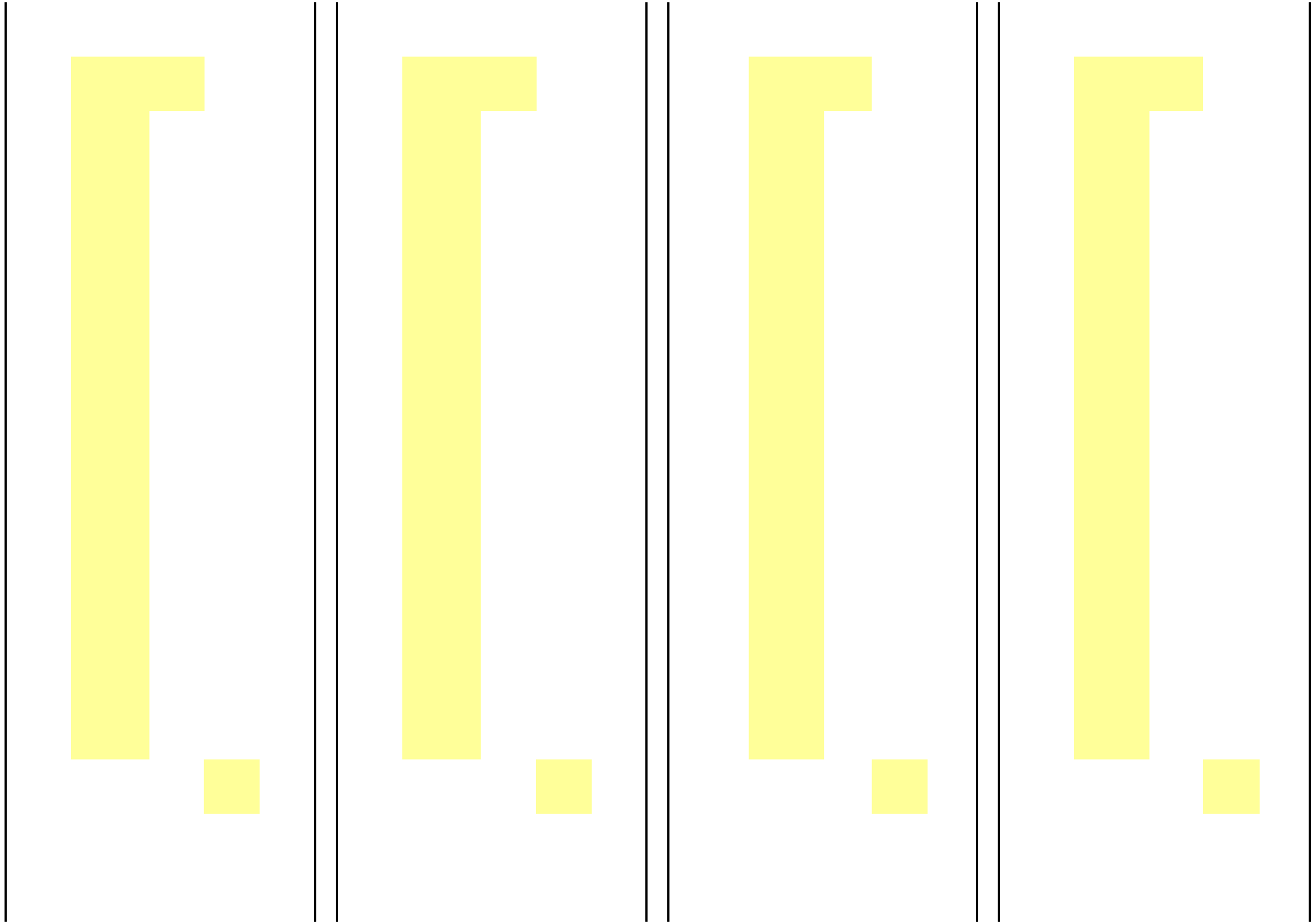

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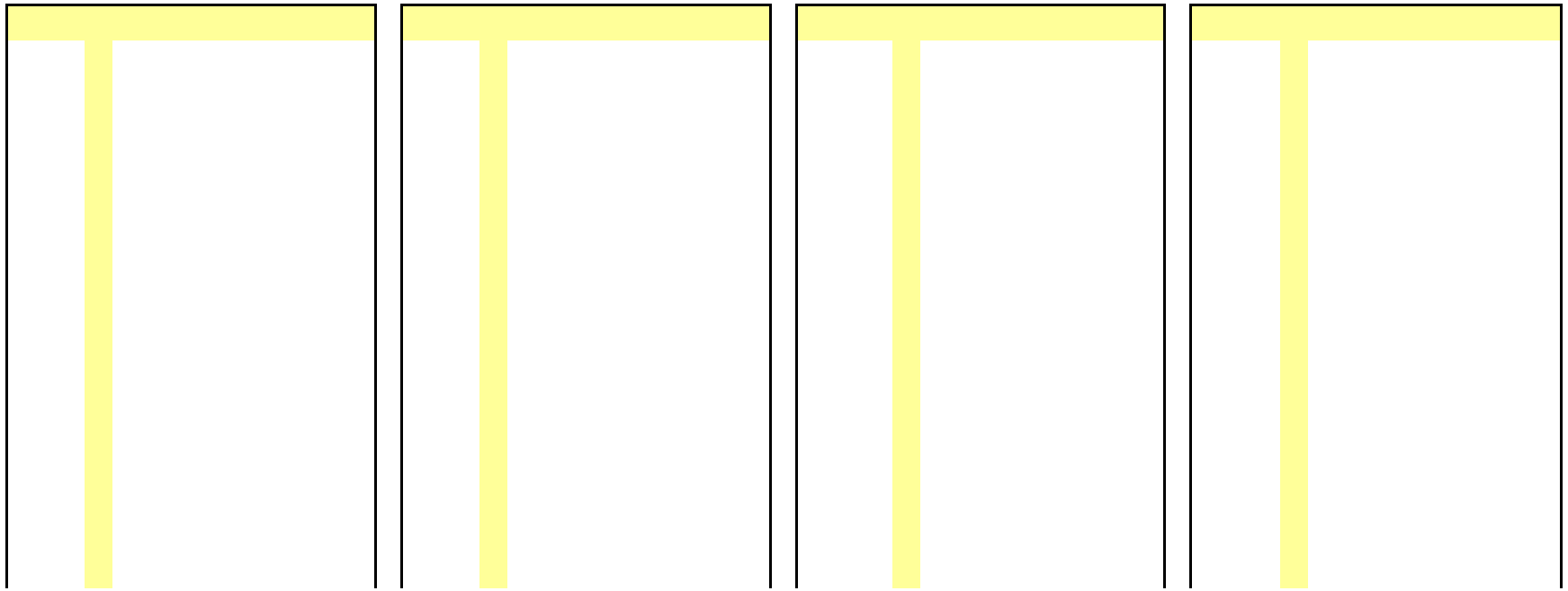

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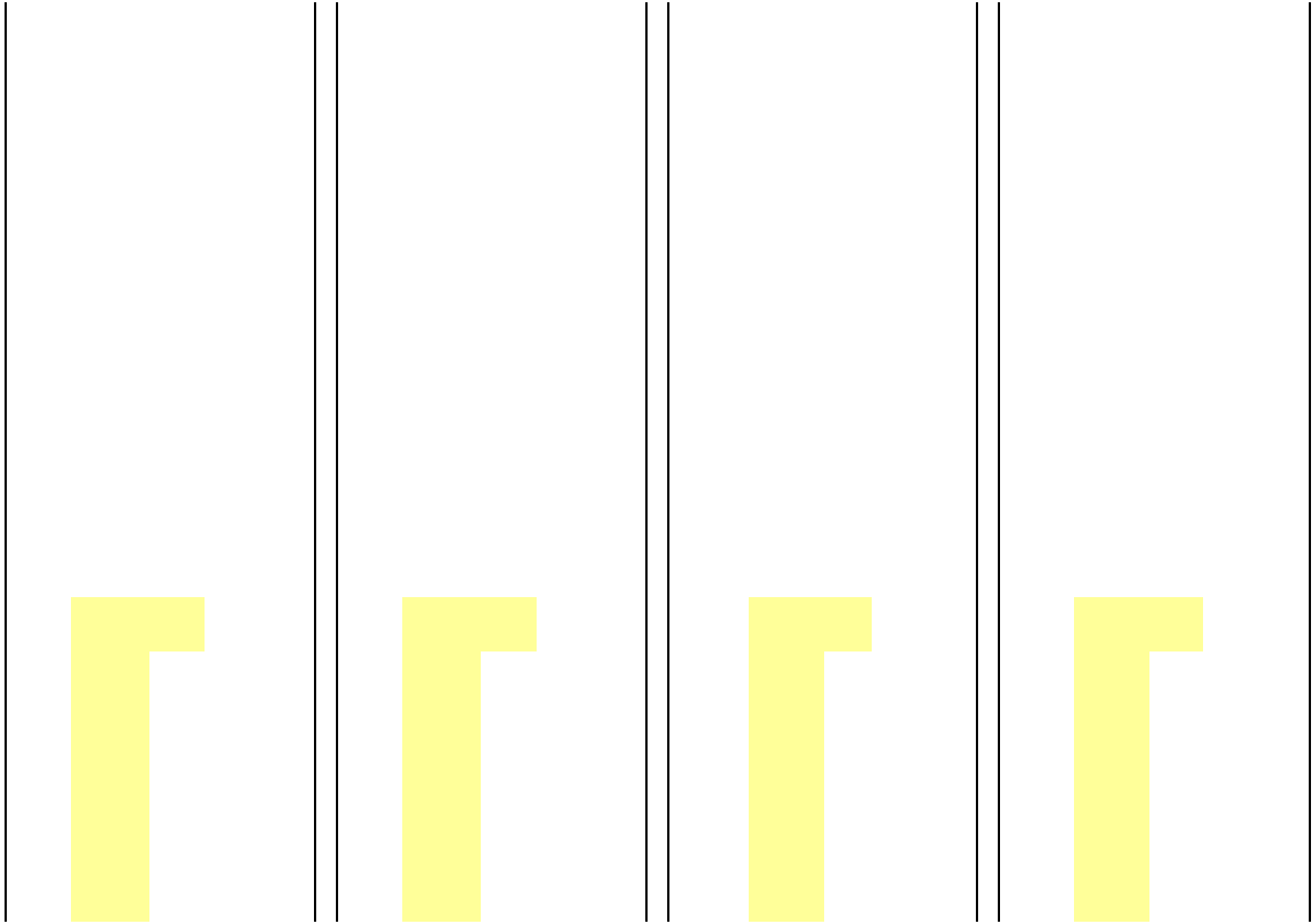

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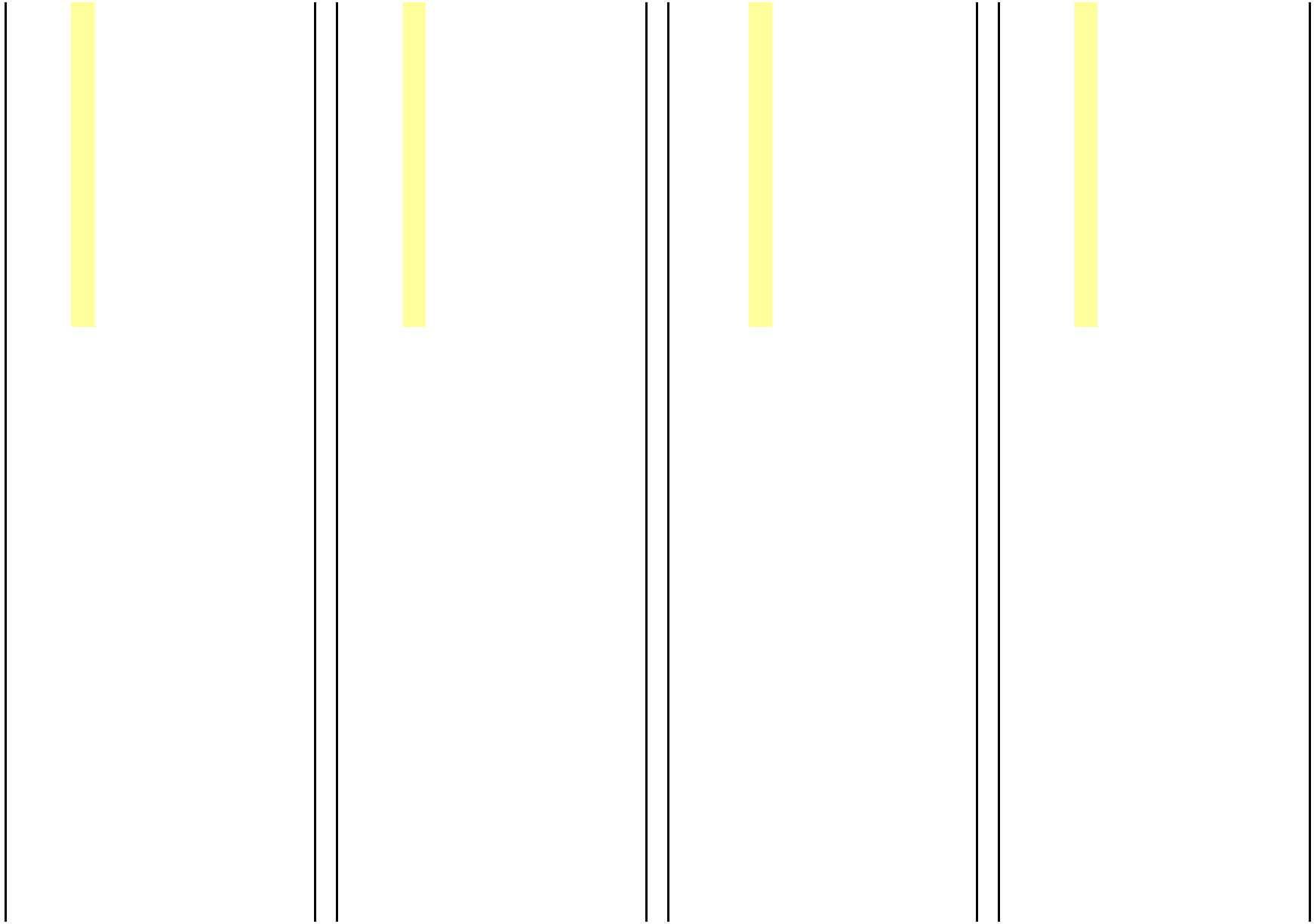

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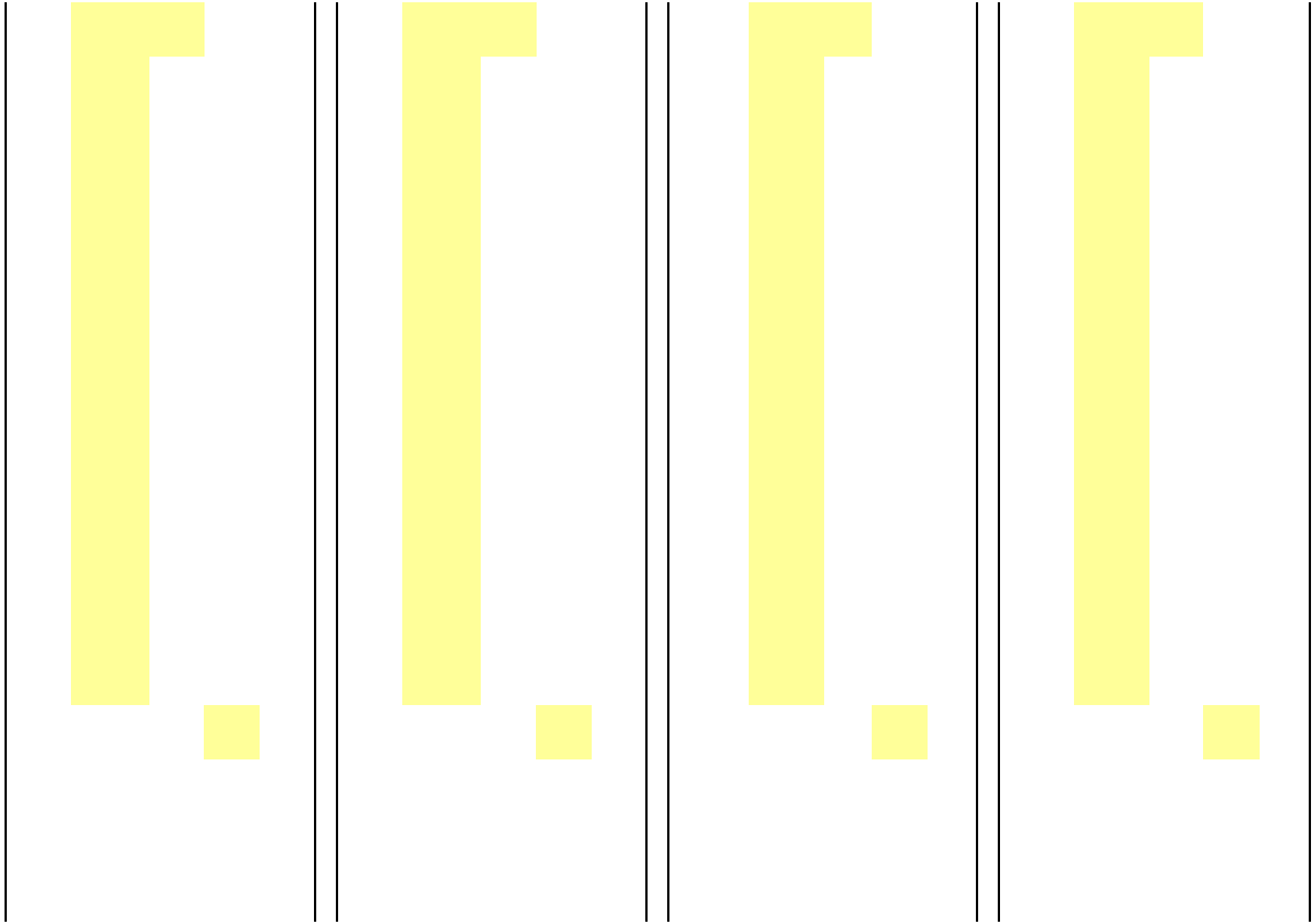

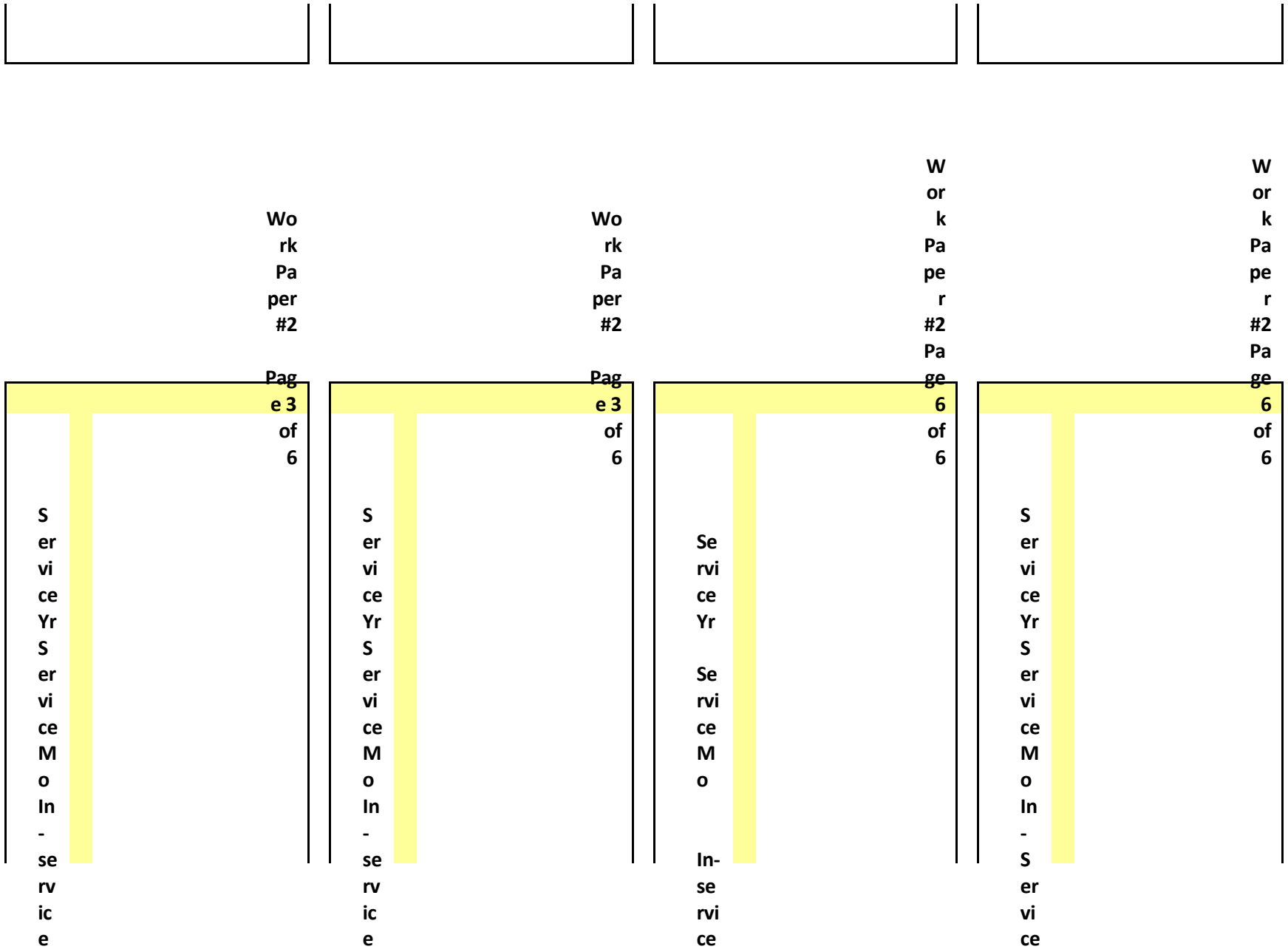
Work Paper #2 Page 3 of 6
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Work Paper #2 Page 3 of 6
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Work Paper #2 Page 6 of 6
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Work Paper #2 Page 6 of 6
Service Yr Service Mo In-Service

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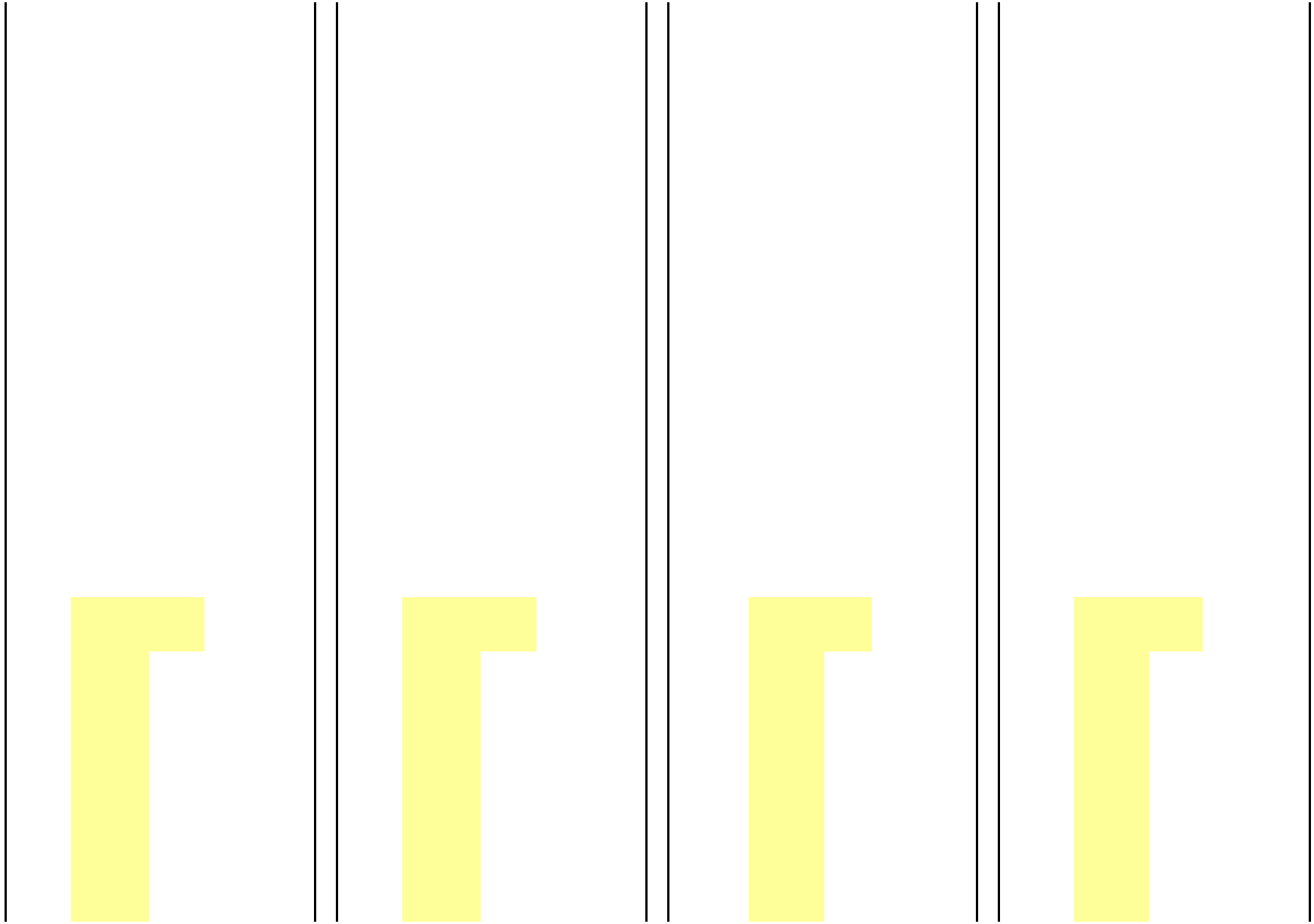

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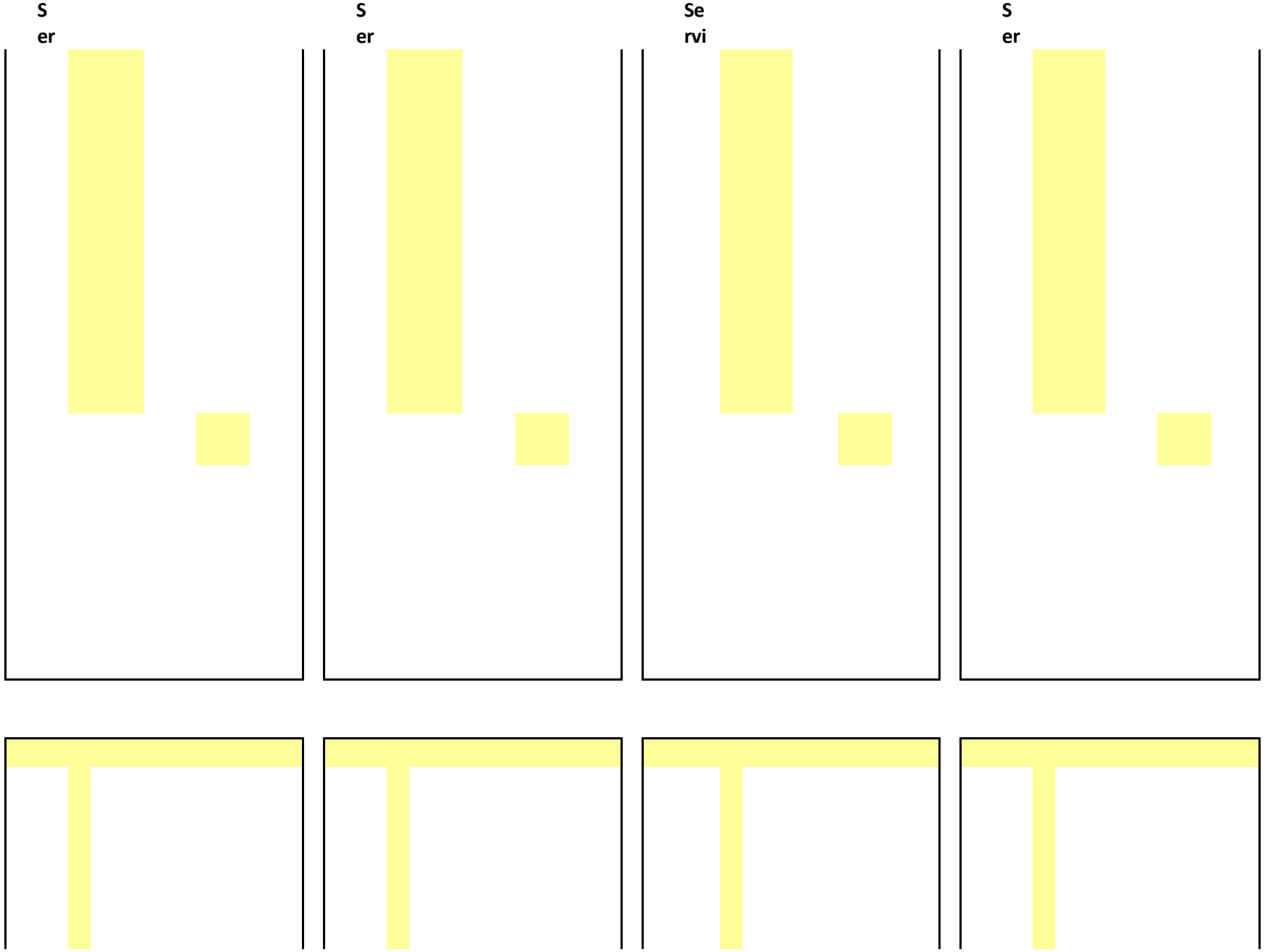
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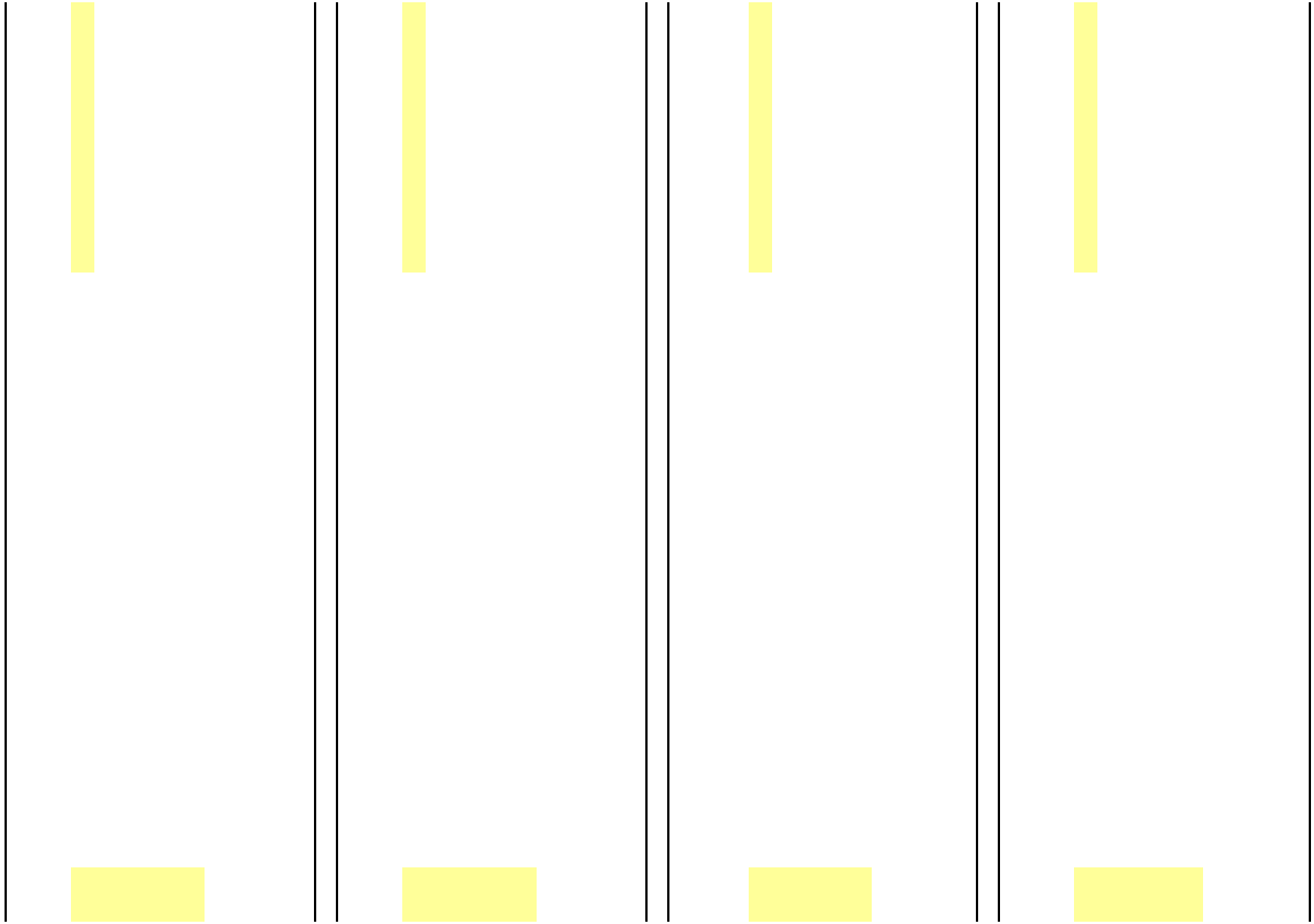

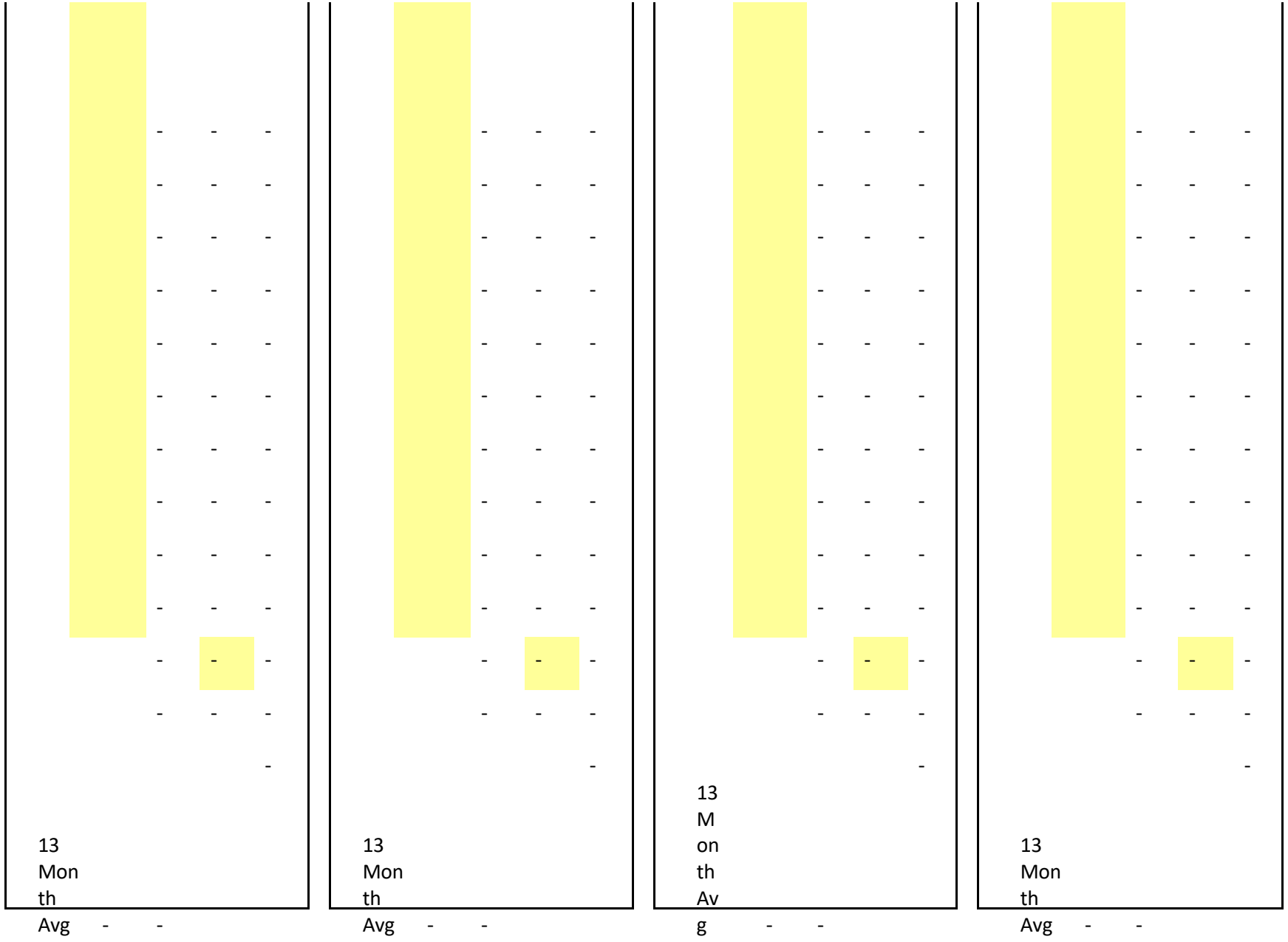
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Note:
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**Basin Electric Power Cooperative**
**Formula Rate Template**
**SPP Facilities - Projected**

**Work Paper #3**
**Page 1 of 2**

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| **Service Yr** | | | | |
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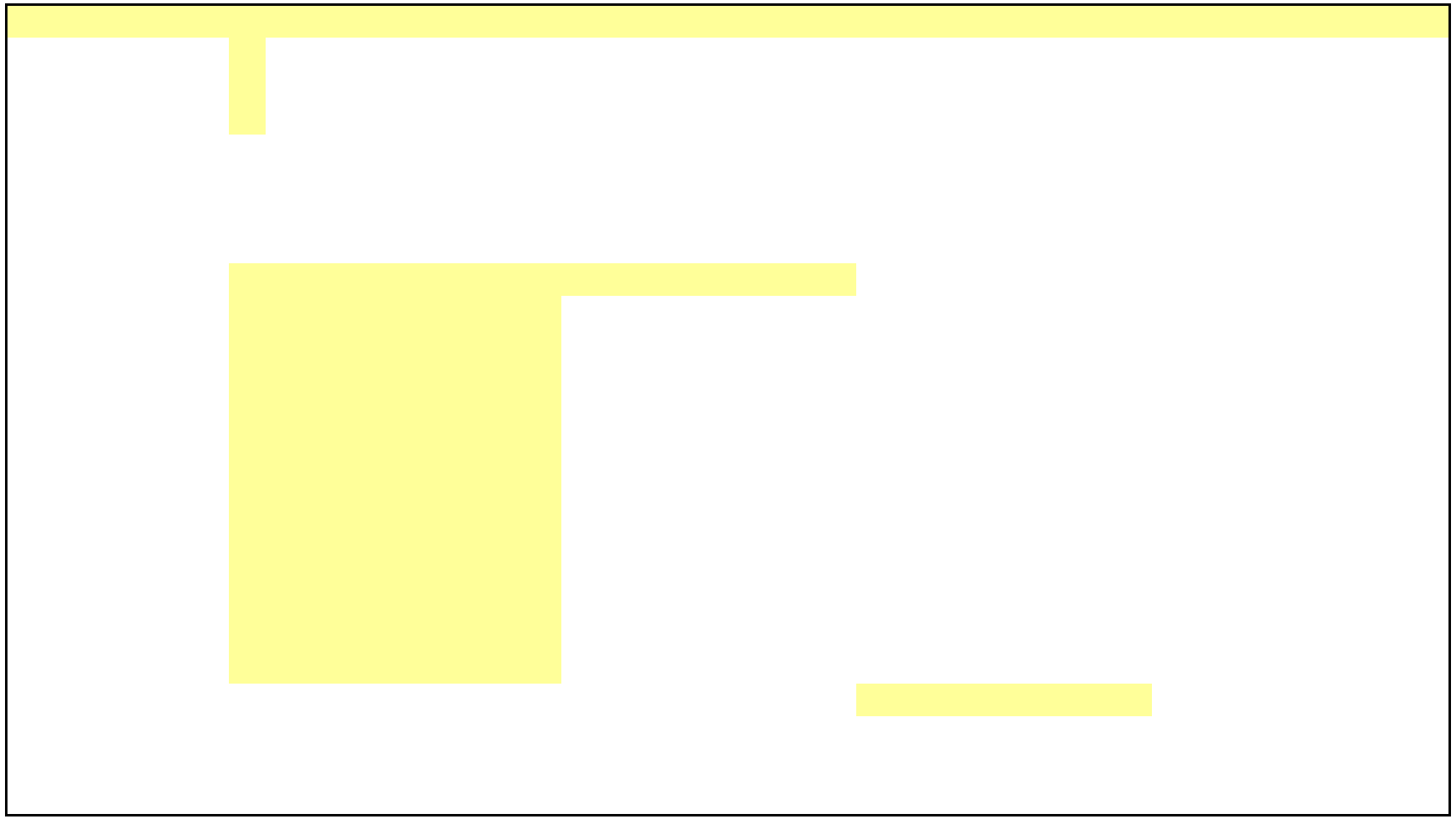
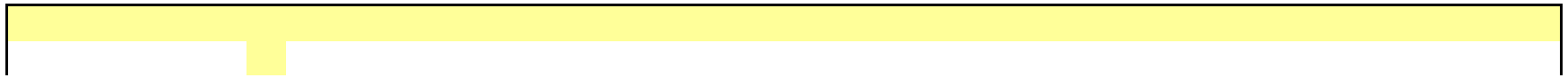
**Work Paper #3**
**Page 2 of 2**

**Service Yr**





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**Basin Electric Power Cooperative**
**Formula Rate Template**

**for the year ended December 31, 20XX**

**Work Paper #4**

**FERC Form 1 - Pages 114, 115 and 117**

**Page 1 of 5**

**Statement Of Income**

| Line | Title of Account | (Ref.) | Total C | Total Pr |
|---|---|---|---|---|

**Basin Electric Power Cooperative**
**Formula Rate Template**

**for the year ended December 31, 20XX**

**Workpaper #4**

**FERC Form 1 - Pages 110-113**

**Page 2 of 5**

**Comparative Balance Sheet (Assets and Other Debits)**

**Page 3 of 5**

**Comparative Balance Sheet (Liabilities and Other Credits)**

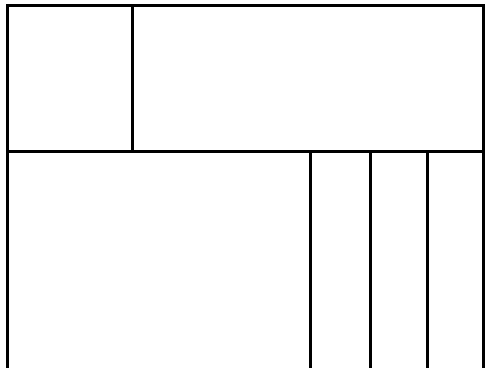
**Line**

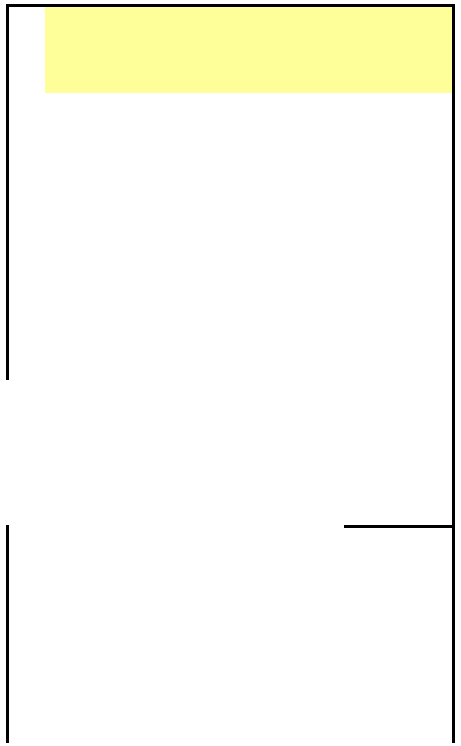
**Workpaper #4 Page 4 of 5**

**LTD & Equity - 20XX Actual**

| Rate | Cost |
|---|---|

| Purpose | (a) | (b) | (c) | (d) | (e) | (f) |
|---|---|---|---|---|---|---|
| | | | | | | |





| Line No. | Title of Account | Current Year to Date Balance for Quarter/Year | Prior Year to Date Balance for Quarter/Year |
|---|---|---|---|
| (a) | | (b) | (c) | (d) |

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| No | (a) | (b) | Operating Expenses | Quarter/Year Balance (c) |
|---|---|---|---|---|
| 1 | **Utility Operating Income** | | | |
| 2 | Operating Revenues (400) | Utility Plant (101-106, 114) | | |

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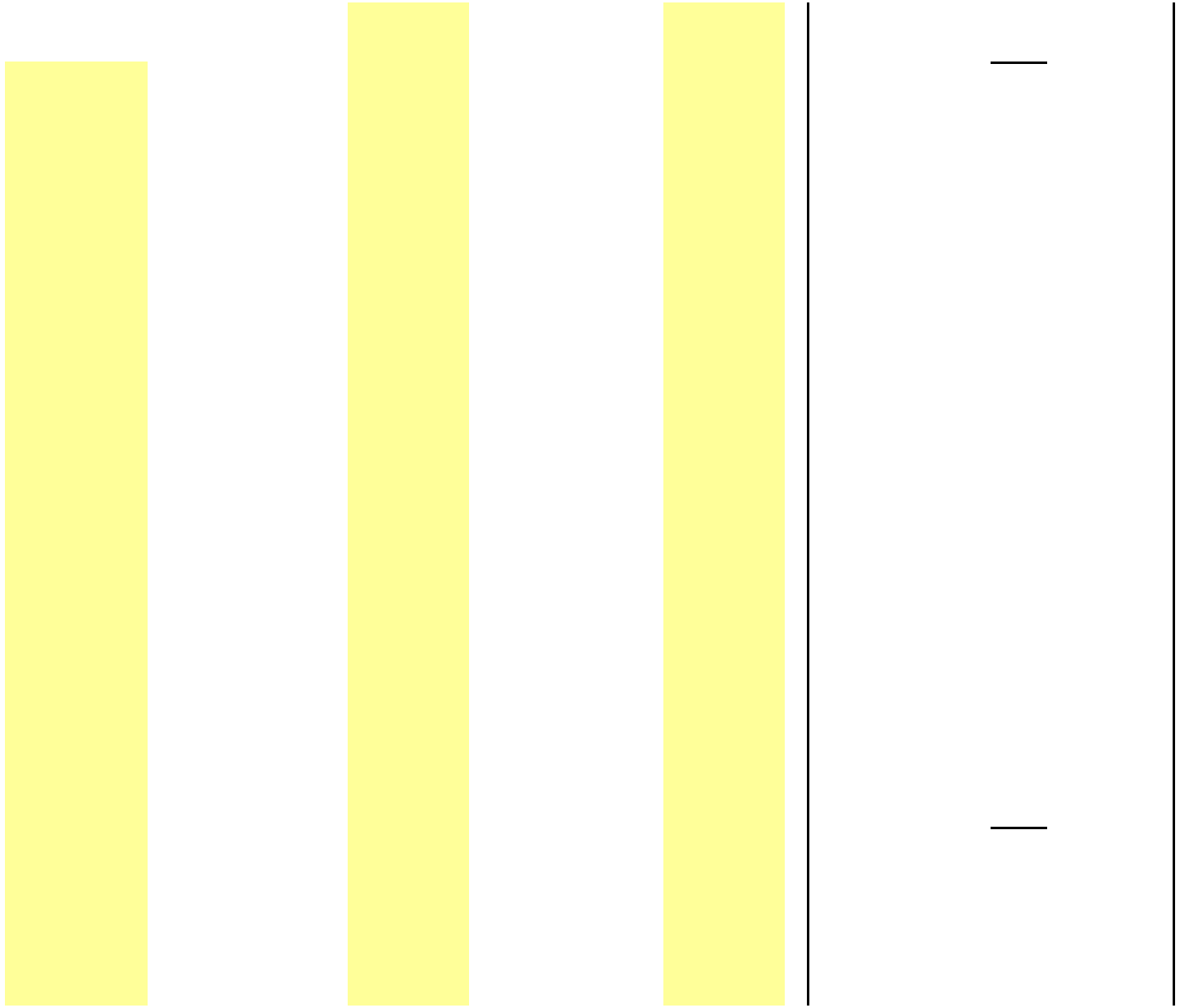
| | | | Progress (107) | | Issued (204) | | | | |
| 4 | Operation Expenses (401) | 4 | **TOTAL Utility Plant (Enter Total of Lines 2 and 3)** | 4 | Capital Stock Subscribed (202, 205) | **5** | Total Long-term Liabilities | Sum Lines 2 thru 4 | **-** |
| 5 | Maintenance Expenses (402) | 5 | (Less) Accum. Prov. For Depr. Amort. Depl. (108, 110, 111, 115) | 5 | Stock Liability for Conversion (203, 206) | | | | |
| 6 | Depreciation Expense (403) | 6 | Net Utility Plant (Enter Total of Line 4 less 5) | 6 | Premium on Capital Stock (207) | **6** | **Current Liabilities** | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 7 | Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.10) | 7 | Other Paid-In Capital (208-211) | **7** | | | |
| | Amor. & Depl. Of Utility Plant | | Nuclear Fuel Materials and Assemblies- | | Installments Received on Capital | | **Total LT & Current Liabil** | Sum Lines | |

8 (404-405) 8 Stock 8 Stock (212) **8 ities** 5 + 7 **-**



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| | | | Provision for Deferred | | 17 | | |
| | | | | (Less) Accum. Prov. For Amor. Of Nucl. Fuel Assemblies (120.5) | 17 | Gas Underground - Noncurrent (117) | Stored 16 |
| | | | | | | **Other Property** | 17 |
| 12 | Regulatory Debits (407.3) | 12 | | | | | |
| 13 | (Less) Regulatory Credits (407.4) | 13 | | | | | |
| 14 | Taxes Other then Income Taxes (408.1) | 14 | | Net Utility Plant (Enter Total of lines 6 and 13) | 14 | | |
| 15 | Income Taxes - Federal (409.1) | 15 | | | | | |
| 16 | - Other (409.1) | 16 | | Utility Plant Adjustments (116) | 15 | | |

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|---|---|---|---|---|---|---|---|---|---|---|
| | Income Taxes (410.1) | | **And Investments** | | | | | | | |
| 18 | (Less) Gains from Disp. Of Utility Plant (411.6) | 18 | Nonutility Property (121) | 18 | Bonds (221) | | | | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 19 | (Less) Accum. Prov. For Depr. and Amort. (122) | 19 | (Less) Reacquired Bonds (222) | | | | | |
| 20 | (Less) Gains from Disp. Of Utility Plant (411.6) | 20 | Investments in Associated Companies (123) | 20 | Advances from Associated Companies (223) | | | | | |
| 21 | Losses from Disp. Of Utility Plant (411.7) | 21 | Investment in Subsidiary Companies (123.1) | 21 | Other Long-Term Debt (224) | | | | | |
| 22 | (Less) Gains from Disposition of Allowances (411.8) | 22 | (For Cost of Account 123.1, See Footnote Page 224, line 42) | 22 | Unamortized Premium on Long-Term Debt | | | | | |

| | Total LTD & Margins & Equities | Sum | 10 + 13 | - | # DIV/0! | # DIV/0! |
|---|---|---|---|---|---|---|
| 14 | | | | | | |

**LTD & Equity - 20XX Estimate**

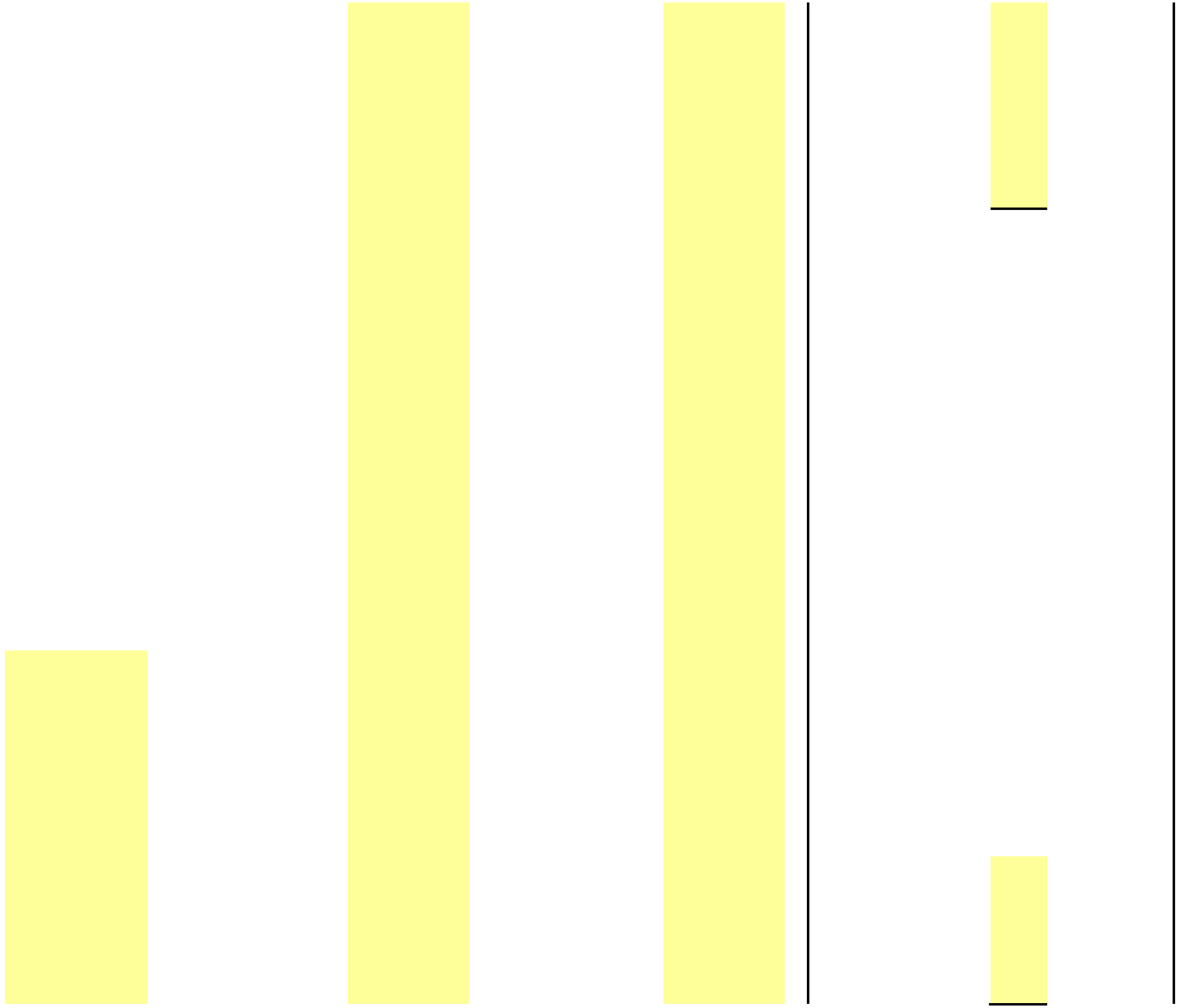
| Line No | Descriptions | Source | 20XX Estimate | Percent | Rate | Cost |
|---|---|---|---|---|---|---|

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23 | Losses from Disposition of Allowances (411.9) | | 23 | Noncurrent Portion of Allowances | | 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | | | | | | |
| 24 | Accretion Expense (411.10) | | 24 | Other Investments (124) | | 24 | Total Long-Term Debt (lines 18 through 23) | | | | | | | - |
| 25 | Total Utility Operating Expenses (Enter Total of lines 4 through 24) | | 25 | Sinking Funds (125) | | 25 | **Other Noncurrent Liabilities** | | | | | | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg 117, line 27 | | 26 | Depreciation Fund (126) | | 26 | Obligations Under Capital Leases - Noncurrent (227) | | | | | | | |
| 27 | Net Utility Operating Income (Carried forward from page 114) | | 27 | Amortization Fund - Federal (127) | | 27 | Accumulated Provision for Property Insurance (228.1) | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | |
| 1 | **Long-term Liabilities** | | | | | | - |
| 2 | Bonds | Estimate | | | | | |
| | Other Long-Term Debt | Estimate | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 28 | Other Income and Deductions | 228 | Other Special Funds (128) | 228 | Accumulated Provision for Injuries and Damages (228.2) | **4** | | xxxx | |
| 29 | Other Income | 229 | Special Funds (Non Major Only) (129) | 229 | Accumulated Provision for Pensions and Benefits (228.3) | **5** | Total Long-term Liabilities | Sum Lines 2 thru 4 | **-** |
| 30 | Nonutility Operating Income | 230 | Long-Term Portion of Derivative Assets (175) | 230 | Accumulated Miscellaneous Operating provisions (228.4) | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | 231 | Long-Term Portion of Derivative Assets - Hedges (176) | 231 | Accumulated Provision for Rate Refunds (229) | **6** | **Current Liabilities** | | |
| | (Less) Costs and Exp. Of Merchandisi | 23 | TOTAL Other Property and | 23 | Long-Term Portion of Derivative Instrument | | | Esti | |

32 ng, job. & 2 Investments 2 Liabilities **7** mate



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| | | | Earnings of 36 Subsidiary | | 3 | | |
| | Contract Work (416) | | | | 6 | | 3 |
| | | | | | | Cash (131) | 5 |
| | Revenues From Nonutility Operations | 3 | | (Lines 18-21 and 23-31) | | Special Deposits (132-134) | 3 6 |
| 33 | (417) | 3 | | **Current and Accrued Assets** | | | |
| | | | | | | | 3 3 |
| | (Less) Expenses of Nonutility operations | 3 | | Cash and Working Funds (Non-major Only) (130) | | | |
| 34 | (417.1) | 4 | | | | | |
| | Nonoperating Rental Income | 3 | | | | | |
| 35 | (418) | 5 | | | | | 3 |
| | Equity in | | | | | | 4 |

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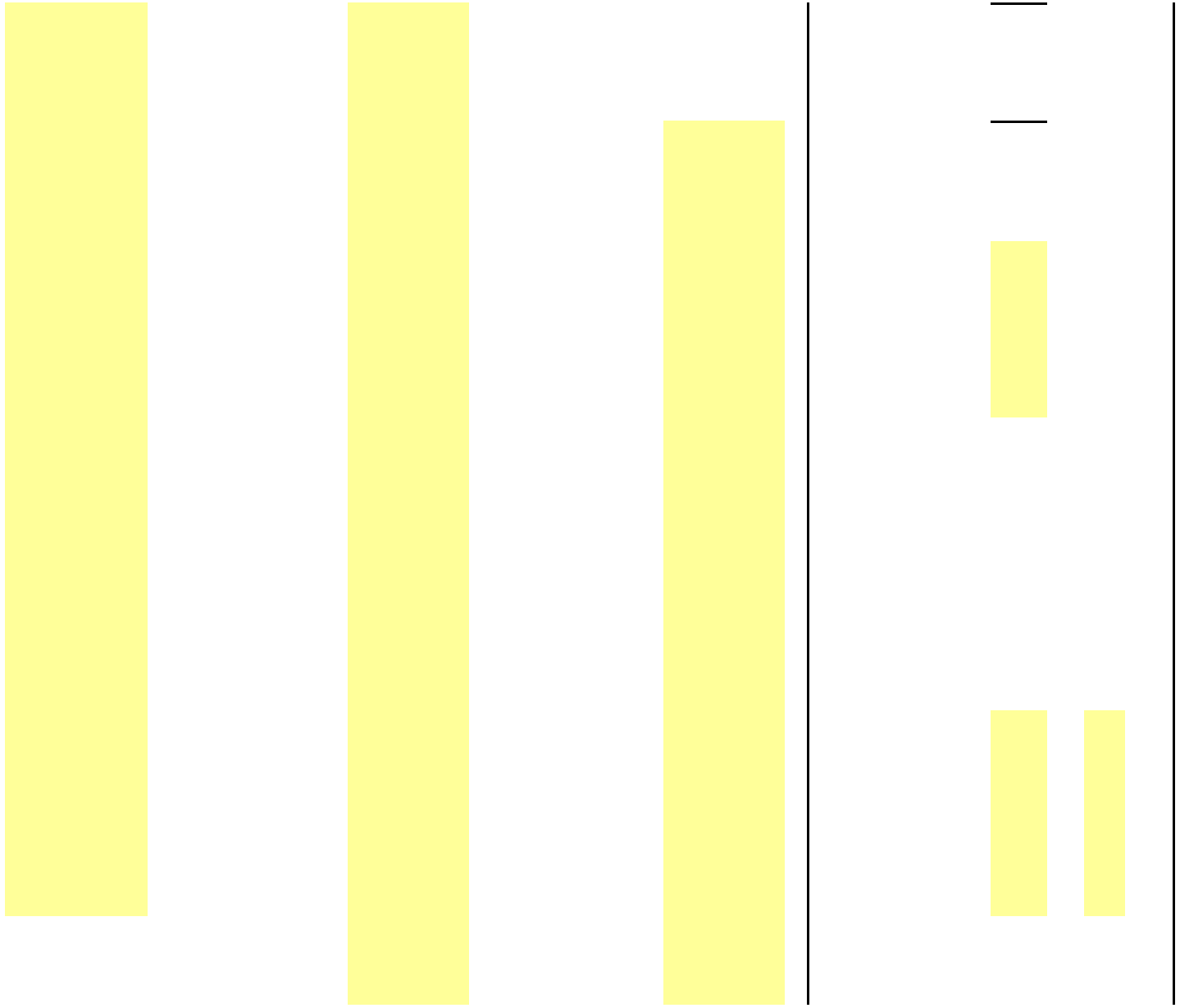
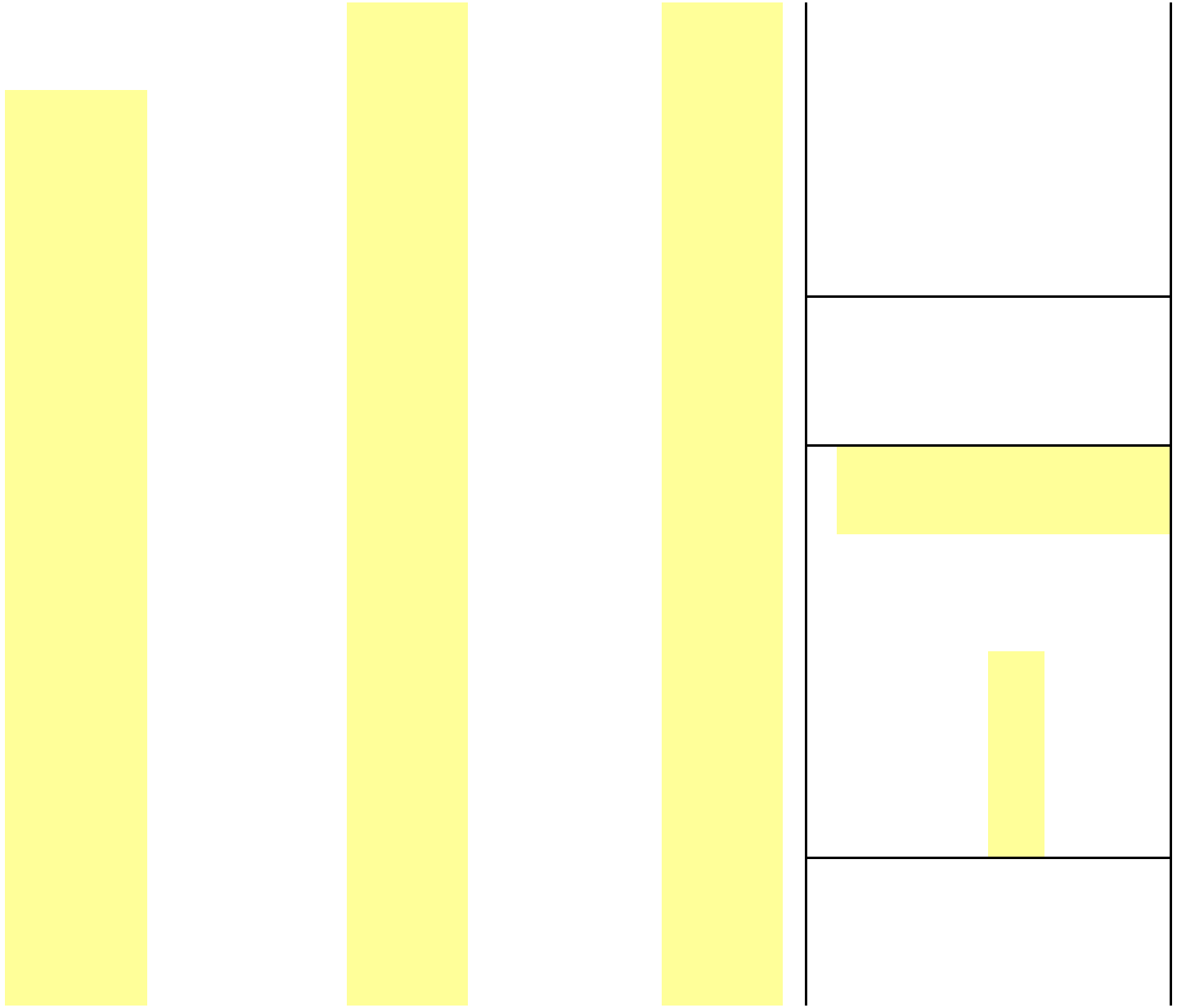
| | Companies (418.1) | | | **Accrued Liabilities** | | **Term Debt** | thru 9a | | **V / 0 !** | **V / 0 !** | **V/ 0!** |
| 37 | Interest and Dividend Income (419) | 37 | Working Fund (135) | 37 | Notes Payable (231) | | | | | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | 38 | Temporary Cash Investments (136) | 38 | Accounts Payable (232) | **11** | | Estimate | - | | |
| 39 | Miscellaneous Nonoperating Income (421) | 39 | Notes Receivable (141) | 39 | Notes Payable to Associated Companies (233) | **12** | **Total Long-Term Debt** | Sum Lines 5 + 11 | - | | |
| 40 | Gain on Disposition of Property (421.1) | 40 | Customer Accounts Receivable (142) | 40 | Accounts Payable to Associated Companies (234) | | | | | | |
| 41 | Total Other Income (Enter Total of lines 31 through 40) | 41 | Other Accounts Receivable (143) | 41 | Customer Deposits (235) | **13** | Total Margins & Equities | **Estimate** | **#DIV/0!** | | **#DIV/0!** |
| | Other Income | 42 | (Less) Accum. | 42 | Taxes Accrued | | | | | | |

42 Deductions 2 Prov. For 2 (236)



| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Uncollectible Acct.-Credit (144) | | | | | | | | | | |
| 43 | Loss on Disposition of Property (421.2) | 43 | Notes Receivable from Associated Companies (145) | 43 | Interest Accrued (237) | **14** | **Total LTD & Margins & Equities** | **Sum 10 + 13** | **-** | **# DIV/0!** | | **# DIV/0!** |
| 44 | Miscellaneous Amortization (425) | 44 | Accounts Receivable from Assoc. Companies (146) | 44 | Dividends Declared (238) | | | | | | | |
| 45 | Donations (426.1) | 45 | Fuel Stock (151) | 45 | Matured Long-Term Debt (239) | | **LTD & Equity - 20XX Estimate** | | | | | |
| 46 | Life Insurance (426.2) | 46 | Fuel Stock Expenses Undistributed (152) | 46 | Matured Interest (240) | **Line** | | | | | | |
| 47 | Penalties (426.3) | 47 | Residuals (Elec) and Extracted Products (153) | 47 | Tax Collections Payable (241) | **No** | **Descriptions** | **Source** | **20XX Estimate** | **Percent** | **Rate** | **Cost** |
| | Exp. For Certain Civic, Political & | 4 | Plant Materials and | 4 | Miscellaneous Current and | | | | | (d | (e | |

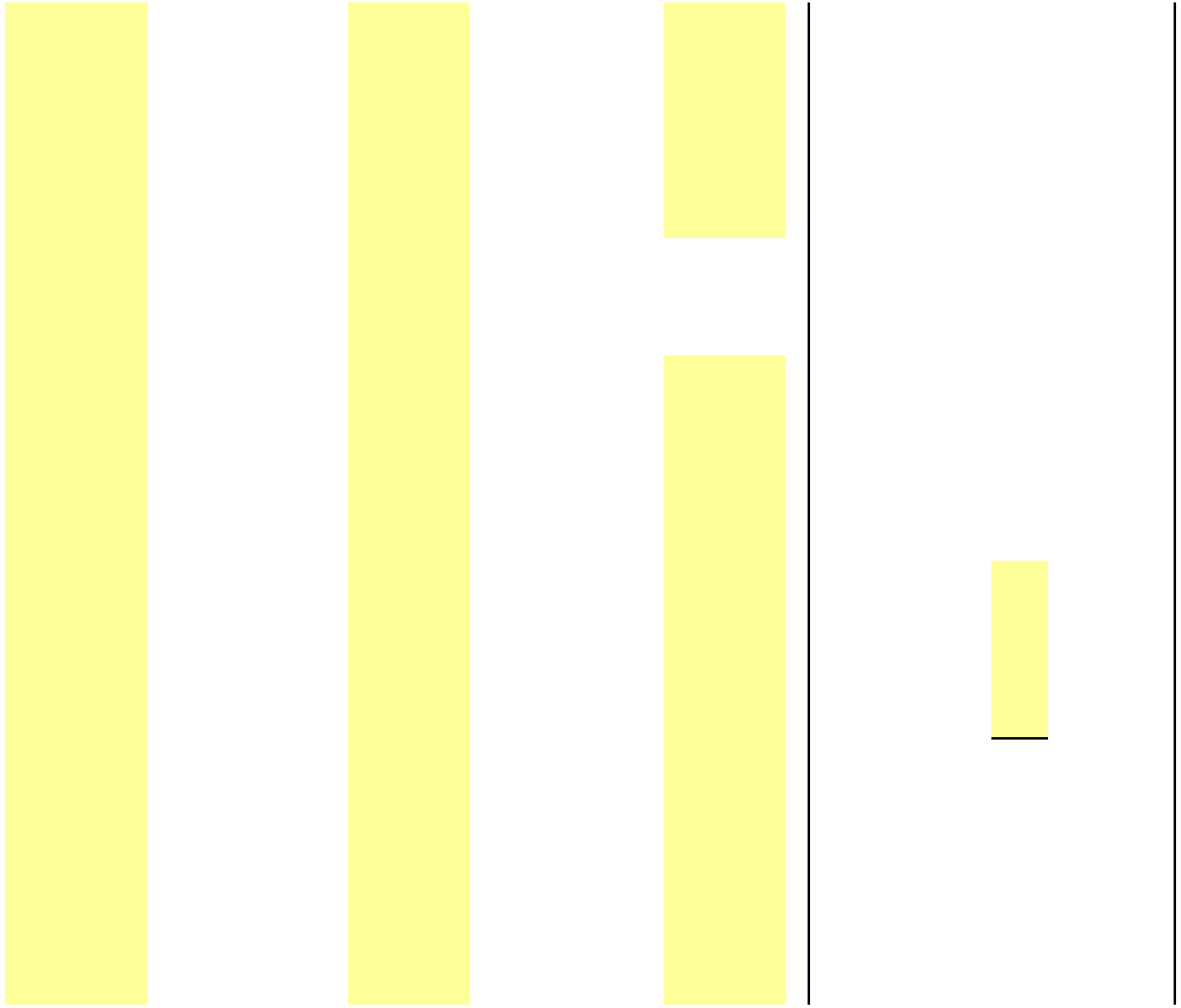
48 Related 8 Operating 8 Accrued (a) (b) (c) ) ) (f)



| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Activities (426.4) | | | Supplies (154) | | | Liabilities (242) | | | | | | | | |
| 49 | Other Deductions (426.5) | | 49 | Merchandise (155) | | 49 | Obligations Under Capital Leases - Current (243) | | | - | | | | | |
| 50 | Total Other Income Deductions (Total of Lines 43 thru 49) | | 50 | Other Materials and Supplies (156) | | 50 | Derivative Instrument Liabilities (244) | | 1 | **Long-term Liabilities** | | | | | |
| 51 | Taxes Applic. To Other Income and Deductions | | 51 | Nuclear Materials Held for Sale (157) | | 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 2 | Bonds | Estimate | | | | |
| 52 | Taxes Other Than Income and Deductions (408.2) | | 52 | Allowances (158.1 and 158.2) | | 52 | Derivative Instrument Liabilities (245) | | 3 | Other Long-Term Debt | Estimate | | | | |
| 53 | Income Taxes-Federal (409.2) | | 53 | (Less) Noncurrent Portion of Allowances | | 53 | (Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges | | 4 | | xxxx | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | Total Current and Accrued liabilities (lines 37 through 53) | | Total Long-term Liabilities | Sum Lines 2 thru 4 | - |
| 54 | Income Taxes-Other (409.2) | 54 | Stores Expense Undistributed (163) | 54 | | | | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 55 | Gas Stored Underground - Current (164.1) | 55 | **Deferred Credits** | | | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 56 | Liquefied Natural Gas Stored and Held for Processing (164.2-164.3) | 56 | Customer Advances for Construction (252) | 6 | **Current Liabilities** | | |
| 57 | Investment Tax Credit Adj.-Net (411.5) | 57 | Prepayments (165) | 57 | Accumulated Deferred Investment of Utility Plant (255) | 7 | | | |
| 58 | (Less) Investment Tax Credits (420) | 58 | Advances for Gas (166-167) | 58 | Deferred Gains from Disposition of Utility Plant (256) | 8 | **Total LT & Current Liabilities** | Sum Lines 5 + 7 | - |
| | Total Taxes on Other | | Interest and | | Other | | | | |

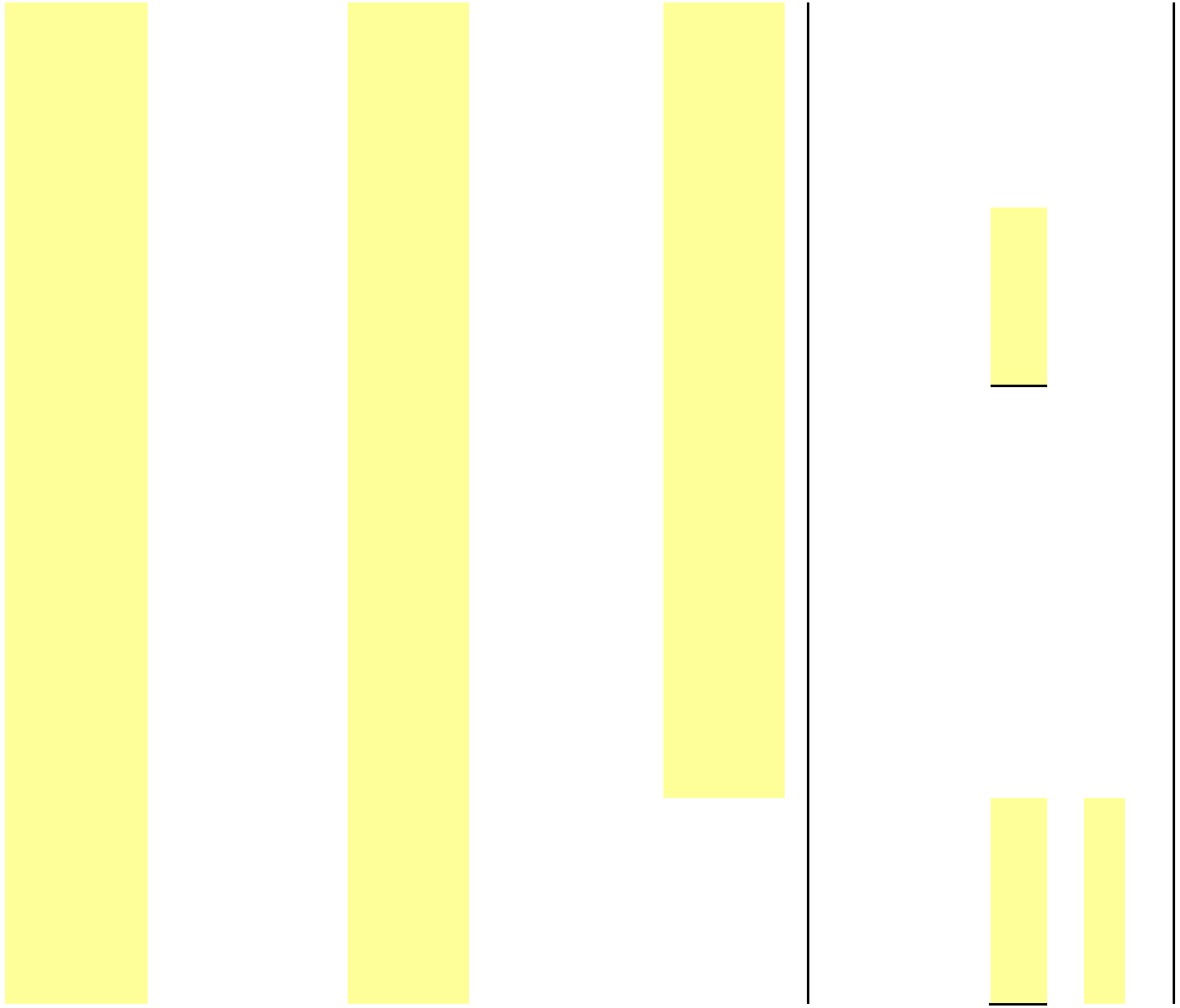
59 Income and 9 Dividends 9 Deferred



| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Deductions (Total of Lines 52-58) | | Receivable (171) | | Credits (253) | | | | | | | | | |
| 60 | Net Other Income and Deductions (Total of lines 41,50, 59) | | 60 | Rents Receivable (172) | 60 | Other Regulatory Liabilities (254) | | | | | | | | |
| 61 | Interest Charges | | 61 | Accrued Utility Revenues (173) | 61 | Unamortized Gain on Reacquired Debt (257) | | | | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 62 | Miscellaneous Current and Accrued Assets (174) | 62 | Accum. Deferred Income Taxes-Accel. Amort. (281) | | | | | | | | |
| | | | | | | | | 9 | **Less: Powder River Patronage (Pass thru Tri-State - Basin Electric - PreCorp)** | Estimate | | | | |
| | | | | | | | | 9a | **Less: Other** | Estimate | - | **#DIV/0!** | | **#DIV/0!** |
| | | | | | | | | 10 | **Total Long Term Debt** | Sum Line 8 - 9a | - | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Amort. Of Debt Disc. And Expense | | Derivative | | Accum. Deferred Income Taxes-Other | | | | | | |
| 63 | (428) | 63 | Instrument Assets (175) | 63 | Property (282) | | | | | | |
| | Amortization of Loss on Reacquired Debt | | (Less) Long-Term Portion of Derivative | | Accum. Deferred Income | | | | | | |
| 64 | (428.1) | 64 | Instrument Assets (175) | 64 | Taxes-Other (283) | **11** | | Estimate | - | | |
| | (Less) Amort. Of Premium on Debt Credit | | Derivative Instrument Assets - | | Total Deferred Credits (lines 56 | | **Total Long-** | Sum Lines | | | |
| 65 | (429) | 65 | Hedges (176) | 65 | through 64) | **12** | **Term Debt** | 5 + 11 | **-** | | |
| | (Less) Amortization of Gain on Reacquired Debt-Credit | | (Less) Long-Term Portion of Derivative Instrument Assets - | | Total Liabilities and Stockholder Equity (lines | | | | | | |
| 66 | (429.1) | 66 | Hedges (176) | 66 | 16,24,35,54 and 65) | | | | | | |
| | Interest on Debt to Assoc. Companies | | Total Current and Accrued Assets | | | | Total Margins & Equit | **Estimat** | | **#DIV/0** | **#DIV/** |
| 66 | | 66 | (Lines 34 | | | **13** | | | | | |

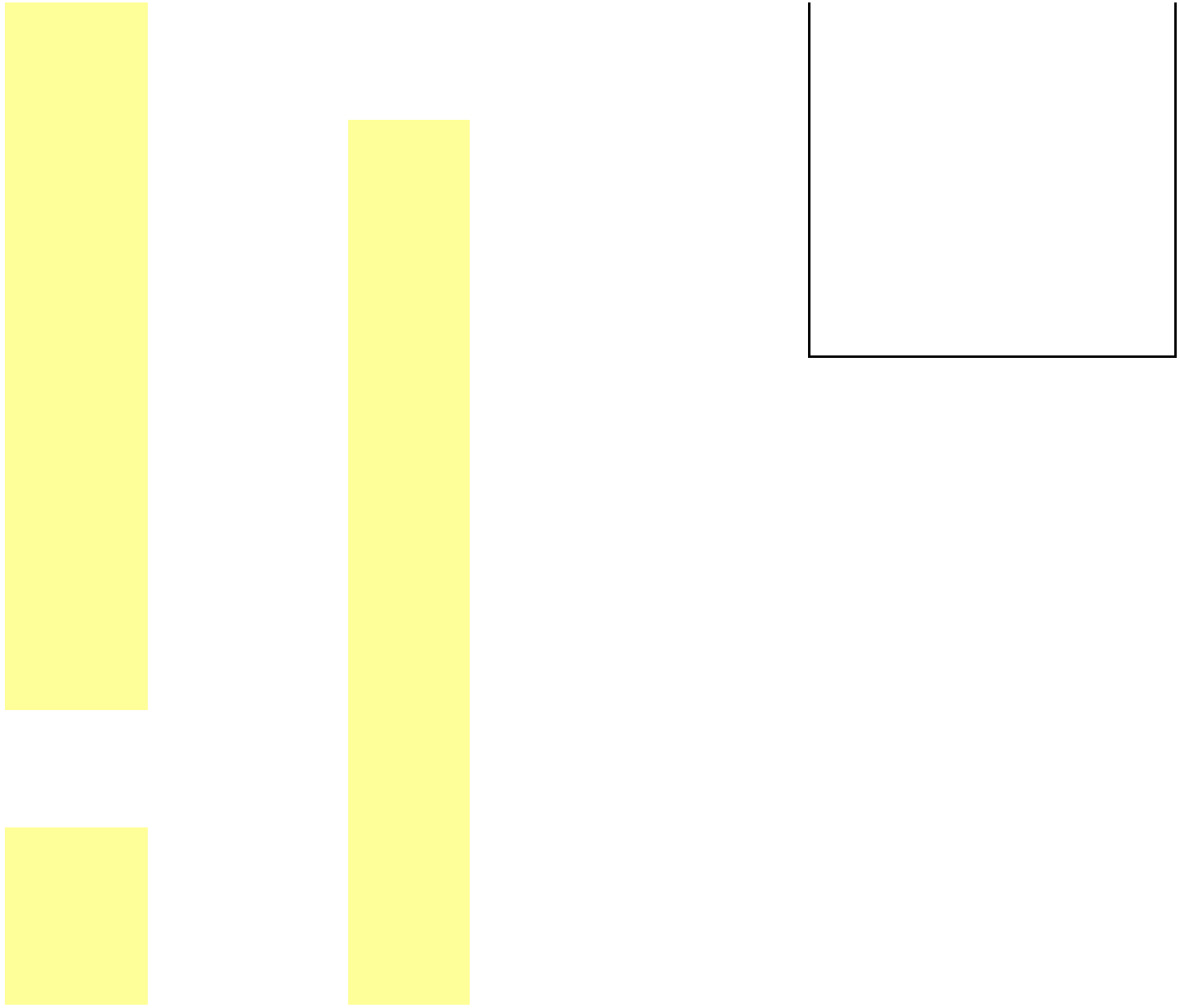
67 (430) 7 through 66) **3** ies **e** **!** **0!**



| | | | |
|---|---|---|---|
| | Other Interest Expense | 6 | **Deferred Debits** |
| 68 | (431) | 8 | |
| | (Less) Allowance for Borrowed Funds Used During Constructio | | Unamortize d Debt |
| 69 | n-Cr. (432) | 6 9 | Expenses (181) |
| | Net Interest Charges (Total of lines 62 thru | | Extraordina ry Property |
| 70 | 69) | 7 0 | Losses (182.1) |
| | Income Before Extraordinar y Items (Total of lines 27, 60, | | Unrecovere d Plant and Regulatory Study Costs |
| 71 | and 70) | 7 1 | (182.2) |
| | Extraordinar | 7 | Other Regulatory Assets |
| 72 | y Items | 2 | (182.3) |
| | Extraordinar y Items | 7 | Prelim. Survey and Investigatio n Charges (Electric) |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Total LTD & Marg ins &** | **Sum** | | **# D I V /** | **# DI V/** | |
| **1 4** | **Equit ies** | **10 + 13** | **-** | **0 !** | **0!** | |

73 (434) 3 (183)



| | | | |
|---|---|---|---|
| | | | Preliminary Natural Gas Survey and Investigation Charges (183.2) |
| 74 | (Less) Extraordinary Deductions (435) | 74 | |
| 75 | Net Extraordinary Items (Total of line 73 less 74) | 75 | Clearing Accounts (184) |
| 76 | Income Taxes - Federal and Other (409.3) | 76 | Temporary Facilities (185) |
| 77 | Extraordinary Items After Taxes (Line 75 less line 76) | 77 | Temporary Facilities (185) |
| 78 | Net Income (Total of line 71 and 77) | 78 | Miscellaneous Deferred Debits (186) |
| | | 79 | Def. Losses from Disposition of Utility Plt. (187) |
| | | 80 | Research, Devel. And |

Note:

The addition of new lines and the removal of outdated lines necessary

to populate or remove data in the 0 Demonstrat

**Basin Electric Power Cooperative**

workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

| | | | |
|---|---|---|---|
| | ze d Loss on Reaquired Debt (189) | 8 1 | |
| | Accumulated Deferred Income Taxes (190) | 8 2 | |
| | Unrecovered Purchase Gas Costs (191) | 8 3 | |
| | Total Deferred Debits (lines 69 through 83) | 8 4 | |
| | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | 8 5 | # |

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**Formula Rate Template**
**for the year ended December 31, 20XX**
**Work Paper #4**
**FERC Form 1 - Page 323**

**Page 5 of 5**

**Electric Operation and Maintenance Expenses**

| Line | Account | Amount for Current Ye | Amount for Previous Ye |
|---|---|---|---|

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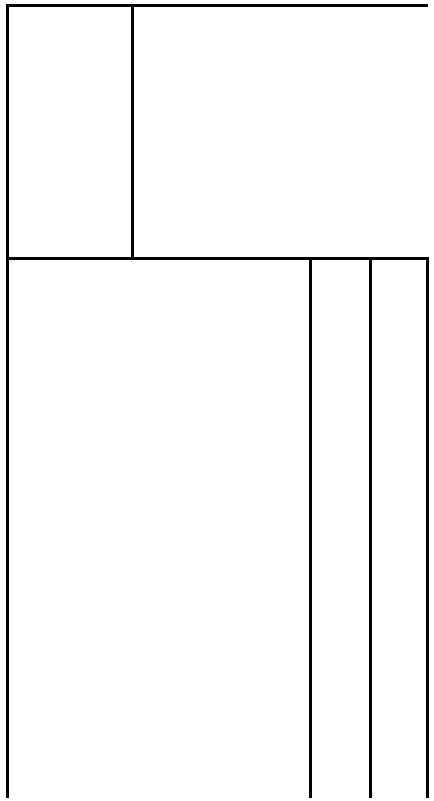


| No. | (a) | (b) | (c) |
|---|---|---|---|
| 180 | Operation (920) | | |
| | Administrative and General | | |
| 181 | Salaries (921) | | |
| | Office Supplies and | | |
| 182 | Expenses (Less) (922) | | |
| | Administrative Expenses Transferred- | | |
| 183 | Credit (923) | | |
| | Outside Services | | |
| 184 | Employed (924) | | |
| | Property | | |
| 185 | Insurance (925) | | |
| | Injuries and | | |
| 186 | Damages (926) | | |
| | Employee Pensions | | |
| 187 | and Benefits (927) | | |
| 188 | Franchise | | |

| | |
|---|---|
| | Requirements |
| | (928) Regulatory Commission |
| 189 | Expenses |
| | (929) (Less) Duplicate |
| 190 | Charges-Cr. |
| | (930.1) General Advertising |
| 191 | Expenses |
| | (930.2) Miscellaneous General |
| 192 | Expenses |
| 193 | (931) Rents |
| | Total Operation (Enter Total of lines 181 |
| 194 | thru 193) |
| | Maintenanc |
| 195 | e |
| | (935) Maintenanc e of General |
| 196 | Plant |
| | Total Administrati ve & General |

197 Expenses

(Total of lines 194 and 196)

**Basin Electric Power Cooperative**
**Formula Rate Template**

**for the year ended December 31, 20XX**

**Work Paper #5**
**FERC Form 1 - Pages 200, 204-207**



**Electric Plant In Service (Account 101,102,103 and 106)**

| FERC Form 1 - Pages 204-207 Line Number | Account | BALANCE BEGINNING OF YEAR | ADDITIONS | RETIREMENTS | ADJUSTMENTS | TRANSFERS | BALANCE AT END OF YEAR |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | ( c) | (d) | ( e) | (f) | (g) |
| 5 | TOTAL Intangible Plant | | | | | | 0 |

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Gross Plant In-Service & Accumulated Depreciation Expenses**
**Adjustments to Gross Plant & Accumulated Depreciation Estimates**
**Work Paper #5**



TOTAL
16 Steam

| BOY / EOY Average | Line | GROSS PLANT IN SERVICE |
|---|---|---|
| (h) | | Production Plant |
| - | 2 | Transmission: |
| | | Plus: |

| | | | | | | |
|---|---|---|---|---|---|---|
| - | 4 | Acquisition | YE 12/31 /20XX | Budget Year | Budget Year | Budget 20XX -XX |
| | | | BOY / EOY Ave. | 20XX | 20XX | BOY / EOY Ave. |
| | | | a | b | c | d |
| | | | - | | - | - |
| | | | - | | - | |
| | | | - | - | - | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Production Plant | | | | | | | | | | | **Adjustment (CUS)** | | | | |
| | TOTAL Nuclear Production | | | | | | | | | | | | | | | |
| 25 | Plant | | | | | | 0 | - | | **5** | | | | | | |
| | TOTAL Hydraulic Production | | | | | | | | | | | **Subtotal w/adjust** | | | | |
| 35 | Plant | | | | | | 0 | - | | **6** | | **ment** | - | - | - | - |
| | TOTAL Other Prod | | | | | | | | | | | | | | | |
| 45 | Plant | | | | | | 0 | - | | | | | | | | |
| | **TOTAL Prod** | | | | | | | | | | | **Distributi** | | | | |
| **46** | **Plant** | **0** | **0** | **0** | **0** | **0** | **0** | | **0** | **7** | | **on** | - | - | - | - |
| | | | | | | | | | | **8** | | **General** | - | - | - | - |
| | (350) Land and Land | | | | | | | | | | | **Intangibl** | | | | |
| 48 | Rights | | | | | | 0 | - | | **9** | | **e** | - | - | - | - |
| | (352) Structures and | | | | | | | | | | | | | | | |
| | Improveme | | | | | | | | | | | **Total Gross** | | | | |
| 49 | nts | | | | | | 0 | - | | **10** | | **Plant** | - | - | - | - |
| | (353) Station | | | | | | | | | | | | | | | |
| 50 | Equipment | | | | | | 0 | - | | | | | | | | |
| | | | | | | | | | | | | **ACCUMU** | | | | |
| | (354) Towers and | | | | | | | | | | | **LATED** | | | | |
| | | | | | | | | | | | | **DEPRECI** | | | | |
| 51 | Fixtures | | | | | | 0 | - | | | | **ATION** | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 52 | (355) Poles and Fixtures | | | | | | 0 | - | | 11 | **Production Plant** | - | | | - |
| 53 | (356) Overhead Conductors and Devices | | | | | | 0 | - | | 12 | | | | | |
| 54 | (357) Underground Conduit | | | | | | 0 | - | | 13 | **Transmission: Depr.** | - | | | - |
| 55 | (358) Underground Conductors and Devices | | | | | | 0 | - | | 14 | **Plus: Acquisition Adjustment (CUS)** | - | | | - |
| 56 | (359) Roads and Trails | | | | | | 0 | - | | 15 | | | | | |
| 57 | (359.1) Asset Retirement Costs for Trans. Plant | | | | | | 0 | - | | 16 | **Subtotal w/adjustments** | **-** | **-** | **-** | **-** |
| **58** | **TOTAL Transmission Plant** | **0** | **0** | **0** | **0** | **0** | **0** | | **0** | | | | | | |
| | | | | | | | | | | 17 | **Distribution** | - | - | - | - |
| 75 | Total Distribution Plant | | | | | | 0 | - | | 18 | **General** | - | - | - | - |
| | Total Transmissio | | | | | | | | | | | | | | |

84 n and 0 - **19**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 86 | Market Operation Plant (389) Land and Land Rights | 0 | - | 20 | **Total Gross Plant** | - | - | - | - |
| 87 | (390) Structures and Improvements | 0 | - | | | | | | |
| 88 | (391) Office Furniture and Equipment | 0 | - | | **NET PLANT IN SERVICE** | | | | |
| 89 | (392) Transportation Equipment | 0 | - | 21 | **Production** | - | - | - | - |
| 90 | (393) Stores Equipment | 0 | - | 22 | **Transmission** | - | - | - | - |
| 91 | (394) Tools, Shop and Garage Equipment | 0 | - | 23 | **Distribution** | - | - | - | - |
| 92 | (395) Laboratory Equipment | 0 | - | 24 | **General** | - | - | - | - |
| 93 | (396) Power Operated Equipment | 0 | - | 25 | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 94 | (397) Communication Equipment | P r o p e r t y | | | | | | | | 0 | - | | **26** |
| 95 | (398) Miscellaneous Equipment | | | | | | | | | 0 | - | | |
| 97 | ((399) Other Tangible Property | 4 | | | | | | | | 0 | - | | |
| 98 | (399.1) Asset Retirement Costs for General Plant | U n d e r | | | | | | | | 0 | - | | |
| 99 | **TOTAL General Plant** | | | | | | | | | **0** | **-** | | |
| **100** | **TOTAL (Accounts 101 and 106)** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | | | | |

**FERC Form 1 - Page 200 Line Number**

| | | | | |
|---|---|---|---|---|
| 0 | - | **TOTAL NET PLANT** | - | - |
| | | | - | - |

| | | | | |
|---|---|---|---|---|
| | Capital Leases | | | |
| 9 | Leased to Others | | 0 | - |
| 10 | Held for Future Use | | 0 | - |
| 11 | Construction Work in Progress | | 0 | - |
| 12 | Acquisition Adjustments | | 0 | - |
| 13 | **Total utility Plant** | | 0 | - |

Notes:

1. Amounts include MBPP (Basin share).
2. Amounts do not include Cornbelt.
3. Use Property audit workpaper for Utility and Non-Utility Plant.
4. Use CWIP roll forward audit workpaper for Construction Work in Progress.
5. Rounding diff correction (if any)

included in Line 2 Additions.

**Work Paper #5 Page 4 of 4**

**BASIN ELECTRIC POWER COOPERATIVE**

**for the year ended December 31, 20XX**

**Work Paper #5**
**FERC Form 1 - Page 219 and 200**

**Page 2 of 4**

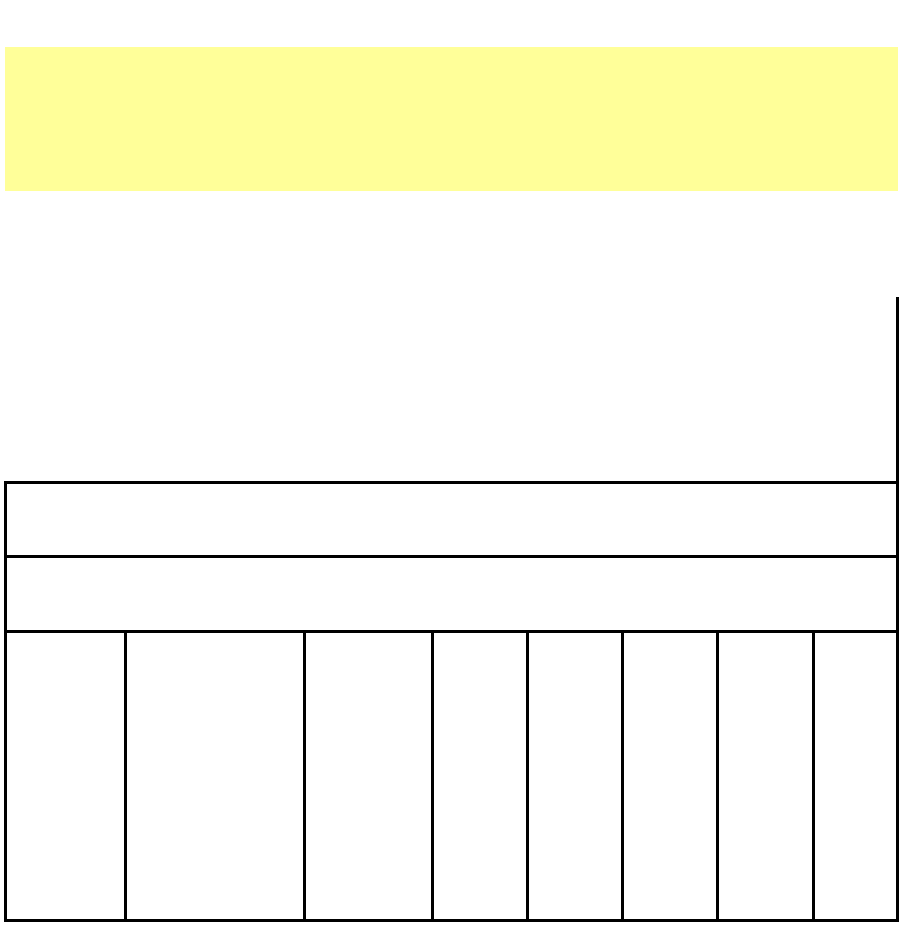
**Accumulated Provision for Depreciation of Electric Utility Plant (Account 108)**
**Section B. Blalances at End of Year According to Functional Classification**

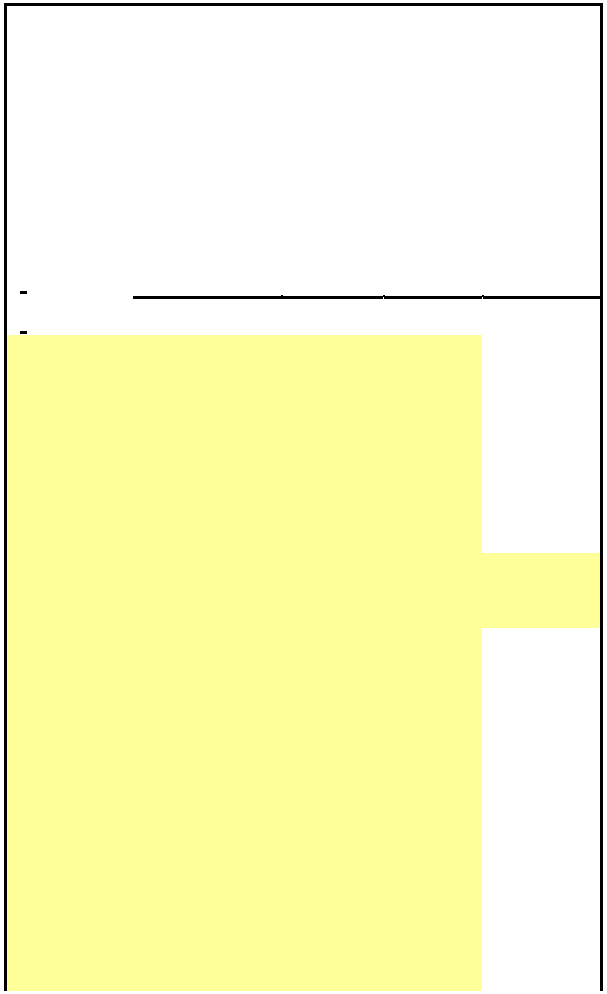
| Line No. | Item | Beginning of Year | Total (c+d+e) | Electric Plant in Service | Electric Plant Held for Future Use | Electric Plant Leased to Others | BOY/EOY Average |
|---|---|---|---|---|---|---|---|

**Member Leases Depreciation ***

| Gross Plant | Annual Depr | Accum Depr | Net Book |
|---|---|---|---|
| | | | - |
| | | | - |
| | | | - |
| | | | - |

a b c d e g -





Page 219

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 20 | Steam Production | | | | | | 0 |
| 21 | Nuclear Production | | | | | | 0 |
| 22 | Hydraulic Production-Conventional | | | | | | 0 |
| 23 | Hydraulic Production-Pumped Storage | | | | | | 0 |
| 24 | Other Production | | | | | | 0 |
| 25 | Transmission | | | | | | 0 |
| 26 | Distribution | | | | | | 0 |
| 27 | Regional Transmission and Market Operation | | | | | | 0 |
| 28 | General | | | | | | 0 |
| 29 | **TOTAL (Enter of Lines 20 thru 28)** | - | - | - | - | - | 0 |

*** If necessary, details can be provided.**

Page 200

| | | Classification | Beginning of Year | Total Company for the Current Year/Quarter Ended | |
|---|---|---|---|---|---|
| 18 | n | Depreciation | | | 0 |
| 24 | n | Depreciation | | | 0 |
| 32 | Adj | Amort of Plant Acquisition | | | 0 |
| 33 | Prov | Total Accum | | | 0 |

Note:
The addition of new lines and the removal of outdated lines

necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of

columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**

**Annual O&M Expense**

**Formula Rate Template**

**12 Months Ending December 31, 20XX**

**Work Paper #6**

**Page 3 of 3**

for the year ended December 31, 20XX

**Work Paper #6**

**Page 2 of 3**

**Annual O & M Expense 20XX / 20XX Estimate**

**Work Paper #6**

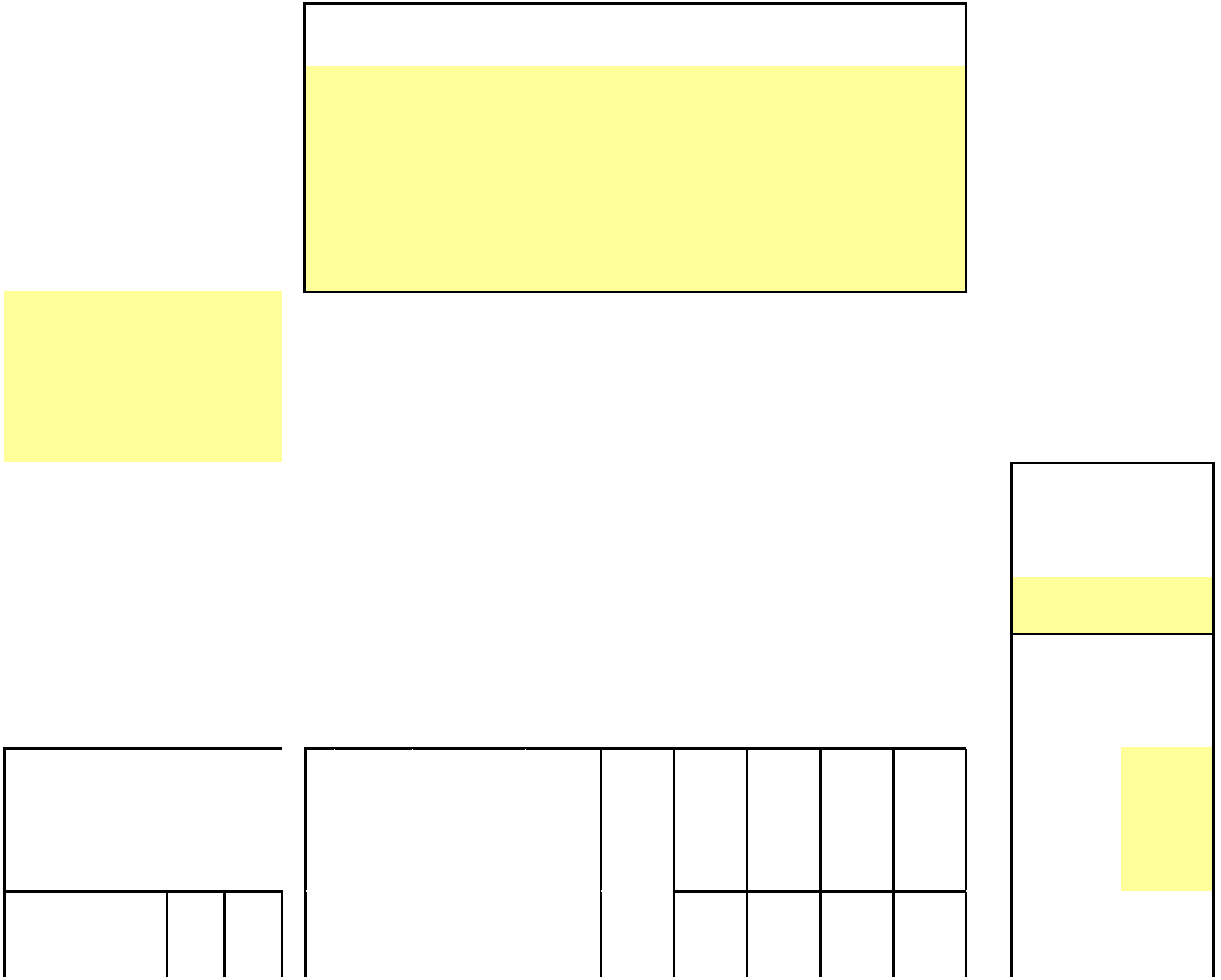
**FERC Form 1 - Page 321**

**Page 1 of 3**

**Electric Operation and Maintenance Expenses**

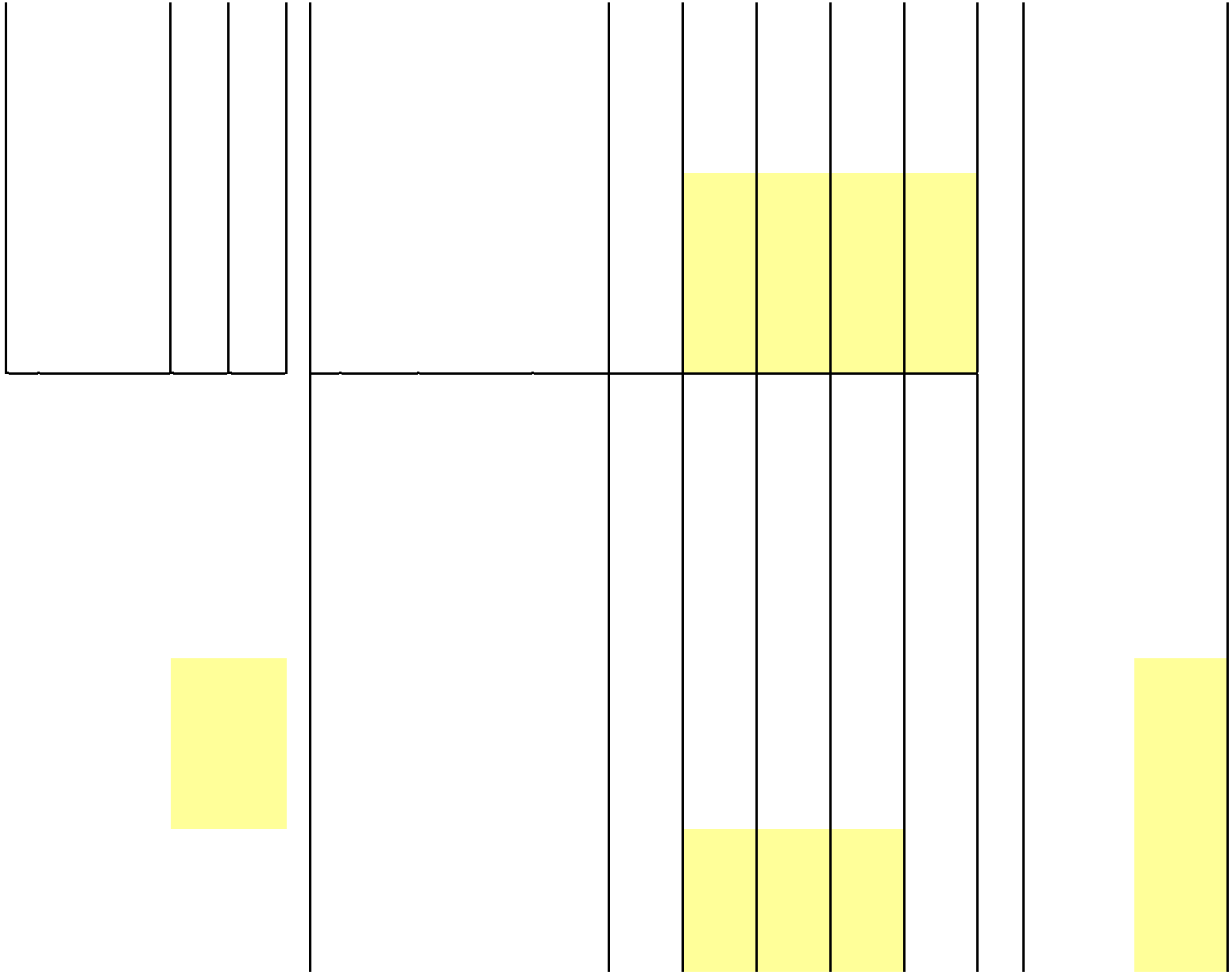
| L | Am | Am | FERC | Total O&M FERC | UMZ Zone 19 | MBPP Transmission | Other Transmission | Total Transmission | 20XXA | 20XX |
|---|---|---|---|---|---|---|---|---|---|---|

| i | Account | ou nt | ou nt | L i | Acco unt | Form 1 - | Ann ual | Ann ual | Ann ual | Ann ual | p p | Fo rec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|



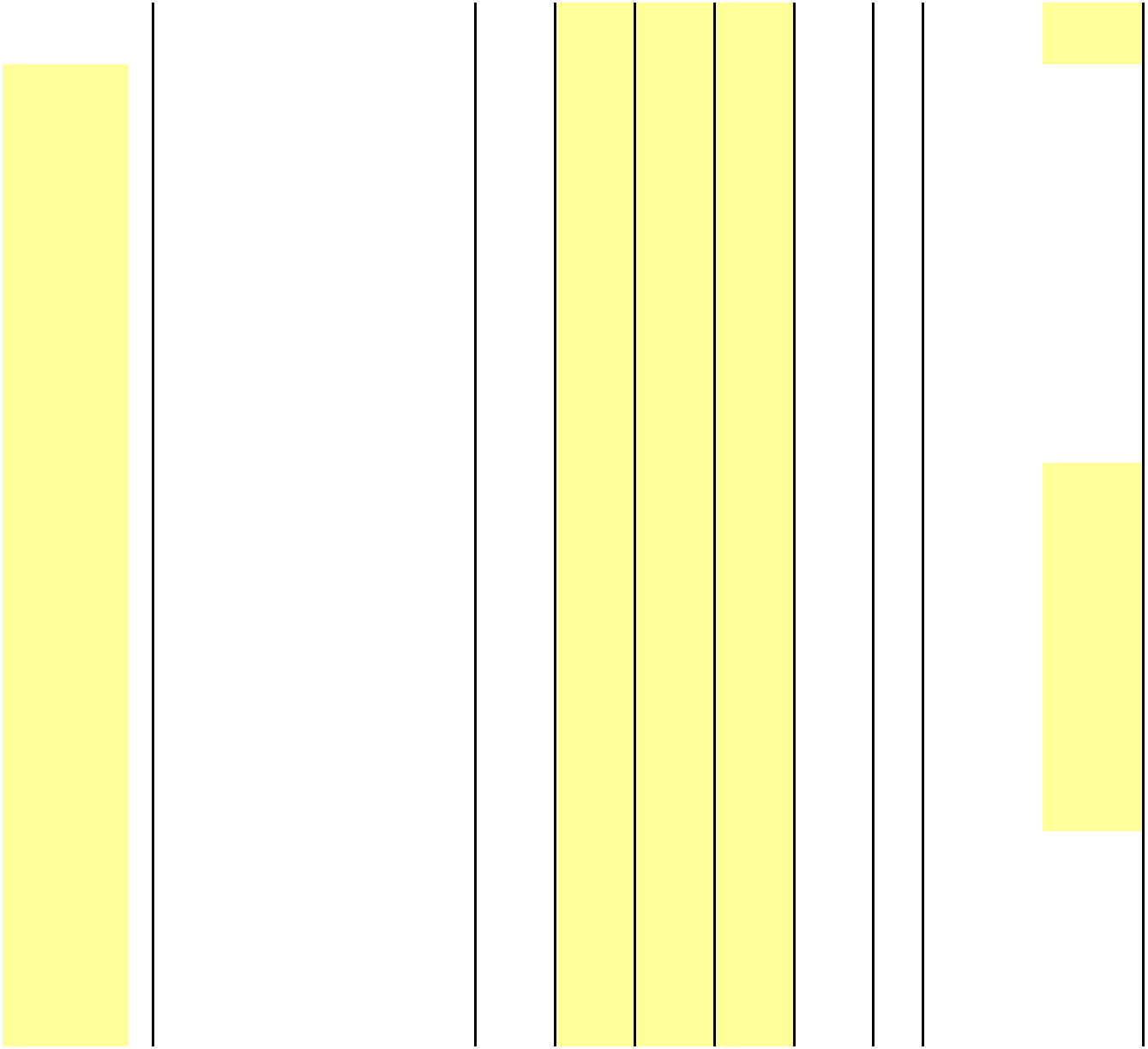
| ne | | for Current Year | for Previous Year | ne | | | | Page 321 | Expense | Expense | Expense | Expense | | roved | ast * |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| No | (a) | (b) | ( c) | No | No. | Description | Source | | YE 12/31/20XX | YE 12/31/20XX | YE 12/31/20XX | YE 12/31/20XX | | Budget * | |
| 81 | **2. Transmission Expenses** | | | | (a) | (b) | (c) | | (d) | (e) | (f) | (g) | | ( a ) | (b) |
| 82 | | | | | | | | | | | | | **Expenses - Operations (FERC 560 - 567)** | | |
| 82 | Operation (560) | | | | | | | | | | | | | | |
| 83 | Operation Supervision and Engineering | | | | | **Transmission Operation Expense** | | | | | | | 1 Transmission Operations | | |
| 8 | | | | | | Operation Supervisi | FERC Form 1, Page | | | | | | Trans of Electricity by | | |

4 1 560 on and 321 - - 2 others



| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 85 | (561.1) Load Dispatch-Reliability | 2 | 562 | Engineering Station Expenses | FERC Form 1, Page 321 | - | - | | | |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 3 | 563 | Overhead Line Expense | FERC Form 1, Page 321 | - | - | **Expenses - Maintenance (FERC 568 - 573)** | | |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | 4 | 565 | Transmission of Electricity by Others | FERC Form 1 page 328-330 | - | - | 3 | Transmission | |
| 88 | (561.4) Scheduling, System Control and Dispatch | | | Miscellaneous Transmission | FERC Form 1, Page | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 8 | Services | | 5 | 566 | Expenses | 321 | - | - |



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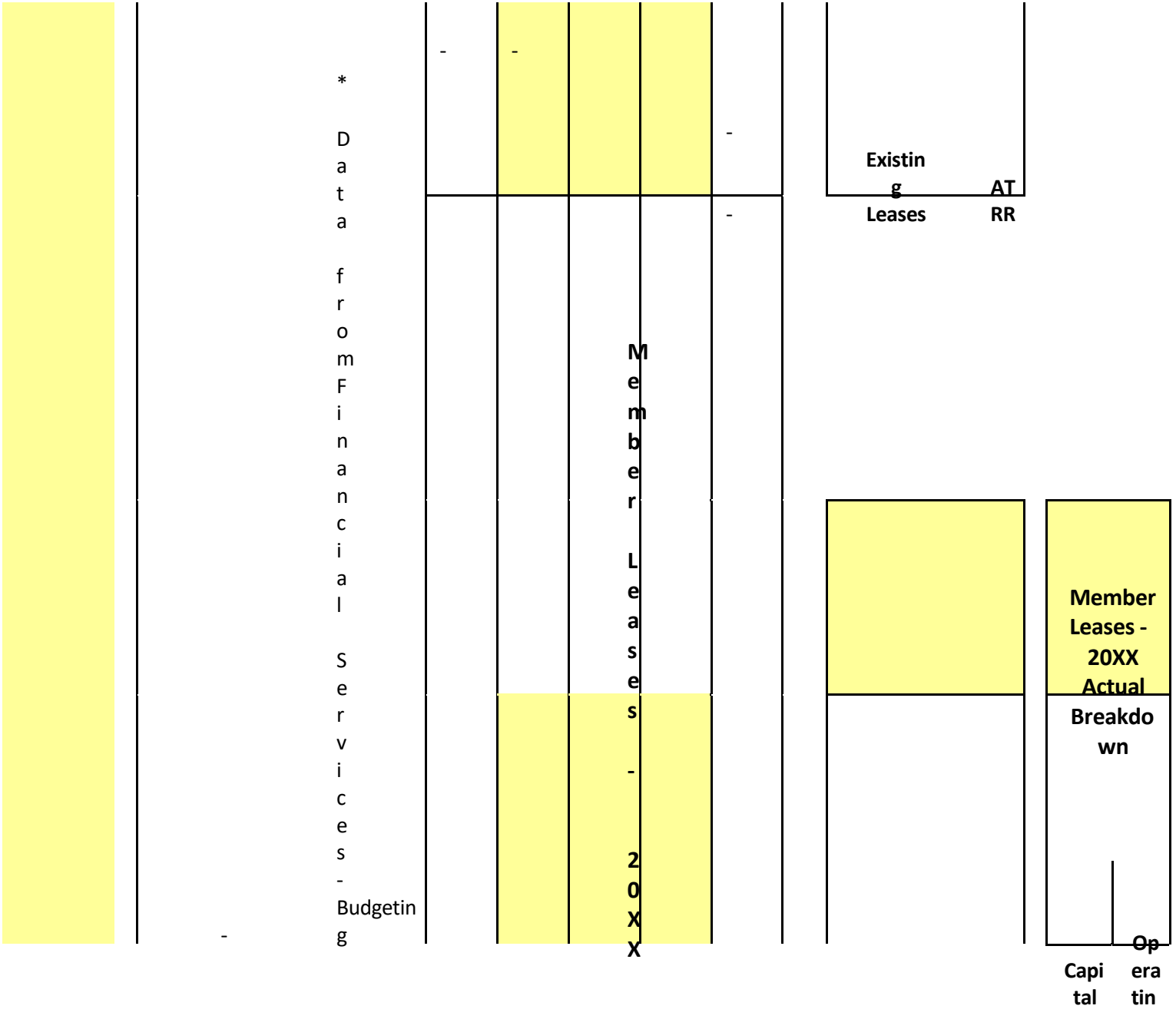
**Actual**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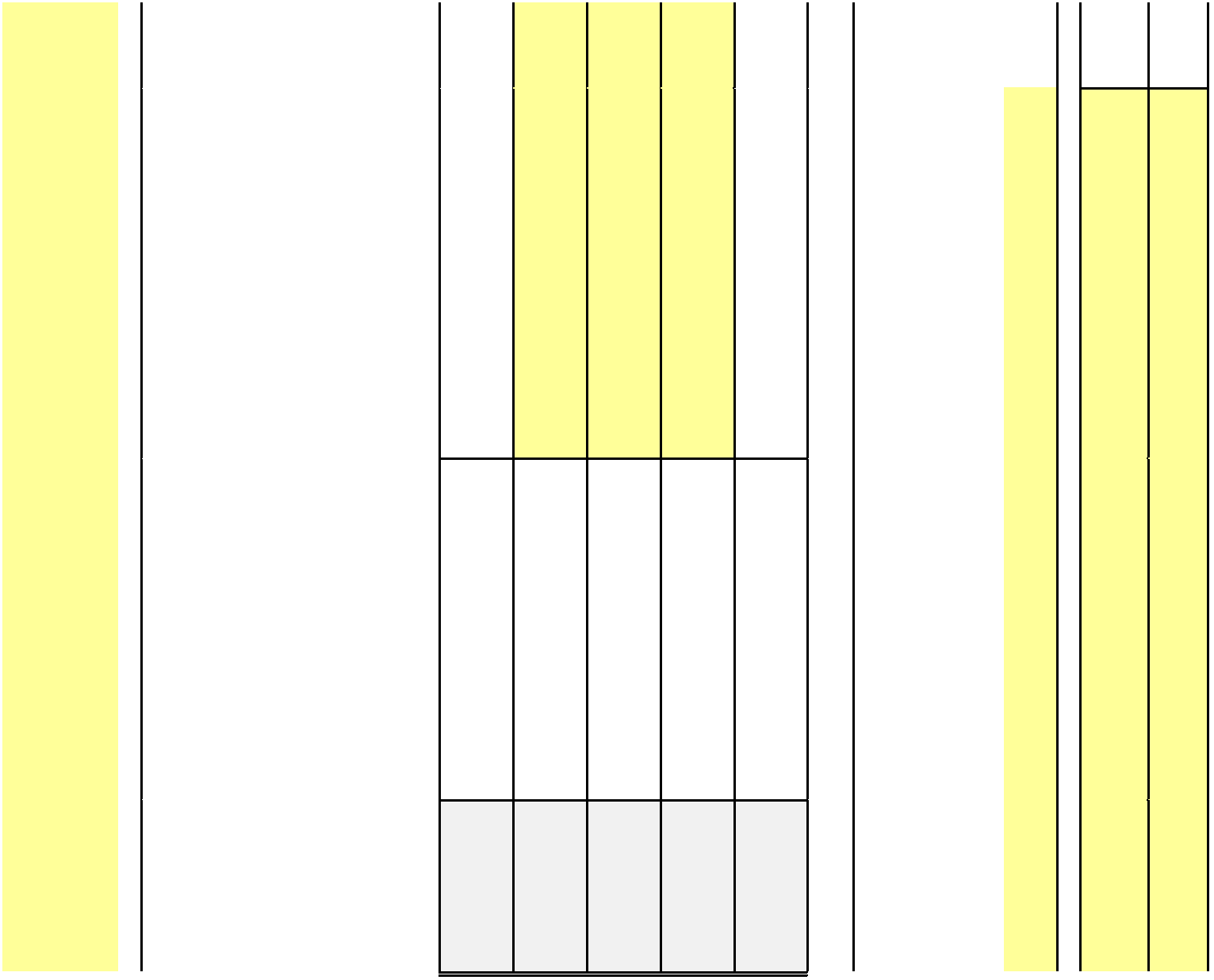
*
Data from Financial Services - Budgeting
Member Leases - 20XX
Existing Leases
ATRR
Member Leases - 20XX Actual Breakdown
Capital
Operatin

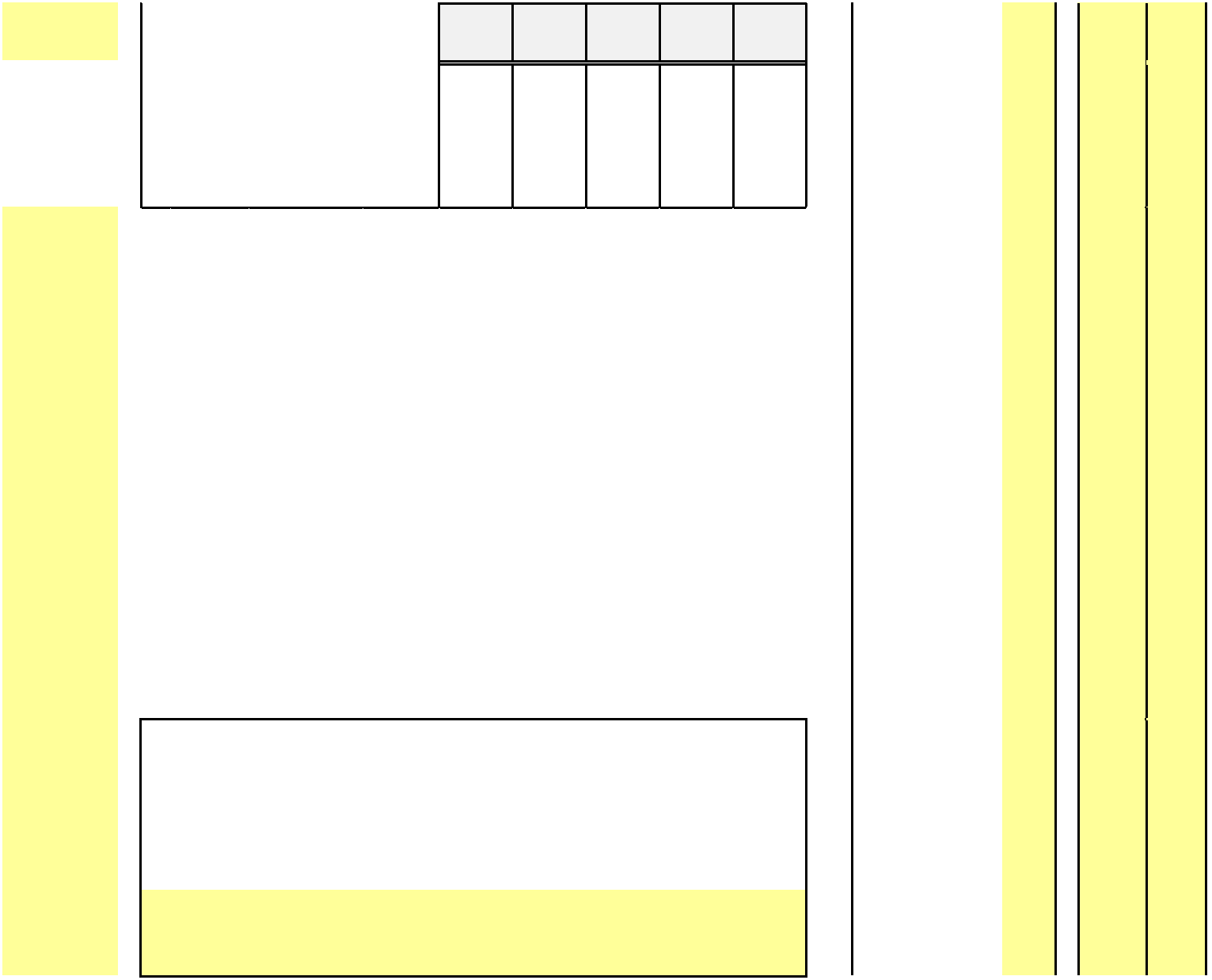
| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Lines Expenses | | | Equipment | Page 321 | | | | | | | | | **Leases** | **g Leases** |
| 95 | (564) Underground Lines Expenses | 9 | 571 | Maintenance of Overhead Lines | FERC Form 1, Page 321 | - | | | | - | | | Central Montana Electric Power Cooperative | | |
| 96 | (565) Transmission of Electricity by Others | 10 | 573 | Maintenance of Miscellaneous Transmission Plant | FERC Form 1, Page 321 | - | | | | - | | | Central Power Elec Coop | | |
| 97 | (566) Miscellaneous Transmission Expense | | | **Total Transmission Maintenance Expense** | sum lines 8 through 10 | - | - | - | - | - | | | Moreau-Grand Central Power Elec Coop - Snake Creek Subs | | |
| 98 | (567) Rents | | | | | | | | | | | | | | |
| 99 | Total Operation (Enter Total of lines 83 | 1 | | **Total Transmission Operation &** | line 7 + line | | | | | | | | East River Electric | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | thru 98) | | 2 | **Mainten** | 11 | - | - | - | - | - | Power |



| | | | |
|---|---|---|---|
| | | **ance Expense** | Cooperative |
| 100 | Maintenance (568) | | Grand Electric Cooperative |
| 101 | Maintenance Supervision and Engineering | | KEM Electric Cooperative |
| 102 | (569) Maintenance of Structures | | LaCreek Electric Association |
| 103 | (569.1) Maintenance of Computer Hardware | | L & O Power Cooperative |
| 104 | (569.2) Maintenance of Computer Software | **Annual O&M Expense From Above Including Adjustments** | Minn Valley Cooperative Light & Power Assn. |
| 100 | (569.3) Maintenan | | Burke |

5 ce of **12 Months Ending December 31, 20XX** Divide



| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Communication Equipment (569.4) Maintenance of Miscellaneous | | | | | | | | | |
| 106 | Regional Transmission Plant | | | | UMZ Zone 19 | MBPP Transmission | Other Transmission | Total Transmission | | Sheridan |
| 107 | (570) Maintenance of Station Equipment | **Line** | **Account** | | **Annual Expense** | **Annual Expense** | **Annual Expense** | **Annual Expense** | | Goldenwest |
| 108 | (571) Maintenance of Overhead Lines | **No** | **No.** | **Description** | **Source** | **YE 12/31/20XX** | **YE 12/31/20XX** | **YE 12/31/20XX** | **YE 12/31/20XX** | Roseb ud Electric Cooperative |
| 109 | (572) Maintenance of Underground Lines | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | Rough rider Electric Cooperative |
| 111 | (573) Maintenance of Miscellane | | | | | | | | | Upper Missouri G&T Electric Cooperati |

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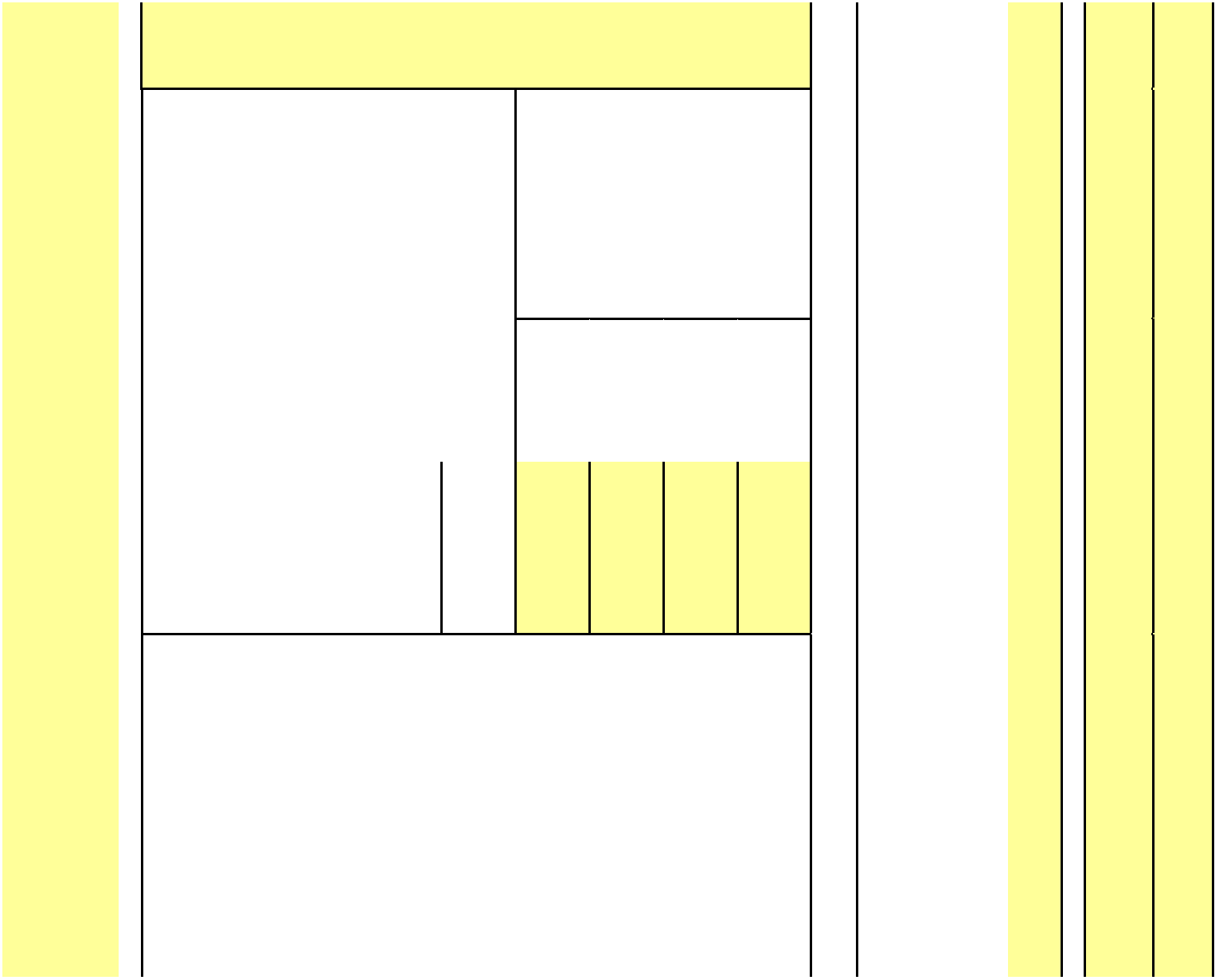
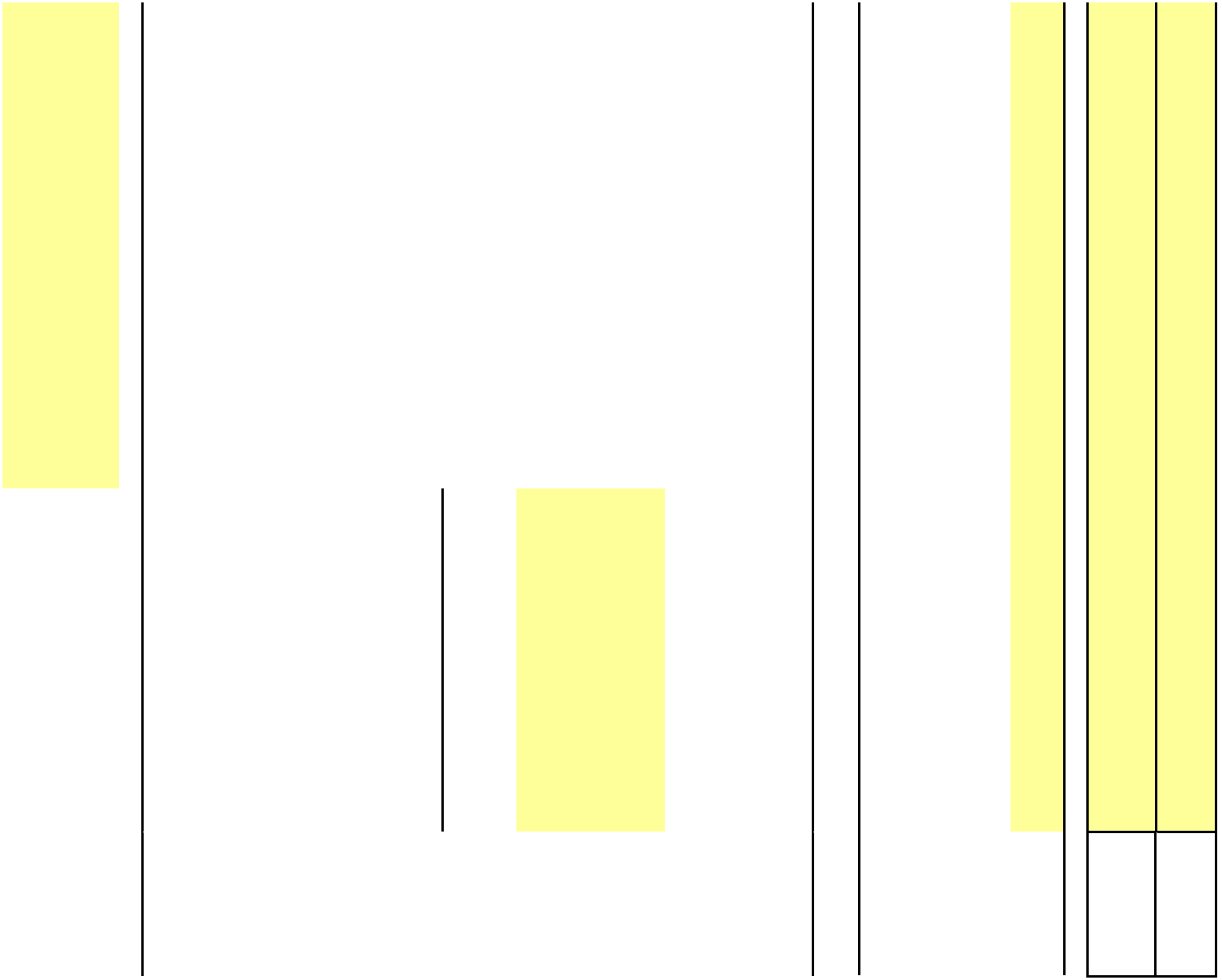


| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Transmission Plant | | | | | | | | | |
| 111 | Total Maintenance (Total of lines 101 thru 110) | 13 | **Total Transmission Operation & Maintenance Expense** | line 12 | - | - | - | - | | West Central Electric Cooperative |
| 112 | Total Transmission Expenses (Total of lines 99 and 111) | | | | | | | | | West River Electric Association |
| | | 14 | **Less: Transmission of Electricity by Others** | FERC Form 1, Page 321, Less FERC Form 1 page 328-330 | - | - | - | - | | Cam-Wal Electric Cooperative |
| | | | | | | | | | **Grand Total w/o Corn** | **$** **$** **$** |

**Belt** - - -



| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 15 | **Plus: Member Lease Payments** | Work Paper #6 | - | - | - | - | |
| | 16 | **Total O&M Transmission (Schedule 5 , Pg3, Line1)** | | - | - | - | - | |
| | 17 | **Transmission - Direct Assign** | | | | | | |
| | 18 | **Total O&M Transmission** | line 16 | - | - | - | - | |

**Basin Electric Power Cooperative**

**Formula Rate Template**

for the year ended December 31, 20XX

**Work Paper #6**

**FERC Form 1 - Page 328-330**

**Page 1 of 3**

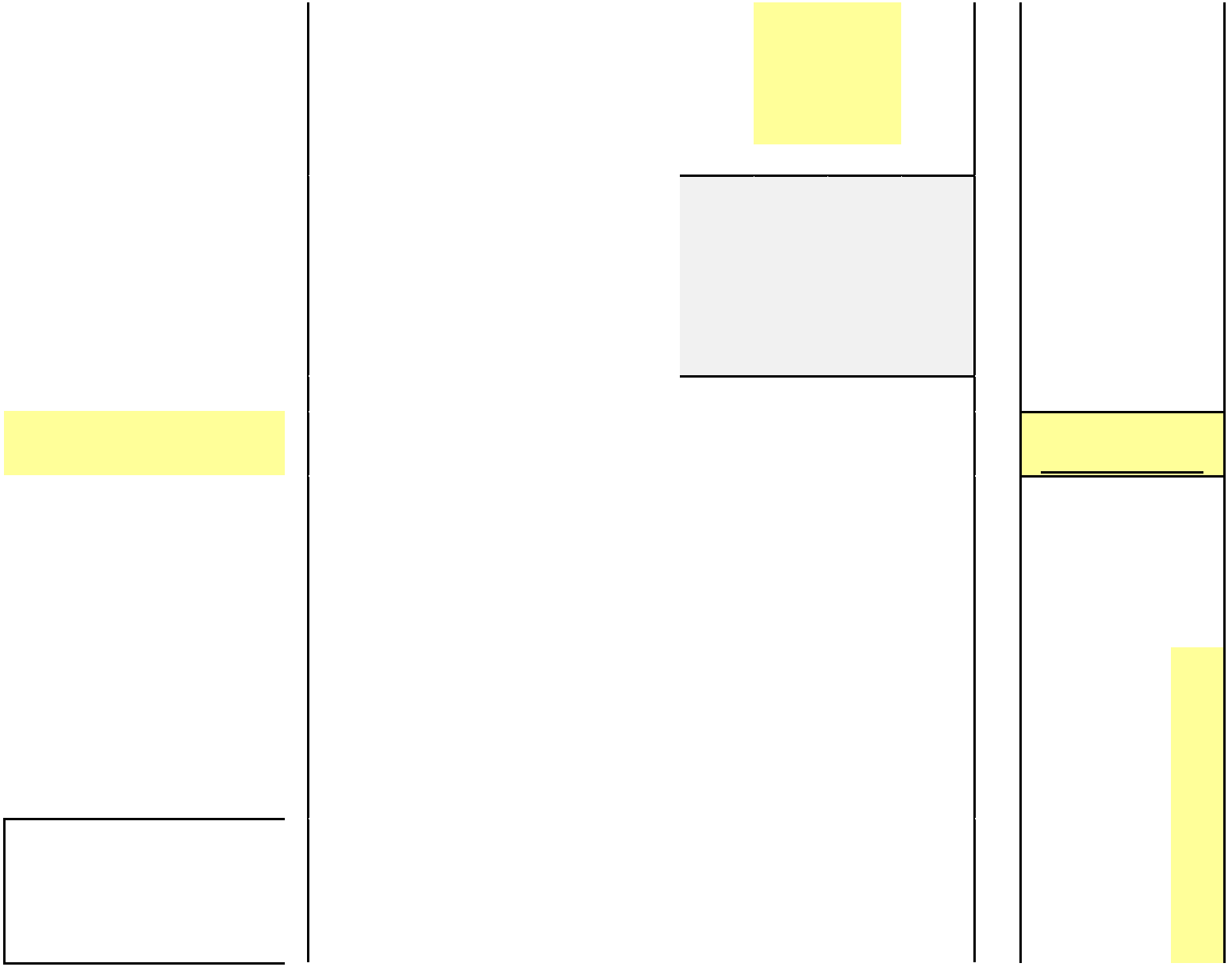
**Transmission Of Electricity**

**Member Leases - 20XX Estimates**

Central Montana Electric Power Cooperative

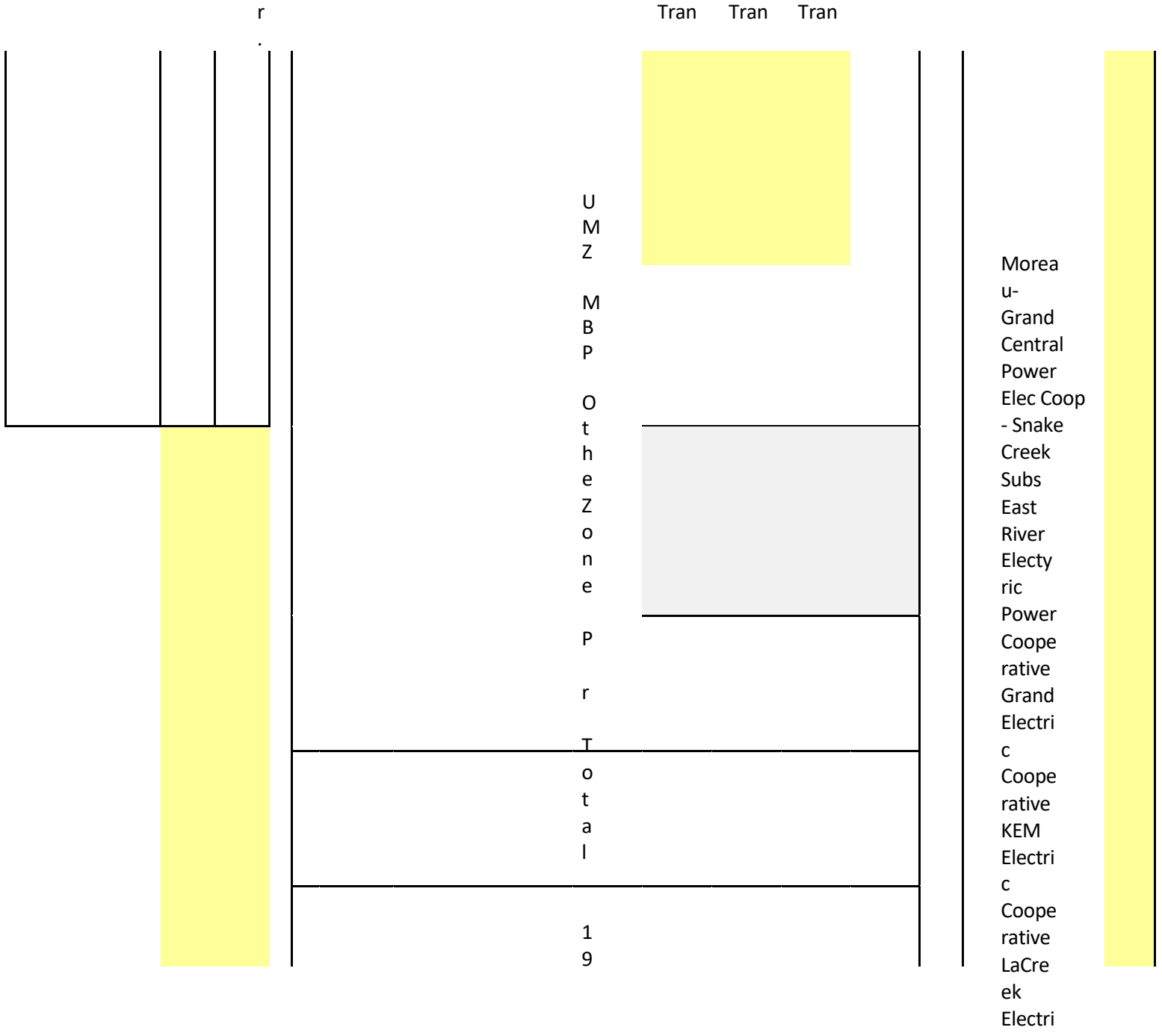
Central Power Elec

**for Others (Account 456.1)** 0 **Less:** Coop



| Line No | Payment Received From (Company of Public Authority) (Footnote Affiliation (a) | (Other Charges) ($) (m) | Total Revenues ($) (n) | Independent |
|---|---|---|---|---|
| 1 | Southwest Power Pool | | | |
| 2 | Black Hills CUS | | | |
| 3 | Missouri Basin Power Project Midcontine | | | |

| | | |
|---|---|---|
| 21 | * Basin Electric Only Costs | - - |
| 22 | **Total Transmission Direct Assign** | **- -** |


r.
Tran
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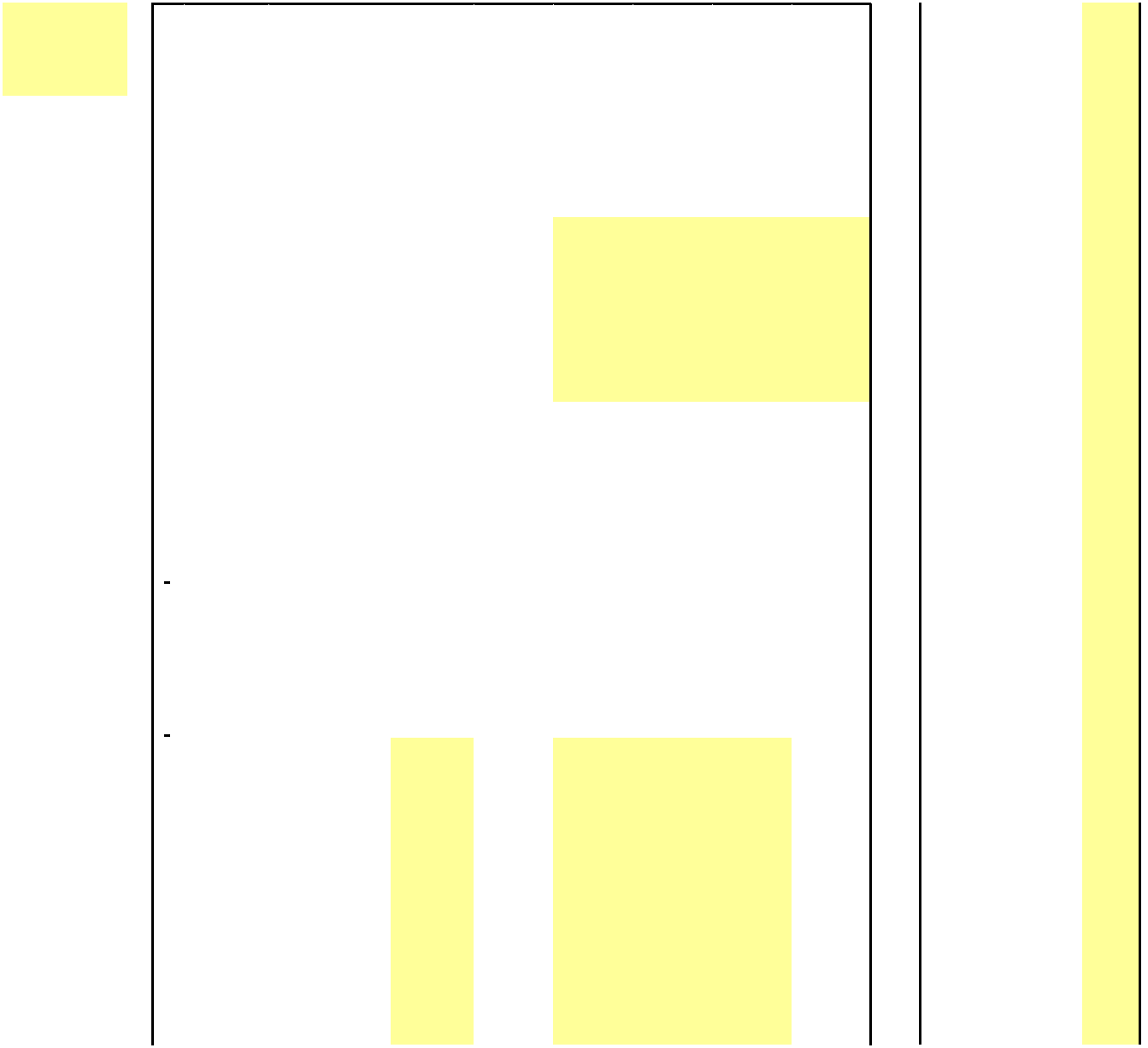
* Costs Other than UMZ, MBPP or Other
UMZ MBP Other Zone Pr Total
19
Moreau-Grand Central Power Elec Coop - Snake Creek Subs
East River Electy ric Power Coope rative
Grand Electri c Coope rative
KEM Electri c Coope rative
LaCre ek Electri

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| nt System Operator | | | | | | smission | smission | smission | c Association |
| | **Line No** | **Account No.** | **Description** | **Source** | **Annual Expense Estimate 20XX Rate Year** | **Annual Expense Estimate 20XX Rate Year** | **Annual Expense Estimate 20XX Rate Year** | **Annual Expense Estimate 20XX Rate Year** | L & O Power Cooperative Minn Valley Cooperative Light & Power Assn. Burke Divide |
| Total - - | | (a) | (b) | (c) | (d) | (e) | (f) | (g) | |
| | | | **Transmission - Direct Assign** | | | | | | Sheridan |
| Note: The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the | 2 | | Transmission O&M Expense | | | | | | Goldenwest Rosebud Electric Coope |

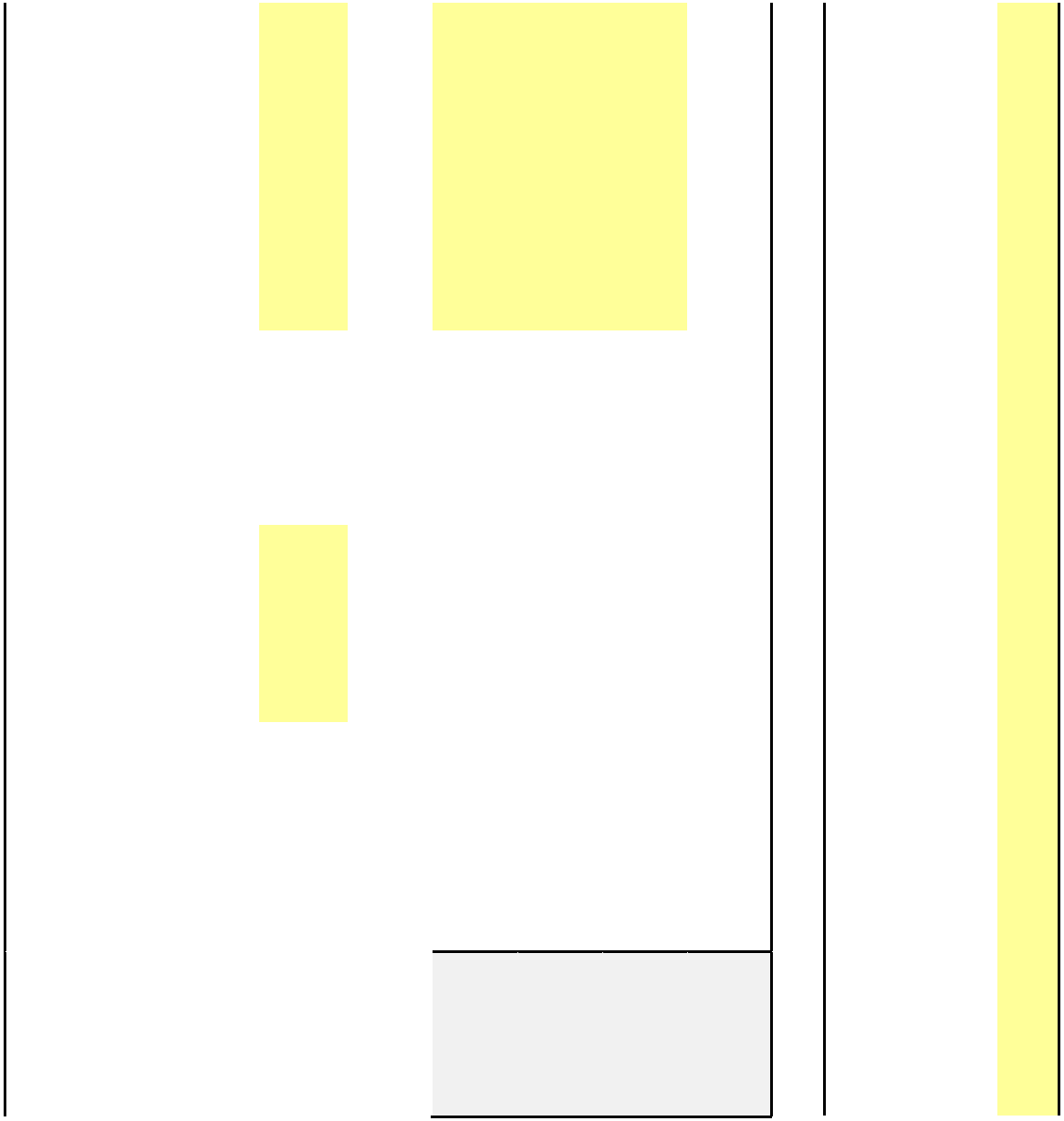
addition or removal of 3 Estimate - rative



columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

| | | | | | | |
|---|---|---|---|---|---|---|
| 24 | **Plus: Member Lease Payments** | - | - | - | - | Roughrider Electric Cooperative<br>Upper Missouri G&T Electric Cooperative<br>West Central Electric Cooperative |
| 25 | **Total Transmission Direct** | | | | | West River Electri |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5 | **Assign** | | - | - | - | - | C |



| | |
|---|---|
| Association Cam-Wal Electric Cooperative | |
| **Grand Total** | **$ -** |

*Includes costs such as Common Use System, Rapid City DC Tie, Wyoming Distributed Generation, 3/40th of Glenham Shunt, Asset Retirement Obligation costs, Acquisition Adjustment costs and MBPP costs for Laramie River Station (LRS) 69kV substation and LRS transformer costs.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**BOY / EOY - Intangibles**

**Work Paper #7 Page 1 of 4**

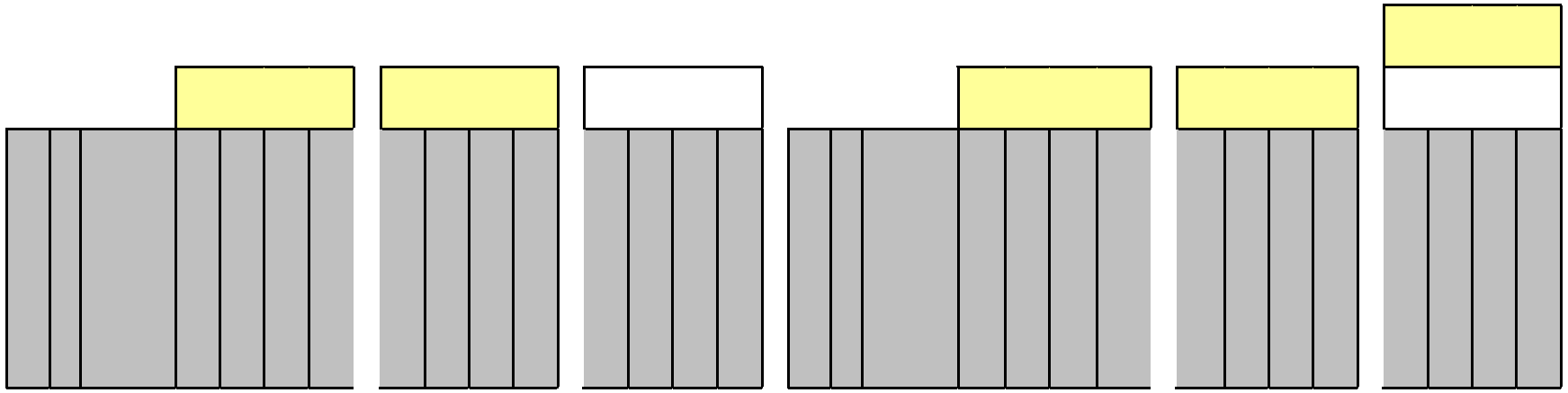
| FERC | CPX | Description | Book BV | 20XX Assets Depry | 20XX Assets Deprl | Net Book Value | 20XX Assets Cost | BOY / EOY Average Net Book Value | BOY / EOY Average Adjustments | BOY / EOY Average Total Depry | BOY / EOY Average Total Deprl | BOY / EOY Average Net Book Value |
|---|---|---|---|---|---|---|---|---|---|---|---|---|

**Basin Electric Power Cooperative**
**Formula Rate Template**
**BOY / EOY - Intangibles**

**Work Paper #7 Page 3 of 4**

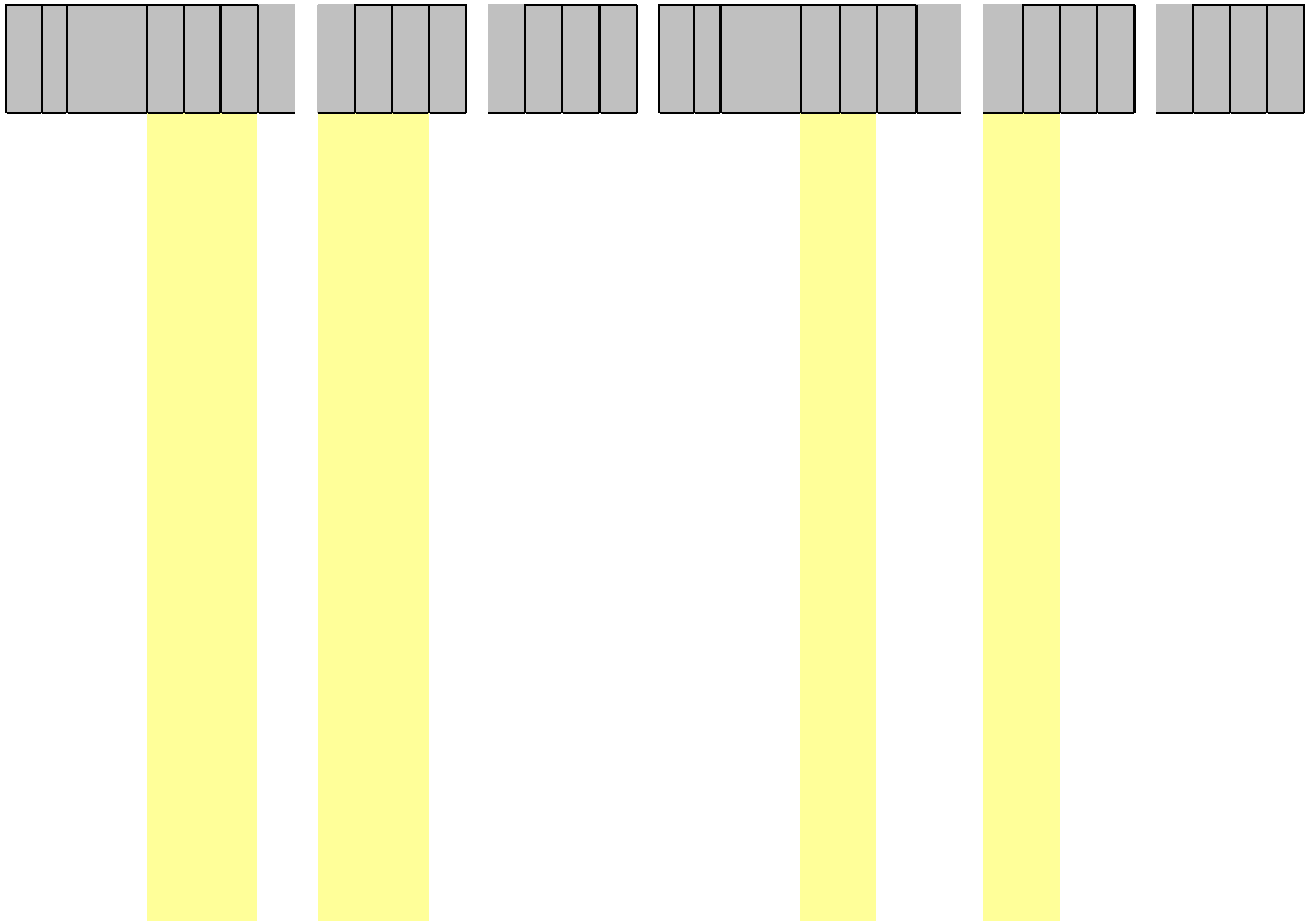
| | | | 20XX Estimate Book Value | 20XX Estimate Adjustments | 20XX Estimate Total Depry | 20XX Estimate Total Deprl | 20XX Estimate Net Book Value | 20XX - 20XX BOY / EOY Average Net Book Value |
|---|---|---|---|---|---|---|---|---|
| FERC | CPX | Description | | | | | | |

T D | T D | o k V | c c o | o o k B a si s | D e p r Y T D | D e p r L T D ue | et B o ok V al s | o o k B a si | D e p r Y T D | D e p r L T D | e t B o o k V | o o k B a si s | D e p r Y T D | D e p r L T D | e t B o o k V



| unt | | | alue | alue | | | | alue | unt | | | alue | | | | | | alue |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 1 | UMZ | | | | | | | 3 | 1 | UMZ | | | | | | | |
| 0 | 2 | Zone | | | | | | | 0 | 2 | Zone | | | | | | | |
| 3 | 7 | 19 | - | - | - | - | - | - | 3 | 7 | 19 | - | - | - | - | - | - | - |
| 3 | 1 | UMZ | | | | | | | 3 | 1 | UMZ | | | | | | | |
| 0 | 8 | Zone | | | | | | | 0 | 8 | Zone | | | | | | | |
| 3 | 5 | 19 | - | - | - | - | - | - | 3 | 5 | 19 | - | - | - | - | - | - | - |
| 3 | 2 | UMZ | | | | | | | 3 | 2 | UMZ | | | | | | | |
| 0 | 7 | Zone | | | | | | | 0 | 7 | Zone | | | | | | | |
| 3 | 2 | 19 | - | - | - | - | - | - | 3 | 2 | 19 | - | - | - | - | - | - | - |
| 3 | 2 | UMZ | | | | | | | 3 | 2 | UMZ | | | | | | | |
| 0 | 9 | Zone | | | | | | | 0 | 9 | Zone | | | | | | | |
| 3 | 7 | 19 | - | - | - | - | - | - | 3 | 7 | 19 | - | - | - | - | - | - | - |
| 3 | 3 | UMZ | | | | | | | 3 | 3 | UMZ | | | | | | | |
| 0 | 2 | Zone | | | | | | | 0 | 2 | Zone | | | | | | | |
| 3 | 2 | 19 | - | - | - | - | - | - | 3 | 2 | 19 | - | - | - | - | - | - | - |
| 3 | 3 | UMZ | | | | | | | 3 | 3 | UMZ | | | | | | | |
| 0 | 2 | Zone | | | | | | | 0 | 2 | Zone | | | | | | | |
| 3 | 5 | 19 | - | - | - | - | - | - | 3 | 5 | 19 | - | - | - | - | - | - | - |
| 3 | 3 | UMZ | | | | | | | 3 | 3 | UMZ | | | | | | | |
| 0 | 3 | Zone | | | | | | | 0 | 3 | Zone | | | | | | | |
| 3 | 3 | 19 | - | - | - | - | - | - | 3 | 3 | 19 | - | - | - | - | - | - | - |
| 3 | 3 | UMZ Zone 19 - Plaza | | | | | | | 3 | 3 | UMZ Zone 19 - Plaza | | | | | | | |
| 0 | 3 | Sub | | | | | | | 0 | 3 | Sub | | | | | | | |
| 3 | 6 | (SPP) | - | - | - | - | - | - | 3 | 6 | (SPP) | - | - | - | - | - | - | - |
| 3 | 3 | UMZ | | | | | | | 3 | 3 | UMZ | | | | | | | |
| 0 | 4 | Zone | | | | | | | 0 | 4 | Zone | | | | | | | |

3 6 19 - - - - - - 3 6 19 - - - - - - -



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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3030 | 4003 | Sub (AQ) Other - 115kV Line - Edgeley Sub to FPL Wind Farm | - | | - | - | - | - | - | 3030 | 4003 | Sub (AQ) Other - 115kV Line - Edgeley Sub to FPL Wind Farm | - | - | | - | - | - | - | - | - |
| 3035 | 4005 | Other - 230kV Line - Ecklund Sub to FPL Wilton Wind Farm | - | | - | - | - | - | - | 3035 | 4005 | Other - 230kV Line - Ecklund Sub to FPL Wilton Wind Farm | - | - | | - | - | - | - | - | - |
| 3036 | 4006 | Other - Prairie Winds ND1 | - | | - | - | - | - | - | 3036 | 4006 | Other - Prairie Winds ND1 | - | - | | - | - | - | - | - | - |
| 3508 | | Other - PGS - Gas | | | | | | | | 3508 | | Other - PGS - Gas | | | | | | | | | |

3 2 Pipeli - - - - - - 3 2 Pipeli - - - - - - -

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 5 | ne (WBI) Other - 115 kV Line - Collector Sub to Hay Butte Sub | | | | - | | | | - | - | - | - | - | | | | | | | | - | - | | | - | - | - | - | | |
| 3 | 8 | Other - AVS/DGC Water Transportation Facilities | | | | - | | | | - | - | - | - | - | | | | | | | | - | - | | | - | - | - | - | | |
| 3 | 9 | Other - Headquarters | | | | - | | | | - | - | - | - | - | | | | | | | | - | - | | | - | - | - | - | | |
| | x | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | x | xxxx | | | | - | | | | - | - | - | - | - | | | | | | | | - | - | | | - | - | - | - | | |
| | | **Subtotal** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Effective Date: 1/1/2020 - Docket #: ER21-104-000 - Page 290

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 9 | | | | | | | | | | | 3 | 9 | | | | | | | | | | |
| 0 | 1 | | | | | | | | | | | 0 | 1 | | | | | | | | | | |
| 3 | 9 | CUS | | | | - | | | | - | - - - - | 3 | 9 | CUS | | | - | - | | | - | - | - - - - |
| | x | | | | | | | | | | | | x | | | | | | | | | | |
| | x | | | | | | | | | | | | x | | | | | | | | | | |
| | x | CUS | | | | - | | | | - | - - - - | | x | CUS | | | - | - | | | - | - | - - - - |
| | | **Subtotal** | - | - | - | - | - | - | - | - | - - - - | | | | - | - | - | - | - | - | - | - | - - - - |
| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 1 | ation | | | | - | | | | - | - - - - | 3 | 1 | GEN | | | - | - | | | - | - | - - - - |
| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 2 | ation | | | | - | | | | - | - - - - | 3 | 2 | GEN | | | - | - | | | - | - | - - - - |
| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
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| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 4 | ation | | | | - | | | | - | - - - - | 3 | 4 | GEN | | | - | - | | | - | - | - - - - |
| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 6 | ation | | | | - | | | | - | - - - - | 3 | 6 | GEN | | | - | - | | | - | - | - - - - |
| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 7 | ation | | | | - | | | | - | - - - - | 3 | 7 | GEN | | | - | - | | | - | - | - - - - |
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| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 8 | ation | | | | - | | | | - | - - - - | 3 | 8 | GEN | | | - | - | | | - | - | - - - - |
| 3 | 2 | NB | | | | | | | | | | 3 | 2 | | | | | | | | | | |
| 0 | 6 | Gener | | | | | | | | | | 0 | 6 | NB | | | | | | | | | |
| 3 | 9 | ation | | | | - | | | | - | - - - - | 3 | 9 | GEN | | | - | - | | | - | - | - - - - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| x | | | | | | | | | | | | | | | | | | | |
| x | | | | | | | | | | | | | | | | | | | |
| x | xxx | | | | - | | | | - | | | | - | - | - | - | | | |
| | **Subtotal** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | - | | | | | | | | | | | | | | |
| | **Total BEPC** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **MBPP (Ault Sub MBPP West) ex. NPPD MBPP - xxx** | | | | - | | | | - | | | | - | - | - | - | | | |
| | | | | | - | | | | - | | | | - | - | - | - | | | |
| | **Subtotal MBPP** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Total** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | NPPD - (Fixed Assets) | | | | | | | | | | | | | | | | | | |
| 54 | (Note A) | | | | - | | | | - | | | | - | - | - | - | | | |

| | | | | | | | | | | | | | | | | | | | |
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| x | | | | | | | | | | | | | | | | | | | |
| x | | | | | | | | | | | | | | | | | | | |
| x | xxx | | | - | - | | | | - | - | | | - | - | - | - | | | |
| | **Subtotal** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Total BEPC** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **MBPP (Ault Sub MBPP West) ex. NPPD MBPP - xxx** | | | - | - | | | | - | - | | | - | - | - | - | | | |
| | | | | - | - | | | | - | - | | | - | - | - | - | | | |
| | **Subtotal MBPP** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Total** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | NPPD - (Fixed Assets) | | | | | | | | | | | | | | | | | | |
| 54 | (Note A) | | | - | - | | | | - | - | | | - | - | - | - | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 1 2 x x x | BEPC Ovhd - (384) Trans (Note B) | | | | - | | | | - | - | - | - | | | | - |
| | xxxx | | | | - | | | | - | - | - | - | | | | - |
| | **Subtotal** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Grand Total BEPC & MBPP** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Notes:**

A NPPD not included in tariff

B Complex 112 is MBPP - Project 005 - Basin only interest-- not included in rate it is ovhd for NPPD & Ault MBPP West

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 1 2 x x x | BEPC Ovhd - (384) Trans (Note B) | | | | - | - | | | - | - | | | - | - | - | - |
| | xxx | | | | - | - | | | - | - | | | - | - | - | - |
| | **Subtotal** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Grand Total BEPC & MBPP** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Notes:**

A NPPD not included in tariff

B Complex 112 is MBPP - Project 005 - Basin only interest-- not included in rate it is ovhd for NPPD & Ault MBPP West

| | | |
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| | **k** | **r** |
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| | | **e** |
| | | **2** |
| C | The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas. | C |
| | **W** | |
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| **20XX Actuals Depreciation - Intangibles** | | |
| **B D D N** | | |
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absent a Federal Power Act section 205 or 206 filing.

The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained with those columns cannot be changed

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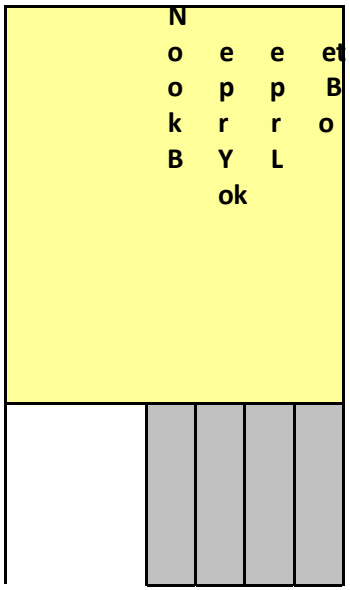
**20XX Estimated Depreciation - Intangibles**

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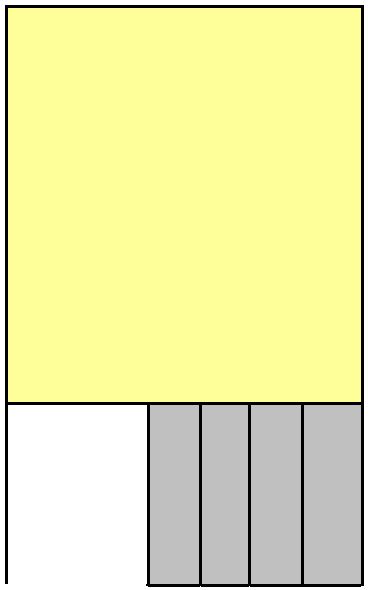


| | Basis | TD | TD | ok Value | of 4 |
|---|---|---|---|---|---|
| CUS Zone 19 | 0 | 0 | 0 | 0 | |
| (UMZ) | 0 | 0 | 0 | 0 | |
| MBPP | 0 | 0 | 0 | 0 | |
| Other | 0 | 0 | 0 | 0 | |
| NPPD | 0 | 0 | 0 | 0 | |
| Total Excluding NB Generation | **0** | **0** | **0** | **0** | |
| NB Generation | **0** | **0** | **0** | **0** | |
| | **0** | **0** | **0** | **0** | |

| | Basis | TD | TD | Value | of 4 |
|---|---|---|---|---|---|
| CUS Zone 19 | 0 | 0 | 0 | 0 | |
| (UMZ) | 0 | 0 | 0 | 0 | |
| MBPP | 0 | 0 | 0 | 0 | |
| Other | 0 | 0 | 0 | 0 | |
| NPPD | 0 | 0 | 0 | 0 | |
| Total Excluding NB Generation | **0** | **0** | **0** | **0** | |
| NB Generation | **0** | **0** | **0** | **0** | |
| | **0** | **0** | **0** | **0** | |

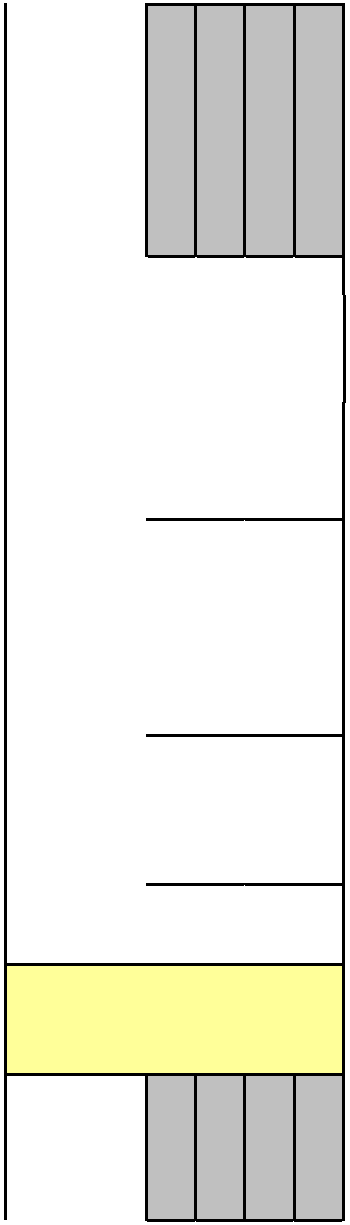
**20XX Actuals Depreciation - Intangibles**

| Boo | Dep | Dep | Net |
|---|---|---|---|

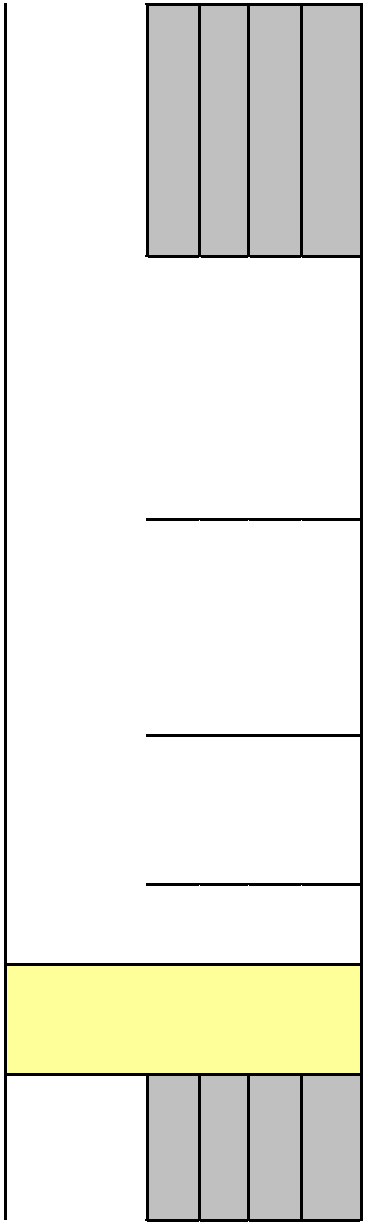
**20XX Estimated Depreciation - Intangibles**

| Boo | Dep | Dep | Net B |
|---|---|---|---|

**k r r B**



**k r r o**



| | Basis | YTD | LTD | ookValue |
|---|---|---|---|---|
| CUS Zone 19 | 0 | 0 | 0 | 0 |
| (UMZ) | 0 | 0 | 0 | 0 |
| MBPP | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 |
| NPPD | 0 | 0 | 0 | 0 |
| **Total Excluding NB Generation** | **0** | **0** | **0** | **0** |
| **NB Generation** | **0** | **0** | **0** | **0** |
| | **0** | **0** | **0** | **0** |

**SUMMARY**
**20XX - 20XX BOY / EOY**
**Average**

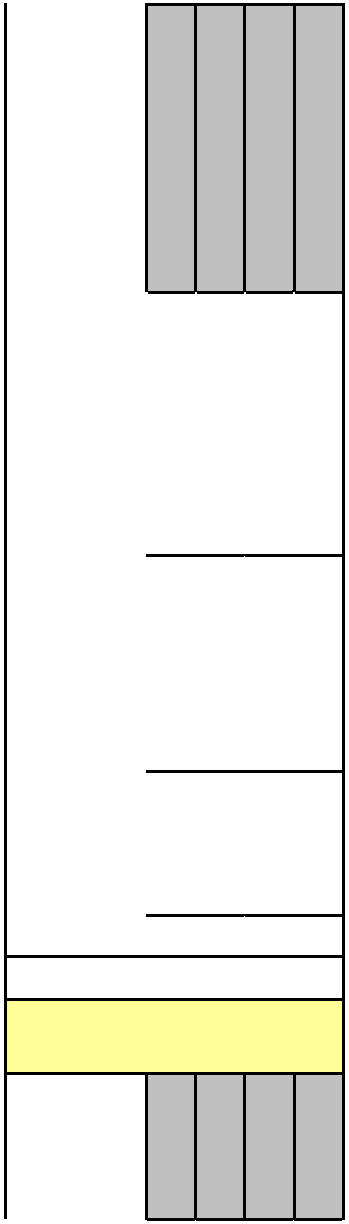
| | Boo | Dep | Dep | Net |
|---|---|---|---|---|


| | Basis | YTD | LTD | ookValue |
|---|---|---|---|---|
| CUS Zone 19 | 0 | 0 | 0 | 0 |
| (UMZ) | 0 | 0 | 0 | 0 |
| MBPP | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 |
| NPPD | 0 | 0 | 0 | 0 |
| **Total Excluding NB Generation** | **0** | **0** | **0** | **0** |
| **NB Generation** | **0** | **0** | **0** | **0** |
| | **0** | **0** | **0** | **0** |

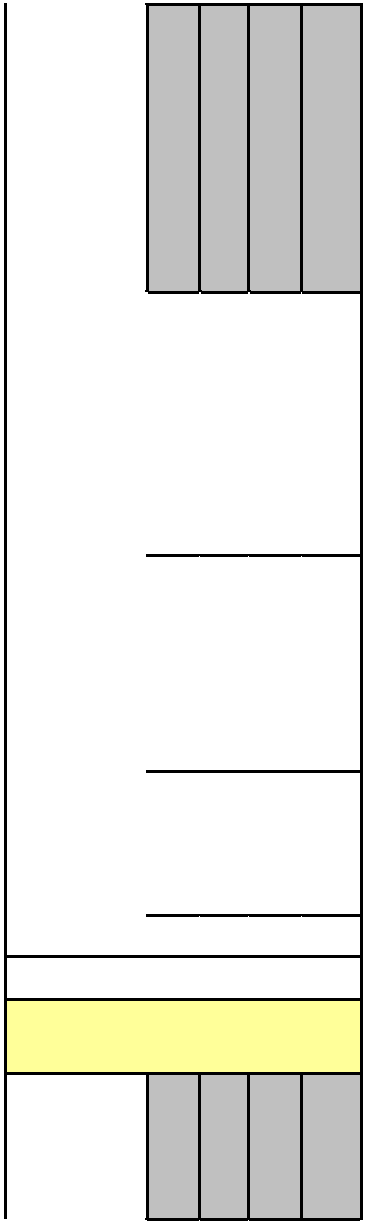
**SUMMARY**
**20XX - 20XX BOY / EOY**
**Average**

| | Boo | Dep | Dep | NetB |
|---|---|---|---|---|

**k r r B**



**k r r o**



| | Basis | YTD | LTD | ookValue |
|---|---|---|---|---|
| CUS Zone 19 (UMZ) | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 |
| MBPP | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 |
| NPPD | 0 | 0 | 0 | 0 |
| **Total Excluding NB Generation** | **0** | **0** | **0** | **0** |
| **NB Generation** | **0** | **0** | **0** | **0** |
| | **0** | **0** | **0** | **0** |

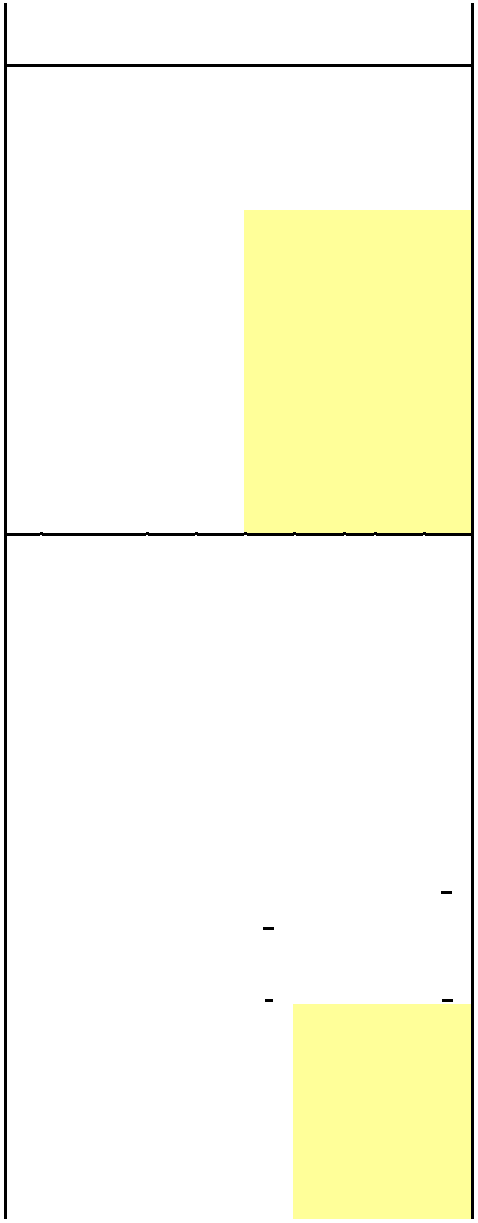
| | Basis | YTD | LTD | okValue |
|---|---|---|---|---|
| CUS Zone 19 (UMZ) | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 |
| MBPP | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 |
| NPPD | 0 | 0 | 0 | 0 |
| **Total Excluding NB Generation** | **0** | **0** | **0** | **0** |
| **NB Generation** | **0** | **0** | **0** | **0** |
| | **0** | **0** | **0** | **0** |

**Basin Electric Power Cooperative**
**Formula Rate Template**

**Depreciation & Amortization Expense - Generation Plants**

| Line No | Account No. | Description | Source | Annual Expense YTD Ending 12/20XX Total | UMZ Zone 19 | MBPP | Other |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (g) | (d) | (e) | (f) |
| | **Depreciation & Amortization Expense** | | | **Total** | **UMZ Zone 19** | **MBPP** | **Other** |
| | **310 -** | **Produ** | | | | | |

1 **316** **c** - - 0 -



| | | | | | |
|---|---|---|---|---|---|
| | | tion Plant (Generation) Other Generation | | | |
| 2 | 340 - 346 | | - | - | - |

**Basin Electric Power Cooperative**

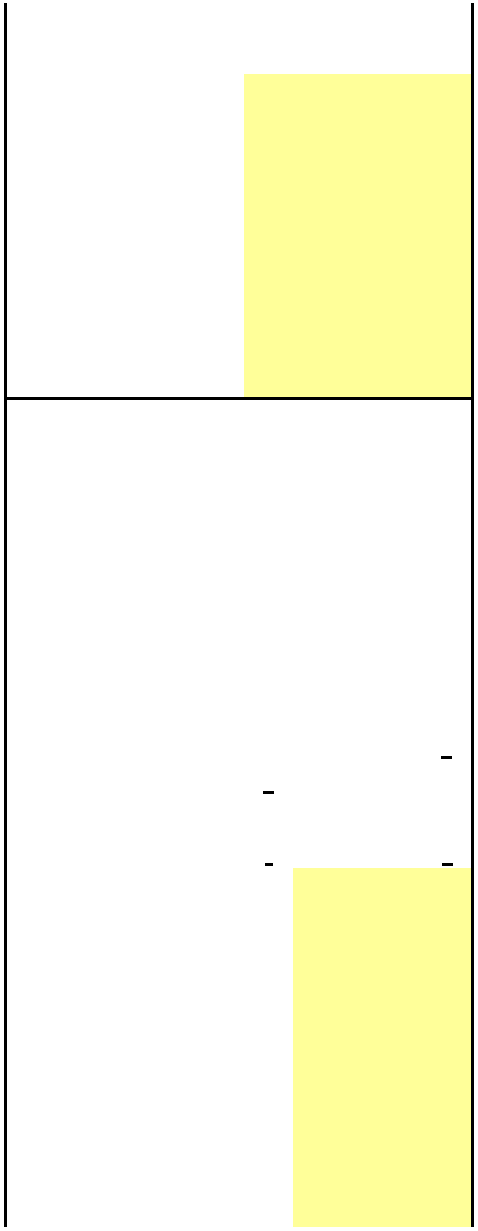
**Formula Rate Template**

**Depreciation & Amortization Expense - Generation Plants**

| Li | Account | | Annual Expense |
|---|---|---|---|

| Line No. | | Description | Source | 20XX Estimate | | | |
|---|---|---|---|---|---|---|---|
| | | | | (g) | (d) | (e) | (f) |
| | | | | Total | UMZ Zone 19 | MBPP | Other |
| | 310 - | Production | | | | | |

1 **316** **P** - - 0 -



| | | | | | |
|---|---|---|---|---|---|
| 2 | **340 - 346** | **Plant (Generation) Other Generation** | - | - | |

**Basin Electric Power Cooperative**

**Formula Rate Template**

**General Plant - FERC Account 389 - 398**

**Work Paper #8 Page 1 of 4**

| Transmission - General Plant | 20XX Actual | | | | 20XX Actual | | | BOY / EOY | 20XX Estimate | | | | 20XX Estimate | BOY / EOY | Annual | BOY / EOY | BOY / EOY | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | | Book Basis | Depr YTD | Net Book Value | Book Basis | Depr YTD | Depr LTD |
| Zone 19 - UMZ (details below) | - | - | - | - | | | | - | - | - | - | - | | | | | | | | |



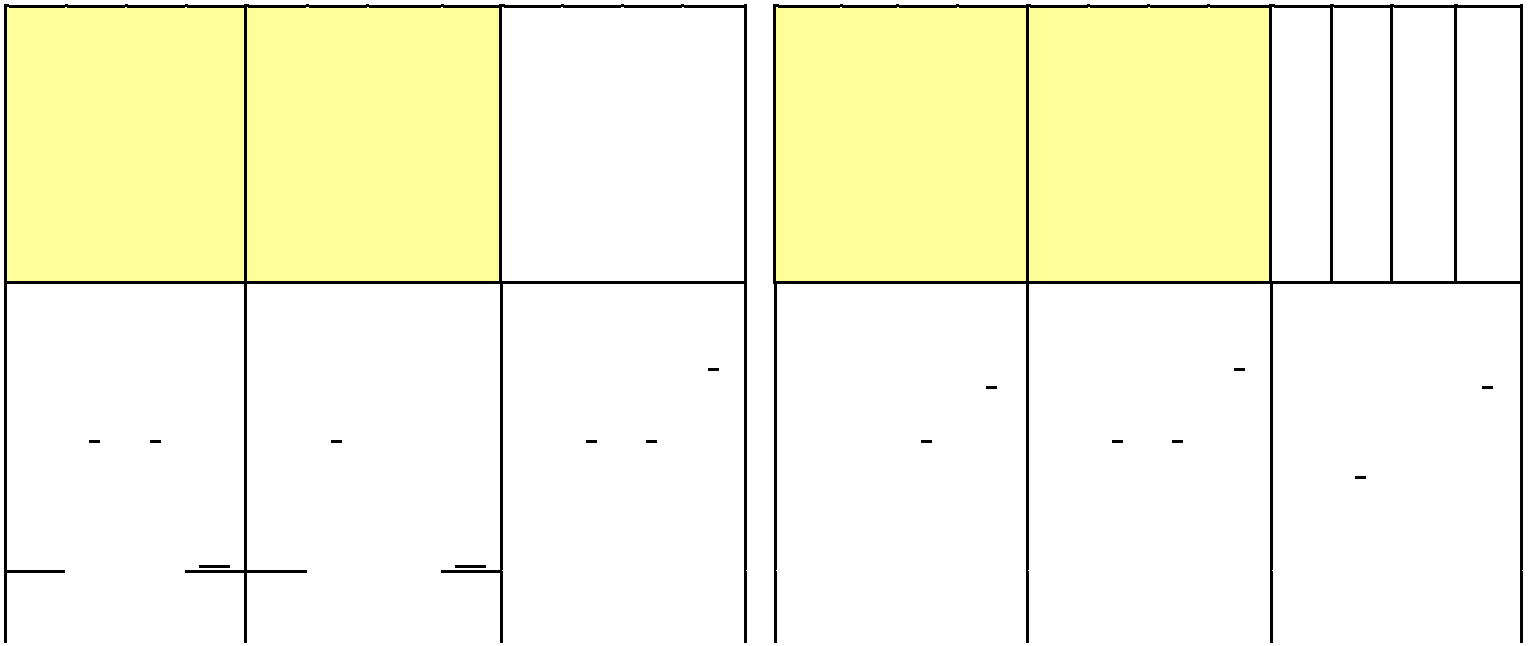
**Basin Electric Power Cooperative**

**Formula Rate Template**

**General Plant - FERC Account 389 - 398**

**Work Paper #8 Page 3 of 4**

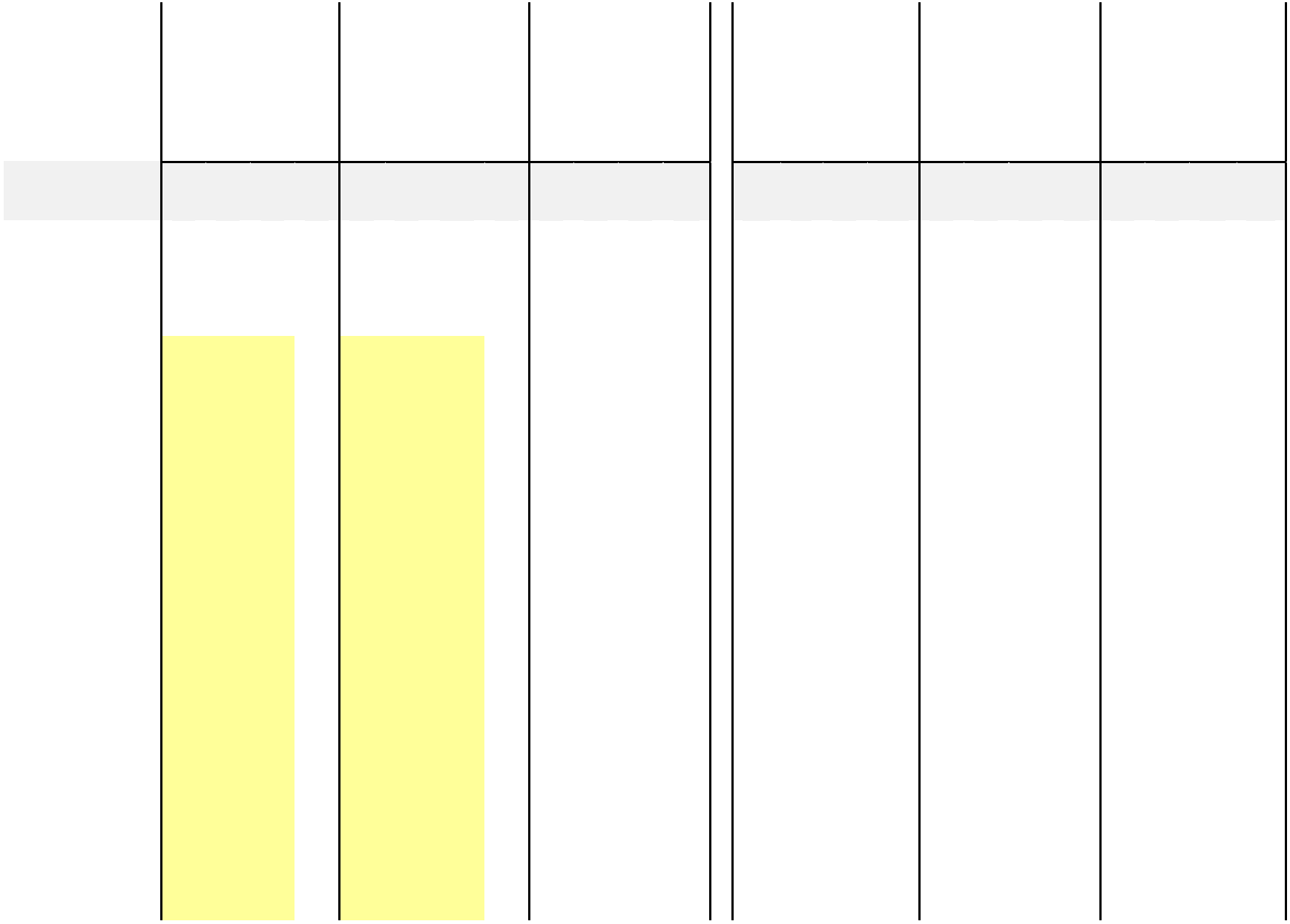
| Net Book Value | Depr | Depr LTD | Net Book Value |
|---|---|---|---|
| | | | |



| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **CUS** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **RCD** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **C** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **MBP** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **P** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Transmission** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

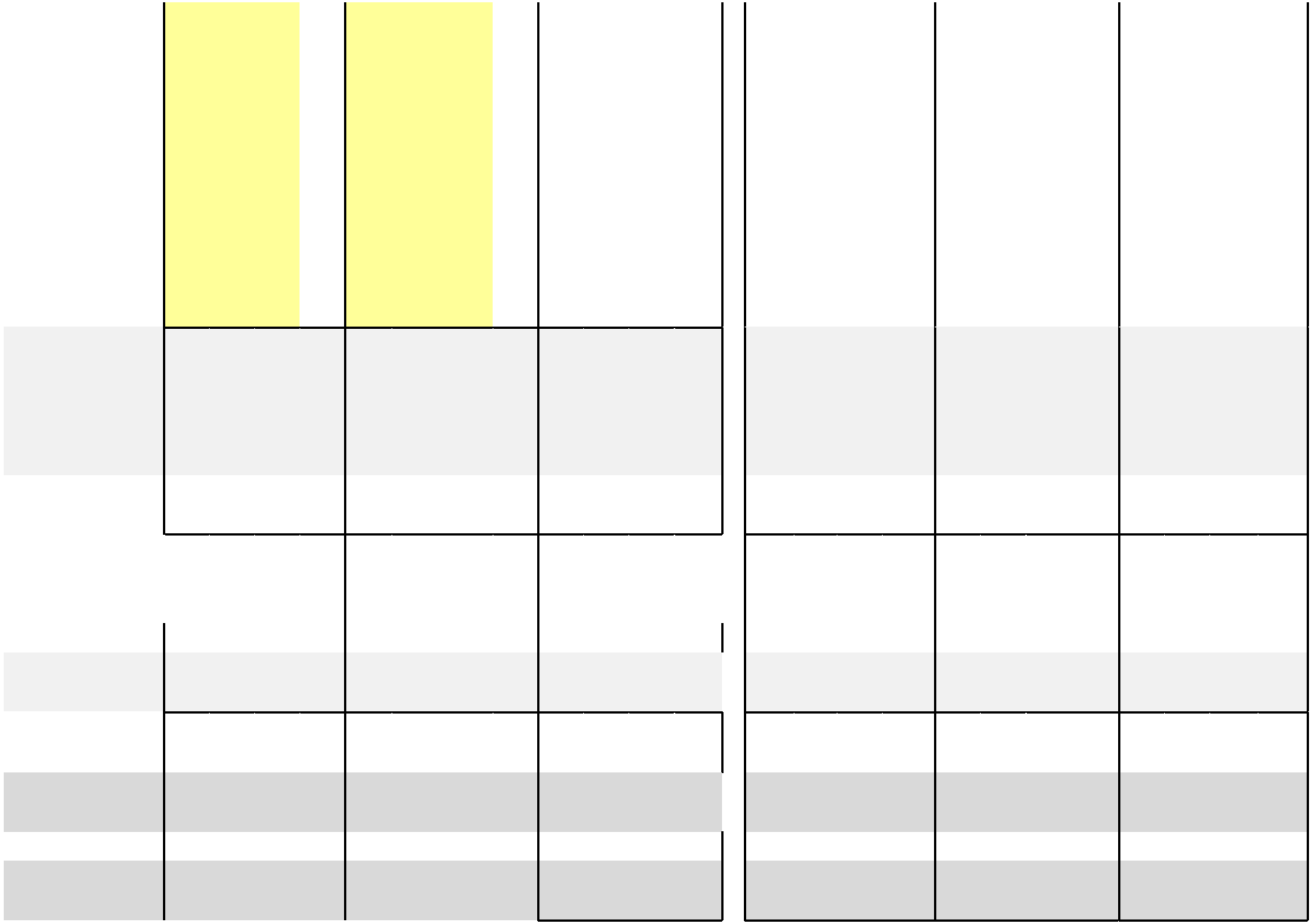
| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Production - General Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Spirit Mou** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **nt** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **LOS** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **WDG** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **DFS** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Grot** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **on** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Deer** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Cree** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **k** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Culb** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **ertso** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **n** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **LCS & PGC (Common &** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Microwave)** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Kummer Ridge Sub**



| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **AVS** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Prairie Winds ND & SD** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Minot Wind** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **MBPP** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Minot Wind 2 - ND1** | | | | - | | | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Production** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Microwave - Production** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Production / Microwave** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Other - Headquarters** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total - General Plant** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **RTO** | | | | | | | | | | | | | | | | | | | | | | | | | |

/ - - - - - - - - - - - - - - - - - - - - - - - -

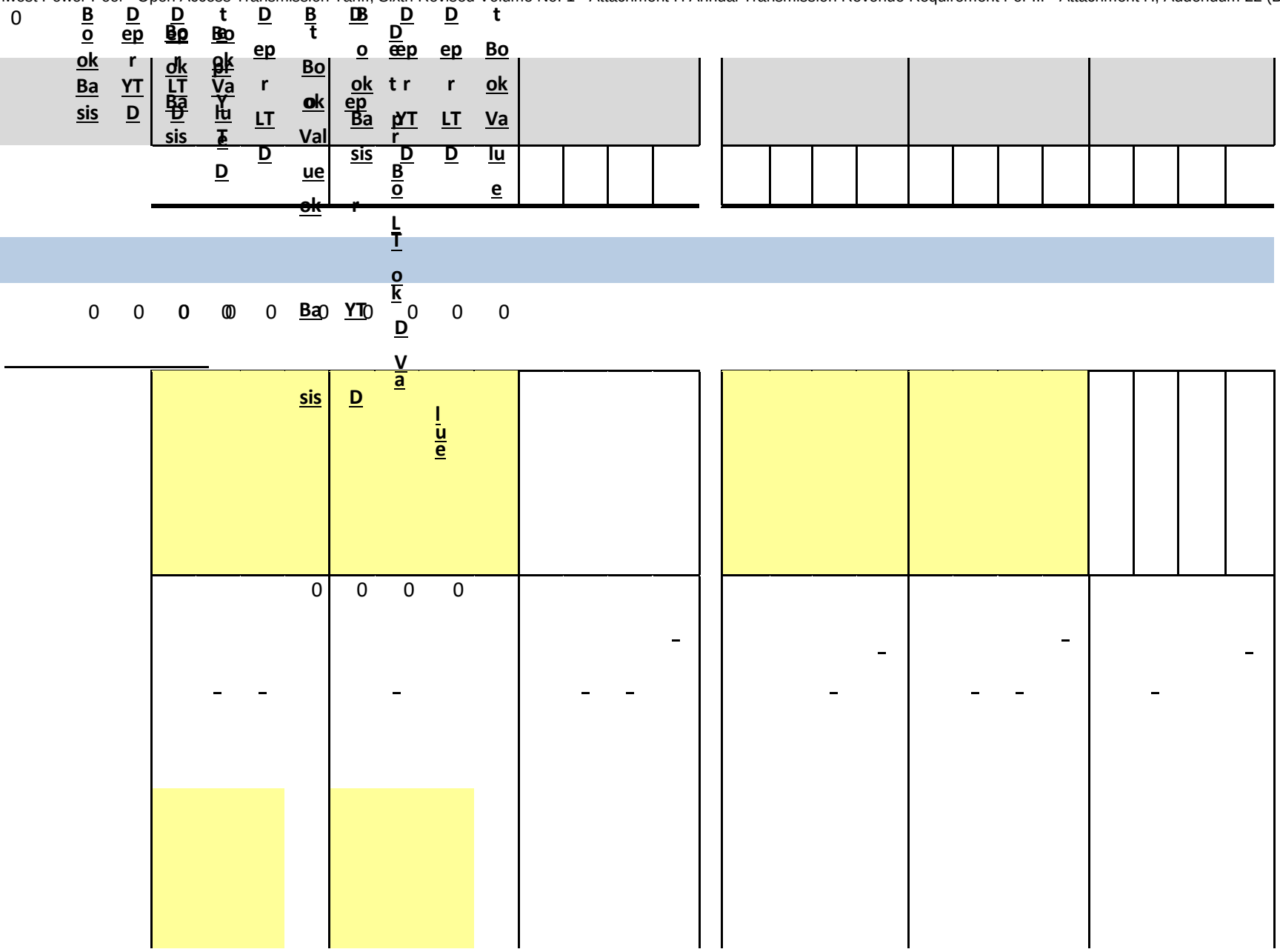


**ISO Plant**

- - - - - - - - - - - - - - - - - - - - - - - - -

**DETAIL:**
**Transmission General Plant - UMZ (Zone 19)**
**- Direct Assign Detail**

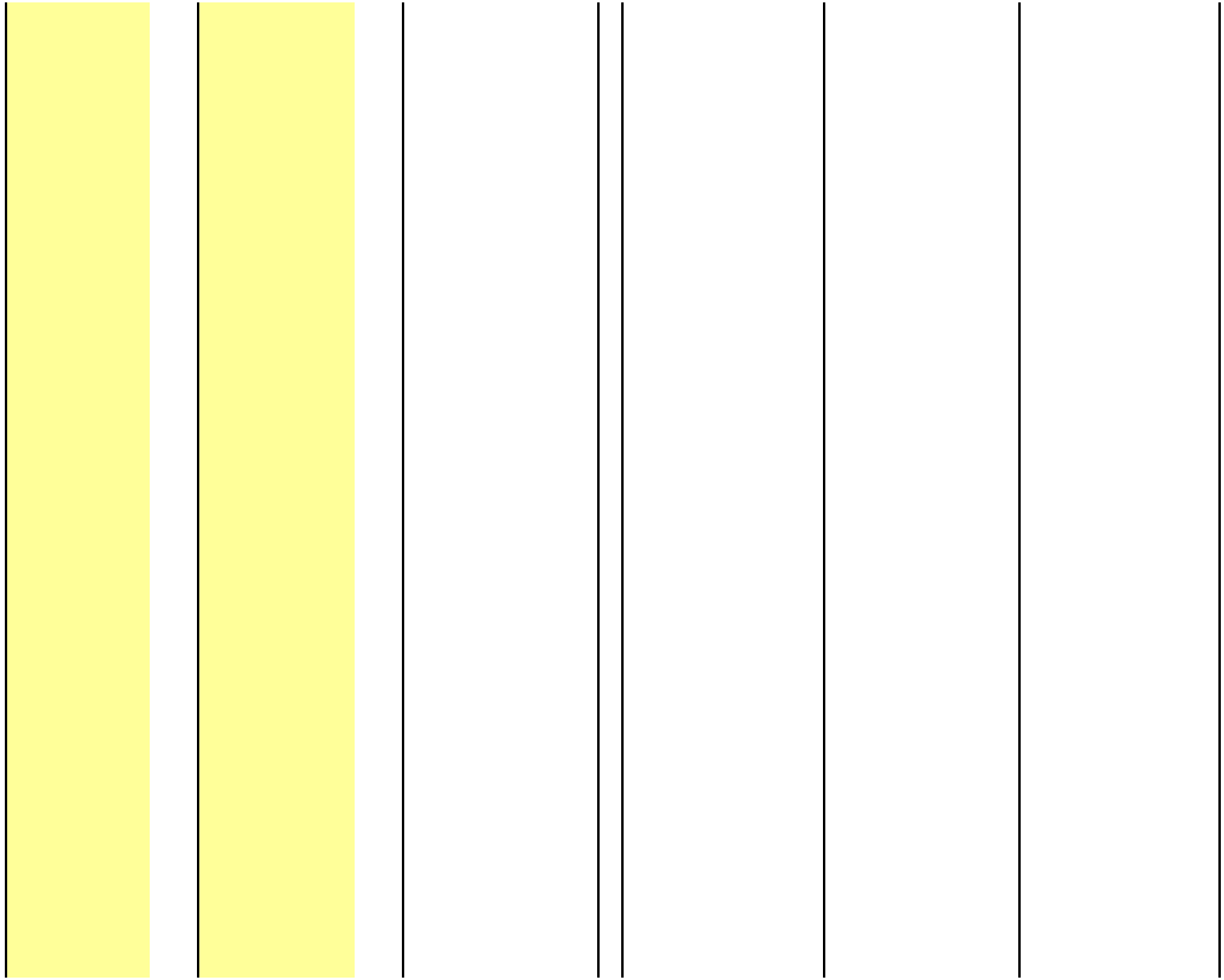
| Microwave | | 20XX Actual | | | | 20XX Actual | | | BOY / EOY | | 20XX Estimate | | 20XX Estimate | | BOY/EOY Annual | | BOY/EOY | BOY/EOY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Complex # | Description | 43 Net on-ND-LOS | Book Basis | YTD Depr | LTD Depr | Net Book Value | | Net | Book Value | | D | Net | | Net | Book Basis | Depr YTD | Depr LTD | Net Book Value |
| | Microwave Communicati | | | | | | | | | | 0 | | | | | | | |



| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 44 | Micro wave Comm unicati on-SD-LOS | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 126 | Micro wave-Broadl and SD Substa tion | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 129 | Micro wavae -067 To SD Border | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 136 | Micro wave Comm-SD-AVS | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 137 | Micro wave Comm-ND-AVS | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 139 | Micro wave Comm-ND-Saskatc hewan | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | Micro wave - 230Kv Ln- Logan- Sask Border -037 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 152 | 345Kv Line- AVS To 153 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 153 | Micro wave - Charlie Crk Sub | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 155 | Micro wave Comm- ND- Charlie Crk | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 236 | 115Kv Line- ND/MT Brd- Richld Sb | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Squaw Gap 115kV Substa | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 237 | tion | | | | 0 | | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |



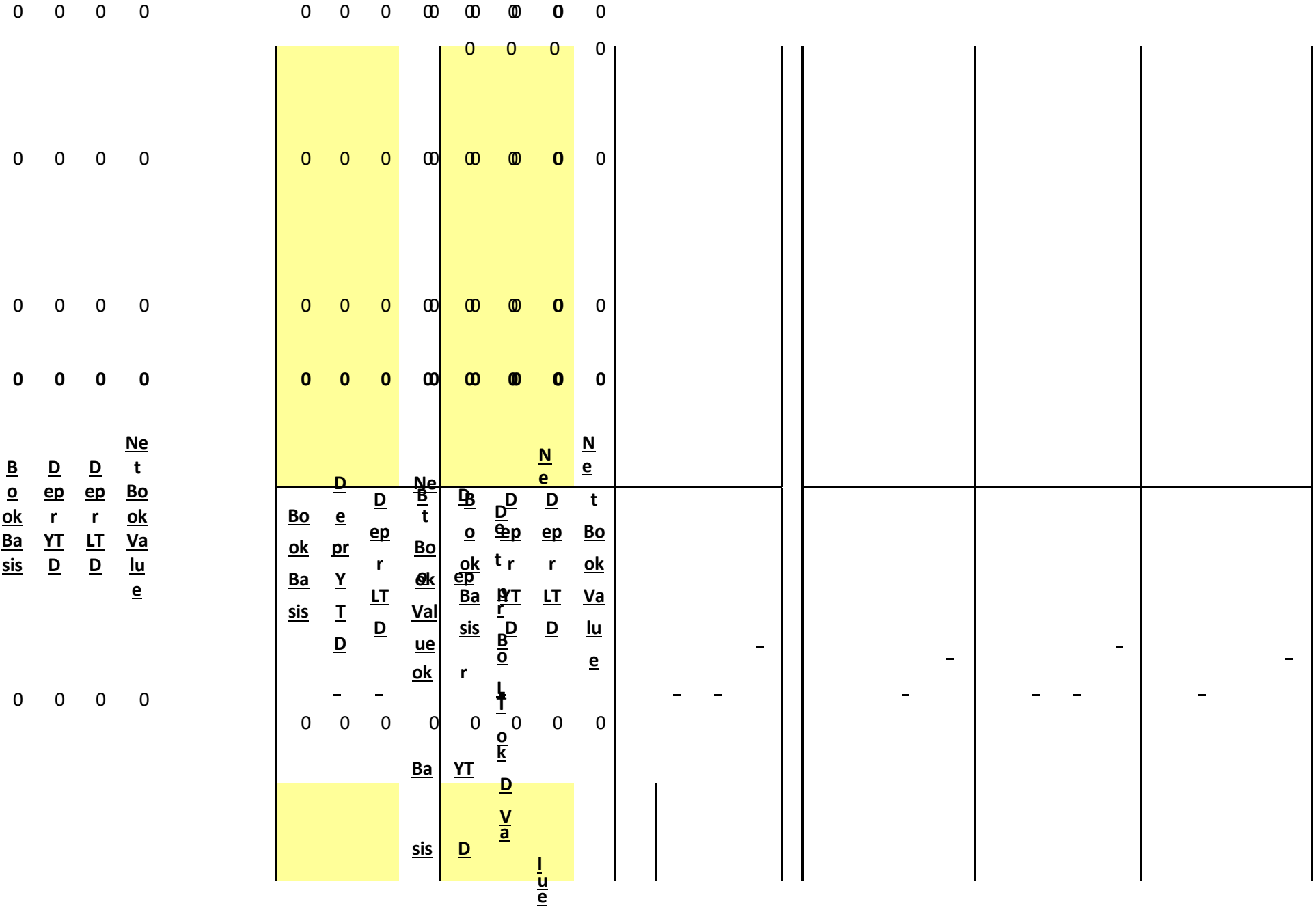
| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 292 | 345/230KV Judson Sub | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 293 | 230/115kV Wheelock Substation | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 296 | Micro wave - Williston - Tioga | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 304 | Micro wave - Williston - Tioga | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 307 & 308 | Comm-SD-Groton Sub 115Kv Tie Line- | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |
| 311 | Wapa-Groton | | 0 | | 0 | | | | | | | | | | | | | | | | | | |
| 365 | 345/115kV | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 369 | Round up Sub 345kV Patent Gate Sub | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 470 | Groton Generating Station U1 | | 0 | | 0 | | | | | | | | | | | | | | | | | | |
| 555 | SW Minot 115/41.6 kV Sub - Microwave | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 556 | Berthold 115 kV Tap - Microwave | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 557 | Kenaston 115 kV Tap Sub Microwave - | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 720 | Sub W AVS & Gro | | 0 | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 735 | Micro wave - Watertown Sub W Grot Micro wave - Logan Sub W Sask | | 0 | T | 0 | | | | | | 0 | | | | 0 |
| 737 | Add Micro wave - AVS Sub W ANG & | | 0 | | | | | | | | 0 | | | | |
| 767 | Charlie | | 0 | | | | | | | | 0 | | | | |
| | **Total Micro wave** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | | | | | | |

**Transmission Maintenance Buildings**

| | Book Basis | Net Book Value | Depr YTD | Book Basis | Depr YTD | Depr LTD | Net Book Value |
|---|---|---|---|---|---|---|---|
| Mandan | | | | | | | |


Book Basis
Depr YTD
Depr LTD
Net Book Value
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Net Book Value

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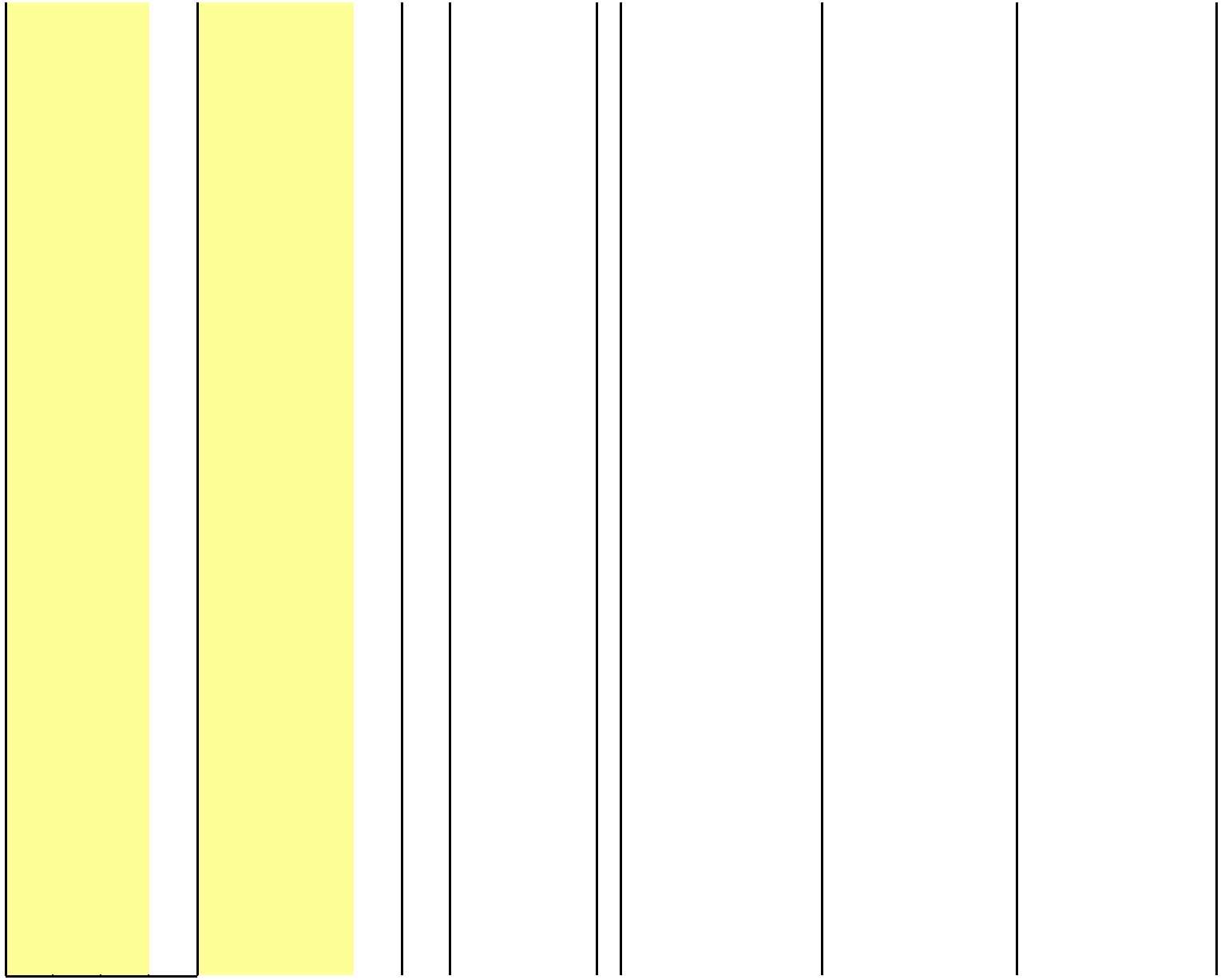
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 71 | Maint Bldg Gettysburg Trans Maint Bldg Groton Trans | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 72 | Maint Bldg Logan Trans | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 109 | Maint Bldg Broadland Trans | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 119 | Maint Bldg AVS Plantsite Trans | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 120 | Maint Bldg Huron Trans | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 214 | Maint Bldg Williston Trans | 0 | 0 | 0 | | 0 | 0 | | | | | | | | | | | | | |

570 Bldg 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0



| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total Transmission Maintenance Buildings** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Grand Total Microwave & TSM Bldgs.** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Less: Microwave Allocated to Generation, Marketing, DGC & Other** | 0 | 0 | 0 | 0 | - | - | - | - | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **0** |
| **Direct Assign - Transmission** | - | - | - | - | - | - | - | - | - | - | - | - | | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | **Work Paper #8** | | | | | | | | | | | | **Work Paper #8** |

**Page**

**Page**

| MBPP General Plant - Direct Assign | 20XX Actual | | | | 20XX Actual | | | | BOY / EOY | | | | 20XX Estimate | | | | 20XX Estimate | | | | BOY / EOY | Annual | EOY / BOY | EOY / BOY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Deprt YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value |
| Maintenance Building | 0 | | | 0 | 0 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Microwave | 0 | | | 0 | 0 | | | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Less: Microwave Allocated to Generation, etc.** | - | - | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Direct Assign - MBPP** | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| **Other General Plant - Direct Assign** | **20XX Actual** | | | | **20XX Actual** | | | | **BOY / EOY** | | | | **20XX Estimate** | | | | **20XX Estimate** | | | | **BOY / EOY** | **Annual** | **BOY / EOY** | **BOY / EOY** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value |
| Common Use System | | | | - | | | | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **Less: Microwave Allocated to Generation, etc.** | - | - | - | - | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
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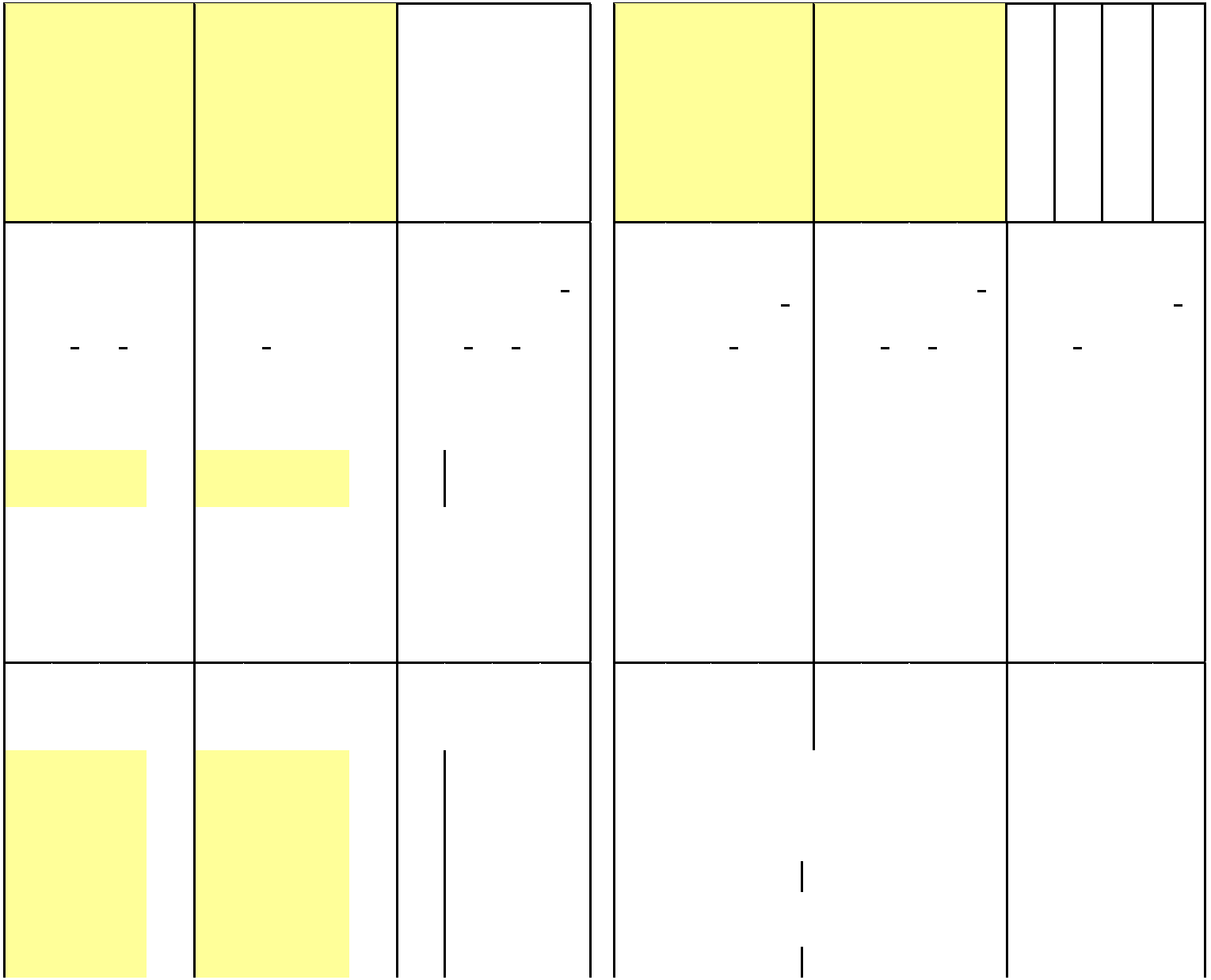

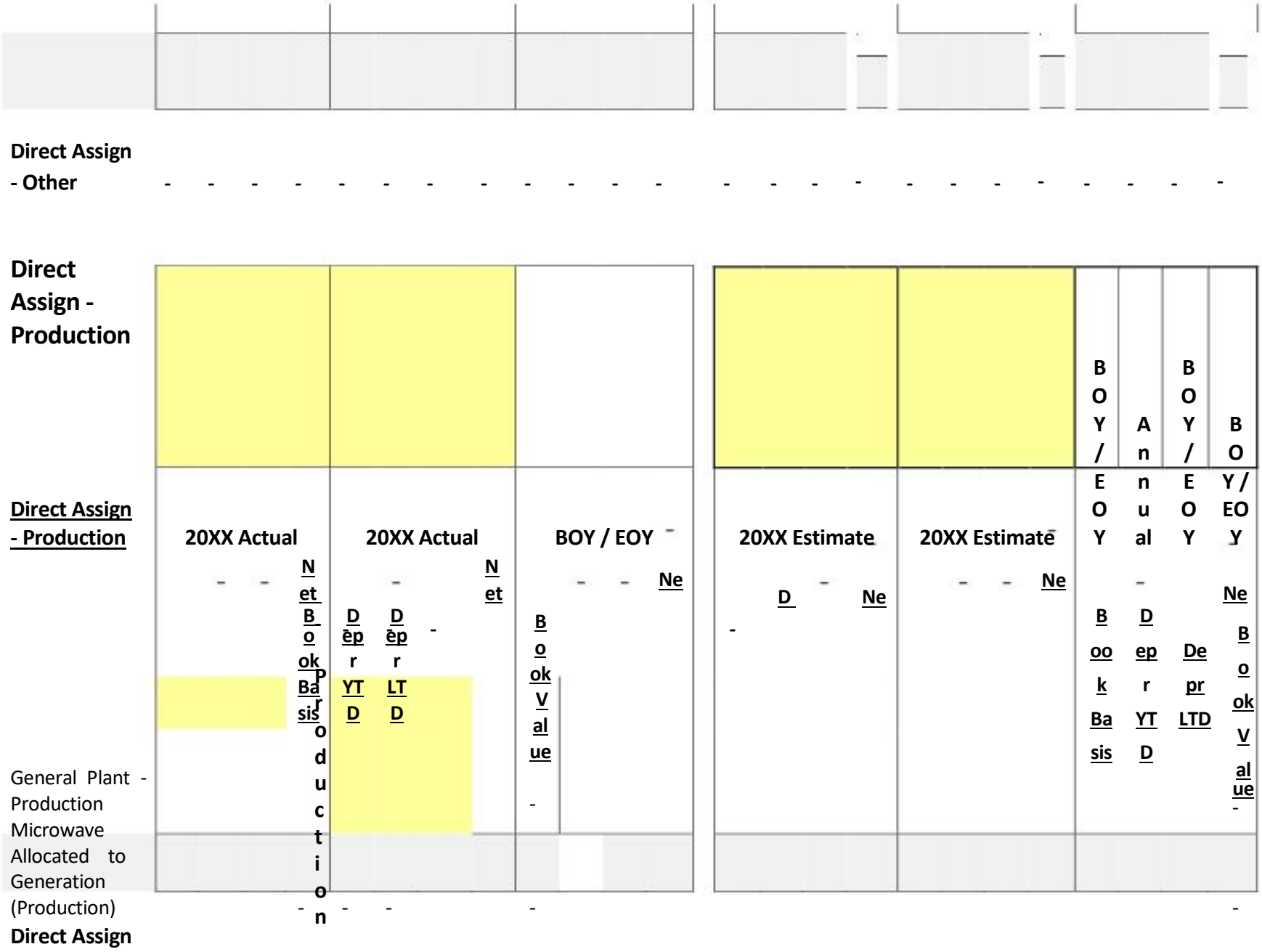
Direct Assign - Other
Direct Assign - Production
Direct Assign - Production
20XX Actual
20XX Actual
BOY / EOY
20XX Estimate
20XX Estimate
Net Book Basis
Production
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Net
Book Value
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D
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BOY / EOY Book Basis
Annual Depr YTD
BOY / EOY Depr LTD
BOY / EOY Net Book Value
General Plant - Production Microwave Allocated to Generation (Production)
Direct Assign

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| RTO / ISO Plant | 20XX Actual | | | | 20XX Actual | | | | BOY / EOY | | | | 20XX Estimate | | | | 20XX Estimate | | | | BOY / EOY | Annual | BOY / EOY | BOY / EOY |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value | Book Basis | Depr YTD | Depr LTD | Net Book Value |
| Other - (Headquarters) | - | - | - | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
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| Total | | | | | | | | | | | | | | | | | | | | | | | | |
| RTO / ISO | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay | okay |

## Microwave Channels - Allocation

**Microwave Channels by Plant - updated w/20XX data received from TSM**

| | Number of Channels | Percent |
|---|---|---|
| **UMZ - Zone 19** | | |
| Transmission | #DIV/0! | |
| Gene | #DI | |

## Microwave Channels - Allocation

**Microwave Channels by Plant - updated w/20XX data received from TSM**

| | Net Book Basis | Net Dep Book YTD Value | Net Dep LTD |
|---|---|---|---|
| **UMZ - Zone 19** | n/0! | - | |

## Microwave Channels - Allocation

**BOY / EOY Average**

| | Number of Channels | Percent | Book Basis | Dep YTD |
|---|---|---|---|---|
| **UMZ - Zone 19** | | | | |
| Transmission | #DIV/0! | | | |
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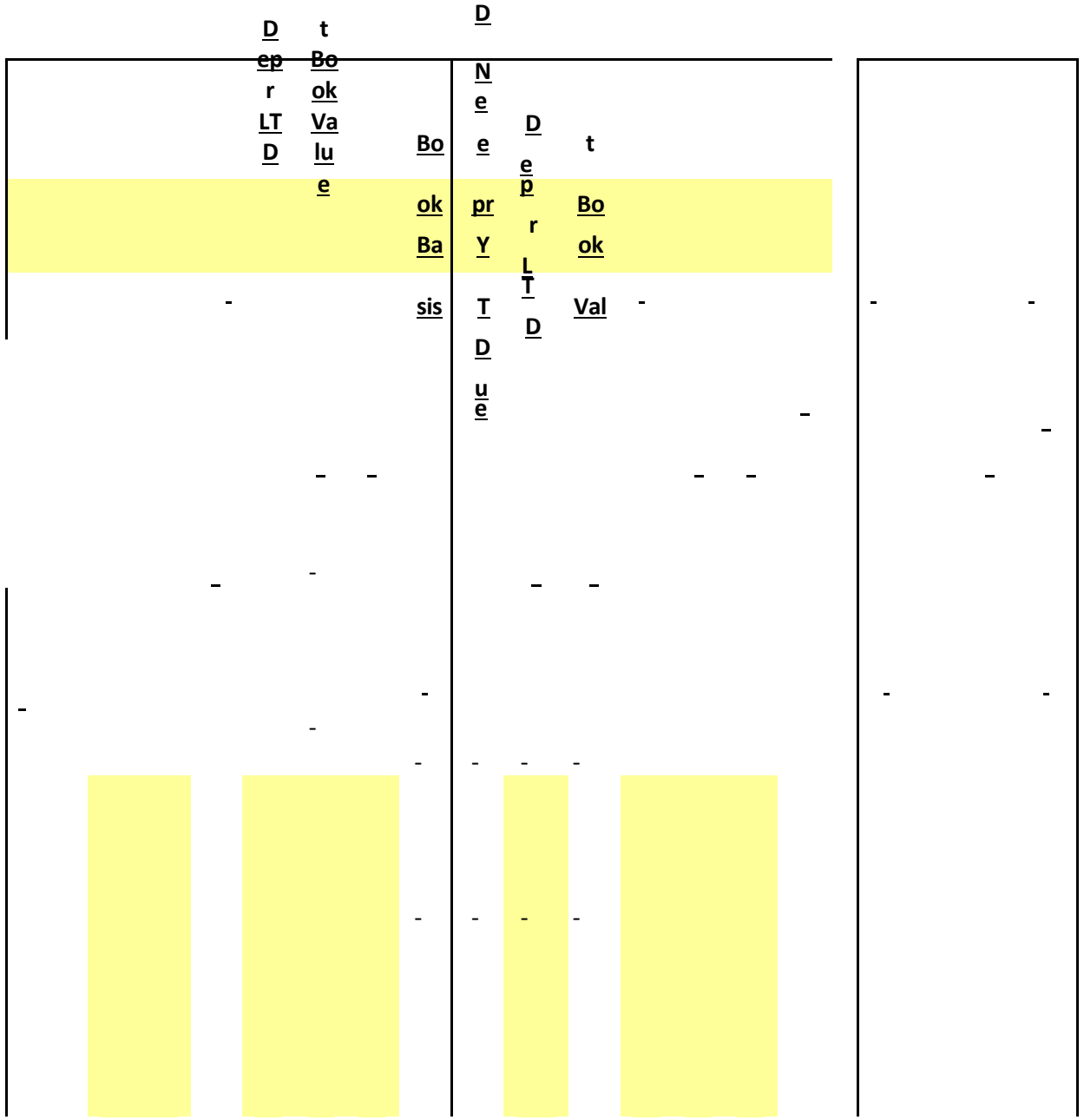

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| **Less: Alloc to Generation, Marketing, DGC & Other** | | | **-** | | **-** | - |

| **MBPP** | **Percent** | **Book Basis** | **Net Book Value** | **Depr LTD** |
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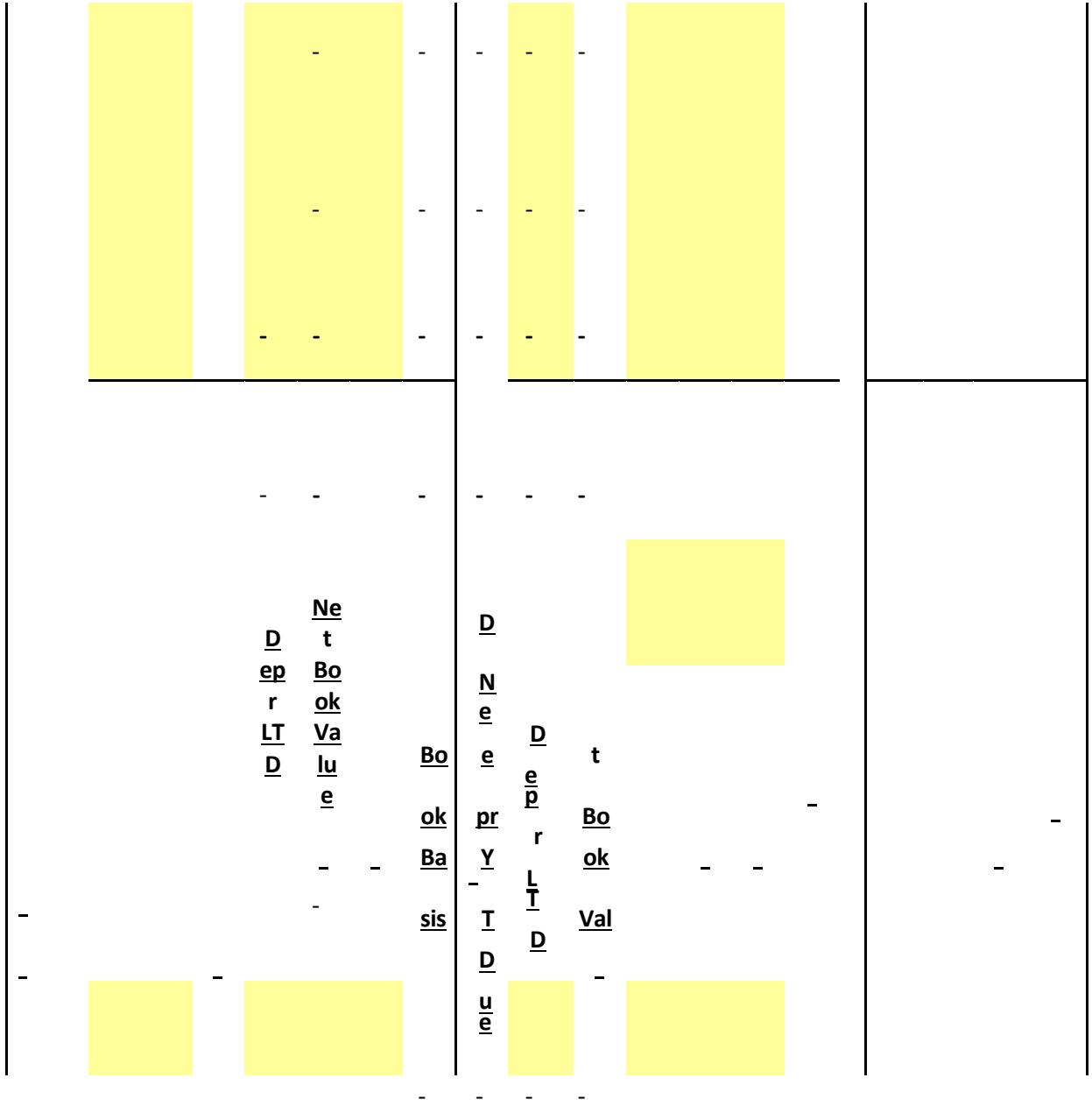
Net Book Value
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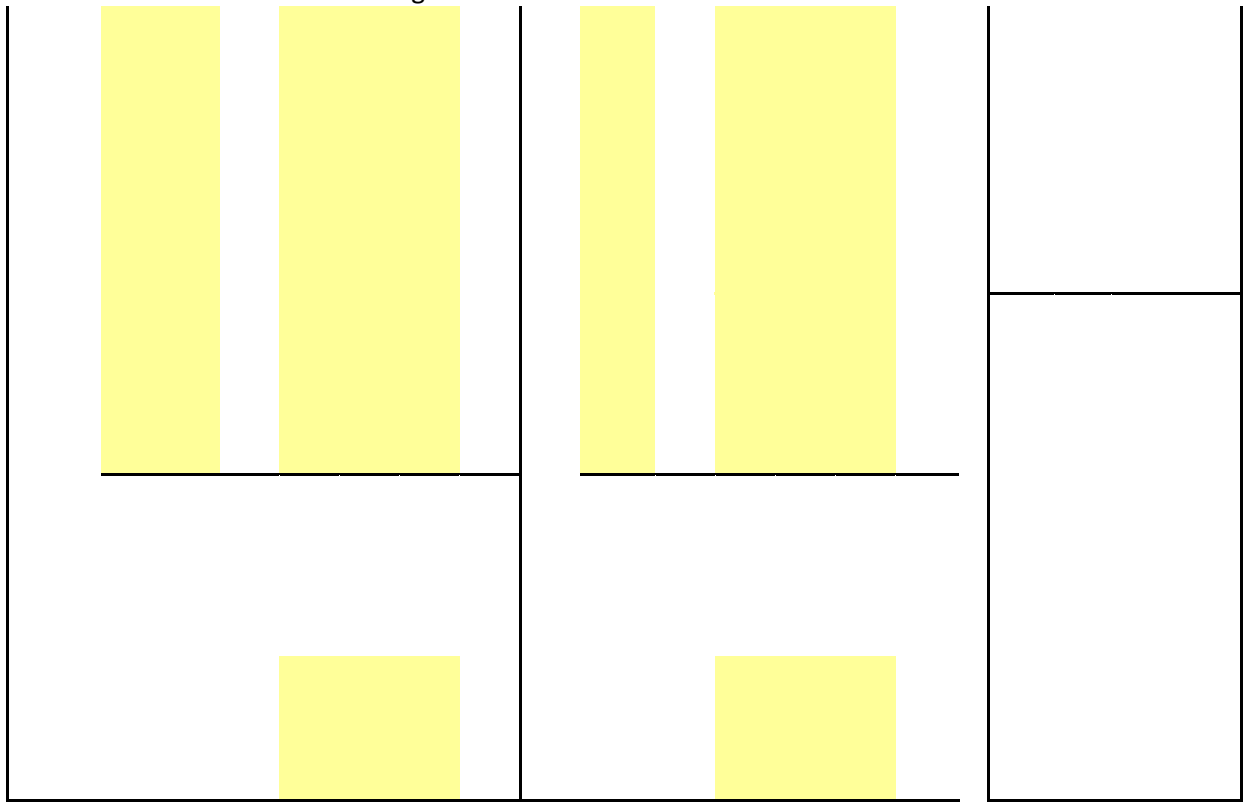
| | | #DIV/0! | | | | | Transmission | #DIV/0! | | | | | | | | | | | |
| Generation | | #DIV/0! | | | | - | Generation | #DIV/0! | | | | - | | | | - | - | - | - |
| Marketing | | #DIV/0! | | | | - | Marketing | #DIV/0! | | | | | | | | | | | |
| **Total** | **0** | **#DIV/0!** | **-** | **-** | **-** | **-** | **Total** | **0** | **#DIV/0!** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| **Less: Alloc to Generation, Marketing, DGC & Other** | | | **-** | **-** | **-** | **-** | **Less: Alloc to Generation, Marketing, DGC & Other** | | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

Note:
The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns

and formulas contained within those columns cannot be changed absent a



Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**Wages & Salaries**
**12 Months Ending 12/31/XX**
**Work Paper #9**



| Line No | Cost Description (Note A) | BEPC or BEPC Share of MBPP | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| | **Generation** | | | | | | | | | | | | | | |
| 1a | | | | | | | | | | | | | | | - |
| 1b | | | | | | | | | | | | | | | - |
| 1c | | | | | | | | | | | | | | | - |
| 1d | | | | | | | | | | | | | | | - |
| 1e | | | | | | | | | | | | | | | - |
| 1f | | | | | | | | | | | | | | | - |
| 1g | | | | | | | | | | | | | | | - |
| 1h | | | | | | | | | | | | | | | - |

1i -

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1j | | | | | | | | | | | | | | - |
| 1k | | | | | | | | | | | | | | - |
| 1l | | | | | | | | | | | | | | - |
| 1m | | | | | | | | | | | | | | - |
| 1n | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | - |
| 2 | **Total Generation** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Transmission** | | | | | | | | | | | | | |
| 3a | | | | | | | | | | | | | | - |
| 3b | | | | | | | | | | | | | | - |
| 3c | | | | | | | | | | | | | | - |
| 3d | | | | | | | | | | | | | | - |
| 3e | | | | | | | | | | | | | | - |
| 3f | | | | | | | | | | | | | | - |
| 3g | | | | | | | | | | | | | | - |
| 3h | | | | | | | | | | | | | | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3i | | | | | | | | | | | | | | - |
| 3j | | | | | | | | | | | | | | - |
| 3k | | | | | | | | | | | | | | - |
| 3l | | | | | | | | | | | | | | - |
| 3m | | | | | | | | | | | | | | - |
| 3n | | | | | | | | | | | | | | - |
| 3o | | | | | | | | | | | | | | - |
| 3p | | | | | | | | | | | | | | - |
| 3q | | | | | | | | | | | | | | - |
| ... | | | | | | | | | | | | | | - |
| 4 | **Total Transmission** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | **Total Generation & Transmission** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | **Administrative & General** | | | | | | | | | | | | | |
| a | | | | | | | | | | | | | | - |
| 6b | | | | | | | | | | | | | | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 c ... | | | | | | | | | | | | | | | - - |
| 7 | **Total Administrative & General** | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | **Distribution** | BEPC | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | **Other Transmission** | BEPC | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | **Total Wages & Salaries for Historic Year** | | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Basin Electric Power Cooperative**
**Wages & Salaries**
**Work Paper #9**



| **Line No** | | | **Estimated Inflati** | **Total Amo** |
|---|---|---|---|---|

| Description | Source | on | unt |
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| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| | **Payroll 20XX (Actual)** | | | |
| 1 | Generation | Page 1, line 2 | N/A | - |
| 2 | Transmission System Maintenance (TSM) | Page 1, line 3n | N/A | - |
| 3 | Shop/Warehouse | Page 1, lines 3a-3m | N/A | - |
| 4 | Share of MBPP (Transmission) | Page 1, lines 3o-3q | N/A | - |
| 5 | Total Transmission | Page 1, line 4 | N/A | - |
| 6 | Administrative & General | Page 1, line 7 | N/A | - |
| 7 | Distribution | Page 1, line 8 | N/A | - |
| 8 | Other Transmission | Page 1, line 9 | N/A | - |
| 9 | Total Wages & Salaries | sum lines 1, 5, 6, 7 & 8 | | - |
| | **Payroll 20XX (Estimated)** | | | |
| 10 | Generation | line 1 + inflation | | - |
| 11 | Transmission System Maintenance (TSM) | line 2 + inflation | | - |

| | | | |
|---|---|---|---|
| 1 | | line 3 + | |
| 2 | Shop/Warehouse | inflation | - |
| 1 | Share of MBPP | line 4 + | |
| 3 | (Transmission) | inflation | - |
| 1 | | line 5 + | |
| 4 | Total Transmission | inflation | - |
| 1 | Administrative & | line 6 + | |
| 5 | General | inflation | - |
| 1 | | line 7 + | |
| 6 | Distribution | inflation | - |
| 1 | Other | line 8 + | |
| 7 | Transmission | inflation | - |
| 1 | Total Wages & | sum lines 10, 14, 15, 16 & | |
| 8 | Salaries | 17 | - |
| | **Payroll 20XX (Estimated)** | | |
| 1 | | line 10 + | |
| 9 | Generation | inflation | - |
| 2 | Transmission System Maintenance | line 11 + | |
| 0 | (TSM) | inflation | - |
| 2 | | line 12 + | |
| 1 | Shop/Warehouse | inflation | - |
| 2 | Share of MBPP | line 13 + | |
| 2 | (Transmission) | inflation | - |
| 2 | | line 14 + | |
| 3 | Total Transmission | inflation | - |
| 2 | Administrative & | line 15 + | |
| 4 | General | inflation | - |
| 2 | | line 16 + | |

| | | | |
|---|---|---|---|
| 5 | Distribution | inflation | - |

| | | | |
|---|---|---|---|
| 2 | Other | line 17 + | |
| 6 | Transmission | inflation | - |
| 2 | Total Wages & | sum lines 19, | |
| 7 | Salaries | and 23-26 | - |

Note:
The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

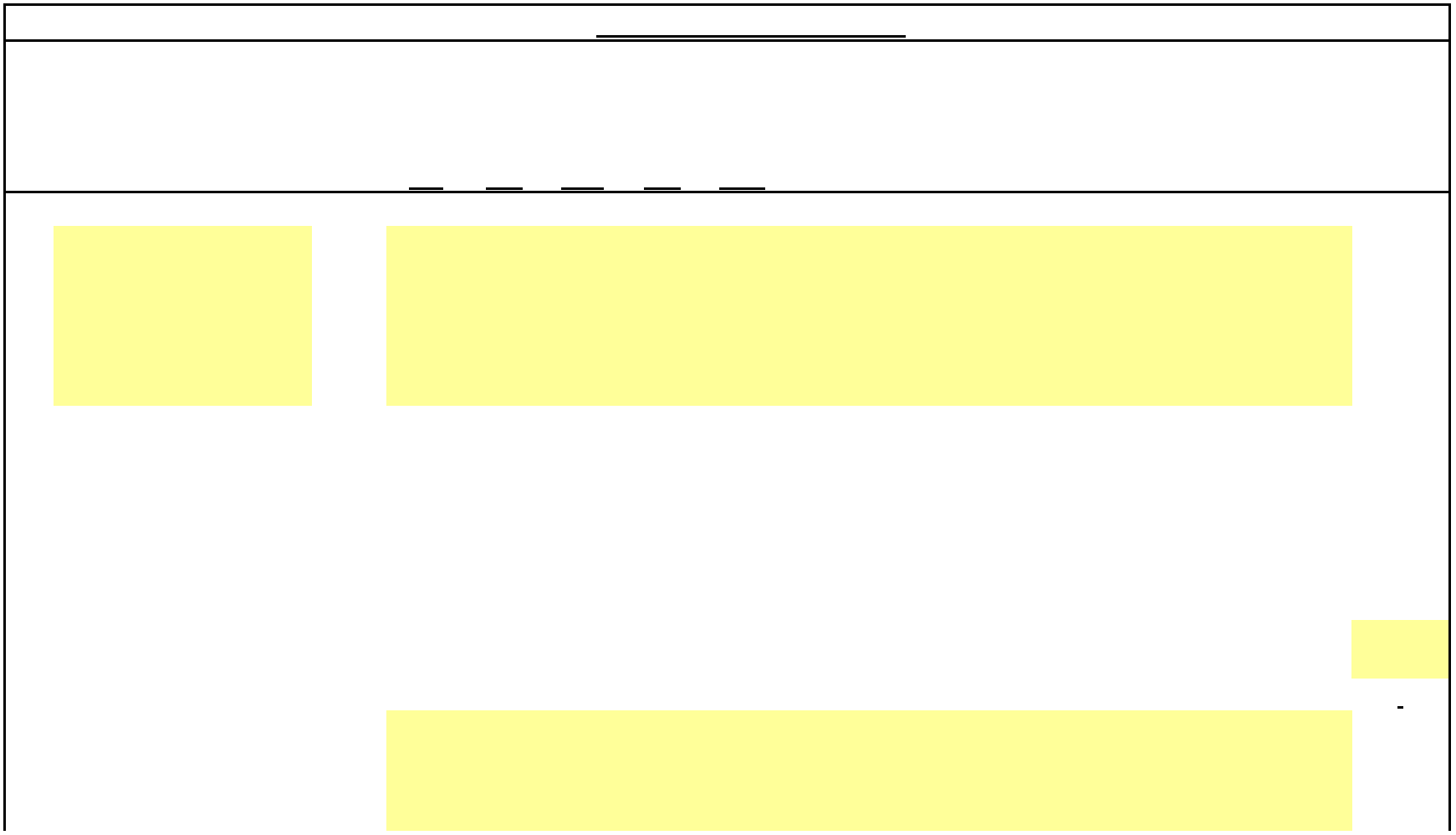
**Basin Electric Power Cooperative**
**Formula Rate Template**
**Gross Receipts Tax; Third Party Payments; Third Party Receipts**
**Work Paper #10**



**Gross Receipts Tax Calculation**

| Line No. | Gross Receipts Tax - Descriptions | | Jan | Feb | Mar | Apr | May | Jun | | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | - |
| 2 | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | - |
| 3 | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | - |
| 4 | **Calculation of Gross Receipts Tax for Common Use System (CUS)** | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | **Actuals** |
| | | | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **2019** |
| 5 | **Basin Electric Peak Load Total System Peak** | | | | | | | | | | | | | | | 0 |

6 **Load** 0



| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | Basin Load % | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| 8 | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | |
| 9 | | | | | | | | | | | | | | | |
| 10 | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 11 | | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | |
| 12 | | | | | | | | | | | | | | - | |
| 13 | | | | | | | | | | | | | | - | |

**Third Party Payments**

| Line No. | **Third Party Payments** | | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **Jun** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | | (n) | (o) |
| 1 | **Third Party Payments - 20XX Actuals** | | | | | | | | | | | | | | | |
| 2 | L&O Electric - Member Lease | | | | | | | | | | | | | | - | |
| 3 | LaCreek Electric - Mbr Lease | | | | | | | | | | | | | | - | |



| Line | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | **Third Party Payments - 20XX Estimate** | | | | | | | | | | | | | |
| 5 | L&O Electric - Member Lease | | | | | | | | | | | | | - |
| 6 | LaCreek Electric - Mbr Lease | | | | | | | | | | | | | - |
| 7 | **Third Party Payments - 20XX Estimate** | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | L&O Electric - Mbr Lease | | | | | | | | | | | | | - |
| 9 | LaCreek Electric - Mbr Lease | | | | | | | | | | | | | - |
| 10 | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | | | |

**Work Paper #10 Page 2 of 2**

**Third Party Receipts**

| No. | Third Party Receipts | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | **Third Party Receipts - 20XX Actuals** | | | | | | | | | | | | | | |
| 2 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | **Third Party Receipts - 20XX Estimate** | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | **Third Party Receipts - 20XX Estimate** | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 10 | | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 11 | | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | | | | |

| **Working Capital** | **Prior Year Actual** | **Rate Year Estimate** |
|---|---|---|
| FERC Form 1 - Page 227 Line 8 - Transmission Plant (Estimated) | | |
| | - | - |

Note:
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| | | |
|---|---|---|
| **Basin Electric - All Facilities** | **Basin Electric - All Facilities** | **SEPARATE CALCULATION APPLYING DEPRECIATION RATE** |
| **Formula Rate Template** | **Formula Rate Template** | **SPP Facilities Only - FERC Account 352 - 356** |
| **Year ending 12/31/20XX** | **Year ending 12/31/20XX** | **** FERC Account 350 Land Excluded**** **Year Ending 12/31/20XX** |
| **FERC Account 350 - 356** | **FERC Account 350 - 356** | |
| | **Y** | **SPP Facilities De** |

**T** **pr -**

| Rate | Complex # | Description | Book Basis | YTD | LTD | Net Book | Rate | Complex | Descriptions | Book Basis | D @ 1.68% | LTD | Net Book | Rate | Complex | Descriptions | Book Basis | YTD @ 1.68% | LTD | Net Book |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 230kV | | | | | | | 230kV | | | | | | | 230kV | | | | |
| | 0 | LO#1 | | | | | | | LO#1 | | | | | | | LO#1 | | | | |
| Other | 1 | Step-Up | | | | | | 010 | Step-Up | | | | | | 010 | Step-Up | | | | |
| | 0 | Sub- | | | | | Other | | Sub- | | | | | | | Sub- | | | | |
| | | Main Tr 230kV | | | | | | | Main Tr 230kV | | | | | Other | | Main Tr 230kV | | | | |
| | 0 | LO#1 | | | | | | | LO#1 | | | | | | | LO#1 | | | | |
| SPP | 1 | Doub | | | | | | 012 | Doub | | | | | | 012 | Doub | | | | |
| | 2 | Circ 011- | | | | | | | Circ 011- | | | | | | | Circ 011- | | | | |
| | | Washb 230kV | | | | | SPP | | Washb 230kV | | | | | SPP | | Washb 230kV | | | | |
| | 0 | Substati | | | | | | | Substati | | | | | | | Substati | | | | |
| SPP | 1 | on- | | | | | | 013 | on- | | | | | | 013 | on- | | | | |
| | 3 | Washbu | | | | | | | Washbu | | | | | | | Washbu | | | | |
| | | rn ND | | | | | SPP | | rn ND | | | | | SPP | | rn ND | | | | |
| | | 115kV | | | | | | | 115kV | | | | | | | 115kV | | | | |
| | 0 | Stanton | | | | | | | Stanton | | | | | | | Stanton | | | | |
| Other | 1 | Tap | | | | | | 014 | Tap | | | | | | 014 | Tap | | | | |
| | 4 | Structur | | | | | Other | | Structur | | | | | | | Structur | | | | |
| | | e H7 | | | | | | | e H7 | | | | | Other | | e H7 | | | | |
| Other | 0 | 115kV | | | | | | | 115kV | | | | | | | 115kV | | | | |
| | 1 | Stanton | | | | | Other | 015 | Stanton | | | | | | 015 | Stanton | | | | |

r **5** Tap(Usb r Tap(Usb Other Tap(Usb

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|---|---|---|---|---|---|
| | | P<br>P | | | Waterto<br>wn |
| | | | r<br>Hwy7N)<br>230/115<br>/69kV | | |
| | **0** | | BEPC | | |
| S<br>P<br>P | **1**<br>**6** | | Substati<br>on<br>345kV | | |
| | **0** | | LO#2<br>Step-Up | | |
| Ot<br>he<br>r | **1**<br>**9** | | Sub-<br>Main | Tr | |
| | **0** | | 345kV-<br>Stanton-<br>SD | | |
| S<br>P<br>P | **2**<br>**1** | | Bord(Ft<br>Thomp | | |
| | **0** | | 345kV-<br>SD<br>Border | | |
| S<br>P<br>P | **2**<br>**2** | | To Ft<br>Thomps<br>on | | |
| | **0** | | 345kV-<br>Stanton-<br>SD | | |
| S<br>P<br>P | **2**<br>**3** | | Bord(W<br>atertwn | | |
| | **0** | | 345kV-<br>SD<br>Border | | |
| S | **2**<br>**4** | | To | | |

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | 025 | 230kV-LO#1 To Logan (Minot, ND) | | | | | | | | | |
| SPP | 026 | | SPP | 025 | 230kV-LO#1 To Logan (Minot, ND) | SPP | 025 | 230kV-LO#1 To Logan (Minot, ND) | | | |
| Other | 030 | | | | | | | | | | |
| SPP | 031 | | | | | | | | | | |
| SPP | 031 | | | | | | | | | | |
| SPP | 033 | | | | | | | | | | |

230kV BEPC Line-016 To 027 230/7.2/4.16kV LO#2 Start-Up S 115kV Line- Logan To Kenmare ND 115kV Line- Logan To Kenmare ND - 33%/67% Regional/Zonal

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Mallard Su | | | Mallard Su | | | Mallard Su |
| SPP | 034 | 230kV Line-042 To 040 345kV Ft | SPP | 034 | 230kV Line-042 To 040 345kV Ft | SPP | 034 | 230kV Line-042 To 040 345kV Ft |
| SPP | 036 | Thomps on Substati on 230/115 Kv | SPP | 036 | Thomps on Substati on 230/115 Kv | SPP | 036 | Thomps on Substati on 230/115 Kv |
| SPP | 037 | Logan Substati on 230/115 kV | SPP | 037 | Logan Substati on 230/115 kV | SPP | 037 | Logan Substati on 230/115 kV |
| SPP | 039 | Storla SD Substati o 230/115 kV Philip | SPP | 039 | Storla SD Substati o 230/115 kV Philip | SPP | 039 | Storla SD Substati o 230/115 kV Philip |
| SPP | 040 | SD Substati o 230kV Philip | SPP | 040 | SD Substati o 230kV Philip | SPP | 040 | SD Substati o 230kV Philip |
| SPP | 042 | SD Tap Substati o | SPP | 042 | SD Tap Substati o | SPP | 042 | SD Tap Substati o |
| SPP | 043 | Microwa ve | SPP | 043 | Microwa ve | SPP | 043 | Microwa ve |

P **3** Commu SPP Commu SPP Commu

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | nication-ND-LOS Microwave | | | nication-ND-LOS Microwave | | | nication-ND-LOS Microwave |
| SPP | 044 | Communication-SD-LOS | SPP | 044 | Communication-SD-LOS | SPP | 044 | Communication-SD-LOS |
| SPP | 046 | Martin SD Usbr Sub Capacitor | SPP | 046 | Martin SD Usbr Sub Capacitor | SPP | 046 | Martin SD Usbr Sub Capacitor |
| SPP | 047 | Armour SD Usbr Sub Capacitor | SPP | 047 | Armour SD Usbr Sub Capacitor | SPP | 047 | Armour SD Usbr Sub Capacitor |
| SPP | 058 | 115Kv Williston ND Substation | SPP | 058 | 115Kv Williston ND Substation | SPP | 058 | 115Kv Williston ND Substation |
| SPP | 060 | 230/115/41.6Kv Dickinson ND Sb | SPP | 060 | 230/115/41.6Kv Dickinson ND Sb | SPP | 060 | 230/115/41.6Kv Dickinson ND Sb |
| SPP | 061 | 115Kv Spirit Mound Switchyard | SPP | 061 | 115Kv Spirit Mound Switchyard | SPP | 061 | 115Kv Spirit Mound Switchyard |
| SPP | 063 | Static Var | | 063 | Static Var | | 063 | Static Var |

P **3** Suppt- SPP Suppt- SPP Suppt-

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | |
| | | Victory Hill | | | | Victory Hill | | | | Victory Hill | |
| | | Mandan | | | | Mandan | | | | Mandan | |
| | 070 | Transmission | | | 070 | Transmission | | | 070 | Transmission | |
| SPP | | Maint Bldg | | SPP | | Maint Bldg | | SPP | | Maint Bldg | |
| | | Gettysburg | | | | Gettysburg | | | | Gettysburg | |
| | 071 | Trans Maint | | | 071 | Trans Maint | | | 071 | Trans Maint | |
| SPP | | Bldg | | SPP | | Bldg | | SPP | | Bldg | |
| | | Groton | | | | Groton | | | | Groton | |
| | 072 | Trans Maint | | | 072 | Trans Maint | | | 072 | Trans Maint | |
| SPP | | Bldg | | SPP | | Bldg | | SPP | | Bldg | |
| | | Logan | | | | Logan | | | | Logan | |
| | 109 | Trans Maint | | | 109 | Trans Maint | | | 109 | Trans Maint | |
| SPP | | Bldg | | SPP | | Bldg | | SPP | | Bldg | |
| | | Mobile | | | | Mobile | | | | Mobile | |
| | 114 | Cap | | | 114 | Cap | | | 114 | Cap | |
| SPP | | Banks | | SPP | | Banks | | SPP | | Banks | |
| | | Broadland Trans | | | | Broadland Trans | | | | Broadland Trans | |
| | 119 | Maint | | | 119 | Maint | | | 119 | Maint | |
| SPP | | Bldg | | SPP | | Bldg | | SPP | | Bldg | |
| | | AVS | | | | AVS | | | | AVS | |
| | 120 | Plantsite Trans Maint | | | 120 | Plantsite Trans Maint | | | 120 | Plantsite Trans Maint | |
| SPP | | Bldg | | SPP | | Bldg | | SPP | | Bldg | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 345kV | | | 345kV | | | 345kV |
| | 12 | Great | | 121 | Great | | 121 | Great |
| Other | 1 | Plains | Other | | Plains | Other | | Plains |
| | | Substation | | | Substation | | | Substation |
| | 1 | 345kV | | | 345kV | | | 345kV |
| Other | 2 | Line-123 | Other | 122 | Line-123 | | 122 | Line-123 |
| | 2 | To ANG | | | To ANG | Other | | To ANG |
| | | 500kV | | | 500kV | | | 500kV |
| | 1 | Broadland SD | | | Broadland SD | | | Broadland SD |
| SPP | 26 | Substation | | 126 | Substation | | 126 | Substation |
| | | 345kV | SPP | | 345kV | SPP | | 345kV |
| | 1 | #1-134 | | | #1-134 | | | #1-134 |
| SPP | 27 | To LO (AVS) No.Ln | | 127 | To LO (AVS) No.Ln | | 127 | To LO (AVS) No.Ln |
| | | 345kV | SPP | | 345kV | SPP | | 345kV |
| | 1 | #2-134 | | | #2-134 | | | #2-134 |
| SPP | 28 | To LO (AVS) So.Ln | | 128 | To LO (AVS) So.Ln | | 128 | To LO (AVS) So.Ln |
| | | 500kV | SPP | | 500kV | SPP | | 500kV |
| SPP | 129 | Line-067 To SD Border | | 129 | Line-067 To SD Border | | 129 | Line-067 To SD Border |
| | | 500kV | SPP | | 500kV | SPP | | 500kV |
| SPP | 130 | Line-SD Border To 126 | | 130 | Line-SD Border To 126 | | 130 | Line-SD Border To 126 |
| SP | 13 | 345kV | | 134 | 345kV | | 134 | 345kV |

P **4** Dbl Cir SPP Dbl Cir SPP Dbl Cir

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | **141** | L-AVS To 127,128 230kV Ln-126 To Usbr Huron Sub 230kV Usbr Huron Sub Additions Manning SD Sub Capacitor Instl 230kV Ln-Logan-Sask Border-037 | | SPP | **141** | L-AVS To 127,128 230kV Ln-126 To Usbr Huron Sub 230kV Usbr Huron Sub Additions Manning SD Sub Capacitor Instl 230kV Ln-Logan-Sask Border-037 | | SPP | **141** | L-AVS To 127,128 230kV Ln-126 To Usbr Huron Sub 230kV Usbr Huron Sub Additions Manning SD Sub Capacitor Instl 230kV Ln-Logan-Sask Border-037 | |
| SPP | **142** | | | SPP | **142** | | | SPP | **142** | | |
| SPP | **145** | | | SPP | **145** | | | SPP | **145** | | |
| SPP | **150** | | | SPP | **150** | | | SPP | **150** | | |
| SPP | **152** | | SPP | **3** | | | | SPP | | | |
| SPP | **153** | | | | | | | 345kV Line-AVS To 345/230/115kV Charlie Crk Charlie Crk Sub | | | 153 Sub |
| SPP | **15** | | | | | | | | | | |

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SPP

**153**

SPP

**152**

Line-AVS

SPP

**153**

345kV Line-AVS To 153 345/230/115kV Charlie Crk Sub

345kV Line-AVS To 153 345/230/115kV Charlie Crk Sub

- 345KV LN Add

**152**

SPP

**153**

SPP

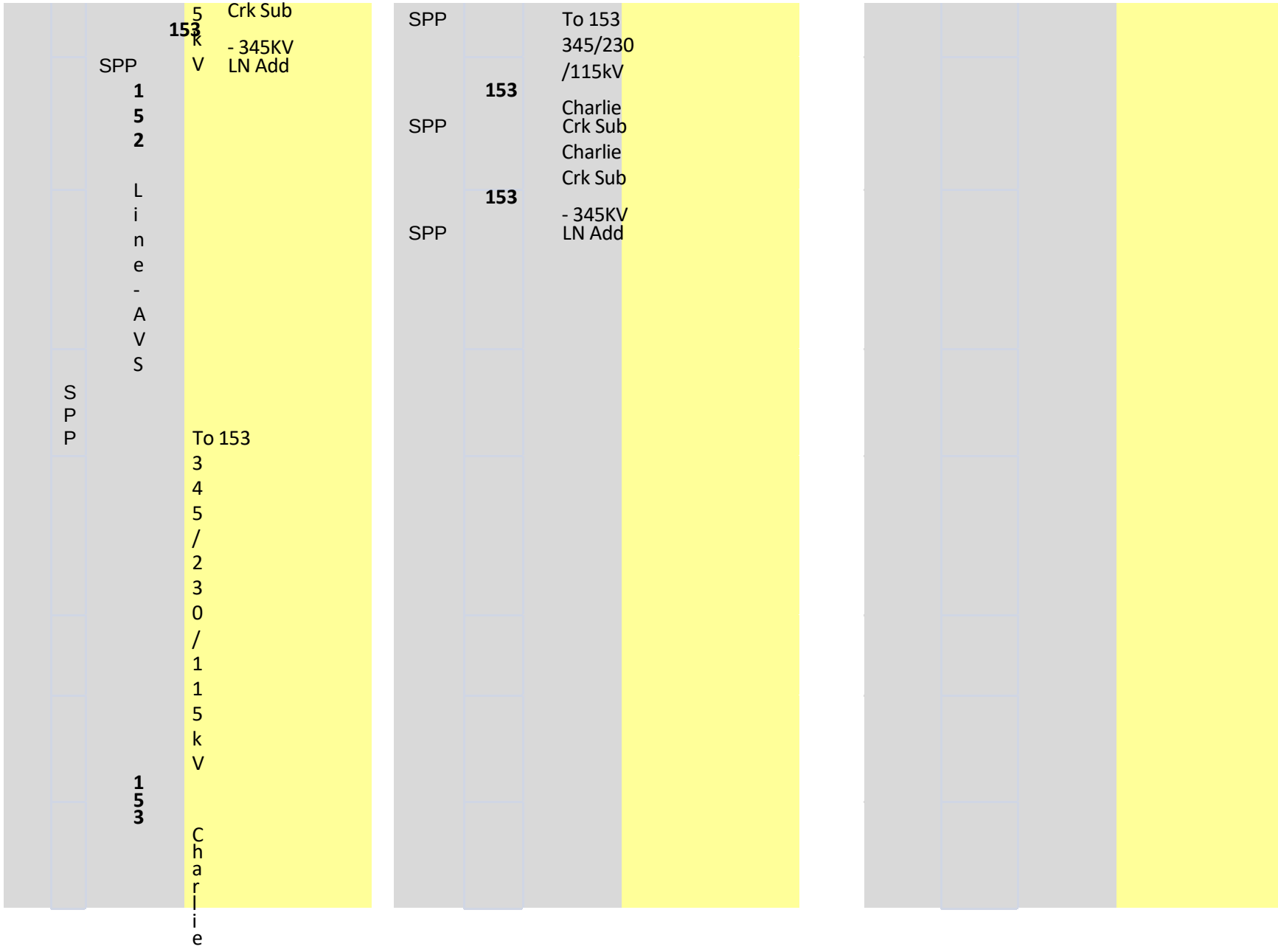
**153**

SPP

345kV Line-AVS To 153 345/230/115kV Charlie Crk Sub

Charlie Crk Sub

- 345KV LN Add



| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | (Activity 4078276 3, 4079011 0) Little | | | | (Activity 4078276 3, 4079011 0) Little | | | | (Activity 4078276 3, 4079011 0) Little | |
| SPP | 179 | Miss Tap 115kV Cap Bank | 1 | SPP | 179 | Miss Tap 115kV Cap Bank | 1 | SPP | 179 | Miss Tap 115kV Cap Bank | 1 |
| SPP | 181 | 230kV Ln- Rhame Sub to Belfield 230kV | 1 | SPP | 181 | 230kV Ln- Rhame Sub to Belfield 230kV | 1 | SPP | 181 | 230kV Ln- Rhame Sub to Belfield 230kV | 1 |
| SPP | 182 | Belfield Substation 230kV | 2 | SPP | 182 | Belfield Substation 230kV | 2 | SPP | 182 | Belfield Substation 230kV | 2 |
| SPP | 183 | Rhame Substation Main | 3 | SPP | 183 | Rhame Substation Main | 3 | SPP | 183 | Rhame Substation Main | 3 |
| Other | 191 | Transformer-AVS 1 | 1 | Other | 191 | Transformer-AVS 1 | 1 | Other | 191 | Transformer-AVS 1 | 1 |
| Other | 192 | Main Transformer-AVS 2 | 2 | Other | 192 | Main Transformer-AVS 2 | 2 | Other | 192 | Main Transformer-AVS 2 | 2 |
| Other | 193 | Spare Transfor | 9 | Other | 193 | Spare Transfor | 9 | Other | 193 | Spare Transfor | 9 |

r **3** mer-AVS



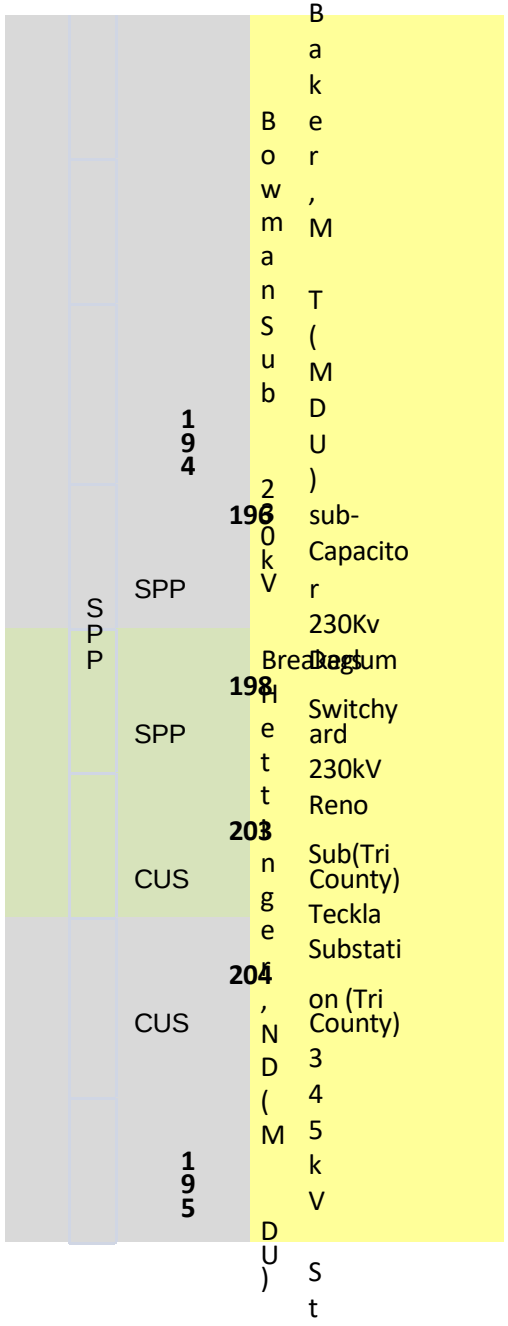
r mer-AVS

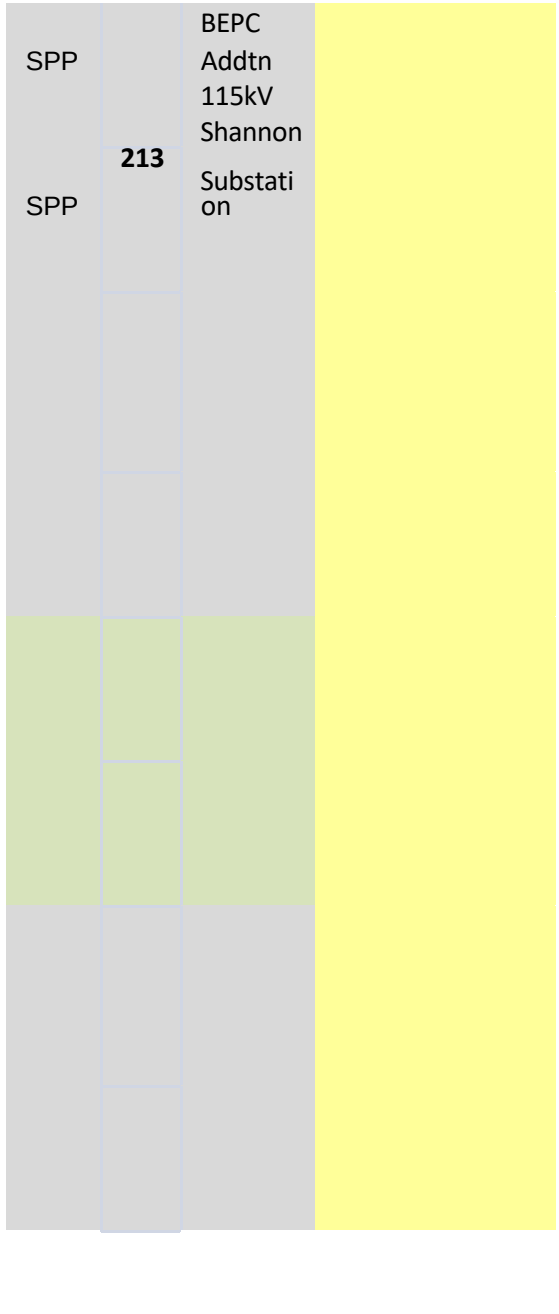


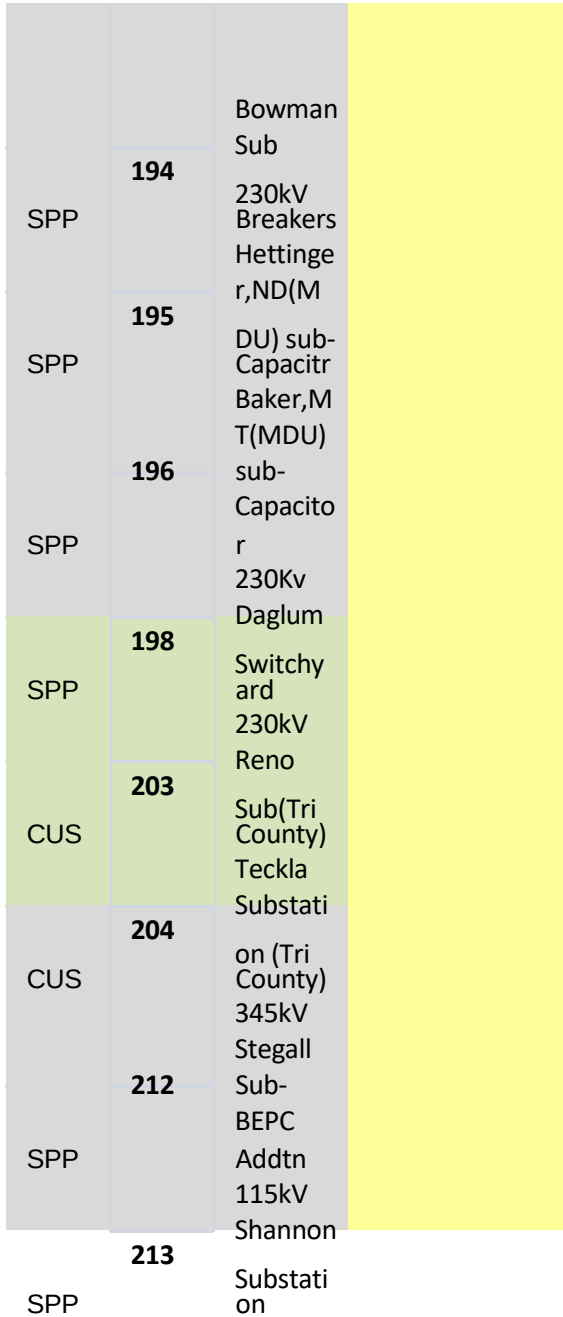
Other mer-AVS

| | | | | | |
|---|---|---|---|---|---|
| | | S | **3** | | |
| | | P | | | |
| | | P | | | |
| S P P | **1 9 4** | | | Bowman Sub 230kV Breakers | |
| S P P | **1 9 5** | | | Hettinger,ND(MDU) Capacitr | sub- |
| S P P | **1 9 6** | | | Baker,MT(MDU) sub-Capacitor 230Kv | |
| S P P | **1 9 8** | | | Daglum Switchyard 230kV | |
| C U S | **2 0 3** | | | Reno Sub(Tri County) | |
| C U S | **2 0 4** | | | Teckla Substation | (Tri |
| S P P | **2 1 2** | | | County) 345kV Stegall Sub-BEPC Addtn 115kV | |
| | **2 1** | | | | |

Shannon Substation



| | | | | |
|---|---|---|---|---|
| | | S | | 230Kv Sub |
| | **2** | Huron | | |
| S P P | **1** **4** | Trans Maint Bldg | | |
| | **2** | Pumpkin Butte | | |
| C U S | **1** **7** | 230KV Substati on | | |
| | **2** | Hughes 230/69K | | |
| C U S | **2** **2** | v Substati on | | |
| | **2** | 230Kv Line | | |
| C U S | **2** **3** | Tongue Rv to DFS | Sw | |
| | **2** | Carr Draw Sub | to | |
| C U S | **2** **4** | DFS Swyd 230K | | |
| | **2** | DFS SwYDto | | |
| C U S | **2** **5** | Hughes Sub 230KV | | |
| C U | **2** **2** **6** | Tongue River | | |

| | | | | | |
|---|---|---|---|---|---|
| SPP | 214 | Huron Trans Maint Bldg Pumpkin Butte | CUS | 222 | v Substation 230Kv Line Tongue Rv to DFS Sw Carr Draw Sub to DFS Swyd 230K DFS SwYDto Hughes Sub 230KV Tongue River |
| CUS | 217 | 230KV Substation Hughes 230/69K | CUS | 223 | |
| | | | CUS | 224 | |
| | | | CUS | 225 | |
| | | | CUS | 226 | 230Kv Sub |


| | | | | | |
|---|---|---|---|---|---|
| SPP | 214 | Huron Trans Maint Bldg Pumpkin Butte | CUS | 222 | v Substation 230Kv Line Tongue Rv to DFS Sw Carr Draw Sub to DFS Swyd 230K DFS SwYDto Hughes Sub 230KV Tongue River |
| CUS | 217 | 230KV Substation Hughes 230/69K | CUS | 223 | |
| | | | CUS | 224 | |
| | | | CUS | 225 | |
| | | | CUS | 226 | 230Kv Sub |

| | | |
|---|---|---|
| CUS | 227 | Sheridan 230Kv Substation Addi 230KV |
| CUS | 228 | LN-Sheridan SubtoTongue 230Kv-Goose |
| CUS | 231 | Cr-TongueR to MT 230kV |
| Other | 232 | Line-MT Brder to Decker 115Kv |
| SPP | 234 | Line-Char Ck-Sqw Gab Sub 115Kv |
| SPP | 235 | Line-Sqw Gap-ND/MT Bordr 115Kv |
| SPP | 236 | Line-ND/MT Brd- |

| | | |
|---|---|---|
| CUS | 227 | Sheridan 230Kv Substation Addi 230KV |
| CUS | 228 | LN-Sheridan SubtoTongue 230Kv-Goose |
| CUS | 231 | Cr-TongueR to MT 230kV |
| Other | 232 | Line-MT Brder to Decker 115Kv |
| SPP | 234 | Line-Char Ck-Sqw Gab Sub 115Kv |
| SPP | 235 | Line-Sqw Gap-ND/MT Bordr 115Kv |
| SPP | 236 | Line-ND/MT Brd- |

| | | |
|---|---|---|
| CUS | 227 | Sheridan 230Kv Substation Addi 230KV |
| CUS | 228 | LN-Sheridan SubtoTongue 230Kv-Goose |
| CUS | 231 | Cr-TongueR to MT 230kV |
| Other | 232 | Line-MT Brder to Decker 115Kv |
| SPP | 234 | Line-Char Ck-Sqw Gab Sub 115Kv |
| SPP | 235 | Line-Sqw Gap-ND/MT Bordr 115Kv |
| SPP | 236 | Line-ND/MT Brd- |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | 23237 | Richld Sb Squaw Gap 115kV Substation | | SPP | 237 | Richld Sb Squaw Gap 115kV Substation | | SPP | 237 | Richld Sb Squaw Gap 115kV Substation | |
| SPP | 23238 | Richland 115/69kV Substation | | SPP | 238 | Richland 115/69kV Substation | | SPP | 238 | Richland 115/69kV Substation | |
| SPP | 23239 | | CUS | SPP | | Roughrider 115/24.9kV | Tap | SPP | | Yellow Creek/Osage | |
| SPP | 23240 | | | SPP | | Bicentennial 115/24.9kV | Tap | | | | |
| SPP | 23241 | | | SPP | | Koch 115/12.47kV Tap | Oil | | | | |
| SPP | 23243 | | | SPP | | East Sidney 115/12.47kV Tap | | | | | |
| | 22774 | | | | | 230Kv Line | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Roughrider | 239 | 115/24.9kV Tap Bicentennial | SPP | Yellow | 239 | Roughrider | 239 | 115/24.9kV Tap Bicentennial | | | | |
| SPP Tap | | 240 | 115/24.9kV Tap Koch Oil | SPP | | 240 | 115/24.9kV Tap Koch Oil | 241 | 115/12.47kV Tap East Sidney | | | | |
| SPP | | 241 | 115/12.47kV Tap East Sidney | SPP | CUS | 243 | 115/12.47kV Tap 230Kv Line | 274 | Yellow Creek/Osage | | | | |
| | | 243 | 115/12.47kV Tap 230Kv Line | CUS | | 274 | Yellow Creek/Osage | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 230Kv | | | 230Kv | | | 230Kv | | | 230Kv |
| | 2 | Line | | | Line | | | Line | | | Line |
| C | 7 | Spearfis | | 275 | Spearfis | | 275 | Spearfis | | 275 | Spearfis |
| U | 5 | h/Yellow | | | h/Yellow | | | h/Yellow | | | h/Yellow |
| S | | Cr | CUS | | Cr | CUS | | Cr | CUS | | Cr |
| | | 230Kv | | | 230Kv | | | 230Kv | | | 230Kv |
| | 2 | Line | | | Line | | | Line | | | Line |
| C | 7 | Yellow | | 276 | Yellow | | 276 | Yellow | | 276 | Yellow |
| U | 6 | Creek/O | | | Creek/O | | | Creek/O | | | Creek/O |
| S | | sage | CUS | | sage | CUS | | sage | CUS | | sage |
| | | 230 kV | | | 230 kV | | | 230 kV | | | 230 kV |
| | 2 | Sully | | | Sully | | | Sully | | | Sully |
| | 7 | Butte | | 278 | Butte | | 278 | Butte | | 278 | Butte |
| S | 8 | Sub | | | Sub | | | Sub | | | Sub |
| P | | (Shunt) | SPP | | (Shunt) | SPP | | (Shunt) | SPP | | (Shunt) |
| | | 230 kV | | | 230 kV | | | 230 kV | | | 230 kV |
| | 2 | Glenha | | | Glenha | | | Glenha | | | Glenha |
| S | 7 | m Sub | | 279 | m Sub | | 279 | m Sub | | 279 | m Sub |
| P | 9 | (Shunt) | SPP | | (Shunt) | SPP | | (Shunt) | SPP | | (Shunt) |
| | | 230/115 | | | 230/115 | | | 230/115 | | | 230/115 |
| | 2 | Kv Line- | | | Kv Line- | | | Kv Line- | | | Kv Line- |
| S | 8 | Judson | | 288 | Judson | | 288 | Judson | | 288 | Judson |
| P | 8 | to Willi | SPP | | to Willi | SPP | | to Willi | SPP | | to Willi |
| | | 230Kv | | | 230Kv | | | 230Kv | | | 230Kv |
| | 2 | Line- | | | Line- | | | Line- | | | Line- |
| S | 8 | Tande to | | 289 | Tande to | | 289 | Tande to | | 289 | Tande to |
| P | 9 | Neset | SPP | | Neset | SPP | | Neset | SPP | | Neset |
| | | 345/230 | | | 345/230 | | | 345/230 | | | 345/230 |
| | 2 | Kv | | | Kv | | | Kv | | | Kv |
| S | 9 | Tande | | 290 | Tande | | 290 | Tande | | 290 | Tande |
| P | 0 | Sub | SPP | | Sub | SPP | | Sub | SPP | | Sub |
| S | 2 | 345/230 | | | 345/230 | | | 345/230 | | | 345/230 |
| P | 9 | kV | | 290 | kV | | 290 | kV | | 290 | kV |

P **0** Tande SPP Tande SPP Tande

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| SPP | 291 | Sub - 33% Regional / 67% Zonal 345Kv Line- Judson to Tande 345/230 KV | SPP | 291 | Sub - 33% Regional / 67% Zonal 345Kv Line- Judson to Tande 345/230 KV | SPP | 291 | Sub - 33% Regional / 67% Zonal 345Kv Line- Judson to Tande 345/230 KV |
| SPP | 292 | Judson Sub- 100% Regional 345/230 KV | SPP | 292 | Judson Sub- 100% Regional 345/230 KV | SPP | 292 | Judson Sub- 33% Regional 345/230 KV |
| SPP | 292 | Judson Sub-33% Regional 230/115 kV | SPP | 292 | Judson Sub-33% Regional 230/115 kV | SPP | 292 | Judson Sub-33% Regional 230/115 kV |
| SPP | 293 | Wheelock Substation 345Kv | SPP | 293 | Wheelock Substation 345Kv | SPP | 293 | Wheelock Substation 345Kv |
| SPP | 294 | Line-AVS to Charlie Crk | SPP | 294 | Line-AVS to Charlie Crk | SPP | 294 | Line-AVS to Charlie Crk |
| SPP | 295 | 230/115 kV | | 295 | 230/115 kV | | 295 | 230/115 kV |

P **5** Blaisdell SPP Blaisdell SPP Blaisdell

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | S | | | | | | |
| | | P | | | | | | |
| | | P | Substation 230Kv Line- Williston to Tioga 230/115 KV Neset (Tioga) Sub Neset Substation 230 kV Bus - 33 % Regional / 67% Zonal 345Kv Line- Charlie Ck to Judso 230Kv Willistn Sub Transformer 115Kv Line- Blaisdell to Bertho | | | | | Substation 230Kv Line- Williston to Tioga 230/115 KV Neset (Tioga) Sub T3 Neset Substation on 230 kV Bus - 33 % Regional / 67% Zonal 345Kv Line- Charlie Ck to Judso 230Kv Willistn Sub Transformer 115Kv Line- Blaisdell to Bertho |
| S P P | 296 | | | Tioga | SPP | 296 | | |
| S P P | 297 | | | T3 | SPP | 297 | | |
| S P P | 297 | | | | SPP | 298 | | |
| S P P | 298 | | | | SPP | 299 | | |
| S P P | 299 | | | | SPP | 303 | | |
| | 303 | | | | | | | |

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| | | | | | |
|---|---|---|---|---|---|
| | | S | | | Witten Substation |
| | | P | | | |
| | | P | | | |
| SPP | **3 0 6** | | BEPC Ovhd (384) Trans-Groton 345/115 Kv | | |
| SPP | **3 1 0** | | Groton Sub Addt 115Kv Tie | Line- | |
| SPP | **3 1 1** | | Wapa-Groton | | |
| SPP | **3 1 4** | | Groton 115kv Capacitor | Banks | |
| Other | **3 2 1** | | 115Kv Line-Double Circ WAPA | to | |
| SPP | **3 2 2** | | 115Kv Line LCS/West PatentGate | | |
| | **3 2 7** | | 230/115 kV | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | 328 | 230/115 kV Watford City (Transf | | SPP | 328 | 230/115 kV Watford City (Transf | | SPP | 328 | 230/115 kV Watford City (Transf | |
| SPP | 329 | 115kV Mission Sub-TransCanada | | SPP | 329 | 115kV Mission Sub-TransCanada | | SPP | 329 | 115kV Mission Sub-TransCanada | |
| SPP | 333 | 115Kv Line Patent/PatentGt Tie | | SPP | 333 | 115Kv Line Patent/PatentGt Tie | | SPP | 333 | 115Kv Line Patent/PatentGt Tie | |
| SPP | 337 | 115kV Line-Blaisdell Tap-Plaza | | SPP | 337 | 115kV Line-Blaisdell Tap-Plaza | | SPP | 337 | 115kV Line-Blaisdell Tap-Plaza | |
| SPP | 338 | Blaisdell Tap Switches 115kV | | SPP | 338 | Blaisdell Tap Switches 115kV | | SPP | 338 | Blaisdell Tap Switches 115kV | |
| SPP | 339 | Line-Blaisdell - Blaisdell 115kV | | SPP | 339 | Line-Blaisdell - Blaisdell 115kV | | SPP | 339 | Line-Blaisdell - Blaisdell 115kV | |
| SPP | 351 | LCS to PatentGate East | | SPP | 351 | LCS to PatentGate East | | SPP | 351 | LCS to PatentGate East | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| SPP | 361 | 69Kv Line-Cornbelt - Wisdom | SPP | 361 | 69Kv Line-Cornbelt - Wisdom | SPP | 361 | 69Kv Line-Cornbelt - Wisdom |
| SPP | 362 | 69Kv Substatn - Cornbelt - Wisdom | SPP | 362 | 69Kv Substatn - Cornbelt - Wisdom | SPP | 362 | 69Kv Substatn - Cornbelt - Wisdom |
| SPP | 365 | 345/115 kV Roundup Sub (100%Regional) | SPP | 365 | 345/115 kV Roundup Sub (100%Regional) | SPP | 365 | 345/115 kV Roundup Sub (100%Regional) |
| SPP | 365 | 345/115 kV Roundup Sub (33%/67% Regional/Zonal) | SPP | 365 | 345/115 kV Roundup Sub (33%/67% Regional/Zonal) | SPP | 365 | 345/115 kV Roundup Sub (33%/67% Regional/Zonal) |
| SPP | 366 | 345Kv Line-Roundup to Kummer R | SPP | 366 | 345Kv Line-Roundup to Kummer R | SPP | 366 | 345Kv Line-Roundup to Kummer R |
| Othe | 367 | 345/115 kV | Othe | 367 | 345/115 kV | | 367 | 345/115 kV |

r **7** Kummer



r Kummer



Other Kummer

A **1**

| | | | | | | |
|---|---|---|---|---|---|---|
| Other | **368** | Ridge Sub 345Kv Line-Patent Gt to Kummer 345kV Patent | Other | **368** | Ridge Sub 345Kv Line-Patent Gt to Kummer 345kV Patent | |
| SPP | **369** | Gate Sub - (100%Regional) 345kV Patent | SPP | **369** | Gate Sub - (100%Regional) 345kV Patent | |
| SPP | **369** | Gate Sub - (33%/67% Regional) 345kV Patent | SPP | **369** | Gate Sub - (33%/67% Regional) 345kV Patent | |
| Other | **369** | Gate Sub Wyoming | Other | **369** | Gate Sub Wyoming | |
| NA | **390** | Distributed Generation WY Dist | NA | **390** | Distributed Generation WY Dist | |
| N | **391** | Gen-Barber | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| NA | Barber Ridge Sub 345Kv Line - Patent Gt to Kummer 345kV Patent Gate Sub | Other | 368 | SPP | 369 | Gate Sub - (100%Regional) 345kV Patent Gate Sub - (33%/67% Regional) 345kV Patent Gate Sub | Other | SPP | 369 | NA | 390 Distributed Generation WY Dist Gen-Barber 391 Wyoming Distributed Generation WY Dist Gen-Barber |

| | | | | | |
|---|---|---|---|---|---|
| | | D | | | |
| | | C | | | |
| | | | Creek Site | | |
| | 3 | | Wy | | Dist |
| | 9 | | Gen- | | |
| NA | 2 | | Arvada Site | NA | |
| | 3 | | WY | | Dist |
| | 9 | | Gen- | | |
| NA | 3 | | Hartzog Site | NA | |
| | 3 | | Microwave | | |
| | 9 | | Comm- | | |
| NA | 4 | | WY-Wy Dist Gen | NA | |
| | 3 | | Dry Creek | | |
| | 9 | | 230/115 /69kV | | |
| SPP | 7 | | Sub | SPP | |
| | 4 | | Prairie Winds | | |
| NA | 0 | | ND1 | NA | |
| | 6 | | Prairie | | |
| | 4 | | Winds | | |
| NA | 0 | | SD1 | NA | |
| | 7 | | RC | | Tie- |
| | 4 | | East | | |
| | 0 | | Interconnect | SPP | |
| SPP | 8 | | | | |
| | 4 | | | | |
| RC | 1 | | Rapid City Tie | RCDC | |
| | 0 | | | | |

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|---|---|---|
| | 4 | 230Kv Line-RC |
| SPP | 411 | Tie to New Undwd |
| RCDC | 412 | 230Kv Ln-BHPL Sub to RC Tie |
| | 4 | RC Tie 230Kv |
| RCDC | 414 | Ln W TermBay BHPL |
| | 4 | 230Kv Line- |
| CUS | 420 | TecklaSub to CarrDr |
| | 4 | 230Kv Carr |
| CUS | 421 | Draw Substation Barber |
| | 4 | Creek Sub |
| Other | 423 | Addition Gillette, WY |
| | 4 | Trans |
| CUS | 30 | Maint. Bldg |

| | | |
|---|---|---|
| | | 230Kv Line-RC |
| SPP | 411 | Tie to New Undwd |
| RCDC | 412 | 230Kv Ln-BHPL Sub to RC Tie |
| | | RC Tie 230Kv |
| RCDC | 414 | Ln W TermBay BHPL |
| | | 230Kv Line- |
| CUS | 420 | TecklaSub to CarrDr |
| | | 230Kv Carr |
| CUS | 421 | Draw Substation Barber |
| | | Creek Sub |
| Other | 423 | Addition Gillette, WY |
| | | Trans |
| CUS | 430 | Maint. Bldg |

| | | |
|---|---|---|
| | | 230Kv Line-RC |
| SPP | 411 | Tie to New Undwd |
| RCDC | 412 | 230Kv Ln-BHPL Sub to RC Tie |
| | | RC Tie 230Kv |
| RCDC | 414 | Ln W TermBay BHPL |
| | | 230Kv Line- |
| CUS | 420 | TecklaSub to CarrDr |
| | | 230Kv Carr |
| CUS | 421 | Draw Substation Barber |
| | | Creek Sub |
| Other | 423 | Addition Gillette, WY |
| | | Trans |
| CUS | 430 | Maint. Bldg |

| | | |
|---|---|---|
| SPP | 444 | 230kV Ln - Crow Lk to Wess Spr |
| NA | 450 | Dry Fork Station Unit 1 (DFS) 230kV |
| CUS | 452 | DFS Switchyard 230kV |
| Other | 453 | Line - DFS U1 GSU |
| Other | 455 | Main Transformer (GSU) - DFS 1 |
| Other | 468 | Main Transformer (GSU) - GGS 1 |
| Other | 469 | Main Transformer (GSU) - GGS 2 |

| | | |
|---|---|---|
| SPP | 444 | 230kV Ln - Crow Lk to Wess Spr |
| NA | 450 | Dry Fork Station Unit 1 (DFS) 230kV |
| CUS | 452 | DFS Switchyard 230kV |
| Other | 453 | Line - DFS U1 GSU |
| Other | 455 | Main Transformer (GSU) - DFS 1 |
| Other | 468 | Main Transformer (GSU) - GGS 1 |
| Other | 469 | Main Transformer (GSU) - GGS 2 |

| | | |
|---|---|---|
| SPP | 444 | 230kV Ln - Crow Lk to Wess Spr |
| NA | 450 | Dry Fork Station Unit 1 (DFS) 230kV |
| CUS | 452 | DFS Switchyard 230kV |
| Other | 453 | Line - DFS U1 GSU |
| Other | 455 | Main Transformer (GSU) - DFS 1 |
| Other | 468 | Main Transformer (GSU) - GGS 1 |
| Other | 469 | Main Transformer (GSU) - GGS 2 |

| | | |
|---|---|---|
| | 4 | Groton |
| SPP | 470 | Generating Station U1 115Kv |
| Other | 472 | Tie Line-Groton to WAPA |
| | 4 | DCS to White |
| Other | 478 | Transmission Line 115KV |
| SPP | 486 | Line-Culberton to WAPA |
| SPP | 550 | Ordway 115Kv Substation |
| SPP | 55 | Berthold 115 kV |
| SPP | 65 | Tap Kenaston 115 kV |
| SPP | 557 | Tap Sub 115Kv |
| SPP | 559 | PGS Switchy |

| | | |
|---|---|---|
| | | Groton |
| SPP | 470 | Generating Station U1 115Kv |
| Other | 472 | Tie Line-Groton to WAPA |
| | | DCS to White |
| Other | 478 | Transmission Line 115KV |
| SPP | 486 | Line-Culberton to WAPA |
| SPP | 550 | Ordway 115Kv Substation |
| SPP | 556 | Berthold 115 kV |
| SPP | 557 | Tap Kenaston 115 kV Tap Sub 115Kv |
| SPP | 559 | PGS Switchy |

| | | |
|---|---|---|
| | | Groton |
| SPP | 470 | Generating Station U1 115Kv |
| Other | 472 | Tie Line-Groton to WAPA |
| | | DCS to White |
| Other | 478 | Transmission Line 115KV |
| SPP | 486 | Line-Culberton to WAPA |
| SPP | 550 | Ordway 115Kv Substation |
| SPP | 556 | Berthold 115 kV |
| SPP | 557 | Tap Kenaston 115 kV Tap Sub 115Kv |
| SPP | 559 | PGS Switchy |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | ard - (Recip) 115Kv | | | | ard - (Recip) 115Kv | | | | ard - (Recip) 115Kv | |
| SPP | 576 | LCS Switchyard 115kV | SPP | 576 | LCS Switchyard 115kV | SPP | 576 | LCS Switchyard 115kV |
| Other | 581 | Line-PGS to OneOK (U1-3) 115kV | Other | 581 | Line-PGS to OneOK (U1-3) 115kV | Other | 581 | Line-PGS to OneOK (U1-3) 115kV |
| Other | 591 | Line-LCS to Hay Creek 230Kv | Other | 591 | Line-LCS to Hay Creek 230Kv | Other | 591 | Line-LCS to Hay Creek 230Kv |
| SPP | 711 | LO#1 Sub W AVS Addition 345 230Kv | SPP | 711 | LO#1 Sub W AVS Addition 345 230Kv | SPP | 711 | LO#1 Sub W AVS Addition 345 230Kv |
| SPP | 720 | LO#2 Sub W AVS & Gro Tioga | SPP | 720 | LO#2 Sub W AVS & Gro Tioga | SPP | 720 | LO#2 Sub W AVS & Gro Tioga |
| SPP | 734 | Sub-Capacitr Bank WO2430 345 | SPP | 734 | Sub-Capacitr Bank WO2430 345 | SPP | 734 | Sub-Capacitr Bank WO2430 345 |
| SP | 73 | 230Kv | | 735 | 230Kv | | 735 | 230Kv |

P **5** Waterto SPP Waterto SPP Waterto

| | | |

12/31/20XX) ) **- 20XX Actuals)**

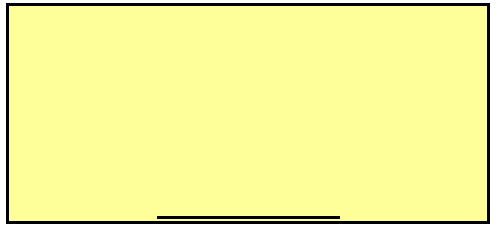












| Summary of 20XX Facilities: | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|
| UMZ - Zone 19 | 0 | 0 | 0 | 0 |
| CUS | 0 | 0 | 0 | 0 |
| RCDC | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 |
| N/A (WY Gen - Arvada, Hartzog, etc. | 0 | 0 | 0 | 0 |
| **Total** | **0** | **0** | **0** | **0** |

| Summary of 20XX Facilities: | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|
| UMZ - Zone 19 | 0 | 0 | 0 | 0 |
| CUS | 0 | 0 | 0 | 0 |
| RCDC | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 |
| N/A (WY Gen - Arvada, Hartzog, etc. | 0 | 0 | 0 | 0 |
| **Total** | **0** | **0** | **0** | **0** |

| | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|
| UMZ - Zone 19 | **0** | **0** | **0** | **0** |
| CUS | **0** | **0** | **0** | **0** |
| RCDC | **0** | **0** | **0** | **0** |
| Other | **0** | **0** | **0** | **0** |
| N/A (WY Gen - Arvada, Hartzog, etc. | **0** | **0** | **0** | **0** |
| **Total** | **0** | **0** | **0** | **0** |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Other | 279 | 230 kV Glenham Sub (Shunt) | $ - | $ - | $ - | $ - | Other | 279 | 230 kV Glenham Sub (Shunt) - 37/40ths | $ - | $ - | $ - | $ - | Other | $ - | $ - | $ - | $ - |

**Breakdown of Facilities By UMZ, CUS, Other and By FERC Type - YE December 31, 20XX**

| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|
| 110200 | 303 | UMZ - Zone 19 | 0 | 0 | 0 | 0 |
| 110005 | 350 - 356 | UMZ - Zone 19 | 0 | 0 | 0 | 0 |
| 11000 | 389 - | UMZ - | | | | |

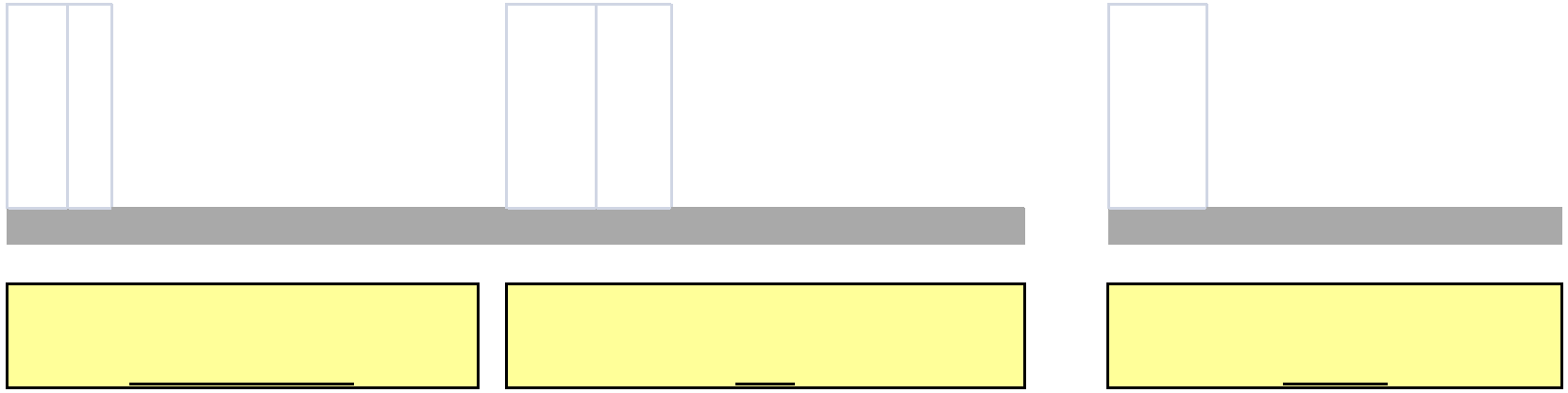
**Breakdown of Facilities By UMZ, CUS, Other and By FERC Type YE December 31, 20XX**

| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|
| 1102 0 | 303 | UMZ - Zone 19 | 0 | 0 | 0 | 0 |
| 1100 5 | 350 - 356 | UMZ - Zone 19 | 0 | 0 | 0 | 0 |
| 1100 | 389 - | UMZ - | | | | |

**Breakdown of Facilities By UMZ, CUS, Other and By FERC Type - BOY/ EOY Ave.**

| | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|
| UMZ - Zone 19 | - | - | - | - |
| UMZ - Zone 19 | - | - | - | - |
| UMZ - Zone | | | | |

5 - **Zone 19** 0 0 0 0 5 **398** **Zone 19** 0 0 0 0 **19** - - - -



| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11110 | 3983533889 | UMZ - Zone 19 | | | | 0 | 11110 | 353 | UMZ - Zone 19 | | | | 0 | UMZ - Zone 19 | - | - | - | - |
| Less: Total UMZ - Zone 19 | 398 | Microwave Adjustment | 0 | 0 | 0 | 0 | Microwave Adj. | 389 - 398 | Microwave Adjustment | 0 | 0 | 0 | 0 | Microwave Adjustment | - | - | - | - |
| | | | 0 | 0 | 0 | 0 | | | Total | 0 | 0 | 0 | 0 | Total | - | - | - | - |

* Groton Clutch

** 230kv Line Rhame Sub to Belfield & 230 kv Line - Williston to Tioga (ARO included in IS but not included in Zone 19 (UMZ)

| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **11020** | **303** | **Common Use System (CUS)** | 0 | 0 | 0 | 0 | **1102 0** | **303** | **Common Use System (CUS)** | 0 | 0 | 0 | 0 | **Common Use System (CUS)** | - | - | - | - |
| 11005 | **350-356** | **Common Use System (CUS)** | 0 | 0 | 0 | 0 | 1100 5 | **350-356** | **Common Use System (CUS)** | 0 | 0 | 0 | 0 | **Common Use System (CUS)** | - | - | - | - |
| 11220 | **354** | **Common Use System (CUS)** | 0 | 0 | 0 | 0 | 1122 0 | **354** | **Common Use System (CUS)** | 0 | 0 | 0 | 0 | **Common Use System (CUS)** | - | - | - | - |
| 1111 | **355** | **Common Use System** | | | | | 1111 | | **Common Use System** | | | | | **Common Use System** | | | | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | **5** | **(CUS)** | 0 | 0 | 0 | 0 | 0 | **355** | **(CUS)** | 0 | 0 | 0 | 0 | **(CUS)** | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 350-356 | | | | | | | 350-356 | | | | | | | | | | | |
| Total | | | 0 | 0 | 0 | 0 | 0 | Total | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 |
| | 389-398 | Common Use System (CUS) | 0 | 0 | 0 | 0 | | 389-398 | Common Use System (CUS) | 0 | 0 | 0 | 0 | | Common Use System (CUS) | - | - | - | - |
| Less: | 389-398 | Microwave Adjustment | 0 | 0 | 0 | 0 | | 389-399 | Microwave Adjustment | 0 | 0 | 0 | 0 | | Microwave Adjustment | - | - | - | - |
| Total - Common Use System (CUS) | | | 0 | 0 | 0 | 0 | 0 | Less: Total - Common Use System (CUS) | | 0 | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 |

| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11020 | 303 | MBPP | 0 | 0 | 0 | 0 | 11020 | 303 | MBPP | 0 | 0 | 0 | 0 | MBPP | 0 | 0 | 0 | 0 |
| 11005 | 350-356 | MBPP | 0 | 0 | 0 | 0 | 11005 | 350-356 | MBPP | 0 | 0 | 0 | 0 | MBPP | 0 | 0 | 0 | 0 |
| 11005 | 389-398 | MBPP | 0 | 0 | 0 | 0 | 11005 | 389-398 | MBPP | 0 | 0 | 0 | 0 | MBPP | 0 | 0 | 0 | 0 |
| **Less: To** | **389-399** | **Microwave Adjustment** | 0 | 0 | 0 | 0 | **Less: Total** | **389-399** | **Microwave Adjustment** | 0 | 0 | 0 | 0 | **Microwave Adjustment** | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **tal** | 0 | 0 | 0 | 0 | - | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |







| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -MBPP | | | | | | 0 | MBPP | | | | | | | | | | | | | |
| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | | Book Basis | YTD | LTD | Net Book |
| 11020 | 303350-35635 | Other | 0 | 0 | 0 | 0 | 11020 | 303 | Other | 0 | 0 | 0 | 0 | Other | 0 | 0 | 0 | 0 |
| 11005 | 356350-35635 | Other | 0 | 0 | 0 | 0 | 11005 | 350-356 | Other | 0 | 0 | 0 | 0 | Other | 0 | 0 | 0 | 0 |
| 11005 | 356350-35353 | Other (MBPP) WDG (Other #2) | 0 | 0 | 0 | 0 | 11005 | 350-356 | Other - MBPP WDG (Other #2) | 0 | 0 | 0 | 0 | Other - MBPP WDG (Other #2) | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11220 | 354389-398 | Other - ARO | 0 | 0 | 0 | 0 | 11220 | 354389-398 | Other - ARO | 0 | 0 | 0 | 0 | Other - ARO | - | | 0 | - | - | |
| 11005 | 354389-398 | Other | 0 | 0 | 0 | 0 | 11005 | 354389-398 | Other | 0 | 0 | 0 | 0 | Other | 0 | | 0 | 0 | 0 | |
| Total | | | 0 | 0 | 0 | 0 | Total | | | 0 | 0 | 0 | 0 | | 0 | | 0 | 0 | 0 | |
| | | | | | | 0 | | | | | | | | | | | | | | |
| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | Account # | FERC Type | | Book Basis | YTD | LTD | Net Book | | Book Basis | YTD | LTD | Net Book | | |
| 11005 | 350-356389-398 | RCDC | 0 | 0 | 0 | 0 | 11005 | 350-356389-398 | RCDC | 0 | 0 | 0 | 0 | RCDC | 0 | | 0 | 0 | 0 | |
| 11005 | 350-356389-398 | RCDC | 0 | 0 | 0 | 0 | 11005 | 350-356389-398 | RCDC | 0 | 0 | 0 | 0 | RCDC | 0 | | 0 | 0 | 0 | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **98** | | | | | | | | | | | | | | |
| **Total** | | 0 | 0 | 0 | 0 | **Total** | 0 | 0 | 0 | 0 | | 0 | 0 | 0 | 0 |

-

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Grand Total FERC Account 350-356** | **0** | **0** | **0** | **0** | **Grand Total FERC Account 350-356** | **0** | **0** | **0** | **0** | **Grand Total FERC Account 350-356** | **0** | **0** | **0** | **0** |

**Summary - MBPP Transmission by FERC Type**

| **Account #** | **FERC Type** | | **Book Basis** | **YTD** | **LTD** | **Net Book** |
|---|---|---|---|---|---|---|
| 11005 | **350** | **MBPP** | | | | 0 |
| 11005 | **350** | | | | | |

**Summary - MBPP Transmission by FERC Type**

| **Account #** | **FERC Type** | | **Book Basis** | **YTD** | **LTD** | **Net Book** |
|---|---|---|---|---|---|---|
| 11005 | **350** | **MBPP** | | | | 0 |
| 11005 | **350** | | | | | |

**Summary - MBPP Transmission by FERC Type**

| | | | **Book Basis** | **YTD** | **LTD** | **Net Book** |
|---|---|---|---|---|---|---|
| 11005 | **350** | **MBPP** | 0 | 0 | 0 | 0 |
| 11005 | **350** | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5 | **2** | **MBPP** | | 0 | 5 | **352** | **MBPP** | | 0 | | **MBPP** | 0 | 0 | 0 | 0 |







| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11005 | **353** | **MBPP** | | | | 0 | 11005 | **353** | **MBPP** | | | | 0 | **MBPP** | 0 | | 0 | 0 | 0 |
| 11005 | **354** | **MBPP** | | | | 0 | 11005 | **354** | **MBPP** | | | | 0 | **MBPP** | 0 | | 0 | 0 | 0 |
| 11005 | **355** | **MBPP** | | | | 0 | 11005 | **355** | **MBPP** | | | | 0 | **MBPP** | 0 | | 0 | 0 | 0 |
| 11005 | **356** | **MBPP** | | | | 0 | 11005 | **356** | **MBPP** | | | | 0 | **MBPP** | 0 | | 0 | 0 | 0 |
| **Total** | | | **0** | **0** | **0** | **0** | | **Total** | | **0** | **0** | **0** | **0** | | **0** | | **0** | **0** | **0** |

-

**Company 800 - MBPP - Overheads Complex 112**

| **Account #** | **FERC Type** | **Book Basis** | **YTD** | **LTD** | **Net Book** |
|---|---|---|---|---|---|

**Company 800 - MBPP Overheads**

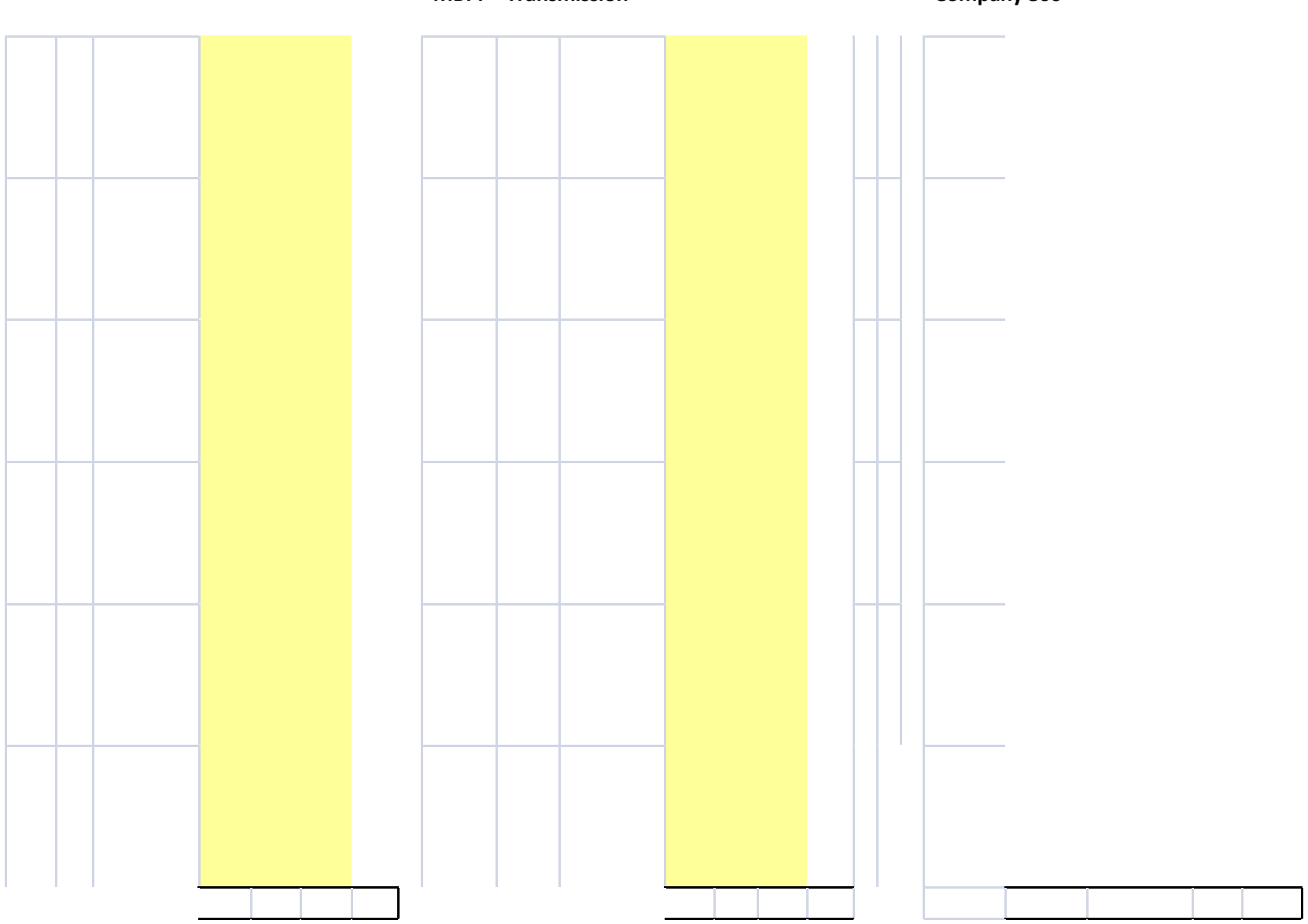
| **Account #** | **FERC Type** | **Book Basis** | **YTD** | **LTD** | **Net Book** |
|---|---|---|---|---|---|

**MBPP Overheads**

| | **Book Basis** | **Depr YTD** | **Depr LTD** | **Net Book Value** |
|---|---|---|---|---|

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11005 | **350** | **MBPP - Complex 112** | | | | 0 | **11005** | **350** | **MBPP - Complex 112** | | | | 0 | **MBPP - Complex 112** | - | - | - | - |
| 11005 | **352** | **MBPP - Complex 112** | | | | 0 | **11005** | **352** | **MBPP - Complex 112** | | | | 0 | **MBPP - Complex 112** | - | - | - | - |
| 11005 | **353** | **MBPP - Complex 112** | | | | 0 | **11005** | **353** | **MBPP - Complex 112** | | | | 0 | **MBPP - Complex 112** | - | - | - | - |
| 11005 | **354** | **MBPP - Complex 112** | | | | 0 | **11005** | **354** | **MBPP - Complex 112** | | | | 0 | **MBPP - Complex 112** | - | - | - | - |
| 11005 | **355** | **MBPP - Complex 112** | | | | 0 | **11005** | **355** | **MBPP - Complex 112** | | | | 0 | **MBPP - Complex 112** | - | - | - | - |
| 11005 | **356** | **MBPP - Complex 112** | | | | 0 | **11005** | **356** | **MBPP - Complex 112** | | | | 0 | **MBPP - Complex 112** | - | - | - | - |
| | | | **0** | **0** | **0** | **0** | | | | **0** | **0** | **0** | **0** | | **0** | **0** | **0** | **0** |

**Less: Company** **Less: Company 800 -** **Less:**


800 - MBPP -
0
MBPP - Transmission
Company 800

**Transmission Included in "Other Transmission"**

| ~~Account #~~ | ~~FERC Type~~ | | ~~Book Basis~~ | ~~YTD~~ | ~~LTD~~ | ~~Net Book~~ |
|---|---|---|---|---|---|---|
| 11005 | 352 & 353 | 69kV LRS Subs & Main Transformers Units 1 - 3 | 0 | 0 | 0 | 0 |

| Account # | FERC Type | Complex # | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|

**Included in "Other Transmission"**

| Account # | FERC Type | | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|
| 11005 | 352 & 353 | 69kV LRS Subs & Main Transformers Units 1 - 3 | 0 | 0 | 0 | 0 |

| Account # | FERC Type | Complex # | Book Basis | YTD | LTD | Net Book |
|---|---|---|---|---|---|---|

**- MBPP - Transmission Included in "Other Transmission"**

| | Book Basis | Depr YTD | Depr LTD | Net Book Value |
|---|---|---|---|---|
| 69kV LRS Subs & Main Transformers Units 1 - 3 | - 0 | - 0 | - 0 | - 0 |

| Complex # | Book Basis | LT YTD | Bo D | Net ok |
|---|---|---|---|---|

| | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11105 | 355 | 231 - CUS | | | | 0 | 11110 | 355 | 231 - CUS | | | | 0 | 231 - CUS | - | - | - | - |
| 11103 | 355 | 328 - SPP | | | | 0 | 11110 | 353 | 328 - SPP | | | | 0 | 328 - SPP | - | - | - | - |
| 11105 | 355 | 232 - CUS | | | | 0 | 11110 | 355 | 232 - CUS | | | | 0 | 232 - CUS | - | - | - | - |
| Total - Acquisition Adjustment | | | 0 | 0 | 0 | 0 | Total - Acquisition Adjustment | | | 0 | 0 | 0 | 0 | | 0 | | 0 | 0 | 0 |
| | | | | 220 | 54 | 0 | | | | | | | | | 0 | | | | |
| 11220 | 354 | | | | | | 181 - Other | | | 0 | | | | | 11220 | 354 | 181 - Other | | |
| 11220 | 354 | | | | | | 296 - Other | | - | 0 | | | | | 11220 | 354 | 296 - Other | | |
| 11220 | 354 | | | | | | 223 - Other | | | 0 | | | | | 11220 | 354 | 223 - Other | | |
| 11220 | 354 | | | | | | 224 - Other | | | 0 | | | | | 11220 | 354 | 224 - Other | | |
| 11220 | 354 | | | | | | 225 - Other | | | 0 | | | | | 11220 | 354 | 225 - Other | | |
| 113 | | | | | | | 228 - Other | | | | | | | | 1122 | 354 | 228 - | | |

**0** **Other**

| | | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11220 | 354 | 234 - Other | | | | 0 | 1122 0 | 354 | 234 - Other | | | | 0 | 234 - Other | - | - | - | - | |
| 11220 | 354 | 235 - Other | | | | 0 | 1122 0 | 354 | 235 - Other | | | | 0 | 235 - Other | - | - | - | - | |
| **Total - ARO - IS Only - Do Not Included In UMZ - Zone 19** | | | **0** | **0** | **0** | **0** | **Total - ARO - Do Not Included In UMZ - Zone 19** | | | **0** | **0** | **0** | **406,100** | | **0** | **0** | **0** | **203,050** | |
| 11220 | 354 | 223 - CUS | | | | 0 | 1122 0 | 354 | 223 - CUS | | | | 0 | 223 - CUS | - | - | - | - | |
| 11220 | 354 | 224 - CUS | | | | 0 | 1122 0 | 354 | 224 - CUS | | | | 0 | 224 - CUS | - | - | - | - | |
| 11220 | 354 | 225 - CUS | | | | 0 | 1122 0 | 354 | 225 - CUS | | | | 0 | 225 - CUS | - | - | - | - | |
| 11220 | 354 | 228 - CUS | | | | 0 | 1122 0 | 354 | 228 - CUS | | | | 0 | 228 - CUS | - | - | - | - | |
| **Total - ARO 11220** | | | **0** | **0** | **0** | **0** | **Total - ARO 11220** | | | **0** | **0** | **0** | **406,100** | | **0** | **0** | **0** | **203,050** | |
| | | | | | | **0** | | | | | | | **0** | | | | | **0** | |
| **Reconcile - to FERC Form 1, Page 207, line 58,** | | | **Book** | | | **Net B** | **Reconcile - to FERC Form 1, Page 207, line** | | | **Book** | **Y** | | **Net B** | | | | | **Net** | |

| plus page 200, line 9 and 12. | Basis | YTD | LTD | ook | 58, plus page 200, line 9 and 12. | Basis | TD | LTD | ook | Book Basis | YTD | LTD | Book |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FERC Account 350 - 356 w/o MBPP** | **0** | **0** | **0** | **0** | **FERC Account 350 - 356 w/o MBPP** | **0** | **0** | **0** | **0** | **FERC Account 350 - 356 w/o MBPP** | **0** | **0** | **0** | **0** |
| **MBPP** | **0** | **0** | **0** | **0** | **MBPP** | **0** | **0** | **0** | **0** | **MBPP** | **0** | **0** | **0** | **0** |
| **MBPP Overheads** | **-** | **-** | **-** | **-** | **MBPP Overheads** | **0** | **0** | **0** | **0** | **MBPP Overheads** | **0** | **0** | **0** | **0** |
| **Acct 11220** | **0** | **0** | **0** | **0** | **Acct 11220 - ARO** | **0** | **0** | **0** | **406,100** | **Acct 11220 - ARO** | **0** | **0** | **0** | **0** |
| **Adjustment** | **-** | **-** | **-** | **-** | **Adjustment** | 0 | 0 | 0 | 0 | **Adjustment** | **-** | **0** | **-** | **-** |
| **Subtotal Acct** | **0** | **0** | **0** | **0** | **Subtotal Acct 1111** | **0** | **0** | **0** | **0** | **Subtotal Acct** | **0** | **0** | **0** | **0** |

**11 0 0 0 0 0 0 0 0 0 11110 0 0 0 0**

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 110 | | | | | | | | | | | | | | |
| Total | 0 | 0 | 0 | 0 | Total | 0 | 0 | 0 | 0 | Total | 0 | 0 | 0 | 0 |
| Acct 12500 - Accum Net Retirement | | 0 | | - | Acct 12500 - Accum Net Retirement | 0 | 0 | | 0 | Acct 12500 - Accum Net Retirement | 0 | 0 | 0 | - |
| Per FERC Form No.1, page 207, line 58 | | | | | Per FERC Form No.1, page 207, line 58 | | | | | | | | | |
| Per FERC Form No.1, page 200, lines 9 and 12 | | | | | Per FERC Form No.1, page 200, lines 9 and 12 | | | | | | | | | |
| | 0 | | | | | 0 | | | | | | | | |

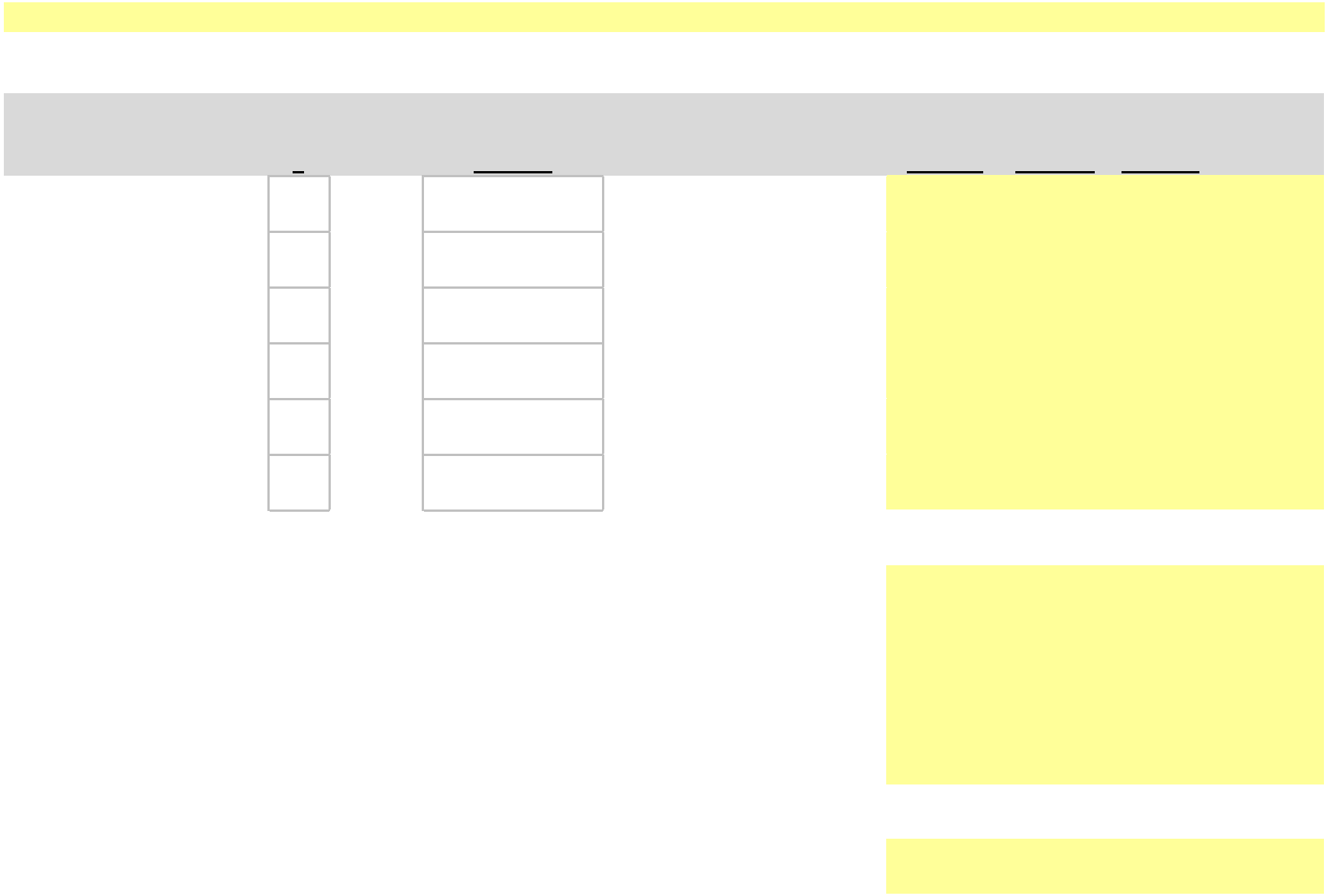
Note:

The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**Basin Electric Power Cooperative**
**Formula Rate Template**
**MBPP Facilities - Year ending 12/31/20XX**
**Work Paper #12**

| ClassSort | Class | Company | SortCode | Complex | CpxDesc | FERC Account | FERC Account Group | AssetGrp | BookBasis Amount | AccumDepr_YTD | AccumDepr_LTD | NetBook Amount |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Plant - Peaking (Oil) | 800 | 311 | 006 | Laramie River #1 | 311 | 310 to 319 Generation | 110 05 | | | | |
| 1 | Plant - Peaking (Oil) | 800 | 311 | 006 | Laramie River #1 | 312 | 310 to 319 Generation | 110 05 | | | | |
| 1 | Plant - Peaking (Oil) | 800 | 311 | 006 | Laramie River #1 | 314 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Substation | 800 | 311 | 006 | Laramie River #1 | 315 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Substation | 800 | 311 | 006 | Laramie River #1 | 394 | 389 to 399 General Plant | 110 05 | | | | |
| 3 | Substation | 800 | 311 | 006 | Laramie River #1 | 399 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **006 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 311 | 007 | Laramie River #2 | 311 | 310 to 319 Generation | 110 05 | | | | |
| 4 | Transmission Line | 800 | 311 | 007 | Laramie River #2 | 312 | 310 to 319 Generation | 110 05 | | | | |
| 4 | Transmission Line | 800 | 311 | 007 | Laramie River #2 | 314 | 310 to 319 Generation | 110 05 | | | | |
| 4 | Transmission Line | 800 | 311 | 007 | Laramie River #2 | 315 | 310 to 319 Generation | 110 05 | | | | |
| | | | | **007 Total** | | | | | - | - | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 310 to 319 | 110 |
| 3 | Substation | 800 | 311 | 008 | Laramie River #3 | 311 | Generation | 05 |



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Substation | 800 | 311 | 008 | Laramie River #3 | 312 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Substation | 800 | 311 | 008 | Laramie River #3 | 314 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Substation | 800 | 311 | 008 | Laramie River #3 | 315 | 310 to 319 Generation | 110 05 | | | | |
| | | | | **008 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 045 | 230Kv LRS Substation-MBPP West | 352 | 350 to 359 Transmission | 110 05 | | | | |
| 3 | Substation | 800 | 31 | 045 | 230Kv LRS Substation-MBPP West | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **045 Total** | | | | | - | - | - | - |
| 1 | Plant - Coal Based | 800 | 31 | 048 | 345Kv LRS Substation-MBPP | 352 | 350 to 359 Transmission | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 31 | 048 | 345Kv LRS Substation-MBPP | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **048 Total** | | | | | - | - | - | - |
| 1 | Plant - Coal Based | 800 | 31 | 049 | 345Kv-048 To Ne Bord-MBPP Steg | 350 | 350 to 359 Transmission | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 31 | 049 | 345Kv-048 To Ne Bord-MBPP Steg | 354 | 350 to 359 Transmission | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 31 | 049 | 345Kv-048 To Ne Bord-MBPP Steg | 356 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **049 Total** | | | | | - | - | - | - |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Plant - Coal Based | 800 | 31 | 050 | 345Kv-Ne Bord To 078-MBPP E St | 350 | 350 to 359 Transmission | 11005 | | | | |
| 1 | Plant - Coal Based | 800 | 31 | 050 | 345Kv-Ne Bord To 078-MBPP E St | 354 | 350 to 359 Transmission | 11005 | | | | |
| 1 | Plant - Coal Based | 800 | 31 | 050 | 345Kv-Ne Bord To 078-MBPP E St | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **050 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 051 | 345Kv-Archer Jct-NE Brd-MBPP E | 350 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 051 | 345Kv-Archer Jct-NE Brd-MBPP E | 354 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 051 | 345Kv-Archer Jct-NE Brd-MBPP E | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **051 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 052 | 345Kv-NE Bord-079-MBPP E Sidne | 350 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 052 | 345Kv-NE Bord-079-MBPP E Sidne | 354 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 052 | 345Kv-NE Bord-079-MBPP E Sidne | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **052 Total** | | | | | - | - | - | - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Transmission Maintenance Bldg | 800 | 31 | 053 | 345Kv-078 To 079-MBPP East | 350 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 053 | 345Kv-078 To 079-MBPP East | 354 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 31 | 053 | 345Kv-078 To 079-MBPP East | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **053 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 41 | 054 | Trans Facil Invest Pd NPPD | 303 | 300 to 310 Intangibles | 11020 | | | | |
| | | | | **054 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 41 | 059 | 69Kv LRS Substation-MBPP | 352 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 41 | 059 | 69Kv LRS Substation-MBPP | 353 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **059 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 073 | 230Kv-048-076-MBPP W (D.Johstn | 350 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Substation | 800 | 31 | 073 | 230Kv-048-076-MBPP W (D.Johstn | 355 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **073 Total** | | | | | - | - | - | - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Transmission Line | 800 | 31 | 074 | 345Kv-048-Co Bord-MBPP W(Story | 350 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 074 | 345Kv-048-Co Bord-MBPP W(Story | 354 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Substation | 800 | 31 | 074 | 345Kv-048-Co Bord-MBPP W(Story | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **074 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 075 | 345Kv-Co Bord-190-MBPP W(Story | 350 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Substation | 800 | 31 | 075 | 345Kv-Co Bord-190-MBPP W(Story | 354 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **075 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 076 | 230Kv Dave Johnston Sub-MBPP W | 350 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 076 | 230Kv Dave Johnston Sub-MBPP W | 353 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **076 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 077 | LRS Plant Site Lines | 354 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 077 | LRS Plant Site Lines | 355 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 077 | LRS Plant Site Lines | 356 | 350 to 359 Transmission | 11005 | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **077** | | | | | | | |
| | | | | **Total** | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 078 | 345/230Kv Stegall NE Sub-MBPP | 350 | 350 to 359 Transmission | 11005 | | | |
| 4 | Transmission Line | 800 | 31 | 078 | 345/230Kv Stegall NE Sub-MBPP | 352 | 350 to 359 Transmission | 11005 | | | |
| 4 | Transmission Line | 800 | 31 | 078 | 345/230Kv Stegall NE Sub-MBPP | 353 | 350 to 359 Transmission | 11005 | | | |
| | | | | **078** | | | | | | | |
| | | | | **Total** | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 079 | 345/230Kv Sidney NE Sub-MBPP E | 350 | 350 to 359 Transmission | 11005 | | | |
| 4 | Transmission Line | 800 | 31 | 079 | 345/230Kv Sidney NE Sub-MBPP E | 352 | 350 to 359 Transmission | 11005 | | | |
| 4 | Transmission Line | 800 | 31 | 079 | 345/230Kv Sidney NE Sub-MBPP E | 353 | 350 to 359 Transmission | 11005 | | | |
| | | | | **079** | | | | | | | |
| | | | | **Total** | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 41 | 083 | 230Kv Tri-State Trans-R&R Addt | 303 | 300 to 310 Intangibles | 11020 | | | |
| | | | | **083** | | | | | | | |
| | | | | **Total** | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 084 | 230Kv Stegl USBR Sub Addt-MBPP | 352 | 350 to 359 Transmission | 11005 | | | |
| | Transmission | | | | 230Kv Stegl USBR Sub Addt- | | 350 to 359 | 110 | | | |

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|---|---|---|---|---|---|---|---|---|
| 4 | Line | 800 | 31 | 084 | MBPP | 353 | Transmission | 05 |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **084** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 085 | 345Kv Ault Co Sub-MBPP West | 303 | 300 to 310 Intangibles | 110 20 | | | | |
| | | | | **085** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 086 | 230Kv Story Co Sub-MBPP West | 350 | 350 to 359 Transmission | 110 05 | | | | |
| 4 | Transmission Line | 800 | 31 | 086 | 230Kv Story Co Sub-MBPP West | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **086** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| 5 | Microwave | 800 | 31 | 088 | 230Kv Stegall Sub-Tri-St Addt | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **088** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| 5 | Microwave | 800 | 91 | 091 | Nebraska Tax Allocation | 354 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **091** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| 5 | Microwave | 800 | 31 | 096 | Tools And Equip-MBPP-Tri-State | 392 | 389 to 399 General Plant | 110 05 | | | | |
| 4 | Transmission Line | 800 | 31 | 096 | Tools And Equip-MBPP-Tri-State | 394 | 389 to 399 General Plant | 110 05 | | | | |
| 4 | Transmission Line | 800 | 31 | 096 | Tools And Equip-MBPP-Tri-State | 398 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **096** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 100 | 230/115Kv Sidney-Tri-State Sub | 350 | 350 to 359 Transmission | 110 05 | | | | |
| | Transmission | | | | 230/115Kv Sidney-Tri-State | | 350 to 359 | 110 | | | | |

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|---|---|---|---|---|---|---|---|---|---|
| 4 | Line | 800 | 31 | 100 | Sub | 352 | Transmission | 05 | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Substation | 800 | 31 | 100 | 230/115Kv Sidney-Tri-State Sub | 353 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **100 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 101 | 230Kv Tie-079-Exist 100-MBPP E | 350 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Substation | 800 | 31 | 101 | 230Kv Tie-079-Exist 100-MBPP E | 354 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 101 | 230Kv Tie-079-Exist 100-MBPP E | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **101 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 102 | 230Kv Tie-050 To 084-MBPP W | 350 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 102 | 230Kv Tie-050 To 084-MBPP W | 354 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 102 | 230Kv Tie-050 To 084-MBPP W | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **102 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 103 | 230Kv Tie Ln-078 To 084-MBPP E | 350 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 103 | 230Kv Tie Ln-078 To 084-MBPP E | 354 | 350 to 359 Transmission | 11005 | | | | |
| 4 | Transmission Line | 800 | 31 | 103 | 230Kv Tie Ln-078 To 084-MBPP E | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **103 Total** | | | | | - | - | - | - |
| | | | | | 345Kv-048 To Co | | 350 to 359 | 11005 | | | | |

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|---|---|---|---|---|---|---|---|---|---|
| 3 | Substation | 800 | 31 | 104 | Border-MBPP W | 350 | Transmission | 05 | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Substation | 800 | 31 | 104 | 345Kv-048 To Co Border-MBPP W | 354 | 350 to 359 Transmission | 11005 | | | | |
| 3 | Substation | 800 | 31 | 104 | 345Kv-048 To Co Border-MBPP W | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **104 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 105 | 345Kv-Co Border-Ault,CO MBPP W | 350 | 350 to 359 Transmission | 11005 | | | | |
| 5 | Microwave | 800 | 31 | 105 | 345Kv-Co Border-Ault,CO MBPP W | 354 | 350 to 359 Transmission | 11005 | | | | |
| 5 | Microwave | 800 | 31 | 105 | 345Kv-Co Border-Ault,CO MBPP W | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **105 Total** | | | | | - | - | - | - |
| 2 | Common Facilities | 800 | 31 | 106 | 230Kv-084-100-MBPP W (Tri-Stat | 354 | 350 to 359 Transmission | 11005 | | | | |
| 2 | Common Facilities | 800 | 31 | 106 | 230Kv-084-100-MBPP W (Tri-Stat | 356 | 350 to 359 Transmission | 11005 | | | | |
| | | | | **106 Total** | | | | | - | - | - | - |
| 2 | Common Facilities | 800 | 31 | 107 | MBPP Stegall Trans Maint Bldg | 352 | 350 to 359 Transmission | 11005 | | | | |
| 2 | Common Facilities | 800 | 31 | 107 | MBPP Stegall Trans Maint Bldg | 392 | 389 to 399 General Plant | 11005 | | | | |
| 2 | Common Facilities | 800 | 31 | 107 | MBPP Stegall Trans Maint Bldg | 393 | 389 to 399 General Plant | 11005 | | | | |
| 2 | Common Facilities | 800 | 31 | 107 | MBPP Stegall Trans Maint Bldg | 394 | 389 to 399 General Plant | 11005 | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Common | | | | MBPP Stegall | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 107 | Trans Maint Bldg | 395 | General Plant | 05 | | | | |
| | Common | | | | MBPP Stegall | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 107 | Trans Maint Bldg | 396 | General Plant | 05 | | | | |
| | Common | | | | MBPP Stegall | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 107 | Trans Maint Bldg | 398 | General Plant | 05 | | | | |
| | | | | **107** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |
| | Common | | | | MBPP LRS Trans | | 350 to 359 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 350 | Transmission | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 350 to 359 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 352 | Transmission | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 390 | General Plant | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 391 | General Plant | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 392 | General Plant | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 393 | General Plant | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 394 | General Plant | 05 | | | | |
| | Common | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 2 | Facilities | 800 | 31 | 108 | Maint Bldg | 395 | General Plant | 05 | | | | |
| | | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 3 | Substation | 800 | 31 | 108 | Maint Bldg | 396 | General Plant | 05 | | | | |
| | Transmission | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 4 | Line | 800 | 31 | 108 | Maint Bldg | 397 | General Plant | 05 | | | | |
| | Transmission | | | | MBPP LRS Trans | | 389 to 399 | 110 | | | | |
| 4 | Line | 800 | 31 | 108 | Maint Bldg | 398 | General Plant | 05 | | | | |
| | | | | **108** | | | | | | | | |
| | | | | **Total** | | | | | - | - | - | - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Transmission Line | 800 | 41 | 116 | Main Transformer-LRS#1 | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **116 Total** | | | | | - | - | - | - |
| 1 | Plant | 800 | 41 | 117 | Main Transformer-LRS #2 | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **117 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 41 | 118 | Main Transformer-LRS #3 | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **118 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 131 | Microwave Comm-WY-MBPP-LRS | 389 | 389 to 399 General Plant | 110 05 | | | | |
| 3 | Substation | 800 | 31 | 131 | Microwave Comm-WY-MBPP-LRS | 397 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **131 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 132 | Microwave Comm-CO-MBPP-LRS | 389 | 389 to 399 General Plant | 110 05 | | | | |
| 4 | Transmission Line | 800 | 31 | 132 | Microwave Comm-CO-MBPP-LRS | 397 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **132 Total** | | | | | - | - | - | - |
| | WAPA Sub - Basin | | | | Microwave Comm-NE- | | 389 to 399 | 110 | | | | |

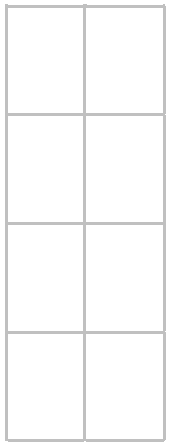
| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 3 | Transformer | 800 | 31 | 133 | MBPP-LRS | 389 | General Plant | 05 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | |
| 4 | Line | 800 | 31 | 133 | Microwave Comm-NE-MBPP-LRS | 397 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **133 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 135 | Microwave Comm-ND-MBPP-LRS | 397 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **135 Total** | | | | | - | - | - | - |
| 3 | Substation | 800 | 31 | 138 | Microwave Comm-SD-MBPP-LRS | 397 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **138 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 31 | 190 | 345Kv Story Co Sub-MBPP W | 350 | 350 to 359 Transmission | 110 05 | | | | |
| 4 | Transmission Line | 800 | 31 | 190 | 345Kv Story Co Sub-MBPP W | 352 | 350 to 359 Transmission | 110 05 | | | | |
| 4 | Transmission Line | 800 | 31 | 190 | 345Kv Story Co Sub-MBPP W | 353 | 350 to 359 Transmission | 110 05 | | | | |
| | | | | **190 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 310 | 380 - 386 RTO/ISO Plants | 110 05 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 311 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 312 | 310 to 319 Generation | 110 05 | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 312 | 310 to 319 Generation | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 314 | 310 to 319 Generation | 112 20 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 315 | 310 to 319 Generation | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 391 | 310 to 319 Generation | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 392 | 389 to 399 General Plant | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 393 | 389 to 399 General Plant | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 394 | 389 to 399 General Plant | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 395 | 389 to 399 General Plant | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 396 | 389 to 399 General Plant | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 397 | 389 to 399 General Plant | 110 05 |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 830 | Common Bldg & Struct-LRS 1 2 3 | 398 | 389 to 399 General Plant | 110 05 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **830 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 831 | Coal Handling-LRS 1 2 3 | 311 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 831 | Coal Handling-LRS 1 2 3 | 312 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 831 | Coal Handling-LRS 1 2 3 | 315 | 310 to 319 Generation | 110 05 | | | | |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 831 | Coal Handling-LRS 1 2 3 | 396 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **831 Total** | | | | | - | - | - | - |
| 3 | Transmission Maintenance Bldg | 800 | 311 | 832 | Water Supply-LRS 1 2 3 | 310 | 310 to 319 Generation | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 832 | Water Supply-LRS 1 2 3 | 311 | 310 to 319 Generation | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 832 | Water Supply-LRS 1 2 3 | 312 | 310 to 319 Generation | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 832 | Water Supply-LRS 1 2 3 | 395 | 389 to 399 General Plant | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 832 | Water Supply-LRS 1 2 3 | 396 | 389 to 399 General Plant | 110 05 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 832 | Water Supply-LRS 1 2 3 | 398 | 389 to 399 General Plant | 110 05 | | | | |
| | | | | **832 Total** | | | | | - | - | - | - |
| | Plant - Coal | | | | Water Treatment-LRS 1 | | 310 to 319 | 110 | | | | |

1 Based 800 311 833 2 3 311 Generation 05



| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Plant - Coal Based | 800 | 311 | 833 | Water Treatment-LRS 1 2 3 | 312 | 310 to 319 Generation | 11005 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 833 | Water Treatment-LRS 1 2 3 | 315 | 310 to 319 Generation | 11005 | | | | |
| | | | | **833 Total** | | | | | - | - | - | - |
| 1 | Plant - Coal Based | 800 | 311 | 834 | Sludge Disposal-LRS 1 2 3 | 312 | 310 to 319 Generation | 11005 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 834 | Sludge Disposal-LRS 1 2 3 | 314 | 310 to 319 Generation | 11005 | | | | |
| 1 | Plant - Coal Based | 800 | 311 | 834 | Sludge Disposal-LRS 1 2 3 | 315 | 310 to 319 Generation | 11005 | | | | |
| | | | | **834 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 311 | 835 | Grounds & Ponds-LRS 1 2 3 | 311 / 312 | 310 to 319 Generation | 11005 | | | | |
| 4 | Transmission Line | 800 | 311 | 835 | Grounds & Ponds-LRS 1 2 3 | 392 | 389 to 399 General Plant | 11005 | | | | |
| | | | | **835 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 311 | 840 | Common Bldgs & Struct-LRS 1 2 | 311 | 310 to 319 Generation | 11005 | | | | |
| 4 | Transmission Line | 800 | 311 | 840 | Common Bldgs & Struct-LRS 1 2 | 312 | 310 to 319 Generation | 11005 | | | | |
| 4 | Transmission Line | 800 | 311 | 840 | Common Bldgs & Struct-LRS 1 2 | 314 | 310 to 319 Generation | 11005 | | | | |
| | | | | **840 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 311 | 844 | Sludge Disposal-LRS 1 2 | 312 | 310 to 319 Generation | 11005 | | | | |
| | Transmission | | | | Sludge Disposal- | | 310 to 319 | 11005 | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Line | 800 | 311 | 844 | LRS | 1 | 2 | 315 | Generation | 05 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **844 Total** | | | | | - | - | - | - |
| 4 | Transmission Line | 800 | 311 | 846 | Scrubber-LRS 1 2 | 311 | 310 to 319 Generation | 11005 | | | | |
| 4 | Transmission Line | 800 | 311 | 846 | Scrubber-LRS 1 2 | 312 | 310 to 319 Generation | 11005 | | | | |
| 4 | Transmission Line | 800 | 311 | 846 | Scrubber-LRS 1 2 | 315 | 310 to 319 Generation | 11005 | | | | |
| | | | | **846 Total** | | | | | - | - | - | - |
| | | | | **Grand Total** | | | | | - | - | - | - |

**MBPP Transmission by FERC Account**

| FERC Account | Total MBPP by Account | | | |
|---|---|---|---|---|
| 350 | 0.00 | 0.00 | 0.00 | 0.00 |
| 352 | 0.00 | 0.00 | 0.00 | 0.00 |
| 353 | 0.00 | 0.00 | 0.00 | 0.00 |
| 354 | 0.00 | 0.00 | 0.00 | 0.00 |
| 355 | 0.00 | 0.00 | 0.00 | 0.00 |
| 356 | 0.00 | 0.00 | 0.00 | 0.00 |
| | **0.00** | **0.00** | **0.00** | **0.00** |

**LESS: MBPP Transmission included in "Other Transmission Detail"**

| Cmplx | Description |
|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| | | 69Kv LRS Substation | | | | |
| 59 | **352** | MBPP | 0.00 | 0.00 | 0.00 | 0.00 |
| | | 69Kv LRS Substation | | | | |
| 59 | **353** | MBPP Main Transformer | 0.00 | 0.00 | 0.00 | 0.00 |
| 116 | **353** | LRS #1 Main Transformer | 0.00 | 0.00 | 0.00 | 0.00 |
| 117 | **353** | LRS #2 Main Transformer | 0.00 | 0.00 | 0.00 | 0.00 |
| 118 | **353** | LRS #3 | 0.00 | 0.00 | 0.00 | 0.00 |
| | | | **0.00** | **0.00** | **0.00** | **0.00** |

| **FERC Account** | | | | |
|---|---|---|---|---|
| 350 | **0.00** | **0.00** | **0.00** | **0.00** |
| 352 | **0.00** | **0.00** | **0.00** | **0.00** |
| 353 | **0.00** | **0.00** | **0.00** | **0.00** |
| 354 | **0.00** | **0.00** | **0.00** | **0.00** |
| 355 | **0.00** | **0.00** | **0.00** | **0.00** |
| 356 | **0.00** | **0.00** | **0.00** | **0.00** |
| **MBPP Transmission ex. Complexes included in "Other"** | **0.00** | **0.00** | **0.00** | **0.00** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **MBPP Transmission** | | 350-356 | (Excludes: cmplx 116, 117, 118, 59) | | | | |
| | | 389-398 | (Maint. Bldgs) | | | | |
| | | 389-398 | (Microwave) (Ault Sub | | | | |
| | | 303 | MBPP West) | | | | |
| | | | | **0.00** | **0.00** | **0.00** | **0.00** |
| **Microwave** | | **Total** | | **0.00** | **0.00** | **0.00** | **0.00** |
| **MW Channels** | | | | | | | |
| Transmission | 650 | 76.11% | | 0.00 | 0.00 | 0.00 | 0.00 |
| Generation | 200 | 23.42% | | 0.00 | 0.00 | 0.00 | 0.00 |
| Marketing | 4 | 0.47% | | 0.00 | 0.00 | 0.00 | 0.00 |
| | **854** | **1.0000** | | **0.00** | **0.00** | **0.00** | **0.00** |
| **MBPP Adjustment for Microwave Communication** | | | | 0.00 | 0.00 | 0.00 | 0.00 |
| **Total MBPP w/MW Adjustment** | | | | **0.00** | **0.00** | **0.00** | **0.00** |

**MBPP Transmission - General Plant**

| | | | | |
|---|---|---|---|---|
| **(FERC Account 389 - 398)** | **0.00** | **0.00** | **0.00** | **0.00** |

| | | | | | |
|---|---|---|---|---|---|
| **MBPP Plant -FERC Account 310 - 315** | | | | | |
| **Generation** | 310 | | | | |
| | 311 | | | | |
| | 312 | | | | |
| | 314 | | | | |
| | 315 | | | | |
| | | **0.00** | **0.00** | **0.00** | **0.00** |

Not
e:
The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

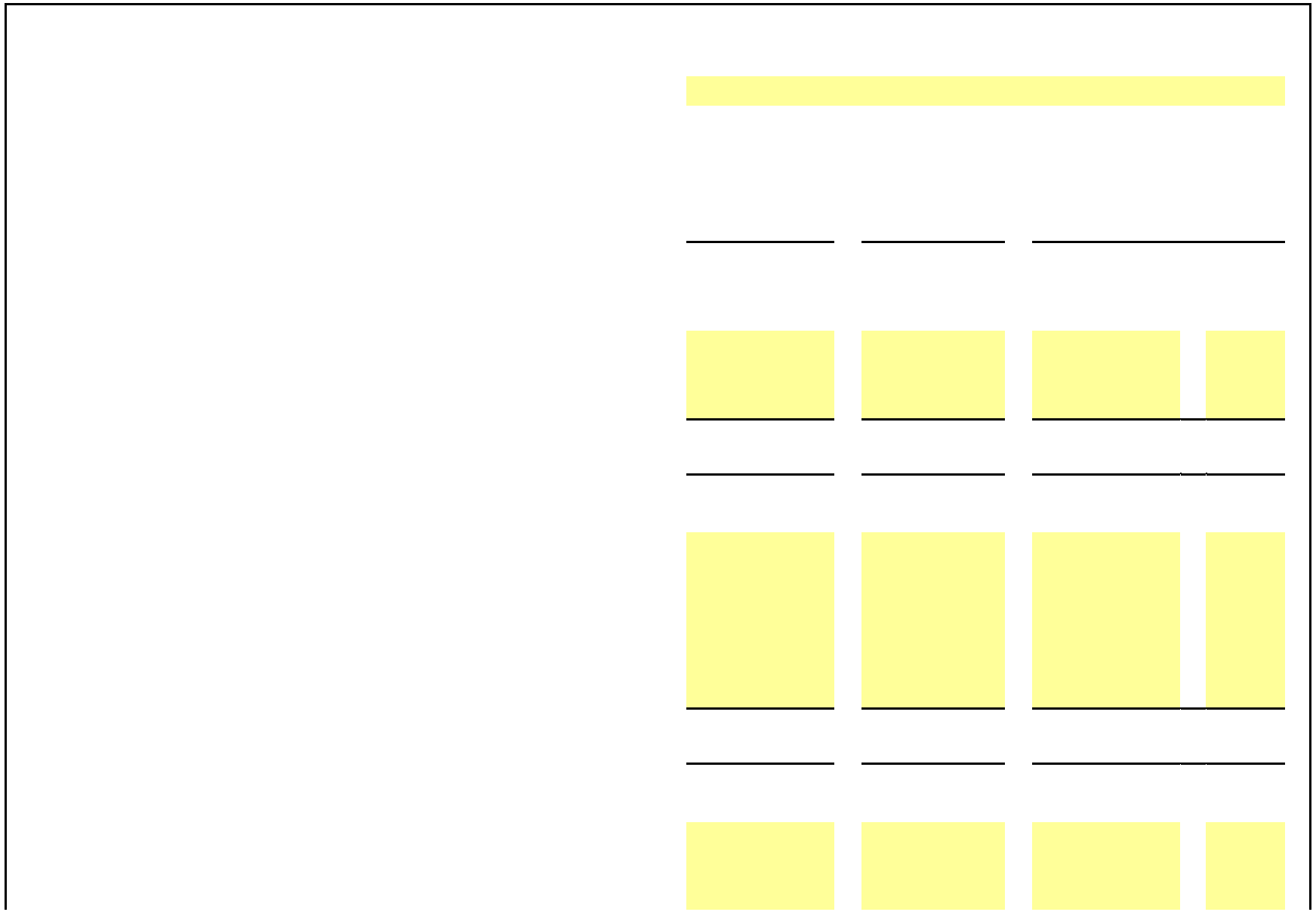
# BEPC Long-Term Debt Summary

**Work Paper #13**

| | | 12/31/20XX | | 12/31/20XX | |
|---|---|---|---|---|---|
| | | Debt Outstanding | Effective Interest Rate | Debt Outstanding | Effective Interest Rate |
| **Long-Term Loans:** | | | | | |
| **CoBank:** | | | | | |
| **2005 Series Notes A and B** | | | | | |
| **2007 Series Notes 1 and 2** | | | | | |
| **2016 Series** | | | | | |
| | **Sub-total** | - | #DIV/0! | - | #DIV/0! |
| **Other Long-Term Debt:** | | | | | |
| **Dry Fork Station Pollution Control** | | | | | |
| **2006 Series A** | | | | | |
| **Wyoming Infrastructure Authority** | | | | | |
| **Wells Fargo--ND Transmisson** | | | | | |
| **2-Year Member Investments** | | | | | |
| **2017 Series A** | | | | | |
| | **Sub-total** | - | #DIV/0! | - | #DIV/0! |
| **Private Placements:** | | | | | |
| **2008 Series A Note No. 1 (MetLife)** | | | | | |

**2008 Series A Notes No. 2 and 4 (MetLife)**

**2008 Series A Note No. 3 (MetLife)**



| | | | | |
|---|---|---|---|---|
| **2008 Series B Note (New York Life)** | | | | |
| **2008 Series C Note (John Hancock)** | | | | |
| **2008 Series D Note (Prudential) 2008 Series E Notes** | | | | |
| **2008 Series F Notes** | | | | |
| **2009 Series C Notes** | | | | |
| **2009 Series D Notes** | | | | |
| **2011 Series A Notes** | | | | |
| **2011 Series B Notes** | | | | |
| **2012 Series A Notes (AIG)** | | | | |
| **2015 Series A Notes** | | | | |
| **2015 Series B Notes** | | | | |
| **2015 Series BK Notes** | | | | |
| **2015 Series C Notes** | | | | |
| **2016 CFC Note** | | | | |
| **Sub-total** | - | #DIV/0! | - | #DIV/0! |
| **Total Long-Term Loans** | - | #DIV/0! | - | #DIV/0! |

Additional Long-term Debt included in Other

| | | |
|---|---|---|
| **Total Long-Term Debt to External Parties (in Thousands) (included in Audited Financials)** | - | - |

**PER FERC Form 1 - page 112 (in Whole Dollars) :**
Line 18. Bonds (221)
Line 21. Other Long-Term Debt

| | | |
|---|---|---|
| **Total Long-Term Debt on FERC Form 1** | $ - | $ - |

Note:
The addition of new lines and the removal of outdated lines necessary to populate or remove data in the workpaper with the changes in future years does not require a
Federal Power Act section 205 or 206 filing. However, the addition or removal of columns and formulas contained within those columns cannot be changed absent a
Federal Power Act section 205 or 206 filing, except to reflect the addition of new lines and the removal of outdated lines in the formulas.

**BASIN ELECTRIC POWER COOPERATIVE**
**FORMULA RATE IMPLEMENTATION PROTOCOLS**

The formula rate template ("Template") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Basin Electric Power Cooperative ("BEPC") for transmission revenue requirement determinations under the Southwest Power Pool, Inc. ("SPP") Open Access Transmission Tariff ("Tariff"). BEPC shall follow the instructions specified in the Formula Rate to calculate annually its Annual Transmission Revenue Requirement ("ATRR"). Recovery of costs associated with existing facilities and new facilities shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the Tariff. The ATRR shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate shall become effective for recovery of BEPC's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act ("FPA").

**Section 1.** **Annual Update**

a. No later than 10 days after the Commission accepts for filing of the Formula Rate, BEPC shall post its projected ATRR for the 2015 Rate Year in accordance with BEPC's Formula Rate ("Annual Update"). Not later than September 30 of 2015 and each subsequent Rate Year, BEPC shall post its Annual Update for the following Rate Year. Beginning in 2016, the Annual Update shall include the True-up Adjustment for the preceding Rate Year as described and defined in

Section 2 below, if applicable. The posting shall be accomplished as follows:

BEPC shall cause an electronic version of the Annual Update to be posted in

both a Portable Document Format and fully-functioning Excel file at a publicly accessible location on the SPP Open Access Same-Time Information System ("OASIS"). Such posting shall include (i) all inputs in sufficient detail to identify the components of BEPC's projected ATRR, and (ii) explanations of the bases for the projections and input data. If the last date for making such posting of the Annual Update should fall on a weekend or a holiday recognized by the Commission, then the posting shall be made no later than the next business day. BEPC shall provide each Annual Update to SPP to serve electronically upon the Service List.[1] The date of the posting shall be the Publication Date.

b. Together with the posting of the Annual Update, BEPC shall cause to be posted on the SPP OASIS the time, date and location for a stakeholder meeting with (i) any Eligible Customer under the Tariff; (ii) any regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; (iii) any consumer advocate authorized by state law to review and contest the rates for any such public utility, or (iv) any party with standing under FPA Section 205 or 206 (collectively, "Interested Parties") in order for BEPC to explain its Annual Update and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual Update ("Stakeholder Meeting"). The initial Stakeholder Meeting shall be held within thirty (30) days after the Commission accepts the Formula Rate for filing. Thereafter, the Stakeholder Meeting shall be held no earlier than October 10 and no later than October 30. BEPC shall provide remote access to the Stakeholder Meeting.

c. To the extent BEPC agrees to make changes in the Annual Update for a given Rate Year, BEPC will coordinate with SPP to ensure such revised Annual Update shall be promptly posted at a publicly accessible location on SPP's OASIS and a link to the OASIS shall be electronically served upon the Service List. Changes posted prior to November 30 of the preceding Rate Year, or the next business day if November 30 is not a business day (or such later date as can be accommodated under SPP's billing practices), shall be reflected in the Annual Update for the Rate Year. Changes posted after that date will be reflected in the Annual True-Up for the Rate Year if the change results in a change in BEPC's actual ATRR for that year.

d. The Annual Update for each Rate Year shall be subject to review, challenge, true-up and refunds or surcharges with interest, to the extent and in the manner provided in these Protocols.

e. On or before December 15 of each year, BEPC will submit an informational filing to the Commission and will provide to SPP, for posting on SPP's OASIS, BEPC's final projected ATRR that will become effective January 1 of the following year. BEPC will submit all Annual Update informational filings in the same docket assigned to BEPC's initial informational filing (Docket No. ER15-1775.[2] BEPC will provide the Annual Update informational filing to SPP to serve on the Service List.

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1

As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP OASIS. As of

January 2016, the Exploder List was titled "Formula Rate Information Notification" and could be accessed at https://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

[2] If Commission policy changes and a new docket is assigned to each annual informational filing, BEPC will request that SPP post the docket number assigned to each informational filing on the SPP OASIS within 5 business days of receiving the new docket number.

**Section 2. True-Up Adjustment**

BEPC will calculate the amount of under- or over-collection of its actual ATRR during the preceding Rate Year ("True-up Adjustment"). The True-up Adjustment shall be the sum of components a and b, determined in the following manner:

a. BEPC's actual revenues collected during the previous Rate Year[3] will be compared to BEPC's actual ATRR for the previous Rate Year calculated in accordance with BEPC's Formula Rate and based upon (i) BEPC's FERC Form No. 1 for that same Rate Year, (ii) any Commission orders specifically applicable to BEPC's calculation of its annual revenue requirement, (iii) the books and records of BEPC (which shall be maintained consistent with the FERC Uniform System of Accounts ("USofA")), (iv) FERC accounting policies and practices applicable to the calculation of annual revenue requirements under formula rates, and (v) any aspects of the Tariff Governing Documents that apply to the calculation of annual revenue requirements under individual transmission owner formula rates,[4] to determine any over- or under-recovery ("True-up Adjustment"). BEPC will include a variance analysis of, at minimum, actual

revenue requirement components of rate base, operating and maintenance expenses, depreciation expense, taxes, return on rate base, and revenue credits as

compared to the corresponding components in the projected ATRR that was calculated for the previous Rate Year with an explanation of material changes.

b. Interest on any over-or under-recovery shall be calculated in accordance with 18 C.F.R. § 35.19a, and shall be accrued from the date on which the over- or underrecovery occurs to the date on which the refunds or surcharges are applied.

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[3] b.

[4]

**Section 3.**

a.

Since the initial year of this rate schedule is a partial year, the actual revenues collected and the Net Revenue Requirement will be converted to monthly amounts. The difference between the monthly actual revenues collected and the monthly Net Revenue Requirement will be multiplied by the number of months the Formula Rate was in effect to calculate the True-up Adjustment.

SPP Governing Documents include the Tariff, Bylaws, Criteria, and Membership Agreements.

shall calculate its actual ATRR and the True-Up Adjustment as described in Section 2 ("Annual True-Up") for such Rate Year, and shall cause such Annual True-Up to be posted, in both a Portable Document Format and fully-functioning Excel format containing the populated template for that year's update, at a publicly accessible location on SPP's OASIS. BEPC also shall cause its FERC Form No. 1 for that Rate Year to be posted on the SPP OASIS by June 1. The information included with the Annual True-Up should be sufficient such that Interested Parties may replicate the calculations. BEPC shall coordinate with SPP to ensure a link to the SPP OASIS is served electronically upon the Service List.

If June 1 falls on a weekend or a holiday recognized by the Commission, then

**Annual True-Up**

Beginning in 2016, on or before June 1 following each Rate Year, BEPC

the postings shall be due not later than the next business day.

c. The date on which the posting occurs shall be that year's "Annual True-Up Publication Date."

d. Together with the posting of the Annual True-Up, BEPC shall cause to be posted on the SPP OASIS the time, date and location for a stakeholder meeting with Interested Parties in order for BEPC to explain its Annual True-Up and to provide Interested Parties an opportunity to seek information and clarifications regarding the Annual True-Up ("Stakeholder Meeting"). The Stakeholder Meeting shall be held no earlier than June 10 and no later than June 30. BEPC shall provide remote access to the Stakeholder Meeting.

e. The Annual True-Up for the Rate Year:

(i) Shall provide, via the Formula Rate worksheets, sufficiently detailed supporting documentation for data (and all adjustments thereto or allocations thereof) used in the Formula Rate that are not stated in the FERC Form No. 1;[5]

(ii) Shall provide notice of any change in BEPC's accounting policies and practices from those in effect for the Rate Year upon which the immediately preceding Annual Update was based that affect the Formula Rate or calculation of the Annual True-Up ("Accounting Change").

Accounting Changes include: (1) the initial implementation of an accounting standard or policy; (2) the initial implementation of

accounting practices for unusual or unconventional items for which the Commission has not provided specific accounting direction; (3) corrections of errors and prior period adjustments; (4) the implementation of new estimation methods or policies that change prior estimates; and (5) changes to income tax elections. To the extent these Accounting Changes affect the inputs to the Formula Rate, BEPC will provide a narrative explanation of the individual impact of those items on charges billed under the Formula Rate and will identify items included in the Annual True-Up at an amount other than on a historic cost basis (*e.g.*, fair value adjustments).

(iii) Shall identify any reorganization or merger transaction during the previous year and provide an explanation of the effect of the accounting for such transactions on inputs to the Formula Rate.

(iv) Shall be subject to review and challenge in accordance with the procedures set forth in Section 4 of these Protocols.

(v) Shall be subject to review and challenge in accordance with the procedures set forth in these Protocols with respect to the prudence of any costs and expenditures included for recovery in the Annual True-Up; provided, however, that nothing in these Protocols is intended to modify the Commission's applicable precedent with respect to the burden of

going forward or burden of proof under formula rates in such prudence challenges; and

(vi) Shall not seek to modify the Formula Rate and shall not be subject to challenge by any Interested Party seeking to modify the Formula Rate. *(i.e.,* any modifications to the Formula Rate will require, as applicable, an FPA Section 205 or Section 206 filing or initiation of a Section 206 investigation).

f. The following Formula Rate inputs shall be stated values to be used in the Formula Rate until changed pursuant to an FPA Section 205 or 206 proceeding: (i) rate of return on common equity ("ROE"); (ii) "Post-Employment Benefits other than Pensions" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges; and (iii) the depreciation and/or amortization rates as set forth in Schedule 7 to the Template.

g. If BEPC constructs a transmission project that is allocated using a regional cost sharing mechanism, it shall coordinate with other transmission owners using formula rates to establish the revenue requirements for recovery of the costs of transmission projects that use the same regional cost sharing mechanism to the extent such transmission owners are required to do so pursuant to their formula rate implementation protocols. Such coordination shall include participation in a joint informational meeting to enable all Interested Parties to understand how the transmission owners are implementing their formula rates for recovering the costs of such projects. Notice of Joint informational meetings shall be posted on the SPP OASIS and served electronically on the Service List by SPP no less than 7 days prior to such meeting.

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[5] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

**Section 4. Information Requests, Challenge Procedures and Annual Review Procedures**

Each Annual True-Up and each Annual Update shall be subject to the following procedures:

a. Interested Parties shall have up to ninety (90) calendar days after each Publication Date (unless such period is extended with the written consent of BEPC) to serve reasonable information requests on BEPC. Any delay in the Publication Date will therefore result in an equivalent extension of time for such requests. Information requests shall be limited to what is necessary to determine: (i) that input data under the Formula Rate are properly recorded in any underlying workpapers; (ii) that BEPC has properly applied the Formula Rate and the procedures in the Protocols; (iii) the accuracy of data and the consistency with the Formula Rate of the actual Net Revenue Requirement (including any True-Up Adjustment) under review; (iv) the extent of accounting changes that affect Formula Rate inputs; and (v) the reasonableness of projected costs included in the projected capital addition expenditures. Information requests shall not solicit information concerning costs or allocations where the

costs or allocation methods have been determined to be appropriate by

Commission in the context of prior BEPC Annual Updates, except that such

information requests shall be permitted if they (i) seek to determine if there has been a change in circumstances or (ii) are in connection with corrections pursuant to Section 6.

b. BEPC shall make a good faith effort to respond to information requests within fifteen (15) business days of receipt of such requests. BEPC shall not assert that responses to information requests are subject to settlement privilege; however, BEPC may require that Interested Parties execute a non-disclosure agreement to obtain access to material that BEPC deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

c. Interested Parties shall have up to the latest of one hundred twenty (120) calendar days after the Publication Date of the Annual True-Up or the Annual Update, thirty (30) calendar days after the receipt of all responses to timely submitted information requests (unless such period is extended with the written consent of BEPC), or thirty (30) calendar days after resolution of a dispute that does not result in the production of additional responses to information requests ("Review Period"), to review the calculations and to notify BEPC in writing of any specific challenges, including challenges related to Accounting Changes and either the Annual True-Up or the Annual Update ("Preliminary Challenge"). BEPC shall promptly cause to be posted all Preliminary Challenges at a publicly accessible location on SPP's OASIS and a link to the SPP OASIS will be electronically served upon the Service List.

BEPC shall respond in writing to a Preliminary Challenge within twenty (20) business days of receipt, and its response shall notify the challenging party of the extent to which BEPC agrees or disagrees with the challenge. If BEPC disagrees with the Preliminary Challenge, its response shall include supporting documentation. BEPC shall promptly cause to be posted responses to all Preliminary Challenges at a publicly accessible location on SPP's OASIS and a link to the SPP OASIS will be electronically served upon the Service List.

d. BEPC and any Interested Parties who have raised Preliminary Challenges shall attempt in good faith to resolve them. If requested, BEPC will appoint a senior representative to work with the Interested Parties toward a resolution of the Preliminary Challenge. Any refunds or additional amounts billed resulting from the resolution of a Preliminary Challenge to an Annual Update shall be applied pursuant to Section 1.b. Any refunds or additional amounts billed resulting from the resolution of a Preliminary Challenge to an Annual True-Up shall be applied to the True-Up Adjustment in the next Annual Update.

e. If BEPC and an Interested Party cannot resolve a Preliminary Challenge to an Annual Update, the Interested Party may file a Formal Challenge with the Commission. An Interested Party shall have until March 31 (or the next business day if March 31 falls on a weekend or holiday recognized by the Commission) following the Review Period to file a Formal Challenge. A Formal Challenge shall:

i. Clearly identify the action or inaction which is alleged to violate the filed

Formula Rate or these Protocols;

ii. Explain how the action or inaction violates the filed Formula Rate or these Protocols;

iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

a. The extent or effect of an Accounting Change;

b. Whether the Annual Update or Annual True-Up fails to include data properly recorded in accordance with these Protocols;

c. The proper application of the Formula Rate and procedures in these Protocols;

d. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual True-Up or projected ATRR;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts, FERC Form No. 1 or any other Commission-filed form that is used in calculating ATRR-related calculations; and

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Preliminary Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

f. The Formal Challenge must be filed in the same docket as BEPC's Annual Update Informational Filing and served on BEPC. Service on BEPC must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger.

g. Any response by BEPC to a Formal Challenge must be submitted to the Commission within thirty (30) calendar days of the date of the filing of the Formal Challenge, and shall be served on the filing party(ies) and the Service List by electronic service on the date of such filing.

h. If the last date for any of the above activities should fall on a weekend or a holiday recognized by the Commission, then the deadline shall be extended to the next business day.

i. In any Commission proceeding concerning an Annual Update, (including corrections) Annual True-Up or Accounting Change(s), BEPC shall support its assertion that the ATRR resulting from its application of the Formula Rate is just and reasonable by demonstrating that it has reasonably and accurately calculated the Annual Update or Annual True-Up and/or reasonably adopted and applied the Accounting Change. BEPC will bear the burden of demonstrating the justness and reasonableness of the ATRR resulting from its application of the Formula Rate.

j. If an Accounting Change or the application of the Formula Rate to BEPC's costs is found by the Commission to be unjust, unreasonable, and/or unduly discriminatory or preferential, then the calculation of the charges to be assessed during the Rate Year then under review, and the charges to be assessed during any subsequent Rate Years, including any True-Up Adjustments, shall not

include such change, but shall include any remedy that may be prescribed by the Commission in the exercise of its discretion as of the effective date of such

remedy, to ensure that the Formula Rate continues to operate in a manner that is just, reasonable, and not unduly discriminatory or preferential; provided that this limitation shall not apply if BEPC demonstrates that circumstances have changed since the Commission's decision.

**Section 5. Rate Filings**

a. Nothing stated herein shall be deemed to limit in any way the right of BEPC to cause SPP to file unilaterally on its behalf, pursuant to Section 205 of the FPA and the regulations thereunder, an application seeking changes to the Formula Rate or to any of the stated value inputs requiring a Section 205 filing under these Protocols (including, but not limited to, ROE, depreciation and amortization rates, and PBOPs); or the right of any other Interested Party to seek such changes or file a complaint concerning the Formula Rate or the application of the Formula Rate to BEPC's costs pursuant to Section 206 of the FPA and the regulations thereunder.

b. BEPC may make limited Section 205 filings to change depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than Pensions, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed change(s) are just and reasonable, and not unduly discriminatory.

c. The party filing pursuant to Sections 205 or 206 bears the standard burden of proof associated with those filings.

**Section 6. Changes to Annual Updates**

If BEPC makes a change to the actual ATRR, including but not limited to a change requiring correction to its FERC Form No. 1 or input data used for a Rate Year that would have affected the Annual True-Up for that Rate Year, BEPC shall promptly (1) request that SPP notify the Service List; (2) file a change to the Annual Update with the Commission as an amended informational filing or compliance filing, as appropriate; and (3) cause such information to be posted at a publicly accessible location on SPP's OASIS. Such changes shall be subject to review at the time they are made and shall be reflected in the next Annual Update, with interest. A changed posting shall reset the deadlines established by these Protocols for Interested Party review and the revised dates shall run from the Publication Date for the change. The scope of review shall be limited to the aspects of the Annual Update affected by the corrections.

**Section 7. Example Timelines for 2015 and 2016 Annual True-ups and Annual Updates**

Calendar Year 2015

| | |
|---|---|
| Not later than 10 days after Commission accepts the Formula Rate for filing | October 10 - October 30 November 30 |
| Within 30 days after Commission accepts the Formula Rate for filing | |
| On or before September 30 | |

Annual Update for 2015 is posted and served. Date posted is the Publication Date. Date of Stakeholder Meeting is posted.

Stakeholder Meeting for 2015 Annual Update.

Annual Update for 2016 Rate Year is posted and served. Date for Stakeholder Meeting is posted.

Stakeholder Meeting for 2016 Annual Update.

Deadline for BEPC to make changes to Annual Update for the 2016 Rate Year. Changes posted

| | |
|---|---|
| | |
| | |

| | |
|---|---|
| | |
| | after the deadline will be included in the following Rate Year's True-Up Adjustment if the change results in a change in BEPC's actual ATRR. |
| December 15 | BEPC makes an informational filing of its ATRR for the following Rate Year. |

| | |
|---|---|
| Calendar Year 2016 | |
| On or before June 1 | BEPC calculates and SPP posts and serves Annual True-Up. The Annual True-Up includes |
| | 2015 actual ATRR and True-Up Adjustment for the 2015 Rate Year. Date posted is the Publication Date. FERC Form No. 1 and date of |
| June 10 - June 30 | Stakeholder Meeting are posted.<br>Stakeholder Meeting. |
| On or before September 30 | BEPC posts Annual Update for 2017 Rate Year, which includes True-Up Adjustment from 2015 |
| October 10 - October 30 | Rate Year and Projected ATRR for the 2017 Rate Year. Date of Stakeholder Meeting is posted.<br>Stakeholder Meeting. |
| November 30 | Deadline for BEPC to make changes to Annual Update for the 2017 Rate Year. Changes posted after the deadline will be included in the 2017 |
| | Rate Year True-Up Adjustment and reflected in the Annual Projection Update for the 2018 Rate Year if the change results in a change in BEPC's actual ATRR. |
| December 15 | BEPC makes an informational filing of its ATRR for the following Rate Year. |

# Addendum 23 to Attachment H

## Heartland Consumers Power District
## Attachment H Workpapers
## For the 12 Months Ending December 31, 20XX

**Index**

Cash Flow
Worksheet A - Divisor
Worksheet B - Plant Balances
Worksheet C - Transmission O&M
Worksheet D - Administrative & General
Worksheet E - FERC Fees
Worksheet F - Debt Service
Worksheet G - EPRI, Regulatory Commission, and Non-Safety
Worksheet H - Taxes Other than Income Tax
Worksheet I - Account 454
Worksheet J - Excluded Transmission Plant and Expenses
Worksheet K - True Up Actuals
Worksheet L - True Up Calculation

Formula Rate Template
Heartland Consumers Power District
Cash Flow, Page 1 of 4
For the 12 Months Ending December 31, 20XX

| Line No. | Description | Source | Total Amount | Allocator | | Allocated Amount (col. c * col. d) |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | | (e) |
| 1 | **GROSS REVENUE REQUIREMENT** | Page 2, line 23, column e | | | | **#DIV/0!** |
| | **REVENUE CREDITS (Note Q)** | | Total | Allocator | | |
| 2 | Account No. 454 | Page 3, line 34, column e | $ - | T P | 0.00% | $ - |
| 3 | Account No. 456 | Page 3, line 37, column e | $ - | T P | 0.00% | $ - |
| 4 | Revenues from Grandfathered Interzonal Transactions | | $ - | T P | 0.00% | $ - |
| 5 | Revenues from service provided by the ISO at a discount | | $ - | T P | 0.00% | $ - |
| 6 | **TOTAL REVENUE CREDITS** | (sum lines 2-5) | | | | **$ -** |
| 6a | Total True-Up Amount | Worksheet L, line 2, column G | | | | $ - |
| 6b | True-Up Interest | Worksheet L, line 19, column G | | | | $ - |

| | | | | |
|---|---|---|---|---|
| 7 | **NET REVENUE REQUIREMENT** | (line 1 - line 6 + line 6a + line 6b) | | **#DIV/0!** |
| | **DIVISOR (Note R)** | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | Worksheet A, line 13, column c | (Note A) | - |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8 | | (Note B) | - |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | - |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | - |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | - |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note P) | | | - |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | - |
| 15 | **Divisor** | (sum lines 8-14) | | **0** |

Attachment H - Cash Flow
Page 2 of 4

Formula Rate Template
Heartland Consumers Power District
Cash Flow, Page 2 of 4
For the 12 Months Ending December 31, 20XX

| **Li** | | **Total** | **Amount** |
|---|---|---|---|

| ne No. | Description | Source | Amount | Allocator | | (col. c * col. d) |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | | (e) |
| | **O&M (Note R)** | | | | | |
| 1 | Transmission | Worksheet C, line 29, column d | $ - | TE | 0.00% | $ - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note S) | Worksheet C, line 10, column d | $ - | NA | 0.00% | $ - |
| 2 | Less Account 565 | Worksheet C, line 14, column d | $ - | TE | 0.00% | $ - |
| 3 | **A&G** | Worksheet D, line 31, column d | $ - | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | Worksheet E, line 4, column d | $ - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F) | Worksheet G (sum lines 1, 3, 7) | $ - | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note F) | Worksheet G, line 5, column d | $ - | TE | 0.00% | $ - |
| 6 | Common | | $ - | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | | $ - | DA | 100.00% | $ - |
| 8 | **TOTAL O&M** | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | **$ -** | | | **#DIV/0!** |
| | **DEBT SERVICE (Note R)** | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 9 | Debt Service (Note T) | Worksheet F, line 12, column e | #DIV/0! | D A | 100.00 % | #DIV/0! |
| 10 | Amortization of premium or discount (Note U) | | | | | |
| 10 a | Account 428 Amortization of Debt Discount and Expense | | $ - | G P | #DIV/0 ! | #DIV/0! |
| 10 b | Account 429 Amortization of Premium on Debt | | $ - | G P | #DIV/0 ! | #DIV/0! |
| 11 | **TOTAL DEBT SERVICE** | (line 9 + line 10a + line 10b) | **#DIV/0!** | | | **#DIV/0!** |
| | **TAXES OTHER THAN INCOME TAXES (Notes G and R)** | | | | | |
| | LABOR RELATED | | | | | |
| 12 | Payroll | Worksheet H, line 1, column c | $ - | W / S | #DIV/0 ! | #DIV/0! |
| 13 | Highway and vehicle | Worksheet H, line 2, column c | $ - | W / S | #DIV/0 ! | #DIV/0! |
| 14 | PLANT RELATED | | | | | |
| 15 | Property | Worksheet H, line 3, column c | $ - | G P | #DIV/0 ! | #DIV/0! |
| 16 | Gross Receipts | Worksheet H, line 4, column c | $ - | N A | 0.00% | $ - |
| 17 | Other | Worksheet H, line 5, column c | $ - | G P | #DIV/0 ! | #DIV/0! |
| 18 | Payments in lieu of taxes | Worksheet H, line 6, column c | $ - | G P | #DIV/0 ! | #DIV/0! |
| 19 | **TOTAL OTHER TAXES** | (sum lines 12, 13, 15, 16, 17, 18) | **$ -** | | | **#DIV/0!** |

| | | | | | | |
|---|---|---|---|---|---|---|
| 20 | **SUBTOTAL** | (sum lines 8, 11, 19) | #DIV/0! | | | #DIV/0! |
| 21 | **MARGIN REQUIREMENT (Note H)** | (Worksheet F, line 14, column e) | #DIV/0! | D A | 100.00 % | #DIV/0! |
| 22 | **SETTLEMENT ADJUSTMENT (Note W)** | | $ 50,000 | D A | 100.00 % | $ 50,000.00 |
| 23 | **REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT H** | (line 20 + line 21 + line 22) | **#DIV/0!** | | | **#DIV/0!** |



Formula Rate Template
Heartland Consumers Power District
Cash Flow, Page 3 of 4
For the 12 Months Ending December 31, 20XX

| Line No. | Description | Source | Total Amount | Allocator | | Transmission (col. c * col. d) | Other |
|---|---|---|---|---|---|---|---|
| | (a) | **(b)** | (c) | (d) | | (e) | (f) |
| | **GROSS PLANT IN SERVICE (Note V)** | | | | | | |
| 1 | Production | Worksheet B, line 14, column c | $ - | N A | 0.00% | $ - | |
| 2 | Transmission | Worksheet B, line 14, column d | $ - | T P | 0.00% | $ - | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 3 | Distribution | Worksheet B, line 14, column e | $ - | NA | 0.00% | $ - | |
| 4 | General | Worksheet B, line 14, column f | $ - | W/S | #DIV/0! | #DIV/0! | |
| 4a | Intangible | Worksheet B, line 14, column g | $ - | W/S | #DIV/0! | #DIV/0! | |
| 5 | Common | Worksheet B, line 14, column h | $ - | CE | #DIV/0! | #DIV/0! | |
| 6 | **TOTAL GROSS PLANT** | (sum lines 1-5) | $ - | GP= | #DIV/0! | #DIV/0! | |
| | **TRANSMISSION PLANT INCLUDED IN ISO RATES** | | | | | | |
| 7 | Total transmission plant | Worksheet B, line 14, column i | | | | $ - | |
| 8 | Less transmission plant excluded from ISO rates (Notes J and V) | Worksheet J, line 6, column c | | | | $ - | |
| 9 | Less transmission plant included in OATT Ancillary Services (Notes K and V ) | Worksheet J, line 2, column c | | | | $ - | |
| 10 | **Transmission plant included in ISO rates** | (line 7 less lines 8 and 9) | | | | **$ -** | |
| 11 | Percentage of transmission plant included in ISO Rates | (line 10 / line 7) | | | TP= | 0.00% | |
| | **TRANSMISSION EXPENSES (Note R)** | | | | | | |
| 12 | Total transmission expenses | (page 2, line 1, column 3) | | | | $ - | |

| | | | | | |
|---|---|---|---|---|---|
| 13 | Less transmission expenses included in OATT Ancillary Services (Note I) | Worksheet J, line 4, column c | $ - | | |
| 14 | Included transmission expenses | (line 12 less line 13) | $ - | | |
| 15 | Percentage of transmission expenses after adjustment | (line 14 / line 12) | | | 0.00% |
| 16 | Percentage of transmission plant included in ISO Rates | (line 11) | | TP | 0.00% |
| 17 | Percentage of transmission expenses included in ISO Rates | (line 15 * line 16) | | TE= | 0.00% |

**WAGES & SALARY ALLOCATOR (W&S) (Note L)**

| | | | $ | Allocation (col.c / line 22a) | | W&S Allocator ($ / Allocation) |
|---|---|---|---|---|---|---|
| 18 | Production | | $ - | 0.00% | | |
| 19 | Transmission | | $ - | 0.00% | = | #DIV/0! |
| 20 | Distribution | | $ - | 0.00% | | |
| 21 a | Customer Accounts | | $ - | 0.00% | | |
| 21 b | Customer Service & Information | | $ - | 0.00% | | |
| 22 a | **Total** | (sum lines 18-21b) | $ - | 0.00% | | |
| 22 b | Administrative & General | | $ - | | | |

**COMMON PLANT ALLOCATOR (CE) (Note M)**

| | | | **Amount** | % Electric (line 23 | Labor Ratio (line 19) |
|---|---|---|---|---|---|

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | / line 26) | | | | |
| 23 | Electric | | $ - | | | | | | | CE |
| 24 | Gas | | $ - | | | 0.00% | * | #DIV/0! | = | #DIV/0! |
| 25 | Water | | $ - | | | | | | | |
| 26 | **Total** | (sum lines 23-25) | $ - | | | | | | | |
| | **REVENUE CREDITS (Note R)** | | | | | | | | | |
| | | | | | | | | Load | | |
| | **ACCOUNT 447 (SALES FOR RESALE)** | | | | | | | | | |
| 31 | a. Bundled Non-RQ Sales for Resale (Note N) | | $ - | D<br>A | 100.00<br>% | | | $ - | | |
| 32 | b. Bundled Sales for Resale included in Divisor on page 1 | | $ - | D<br>A | 100.00<br>% | | | $ - | | |
| 33 | **Total** | (line 31 less line 32) | | | | | | $ - | | |
| 34 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O) | Worksheet I, line 2, column c | $ - | D<br>A | 100.00<br>% | | | | | $0 |
| | ACCOUNT 456 (OTHER ELECTRIC REVENUES) | | | | | | | | | |
| 35 | a. Transmission charges for all transmission transactions | | | D<br>A | 100.00<br>% | | | | | $0 |
| 36 | b. Transmission charges for all transmission transactions included in Divisor on page 1 | | | D<br>A | 100.00<br>% | | | | | $0 |
| 37 | Total of (a)-(b) | (line 35 less line 36) | $ - | | | | | | | $0 |

Attachment H - Cash

Formula Rate Template
Heartland Consumers Power District
Cash Flow, Page 3 of 4
For the 12 Months Ending December 31, 20XX

| Note Letter | |
|---|---|
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any. |
| F | Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, |

| | |
|---|---|
| | ISO filings, or transmission siting. |
| G | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| H | The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement Heartland uses is based on the Fixed Charge Coverage Ratio ("FCCR") approved for use in setting rates by the Heartland Board of Directors. Heartland's Margin Requirement is fixed at 20% and will not be changed absent a Section 205 filing. |
| I | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.1, 561.2, 561.3 and 561.BA. |
| J | Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test For Heartland this amount represents the step-up transmission facilities associated with the Laramie River Station. |
| K | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For Heartland, these amounts are related to TP II - East River facilities and improvements made to to Nebraska Public Power District's transmission system through the Missouri Basin Power Project. These transmission assets are on the HCPD balance sheet until 2017 but the transmission assets are paid for by East River so are not includable in the HCPD ATRR. |
| L | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator at page 3, line 23 equal to the amount of transmission plant includable in ISO rates divided by the sum of total gross production, transmission, and distribution plant. All of Heartland's employees are assigned to A&G. After 2017 there will be no amount included from TP II on this line. assigned to A&G. After 2017 there will be no amount included from TP II on this line. |

M Enter dollar amounts.

N Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor.

O Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

P Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

Q The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

R Calculated using end of year projected amounts.

S Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. revenue requirements.

T Debt service calculation is supported by the debt service work paper and is comprised of the gross plant allocator portion of the Heartland long-term debt plus the transmission-related portion of the debt service for the Public Power Generation Agency payments. The work paper calculates the transmission only debt service that is entered on line 9, page 2 0f 4 so it is 100% directly assigend to the ATRR.

U Includes amounts recorded to accounts 428 and 429.

V Calculated using 13 month average balance. Gross Plant in Service amounts exclude Asset Retirement Obligation amounts unless

| | |
|---|---|
| | authorized by FERC. |
| W | For the 2016, 2017, and 2018 rate years, per the settlement agreement in FERC Docket No. ER15-1777. An annual amount of $50,000 for each rate year of 2016, 2017, and 2018. |

| | | | |
|---|---|---|---|
| Formula Rate Template | | | |
| Heartland Consumers Power District | | | |
| Worksheet A, Divisor | | | |
| For the 12 Months Ending December 31, 20XX | | | |
| | | | |
| **Line No.** | | | **12 CP Load** |
| **No.** | **Month** | **Source** | **(in kWh)** |
| | (a) | (b) | (c) |
| | | | |
| | **Average of 12 coincident system peaks for requirements (RQ) service** | | |
| 1 | January | | - |
| 2 | February | | - |
| 3 | March | | - |
| 4 | April | | - |
| 5 | May | | - |
| 6 | June | | - |
| 7 | July | | - |
| 8 | August | | - |
| 9 | September | | - |
| 10 | October | | - |
| 11 | November | | - |
| 12 | December | | - |
| | | | |
| 13 | **12 Month Average** | **(sum lines 1-12) / 12** | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Formula Rate Template | | | | | | | | | |
| Heartland Consumers Power District | | | | | | | | | |
| Worksheet B, Plant Balances | | | | | | | | | |
| For the 12 Months Ending December 31, 20XX | | | | | | | | | |
| | | | | | | | | | |
| | | | | | | | | | **Total Gross Plant in Service** |
| **Line No.** | **Gross Plant in Service** | **Source** | **Production** | **Transmission** | **Distribution** | **General** | **Intangible** | **Common** | (sum col. d - col. i) |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | | | | | | | | | |
| 1 | December | | | | | | | | $ - |
| 2 | January | | | | | | | | $ - |
| 3 | February | | | | | | | | $ - |
| 4 | March | | | | | | | | $ - |
| 5 | April | | | | | | | | $ - |
| 6 | May | | | | | | | | $ - |
| 7 | June | | | | | | | | $ - |
| 8 | July | | | | | | | | $ - |
| 9 | August | | | | | | | | $ - |
| 10 | September | | | | | | | | $ - |
| 11 | October | | | | | | | | $ - |
| 12 | November | | | | | | | | $ - |
| 13 | December | | | | | | | | $ - |
| | | | | | | | | | |
| 14 | **13 Month Average** | **(sum lines 1-13) / 13** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| | | | | | | | | | **Total Accumulated** |
| | | | | | | | | | **Depreciation** |
| **Line No.** | **Accumulated Depreciation** | **Source** | **Production** | **Transmission** | **Distribution** | **General** | **Intangible** | **Common** | (sum col. d - col. i) |
| | (a) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| | | | | | | | | | |
| 15 | December | | | | | | | | $ - |
| 16 | January | | | | | | | | $ - |
| 17 | February | | | | | | | | $ - |
| 18 | March | | | | | | | | $ - |
| 19 | April | | | | | | | | $ - |
| 20 | May | | | | | | | | $ - |
| 21 | June | | | | | | | | $ - |
| 22 | July | | | | | | | | $ - |
| 23 | August | | | | | | | | $ - |
| 24 | September | | | | | | | | $ - |
| 25 | October | | | | | | | | $ - |
| 26 | November | | | | | | | | $ - |
| 27 | December | | | | | | | | $ - |
| | | | | | | | | | |
| 28 | **13 Month Average** | **(sum lines 15-27) / 13** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | |
| | | | | | | | | | **Total Net Plant in** |
| | | | | | | | | | **Service** |

| Line No. | Net Plant | Source | Production | Transmission | Distribution | General | Intangible | Common | (sum col. d - col. i) |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| | | | | | | | | | |
| 29 | December | (line 1 - line 15) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 30 | January | (line 2 - line 16) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 31 | February | (line 3 - line 17) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 32 | March | (line 4 - line 18) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 33 | April | (line 5 - line 19) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 34 | May | (line 6 - line 20) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 35 | June | (line 7 - line 21) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 36 | July | (line 8 - line 22) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 37 | August | (line 9 - line 23) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 38 | September | (line 10 - line 24) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 39 | October | (line 11 - line 25) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 40 | November | (line 12 - line 26) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 41 | December | (line 13 - line 27) | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | |
| 42 | **13 Month Average** | **(sum lines 29-41) / 13** | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | | | | | | | | |
| | | | | | | | | | **Total Depreciation** |
| **Line No.** | **Depreciation** | **Source** | **Production** | **Transmission** | **Distribution** | **General** | **Intangible** | **Common** | (sum col. d - col. i) |
| | (a) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
| | | | | | | | | | |
| 43 | **Total Depreciation** | HCPD Audited | | | | | | $ | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Expense** | Financials | | | | | | - | - |

| | | | | |
|---|---|---|---|---|
| Formula Rate Template | | | | |
| Heartland Consumers Power District | | | | |
| Worksheet C, Transmission O&M | | | | |
| For the 12 Months Ending December 31, 20XX | | | | |
| | | | | |
| **Line** | | | | |
| **No.** | **Account** | **Description** | **Source** | **Amount** |
| | (a) | (b) | (c) | (d) |
| | | | | |
| | | **Operation** | | |
| 1 | 560 | Operation Supervision and Engineering | HCPD Audited Financials | |
| 2 | 561 | Load Dispatching | " | |
| 3 | 561.1 | Load Dispatch – Reliability | " | |
| 4 | 561.2 | Load Dispatch – Monitor and Operate Transmission System | " | |
| 5 | 561.3 | Load Dispatch – Transmission Service and Scheduling | " | |
| 6 | 561.4 | Scheduling, System Control and Dispatch Services | " | |
| 7 | 561.5 | Reliability, Planning and Standards Development | " | |
| 8 | 561.6 | Transmission Service Studies | " | |
| 9 | 561.7 | Generation Interconnection Studies | " | |
| 10 | 561.8 | Reliability, Planning and Standards Development Service | " | |
| 11 | 562 | Station Expenses | " | |
| 12 | 563 | Overhead Lines Expenses | " | |
| 13 | 564 | Underground Lines Expenses | " | |
| 14 | 565 | Transmission of Electricity by Others | " | |
| 15 | 566 | Miscellaneous Transmission Expenses | " | |
| 16 | 567 | Rents | " | |
| 17 | | **Total Operation Expense** | (sum lines 1-16) | $ - |
| | | | | |
| | | **Maintenance** | | |
| 18 | 568 | Maintenance Supervision and Engineering | HCPD Audited Financials | |
| 19 | 569 | Maintenance of Structures | " | |
| 20 | 569.1 | Maintenance of Computer Hardware | " | |

| | | | | |
|---|---|---|---|---|
| 21 | 569.2 | Maintenance of Computer Software | " | |
| 22 | 569.3 | Maintenance of Communication Equipment | " | |
| 23 | 569.4 | Maintenance of Miscellaneous Regional Transmission Plant | " | |
| 24 | 570 | Maintenance of Station Equipment | " | |
| 25 | 571 | Maintenance of Overhead Lines | " | |
| 26 | 572 | Maintenance of Underground Lines | " | |
| 27 | 573 | Maintenance of Miscellaneous Transmission Plant | " | |
| 28 | | **Total Maintenance Expense** | (sum lines 18-27) | $ - |
| | | | | |
| 29 | | **Total Transmission O&M Expense** | (line 17 + line 28) | **$ -** |

| | | | | |
|---|---|---|---|---|
| Formula Rate Template | | | | |
| Heartland Consumers Power District | | | | |
| Worksheet D, A&G | | | | |
| For the 12 Months Ending December 31, 20XX | | | | |
| | | | | |
| **Line** | | | | |
| **No.** | **Account** | **Description** | **Source** | **Amount** |
| | (a) | (b) | (c) | (d) |
| | | | | |
| | | **Customer Accounts Expenses** | | |
| 1 | 901 | Supervision | HCPD Audited Financials | $ - |
| 2 | 902 | Meter Reading Expenses | " | $ - |
| 3 | 903 | Customer Records and Collection Expenses | " | $ - |
| 4 | 904 | Uncollectible Accounts | " | $ - |
| 5 | 905 | Miscellaneous Customer Accounts Expenses | " | $ - |
| 6 | | **Total Customer Accounts Expense** | (sum lines 1-5) | $ - |
| | | | | |
| | | **Customer Service and Informational Expenses** | | |
| 7 | 907 | Supervision | HCPD Audited Financials | $ - |
| 8 | 908 | Customer Assistance Expenses | " | $ - |
| 9 | 909 | Informational and Instructional Expenses | " | $ - |
| 10 | 910 | Miscellaneous Customer Service and Informational Expenses | " | $ - |
| 11 | | **Total Customer Service and Informational Expenses** | (sume lines 7-10) | $ - |
| | | | | |
| | | **Sales Expenses** | | |
| 12 | 911 | Supervision | HCPD Audited Financials | $ - |
| 13 | 912 | Demonstrating and Selling Expenses | " | $ - |
| 14 | 913 | Advertising Expenses | " | $ - |
| 15 | 916 | Miscellaneous Sales Expenses | " | $ - |
| 16 | | **Sales Expenses** | (sum lines 12-15) | $ - |
| | | | | |

| | | | | |
|---|---|---|---|---|
| | | **Administrative and General Expenses** | | |
| 17 | 920 | Administrative and General Salaries | HCPD Audited Financials | $ - |
| 18 | 921 | Office Supplies and Expenses | " | $ - |
| 19 | 922 | Administrative Expenses Transferred Credit | " | $ - |
| 20 | 923 | Outside Services Employed | " | $ - |
| 21 | 924 | Property Insurance | " | $ - |
| 22 | 925 | Injuries and Damages | " | $ - |
| 23 | 926 | Employee Pension and Benefits | " | $ - |
| 24 | 927 | Franchise Requirements | " | $ - |
| 25 | 928 | Regulatory Commission Expenses | " | $ - |
| 26 | 929 | Duplicate Charges Credit | " | $ - |
| 27 | 930.1 | General Advertising Expenses | " | $ - |
| 28 | 930.2 | Miscellaneous General Expenses | " | $ - |
| 29 | 931 | Rents | " | $ - |
| 30 | 935 | Maintenance of General Plant | " | $ - |
| 31 | | **Administrative and General Expenses** | (sum lines 17-30) | $ - |

| | | | | |
|---|---|---|---|---|
| Formula Rate Template | | | | |
| Heartland Consumers Power District | | | | |
| Worksheet E, FERC Fees | | | | |
| For the 12 Months Ending December 31, 20XX | | | | |
| | | | | |
| **Line** | | | **Account** | |
| **No** | **FERC Fees Recorded to Expense during the Year** | **Source** | **Charged** | **Amount** |
| | (a) | (b) | (c) | (d) |
| | | | | |
| 1 | FERC fees payable to FERC | | | $ - |
| 2 | FERC fees paid to SPP | | | $ - |
| 3 | Other FERC fees paid | | | $ - |
| | | | | |
| 4 | **Total** | (sum lines 1-3) | | **$ -** |

Formula Rate Template

Heartland Consumers Power District

Worksheet F, Debt Service

For the 12 Months Ending December 31, 20XX

| Line No. | Description | Source | Total Amount | % Allocated to HCPD (Note A) | HCPD Amount (col. d * col. e) |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **HCPD Annual Debt Service** | | | | |
| 1a | Series 2011 | | | | |
| 1b | Series 2015A | | | | |
| 1c | Series 1992 | | | | |
| 1d | Series 2010 | | | | |
| 2 | **Total HCPD Annual Debt Service** | (sum line 1a-1XX) | | | **$0** |
| | | | | | |
| 3 | Gross Plant Allocator | (Cash Flow, page XX, line XX) | | | #DIV/0! |
| 4 | **Total Transmission-Related Debt Service** | (line 2 * line 3) | | | **#DIV/0!** |
| | | | | | |
| 5 | Margin Requirement Percentage (Note A) | | | | 20.00% |
| 6 | **Margin Requirement on Debt Service and Fixed Charge** | (line 4 * line 5) | | | **#DIV/0!** |
| | | | | | |
| 7 | **Total Transmission Debt Service and Fixed Charge** | (line 4 + line 6) | | | **#DIV/0!** |

Notes:

A This percentage is fixed and will not be changed absent a Section 205 filing.

Formula Rate Template

Heartland Consumers Power District

Worksheet G, EPRI, Regulatory Commission, and Non Safety Advertising Expenses

For the 12 Months Ending December 31, 20XX

| Line No. | Account | Description | Source | Amount |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | | | | |
| 1 | | **EPRI Costs** | | $ - |
| | | | | |
| | | **Regulatory Commission Expense (provide a brief but descriptive list of charges)** | | |
| 2a | 928 | Commission Expense for SPP ATRR filing | | |
| 2XX | | Motion for waiver - EL16-1-000 | | |
| 3 | | **Total Regulatory Commission Expense** | (sum lines 2a-2XX) | **$ -** |
| | | | | |
| | | **Transmission Related Regulatory Commission Expense (provide a brief but descriptive list of charges)** | | |
| 4a | 928 | Commission Expense for SPP ATRR filing | | $ - |
| 4XX | | XXXXX | | $ - |
| 5 | | **Total Regulatory Commission Expense** | (sum lines 4a-4XX) | **$ -** |
| | | | | |
| | | **Non Safety Advertising (provide a brief but descriptive list of charges)** | | |
| 6a | 930.1 | Advertising costs for required public notices in local newspapers. | | $ - |
| 6XX | | XXXXX | | $ - |
| 7 | | **Total Non Safety Advertising Expense** | (sum lines 6a-6XX) | **$ -** |

| | | | |
|---|---|---|---|
| Formula Rate Template | | | |
| Heartland Consumers Power District | | | |
| Worksheet H, Taxes Other than Income Tax | | | |
| For the 12 Months Ending December 31, 20XX | | | |
| | | | |
| **Line** | | | |
| **No** | **Description** | **Source** | **Amount** |
| | (a) | (b) | (c) |
| | | | |
| | **Taxes Other than Income Tax** | | |
| 1 | Payroll | | |
| 2 | Highway & Vehicle | | |
| 3 | Property | | |
| 4 | Gross Receipts | | |
| 5 | Other | | |
| 6 | Payment In Lieu of Taxes (Transfer) | | |
| 7 | **Total** | (sum lines 1-6) | **$** - |

| | | | |
|---|---|---|---|
| Formula Rate Template | | | |
| Heartland Consumers Power District | | | |
| Worksheet I, Account 454 | | | |
| For the 12 Months Ending December 31, 20XX | | | |
| | | | |
| **Line** | | | |
| **No.** | **Description** | **Source** | **Amount** |
| | (a) | (b) | (c) |
| | | | |
| | **Account 454 (Rent from Electric Property)** | | |
| 1a | Use of pro-rata share of 110 MW of transmission access on MBPP west-side transmsision system | | |
| 1XX | XXXXX | | $ - |
| 2 | **Total Account 454** | (sum lines 1a-1XX) | **$ -** |

| | | | |
|---|---|---|---|
| Formula Rate Template | | | |
| Heartland Consumers Power District | | | |
| Worksheet J, Excluded Transmission Plant and Expenses | | | |
| For the 12 Months Ending December 31, 20XX | | | |
| | | | |
| Line | | | |
| No. | Description | Source | Amount |
| | (a) | (b) | (c) |
| | | | |
| | **OATT Ancillary Services** | | |
| | Transmission Plant Included in OATT Ancillary Services | | |
| 1a | Generator step-up facilities at Laramie River Station (Note A) | | |
| 1.XX | | | $ - |
| 2 | Total Transmission Plant Included in OATT Ancillary Services | (sum lines 1a-1.XX) | $ - |
| | | | |
| | Expenses Included in OATT Ancillary Services | | |
| 3a | XXXXX | | $ - |
| 3.XX | XXXXX | | $ - |
| 4 | Total Expenses Included in OATT Ancillary Services | (sum lines 3a-3.XX) | $ - |
| | | | |
| | **Transmission Plant Excluded from ISO Rates** | | |
| 5a | Transmission Project II (TP-II) (Note B) | | |
| 5b | MBPP - NPPD System Upgrades (Note C) | - | - |
| 6 | Total Transmission Plant Excluded from ISO Rates | (sum lines 5a-5.XX) | $ - |
| | | | |
| | | | |
| Notes | | | |
| A | This amount represents the step-up transmission facilities associated with the Laramie River Station. | | |
| B | These transmission assets are on the HCPD balance sheet until 2017 but the transmisssion assets are | | |
| | paid for by East River so are not includable in the HCPD ATRR. | | |
| C | This amount represents the Heartland's portion of the payments required to Nebraska Public Power | | |
| | District (NPPD) for improvements to their system through the Missouri Basin Power Project. NPPD | | |

| | | | |
|---|---|---|---|
| | has ownership and the asset is not eligible for rate recovery. | | |

Worksheet K

Page 1 of 4

Formula Rate Template

Heartland Consumers Power District

Worksheet K, Actuals Page 1 of 4

For the 12 Months Ending December 31, 20XX

| Line No. | | Description | Source | Total Amount | | Allocator | | | Allocated Amount (col. c * col. d) |
|---|---|---|---|---|---|---|---|---|---|
| | | (a) | (b) | (c) | | (d) | | | (e) |
| 1 | | **GROSS REVENUE REQUIREMENT** | Page 2, line 22, column e | | | | | | **$ -** |
| | | **REVENUE CREDITS (Note Q)** | | Total | | Allocator | | | |
| 2 | | Account No. 454 | | $ - | | TP | 0.00% | | $ - |
| 3 | | Account No. 456 | | | | TP | 0.00% | | $ - |
| 4 | | Revenues from Grandfathered Interzonal Transactions | | $ - | | TP | 0.00% | | $ - |
| 5 | | Revenues from service provided by the ISO at a discount | | $ - | | TP | 0.00% | | $ - |
| 6 | | **TOTAL REVENUE CREDITS** | (sum lines 2-5) | | | | | | **$ -** |
| 6a | | Total True-Up Amount | | | | | | | $ - |
| 6b | | True-Up Interest | | | | | | | $ - |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | | **NET REVENUE REQUIREMENT** | (line 1 - line 6 + line 6a + line 6b) | | | | | | **$ -** | | |
| | | | | | | | | | | | |
| | | **DIVISOR (Note R)** | | | | | | | | | |
| 8 | | Average of 12 coincident system peaks for requirements (RQ) service | | | | | | (Note A) | - | | |
| 9 | | Plus 12 CP of firm bundled sales over one year not in line 8 | | | | | | (Note B) | - | | |
| 10 | | Plus 12 CP of Network Load not in line 8 | | | | | | (Note C) | - | | |
| 11 | | Less 12 CP of firm P-T-P over one year (enter negative) | | | | | | (Note D) | - | | |
| 12 | | Plus Contract Demand of firm P-T-P over one year | | | | | | | - | | |
| 13 | | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note P) | | | | | | | - | | |
| 14 | | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | | | | - | | |
| 15 | | **Divisor** | (sum lines 8-14) | | | | | | **0** | | |
| | | | | | | | | | | | |
| | | | | | | Worksheet K | | | | | |
| | | | | | | | | Page 2 of 4 | | | |
| | | | | | | | | | | | |

Formula Rate Template

Heartland Consumers Power District

Worksheet K, Actuals Page 2 of 4

For the 12 months ending 12/31/20xx

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | | | | **Total** | | | | | **Amount** | | |
| **No.** | | **Description** | **Source** | **Amount** | | **Allocator** | | | (col. c * col. d) | | |
| | | (a) | (b) | (c) | | (d) | | | (e) | | |
| | | | | | | | | | | | |
| | | **O&M (Note R)** | | | | | | | | | |
| 1 | | Transmission | | $ - | | TE | 0.00% | | $ - | | |
| 1a | | Less LSE Expenses included in Transmission O&M Accounts (Note S) | | $ | | N | 0.00% | | $ | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | - | | A | | | - | | |
| 2 | | Less Account 565 | | $ - | | TE | 0.00% | | $ - | | |
| 3 | | **A&G** | | $ - | | W/S | 0.00% | | $ - | | |
| 4 | | Less FERC Annual Fees | | $ - | | W/S | 0.00% | | $ - | | |
| 5 | | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F) | | $ - | | W/S | 0.00% | | $ - | | |
| 5a | | Plus Transmission Related Reg. Comm. Exp. (Note F) | | $ - | | TE | 0.00% | | $ - | | |
| 6 | | Common | | $ - | | CE | 0.00% | | $ - | | |
| 7 | | Transmission Lease Payments | | $ - | | DA | 100.00% | | $ - | | |
| 8 | | **TOTAL O&M** | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | **$ -** | | | | | **$ -** | | |
| | | | | | | | | | | | |
| | | **DEBT SERVICE (Note R)** | | | | | | | | | |
| 9 | | Debt Service (Note T) | | $ - | | DA | 100.00% | | $ - | | |
| 10 | | Amortization of premium or discount (Note U) | | | | | | | | | |
| 10a | | Account 428 Amortization of Debt Discount and Expense | | $ - | | GP | 0.00% | | $ - | | |
| 10b | | Account 429 Amortization of Premium on Debt | | $ - | | GP | 0.00% | | $ - | | |
| 11 | | **TOTAL DEBT SERVICE** | (line 9 + line 10a + line 10b) | **$ -** | | | | | **$ -** | | |
| | | | | | | | | | | | |
| | | **TAXES OTHER THAN INCOME TAXES (Notes G and R)** | | | | | | | | | |
| | | LABOR RELATED | | | | | | | | | |
| 12 | | Payroll | | $ - | | W/S | 0.00% | | $ - | | |
| 13 | | Highway and vehicle | | $ - | | W/S | 0.00% | | $ - | | |
| 14 | | PLANT RELATED | | | | | | | | | |
| 15 | | Property | | $ - | | GP | 0.00% | | $ - | | |
| 16 | | Gross Receipts | | $ - | | NA | 0.00% | | $ - | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 17 | | Other | | $ - | | GP | 0.00% | | $ - | | |
| 18 | | Payments in lieu of taxes | | $ - | | GP | 0.00% | | $ - | | |
| 19 | | **TOTAL OTHER TAXES** | (sum lines 12, 13, 15, 16, 17, 18) | **$ -** | | | | | **$ -** | | |
| | | | | | | | | | | | |
| 20 | | **SUBTOTAL** | (sum lines 8, 11, 19) | $ - | | | | | $ - | | |
| | | | | | | | | | | | |
| 21 | | **MARGIN REQUIREMENT (Note H)** | | $ - | | DA | 100.00% | | $ - | | |
| | | | | | | | | | | | |
| 22 | | **REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT H** | (line 20 + line 21) | **$ -** | | | | | **$ -** | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | Worksheet K |
| | | | | | | | | | | | Page 3 of 4 |
| | | | | | | | | | | | |

Formula Rate Template

Heartland Consumers Power District

Worksheet K, Actuals Page 3 of 4

For the 12 months ending 12/31/20xx

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | | | | **Total** | | | | | **Transmission** | | |
| **No.** | | **Description** | **Source** | **Amount** | | **Allocator** | | | (col. c * col. d) | | **Other** |
| | | (a) | **(b)** | (c) | | (d) | | | (e) | | (f) |
| | | | | | | | | | | | |
| | | **GROSS PLANT IN SERVICE (Note V)** | | | | | | | | | |
| 1 | | Production | | $ - | | NA | 0.00% | | $ - | | |
| 2 | | Transmission | | $ - | | TP | 0.00% | | $ - | | |
| 3 | | Distribution | | $ - | | NA | 0.00% | | $ - | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | | General | | $ - | | W/S | 0.00% | | $ - | | |
| 4a | | Intangible | | $ - | | W/S | 0.00% | | $ - | | |
| 5 | | Common | | $ - | | CE | 0.00% | | $ - | | |
| 6 | | **TOTAL GROSS PLANT** | (sum lines 1-5) | $ - | | GP= | 0.00% | | $ - | | |
| | | | | | | | | | | | |
| | | **TRANSMISSION PLANT INCLUDED IN ISO RATES** | | | | | | | | | |
| | | | | | | | | | | | |
| 7 | | Total transmission plant | | | | | | | $ - | | |
| 8 | | Less transmission plant excluded from ISO rates (Notes J and V) | | | | | | | $ - | | |
| 9 | | Less transmission plant included in OATT Ancillary Services (Notes K and V ) | | | | | | | $ - | | |
| 10 | | **Transmission plant included in ISO rates** | (line 7 less lines 8 and 9) | | | | | | **$ -** | | |
| | | | | | | | | | | | |
| 11 | | Percentage of transmission plant included in ISO Rates | (line 10 / line 7) | | | | | TP= | 0.00% | | |
| | | | | | | | | | | | |
| | | **TRANSMISSION EXPENSES (Note R)** | | | | | | | | | |
| | | | | | | | | | | | |
| 12 | | Total transmission expenses | (page 2, line 1, column 3) | | | | | | $ - | | |
| 13 | | Less transmission expenses included in OATT Ancillary Services (Note I) | | | | | | | $ - | | |
| 14 | | Included transmission expenses | (line 12 less line 13) | | | | | | $ - | | |
| | | | | | | | | | | | |
| 15 | | Percentage of transmission expenses after adjustment | (line 14 / line 12) | | | | | | 0.00% | | |
| 16 | | Percentage of transmission plant included in ISO Rates | (line 11) | | | | | TP | 0.00% | | |
| 17 | | Percentage of transmission expenses included in ISO Rates | (line 15 * line 16) | | | | | TE= | 0.00% | | |
| | | | | | | | | | | | |
| | | **WAGES & SALARY ALLOCATOR (W&S) (Note L)** | | | | | | | | | |
| | | | | | | | Allocation | | W&S Allocator | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | $ | | | (col.c / line 22a) | | ($ / Allocation) | | | |
| 18 | | Production | | $ - | | | 0.00% | | | | | |
| 19 | | Transmission | | $ - | | | 0.00% | = | 0.00% | | | |
| 20 | | Distribution | | $ - | | | 0.00% | | | | | |
| 21 a | | Customer Accounts | | $ - | | | 0.00% | | | | | |
| 21 b | | Customer Service & Information | | $ - | | | 0.00% | | | | | |
| 22 a | | **Total** | (sum lines 18-21b) | $ - | | | 0.00% | | | | | |
| | | | | | | | | | | | | |
| 22 b | | Administrative & General | | $ - | | | | | | | | |
| | | | | | | | | | | | | |
| | | **COMMON PLANT ALLOCATOR (CE) (Note M)** | | | | | % Electric | | Labor Ratio | | | |
| | | | | **Amount** | | | (line 23 / line 26) | | (line 19) | | | |
| 23 | | Electric | | $ - | | | | | | | | CE |
| 24 | | Gas | | $ - | | | 0.00% | * | 0.00% | = | 0.00% | |
| 25 | | Water | | $ - | | | | | | | | |
| 26 | | **Total** | (sum lines 23-25) | $ - | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | **REVENUE CREDITS (Note R)** | | | | | | | | | | |
| | | | | | | | | | Load | | | |
| | | **ACCOUNT 447 (SALES FOR RESALE)** | | | | | | | | | | |
| 31 | | a. Bundled Non-RQ Sales for Resale (Note N) | | $ - | | D A | 100.00% | | $ - | | | |
| 32 | | b. Bundled Sales for Resale included in Divisor on page 1 | | $ - | | D A | 100.00% | | $ - | | | |
| 33 | | **Total** | (line 31 less line 32) | | | | | | $ - | | | |
| | | | | | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 34 | | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O) | | $ - | | D A | 100.00% | | $0 | | |
| | | | | | | | | | | | |
| | | ACCOUNT 456 (OTHER ELECTRIC REVENUES) | | | | | | | | | |
| 35 | | a. Transmission charges for all transmission transactions | | $0 | | D A | 100.00% | | $0 | | |
| 36 | | b. Transmission charges for all transmission transactions included in Divisor on page 1 | | $0 | | D A | 100.00% | | $0 | | |
| 37 | | Total of (a)-(b) | (line 35 less line 36) | $ - | | | | | $0 | | |
| | | | | | | | | | | | |
| | | | | Worksheet K | | | | | | | |
| | | | | Page 4 of 4 | | | | | | | |
| | | | | | | | | | | | |
| Formula Rate Template | | | | | | | | | | | |
| Heartland Consumers Power District | | | | | | | | | | | |
| Worksheet K, Actuals Page 4 of 4 | | | | | | | | | | | |
| For the 12 months ending 12/31/20xx | | | | | | | | | | | |
| | | | | | | | | | | | |
| No te | | | | | | | | | | | |
| Let ter | | | | | | | | | | | |
| A | | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. | | | | | | | | | |
| | | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for | | | | | | | | | |
| | | this service in its system resource planning). | | | | | | | | | |
| B | | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable | | | | | | | | | |
| | | even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" | | | | | | | | | |
| | | for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. | | | | | | | | | |
| | | LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. | | | | | | | | | |
| C | | LF as defined above at time of applicable pricing zone coincident monthly peaks. | | | | | | | | | |
| D | | LF as defined above at time of applicable pricing zone coincident monthly peaks. | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| E | | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any. | | | | | | | | |
| F | | Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety | | | | | | | | |
| | | related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, | | | | | | | | |
| | | ISO filings, or transmission siting. | | | | | | | | |
| G | | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. | | | | | | | | |
| | | Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula | | | | | | | | |
| | | Template, since they are recovered elsewhere. | | | | | | | | |
| H | | The Margin Requirement is the margin the utility uses in calculating rates applicable to its native load sales. The Margin Requirement | | | | | | | | |
| | | Heartland uses is based on the Fixed Charge Coverage Ratio ("FCCR") approved for use in setting rates by the Heartland Board of Directors. | | | | | | | | |
| | | Heartland's Margin Requirement is fixed at 20% and will not be changed absent a Section 205 filing. | | | | | | | | |
| I | | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.1, 561.2, | | | | | | | | |
| | | 561.3 and 561.BA. | | | | | | | | |
| J | | Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test | | | | | | | | |
| | | For Heartland this amount represents the step-up transmission facilities associated with the Laramie River Station. | | | | | | | | |
| K | | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, | | | | | | | | |
| | | which are deemed to included in OATT ancillary services. For Heartland, these amounts are related to TP II - East River facilities and improvements made to | | | | | | | | |
| | | to Nebraska Public Power District's transmission system through the Missouri Basin Power Project. These transmission assets are | | | | | | | | |
| | | on the HCPD balance sheet until 2017 but the transmisssion assets are paid for by East River so are not includable in the HCPD ATRR. | | | | | | | | |
| L | | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S | | | | | | | | |
| | | allocator at page 3, line 23 equal to the amount of transmission plant includable in ISO rates divided by the sum of total gross production, | | | | | | | | |
| | | transmission, and distribution plant. All of Heartland's employees are assigned to A&G. After 2017 there will be no amount included from TP II on this line. | | | | | | | | |
| | | assigned to A&G. After 2017 there will be no amount included from TP II on this line. | | | | | | | | |
| M | | Enter dollar amounts. | | | | | | | | |
| N | | Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account | | | | | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | No. 456 and all other uses are to be included in the divisor. | | | | | | | | | |
| O | | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. | | | | | | | | | |
| P | | Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 | | | | | | | | | |
| | | and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate | | | | | | | | | |
| | | pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1. | | | | | | | | | |
| Q | | The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) | | | | | | | | | |
| | | or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include | | | | | | | | | |
| | | revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct | | | | | | | | | |
| | | assignment facilities and GSUs) which are not recovered under this Rate Formula Template. | | | | | | | | | |
| R | | Calculated using end of year projected amounts. | | | | | | | | | |
| S | | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. | | | | | | | | | |
| | | revenue requirements. | | | | | | | | | |
| T | | Debt service calculation is supported by the debt service work paper and is comprised of the gross plant allocator portion of the Heartland long-term | | | | | | | | | |
| | | debt plus the transmission-related portion of the debt service for the Public Power Generation Agency payments. The work paper calculates | | | | | | | | | |
| | | the transmission only debt service that is entered on line 9, page 2 0f 4 so it is 100% directly assigend to the ATRR. | | | | | | | | | |
| U | | Includes amounts recorded to accounts 428 and 429. | | | | | | | | | |
| V | | Calculated using 13 month average balance. Gross Plant in Service amounts exclude Asset Retirement Obligation amounts unless | | | | | | | | | |
| | | authorized by FERC. | | | | | | | | | |

Formula Rate Template

Heartland Consumers Power District

Worksheet L, True Up Calculation

For the 12 Months Ending December 31, 20XX

| Line No. | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| | 20XX | | 20XX | | 20XX | | | |
| 1 | Historic Year | | Historic Year | | Residual ATRR | | Historic Year | |
| | Actual ATRR | | Projected ATRR | | True-Up Amount | | ATRR True-Up | |
| 2 | $ - | - | $ - | + | $ - | = | $ - | |

**Calculated Interest on True-Up Refunds or Surchages**

| | Quarter | Year | Over (Under) Recovery Plus Interest | Quarter | Average Monthly Interest Rate | Calculated Quarterly Interest | Amortization | Refund (Surcharge) Owed |
|---|---|---|---|---|---|---|---|---|
| | | | | | 0.00000% | | | |
| | | | | | (Note A) | | | |
| | | | | | | **Quarterly** | | |
| 3 | First | | $ - | 4 | 0.00000% | $ - | | $ - |
| 4 | Second | | $ - | 3 | 0.00000% | $ - | | $ - |
| 5 | Third | | $ | 2 | 0.00000% | $ | | $ |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | - | | | | | | - | | | | | - |
| 6 | | Fourth | | | | $ - | | 1 | | 0.00000% | | $ - | | | | | $ - |
| 7 | | | | | | | | | | | | $ - | | | | | $ - |
| | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | **Quarterly** | | | | | |
| 8 | | First | | | | $ - | | 4 | | 0.00000% | | $ - | | | | | $ - |
| 9 | | Second | | | | $ - | | 3 | | 0.00000% | | $ - | | | | | $ - |
| 10 | | Third | | | | $ - | | 2 | | 0.00000% | | $ - | | | | | $ - |
| 11 | | Fourth | | | | $ - | | 1 | | 0.00000% | | $ - | | | | | $ - |
| | | | | | | | | | | | | | | | | | |
| | | **Over (Under Recovery) Plus Interest Amortized and Recovered Over 12 Months** | | | | | | | | | | **Quarterly** | | | | | |
| 12 | | First | | | | $ - | | | | 0.00000% | | $ - | | | $ - | | $ - |
| 13 | | Second | | | | $ - | | | | 0.00000% | | $ - | | | $ - | | $ - |
| 14 | | Third | | | | $ - | | | | 0.00000% | | $ - | | | $ - | | $ - |
| 15 | | Fourth | | | | $ - | | | | 0.00000% | | $ - | | | $ - | | $ - |
| 16 | | | | | | | | | | | | $ - | | | | | |
| | | | | | | | | | | | | | | | | | |
| 17 | | Total Amount of True-Up Adjustment | | | | | | | | | | | | | $ - | | |
| 18 | | Less Over (Under) Recovery | | | | | | | | | | | | | $ - | | |
| 19 | | Total Interest | | | | | | | | | | | | | $ - | | |
| | | | | | | | | | | | | | | | | | |
| Notes: | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | |
| A | | Interest payable will be calculated using an average interest rate for the twenty-four (24) months during which the over- or under-recovery in the ATRR | | | | | | | | | | | | | | | |
| | | or load volume changes exists. Interest will be compounded quarterly. Interest on any under-recovery of the ATRR or any under-recovery due to load | | | | | | | | | | | | | | | |
| | | volume changes will be based on the annual average of the one-month London Interbank Offer Rate (LIBOR) plus 135 basis points, capped at the applicable Commission | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | refund interest rate. | | | | | | | | | | | | | |

# HEARTLAND CONSUMERS POWER DISTRICT
# FORMULA RATE IMPLEMENTATION PROTOCOLS

## Section I. Applicability

The following procedures shall apply to Heartland Consumers Power District's ("Heartland") calculation of its annual transmission revenue requirement ("ATRR"), True-Up Adjustment, and Projected ATRR. The ATRR shall be determined for January 1 to December 31 of a given calendar year (the "Rate Year"). The Formula Rate Template shall become effective for recovery of Heartland's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission ("Commission") under Section 205 of the Federal Power Act ("FPA"). The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the FPA.

## Section II. Annual True-Up and Projected ATRR

A. Beginning on or before June 1, 2016, and on or before each subsequent June 1, Heartland shall determine its Annual True-Up pursuant to these Protocols, to derive a True-Up Adjustment to be included in Heartland's projected ATRR ("Projected ATRR") for the subsequent Rate Year.

B. On or before June 1, 2016, and on or before each subsequent June 1, Heartland shall post its Annual True-Up, actual ATRR, and True-Up Adjustment at a publicly accessible location on the SPP OASIS. Within ten business days after the OASIS posting of its Annual True-Up, Heartland shall notify Interested Parties via the SPP email exploder titled "Formula Rate Posting Information Notification" of the website address where such information is posted.

C. On or before October 1, 2015, and on or before each subsequent October 1, Heartland shall provide its Projected ATRR to SPP and post such information at a publicly accessible location on the SPP OASIS. Within ten business days after the OASIS posting of its Projected ATRR, Heartland shall notify Interested Parties via the SPP email exploder titled "Formula Rate Posting Information Notification" of the website address where such information is posted.

D. If the date for posting the Annual True-Up or the Projected ATRR falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the Projected ATRR will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

E. The Annual True-Up shall:

1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas intact;

2. Be based on Heartland's audited financial statements for the prior calendar year;

3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the Annual True-Up that are not otherwise available in audited financial statements, and provide a hyperlink (on SPP's OASIS) that redirects to that portion of Heartland's publicly accessible website where Heartland's audited financial statements are posted;

4. Identify all material adjustments made to the audited financial statements data in determining formula inputs;

5.Provide information sufficient such that Interested Parties may replicate the calculation.

6. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

a. Identify:

i. The initial implementation of an accounting standard or policy;
ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
iii. Correction of errors and prior period adjustments that affect the True-Up Adjustment calculation;
iv. The implementation of new estimation methods or policies that change prior estimates; and
v. changes to income tax elections (if applicable);

b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up;

d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

F. The Projected ATRR shall:

1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas intact;

2. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the Projected ATRR;

3. With respect to any Accounting Change:

a. Identify:

i. The initial implementation of an accounting standard or policy;
ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
iii. Correction of errors and prior period adjustments that impact the Projected ATRR calculation;
iv. The implementation of new estimation methods or policies that change prior estimates; and
v. Changes to income tax elections (if applicable);

b. Identify items included in the Projected ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Projected ATRR;

d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these protocols, a narrative explanation of the individual impact of such changes on the Projected ATRR.

G. Heartland shall hold an open meeting among Interested Parties (“Annual True-Up Meeting”) between the Publication Date and September 1 of each year. No less than seven (7) days prior to such Annual True-Up Meeting, Heartland shall provide notice on a publicly accessible location on of the SPP OASIS of the time, date, and location of the Annual True-Up Meeting. For purposes of these Protocols, the term “Interested Parties” includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall (i) permit Heartland to explain and clarify its Annual True-Up and True-Up Adjustment and (ii) provide Interested Parties an opportunity to seek information and clarifications from Heartland about the Annual True-Up and True-Up Adjustment. Heartland shall allow Interested Parties to participate in the Annual True-Up Meeting in person or via telephone or other remote access mechanism (e.g., webex).

H. Heartland shall hold an open meeting among Interested Parties between the date that the Projected ATRR is posted to the Heartland page on the SPP OASIS (as described in Section II.C of these protocols) and October 31 of each year (“Annual Projected Rate Meeting”). No less than seven (7) days prior to such Annual Projected Rate Meeting, Heartland shall provide notice at a publicly accessible location on the SPP OASIS of the time, date, and location of the Annual Projected Rate Meeting. The Annual Projected Rate Meeting shall (i) permit Heartland to explain and clarify its Projected ATRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from Heartland about the Projected ATRR. Heartland shall allow

Interested Parties to participate in the Annual Projected Rate Meeting in person or via telephone or other remote access mechanism (e.g., webex).

I. If Heartland constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of Joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via email no less than 7 days prior to such meeting.

**Section III. Information Exchange Procedures**

Each Annual True-Up and Projected ATRR shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until December 1 following the Publication Date (unless such period is extended with the written consent of Heartland or by FERC order) to serve reasonable information and document requests on Heartland ("Information Exchange Period"). If December 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) The extent or effect of an Accounting Change;

(2) Whether the Annual True-Up or Projected ATRR fails to include data properly recorded in accordance with these protocols;

(3) The proper application of the formula rate and procedures in these protocols;

(4) The accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or Projected ATRR;

(5) The prudence of actual costs and expenditures;

(6) The effect of any change to the underlying Uniform System of Accounts; or

(7) Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. Heartland shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Heartland shall respond to all information and document requests received on or before December 1 by no later than January 10 following the Publication Date, unless the Information Exchange Period is extended by Heartland or FERC.

C. Heartland will cause to be posted at a publicly accessible location on the SPP OASIS all information requests regarding Heartland ATRR in SPP from Interested Parties and Heartland's response(s) to such requests; except, however, if responses to information and document requests include material deemed by Heartland to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Heartland and the requesting party.

D. Heartland shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing Heartland's Annual True-Up or Projected ATRR.

**Section IV. Resolution of Issues and Challenges to Projected ATRR Update and/or Annual True-Up**

No later than January 10 of each year, any Interested Party may notify Heartland in writing of any specific challenge(s) to any component of the most recently posted Annual True-up and/or Projected ATRR ("Preliminary Challenge"). Within five (5) business days of receiving notice of such challenge(s), Heartland shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) at a publicly accessible location on the SPP OASIS. Heartland and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations. Any modification to the Annual True-up or the Projected ATRR that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the Projected ATRR and Annual True-up for the next Rate Year and incorporated into Heartland's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the Projected ATRR, such changes shall be incorporated into the Projected ATRR for the next rate year.

Heartland shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which Heartland agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the Projected ATRR or Annual True-up will result. If Heartland disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.

If Heartland and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of Heartland's response to the issue(s), senior management representatives of Heartland and the Interested Parties shall meet to try to resolve the issue(s).

If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, any Interested Party that has not resolved any Preliminary Challenge to an Annual True-up may then file with FERC a Formal Challenge to an Annual True-up pursuant to these Implementation Procedures ("Formal Challenge"). An Interested Party shall have until March 22 to file a Formal Challenge with FERC.

In any proceeding ordered by the FERC in response to a Formal Challenge raised under these Implementation Procedures, Heartland shall bear the burden of demonstrating the justness and reasonableness of the charges resulting from its application of the Formula Rate, and of proving that it properly applied the Formula Rate, properly calculated the challenged Projected ATRR or Annual True-up pursuant to the Formula Rate, and that adoption of any material change is just and reasonable. Nothing herein is intended to alter the burden applied by FERC with respect to prudence challenges.

**Section V. Changes to True-Up Adjustment or Projected ATRR**

Any changes to the data inputs, including but not limited to revisions as the result of any FERC proceeding to consider the Annual True-Up or Projected ATRR, or as a result of the procedures set forth herein, shall be incorporated into the Projected ATRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols. The fixed margin percentage of 20% set forth in Heartland's Formula Rate Template will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act.

**Section VI. Informational Filings**

By March 15 of each year, Heartland shall submit to FERC an informational filing ("Informational Filing") of its Projected ATRR for the Rate Year, including its Annual True-Up and True-Up Adjustment. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that Heartland has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Any challenges to the implementation of the Formula Rate must be made through the challenge procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing. Heartland shall provide notification of each Informational Filing through notification to the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

**Section VII. Calculation of True-Up Adjustment**

**True-Up Procedure**

The True-Up Adjustment will be determined in the following manner:

(1) Actual ATRR for the previous year shall be compared to the Projected ATRR for the same year ("True-Up Year") to determine any excess or shortfall in the Projected ATRR that was used for billing purposes in the True-Up Year. In addition, actual divisor load, the average 12 monthly coincident peaks ("12 CP") will be compared to the projected 12 CP and the difference multiplied by the rate calculated in the Formula Rate Template to determine any excess or shortfall in collection due load volume. The sum of the excess or shortfall due to the actual versus Projected ATRR and the excess or shortfall due to load volume will constitute the True-Up Adjustment. The True-Up Adjustment and related calculations will be posted at a publicly accessible location on the SPP OASIS no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the Heartland audited financial statements for the previous year, as set forth in Section II of these protocols.

(2) Interest on any over recovery of the ATRR or any over recovery due to load volume changes will be determined based on the Commission's regulation at 18 C.F.R. § 35.19a. Interest on any under recovery of the ATRR or any under recovery due to load volume changes will be based on the annual average of the one-month London Interbank Offer Rate ("LIBOR") plus 135 basis points capped at the applicable Commission refund interest rate. In either case, the interest payable will be calculated using an average interest rate for the twenty-four (24) months during which the over or under recovery in the ATRR or load volume changes exists. The interest amount (Page 1, Line 6i of Attachment H- Heartland) will be included in the projected costs made available by October 1 in accordance with Section II.C above.

(3) The ATRR for transmission services for the following year shall be the sum of the Projected ATRR for the following year, plus or minus the True-Up Adjustment (sum of Page 1, Lines 6+6c-6h+6i of Attachment H- Heartland) from the previous year, if any, including interest as explained above.

(4) Heartland may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

**Example True-Up of 2012 ATRR:**
Projected ATRR was $7,000,000, projected load was 600,000 kW.
Actual 2016 net ATRR calculated based on the Formula Rate Template data available in
June 2017 is $6,800,000, actual 12 CP load is 580,000 kW. The rate calculated in the Formula Rate Template to determine any excess or shortfall in collection due load volume = $15 per kW-yr

**True-Up Calculation:**
There is an over recovery of the ATRR equal to $200,000 ($7,000,000 - $6,800,000 = $200,000).
There is a $300,000 shortfall in revenue collection due to volume
((600,000 kW – 580,000 kW) x $15.00 per kW-yr = $300,000).
The total True-Up Adjustment amount would be a net under recovery of $100,000 ($300- 000 - $200,000 = $100,000), which would be applied as an increase to the 2018 Projected ATRR beginning January 2018.

# ADDENDUM 24 TO ATTACHMENT H

**Missouri River Energy Services**

**12 Months Ended December 31, 20XX** **20XX**

**13 Months Ended December 31, 20XX** **20XX**



# Missouri River Energy Services

Formula Rate Template for SPP Zone 19 Transmission Index

Projected 12 Months Ended December 31, 20XX

| Line No | Schedule | Description | Updated? |
|---|---|---|---|
| 1 | Attachment H | ATRR Calculation | |
| 2 | Schedule 1 | SPP Directed ATRR | |
| 3 | Schedule 2 | Attachment MM ATRR (MISO) | |
| 4 | Schedule 3 | Attachment GG ATRR (MISO) | |
| 5 | Schedule 4 | SPP Directed Plant | |
| 6 | Schedule 5 | Plant Balances | |
| 7 | Schedule 6 | CWIP | |
| 8 | Schedule 7 | Bond Proceeds | |
| 9 | Schedule 8 | Transmission O&M | |
| 10 | Schedule 9 | A&G | |
| 11 | Schedule 10 | Other Expense and Income | |
| 12 | Schedule 11 | Interest Rates | |
| 13 | Schedule 12 | True-up | |

Key:

= Shaded Value (Denotes Manual Input)

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H: ATRR Summary

12 Months Ended December 31, 20XX

| Line No. | (1) Description | (2) Reference | (3) Total Company $ | (4) Allocator #1 | (5) | (6) Total Transmission $ | (7) Allocator #2 | (8) Zone 19 (UMZ) Transmission $ | (9) MISO Transmission $ |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Gross Revenue Requirement** | **Page 2, line 27** | **-** | | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| | **Revenue Credits** | | | | | | | | |
| 2 | Account No. 454 | Schedule 10, line 15 | - | DA100 | 100.000% | - | Direct Assign | - | - |
| 3 | Account No. 456 | Schedule 10, line 20 | - | DA100 | 100.000% | - | Direct Assign | - | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | Schedule 10, line 27 | - | DA10 | 100. | - | Direct As | - | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | 0 | 0 0 % | | sign | | |
| 5 | Revenues from service provided by the ISO at a discount | Schedule 10, line 28 | - | DA 100 | 100.00% | - | Direct Assign | - | - |
| 6 | **Total Revenue Credits** | **sum lines 2-5** | | | | **-** | | **-** | **-** |
| 7 | MISO Attachment GG ATRR | Schedule 3, page 2, line 2, col 10 | #DIV/0! | DA 100 | 100.00% | #DIV/0! | 100% MISO | - | #DIV/0! |
| 8 | MISO Attachment MM ATRR | Schedule 2, page 2, line 2, col 14 | #DIV/0! | DA 100 | 100.00% | #DIV/0! | 100% MISO | - | #DIV/0! |
| 9 | ATRR for SPP Directed Projects | Schedule 1, page 2, line 2, col 9 | #DIV/0! | DA 100 | 100.00% | #DIV/0! | 100% UMZ | #DIV/0! | - |
| 10 | **Total Reductions** | **sum lines 7-9** | | | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| 11 | Historic Year True-Up (Including Interest) | Schedule 12, line 6 | | | | - | Direct Assign | - | - |
| 12 | **Net Revenue Requirement** | **line 1 - line 6 - line 10 + line** | | | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |

**11**



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H: ATRR Summary

12 Months Ended December 31, 20XX

| Line No. | (1) Description | (2) Reference | (3) Total Company $ | (4) Allocator #1 (Note H) | (5) | (6) Total Transmission $ | (7) Allocator #2 (Note H) | (8) Zone 19 (UMZ) Transmission $ | (9) MISO Transmission $ |
|---|---|---|---|---|---|---|---|---|---|
| | **O&M Expense** | | | | | | | | |
| 1 | Transmission O&M Expense | Schedule 8, line 31 | - | DA100 | 100.000% | - | DA&Allocated | #DIV/0! | #DIV/0! |
| 2 | Less LSE Expenses included in Transmission O&M Accounts (Note I) | Schedule 8, line 32 | - | DA100 | 100.000% | - | Direct Assign | #DIV/0! | #DIV/0! |
| 3 | Less transmission expenses included in OATT Ancillary Services (Note J) | Schedule 8, lines 5, 6, 7 | - | DA100 | 100.000 | - | Direct Assign | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | % | | | | |
| | | | | DA | 100. | | Direct | | |
| 4 | Less Account 565 | Schedule 8, line 16 | - | 100 | 000% | - | Assign | #DIV/0! | #DIV/0! |
| 5 | **Total Transmission O&M Expense** | **line 1 less lines 2, 3, 4** | **-** | | | **-** | | **#DIV/0!** | **#DIV/0!** |
| | **A&G Expense** | | | | | | | | |
| 6 | A&G - MBPP | Schedule 9, line 15, col 4 & line 24, col 3 | - | Direct | Assign | #DIV/0! | Direct Assign | #DIV/0! | #DIV/0! |
| 7 | A&G - Other | Schedule 9, line 15, col 5 | - | W/S | #DIV/0! | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 8 | Less FERC Annual Fees | Schedule 9, line 16 | - | W/S | #DIV/0! | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 9 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note A) | Schedule 9, line 17 | - | W/S | #DIV/0! | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 10 | Plus Transmission Related Reg. Comm. Exp. (Note A) | Schedule 9, line 18 | - | DA100 | 000% | - | Allocated | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 11 | **Total A&G Expense** | **line 6 + line 7 + line 10 less lines 8, 9** | **-** | | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| 12 | Common Expense | Schedule 10, line 2 | - | CE | #DIV/0! | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 13 | Transmission Lease Payments | Schedule 10, line 3 | - | DA1000 | 100.000% | - | Direct Assign | - | - |
| 14 | **Subtotal O&M Expense** | **sum lines 5, 11, 12, 13** | **-** | | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| | **Annual Debt Service** | | | | | | | | |
| 15 | Annual Principal | MRES Annual Report | - | NP1 | #DIV/0! | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 16 | Annual Interest | MRES Annual Report | - | NP1 | #DIV/0! | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 17 | **Total Annual Debt Service** | **sum lines 15-16** | **-** | | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| | **Taxes Other than Income Taxes (Note B)** | | | | | | | | |
| | LABOR RELATED | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 18 | Payroll | Schedule 10, line 4 | - | W/S | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| 19 | Highway and vehicle | Schedule 10, line 5 | - | W/S | #DIV/0! | Allocated | #DIV/0! | #DIV/0! |
| | PLANT RELATED | | | | | | | |
| 20 | Property | Schedule 10, line 10 | - | Direct Assign | - | DA & Allocated | - | - |
| 21 | Gross Receipts | Schedule 10, line 11 | - | Direct Assign | - | Allocated | #DIV/0! | #DIV/0! |
| 22 | Other | Schedule 10, line 12 | - | Direct Assign | - | Allocated | #DIV/0! | #DIV/0! |
| 23 | Payments in lieu of taxes | Schedule 10, line 13 | - | Direct Assign | - | Allocated | #DIV/0! | #DIV/0! |
| 24 | **Total Taxes Other than Income Taxes** | **sum lines 18, 19, 20-23** | **-** | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| 25 | **Subtotal** | **sum lines 14, 17, 24** | **-** | | **#DIV/0!** | | **#DIV/0!** | **#DIV/0!** |
| 26 | Margin Requirement (Note C) | line 17 * 90% | - | | #DIV/0! | | #DIV/0! | #DIV/0! |
| 27 | **Gross Revenue Requirement** | **line 25 + line** | **-** | | **#DIV/** | | **#DIV/** | **#DIV/** |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **26** | | | **0!** | **0!** | **0!** |



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H: ATRR Summary

12 Months Ended December 31, 20XX

| **Line No.** | (1) **Description** | (2) **Reference** | (3) **Total Company $** | (4) **Allocator #1** | (5) | (6) **Total Transmission $** |
|---|---|---|---|---|---|---|
| | **Transmission Plant Included in ISO Rates** | | | | | |
| 1 | Total transmission plant (Note D) | Schedule 5, line 14, col 5 + col 6 | - | DA100 | 100.000% | - |
| 2 | Less transmission plant excluded from ISO rates (Note E) | Schedule 5, line 14, col 25 + 26 | - | DA100 | 100.000% | - |
| 3 | Less transmission plant included in OATT Ancillary Services (Note F) | Schedule 5, line 14, col 27 + 28 | - | DA100 | 100.000% | - |
| 4 | **Total Transmission plant included in ISO rates** | **line 1 less** | **0** | | | **0** |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | **lines 2, 3** | | | | | |
| 5 | Percentage of Transmission Plant included in ISO Rates (TP) | line 4 / line 1 | | | | **0.00%** | **= TP** |
| | **Wages & Salaries** | | | | | | |
| 6 | Production | Schedule 10, line 22 | - | DA | 0.00% | - | |
| 7 | Transmission | Schedule 10, line 23 | - | TP | 0.00% | - | |
| 8 | Distribution | Schedule 10, line 24 | - | DA | 0.00% | - | |
| 9 | Other | Schedule 10, line 25 | - | DA | 0.00% | - | |
| 10 | **Total Wages & Salaries** | **sum lines 6-9** | **-** | | | **-** | |
| 11 | Wages & Salaries Allocator (W/S) | (line 10, col 6) / (line 10, col 3) | | | | **#DIV/0!** | **= W/S** |
| | **Common Allocator** | | | | | | |
| 12 | Electric | Schedule 5, line 14, col 11 | - | W/S | #DIV/0! | #DIV/0! | |
| 13 | Gas | | - | DA | 0.0 | - | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | 0% | | |
| | | | | | | 0. | | |
| | | | | | D | 00 | | |
| 14 | Water | | - | | A | 00% | - | |
| 15 | **Total Plant** | **sum lines 12-14** | **-** | | | | **#DIV/0!** | |
| 16 | Common Expense Allocator (CE) | (line 15, col 6) / (line 15, col 3) | | | | | **#DIV/0!** | **= CE** |
| | **Net Plant Allocator for Debt Service** | | | | | | | |
| | | | | | | 100. | | |
| | | Schedule 5, line 42, col | | | D | 00. | | |
| 17 | Transmission Net Plant in Service | 5 + col 6 | - | | A | 100% | - | |
| | | Schedule 5, line 42, col | | | | 0. | | |
| 18 | Production Net Plant in Service | 3 + col 4 | - | | D | 00% | - | |
| | | | | | | 100. | | |
| | | Schedule 6, line | | | D | 00. | | |
| 19 | Transmission CWIP, Excluding Retainage (Note G) | 14, col 10 | - | | A | 100% | - | |
| | | Schedule 6, line | | | | 0. | | |
| 20 | Production CWIP, Excluding Retainage (Note G) | 14, col 13 | - | | D | 00% | - | |
| | | Schedule 7, line | | | | 0. | | |
| 21 | Bond Proceeds for New Generation on Deposit (Note G) | 14, col 3 | - | | D | 00% | - | |
| 22 | **Total Net Plant** | **sum** | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 2 | | **lines 17-21** | **-** | **-** | |
| 2<br>3 | Net Plant Allocator for Debt Service (NP1) | (line 22, col 6) / (line 22, col 3) | | **#DIV/0!** | **= NP1** |



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H: ATRR Summary

12 Months Ended December 31, 20XX

Notes:

A Line 9 contains EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 10 contains Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting.

B Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

C MRES' Margin Requirement is dollar figure equal to a percentage (referred to as the margin ratio) of the annual total of actual debt service payments made by MRES. MRES' margin ratio is fixed at 90% and cannot be changed absent a FERC order. MRES' margin ratio is based on the Debt Service Coverage Ratio ("DSC") charged to MRES' native load.

D Calculated using 13 month average balance. Gross Plant in Service

amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. MRES follows the Zone 19 (Upper Missouri Zone) Attachment AI Guidance Document as outlined in the Settlement Agreement filed in ER15-1943 for facilities which costs are recovered via this template. In the event that SPP revises and the Commission approves revisions to Attachment AI and the revised version of Attachment AI conflicts with the guidance document, Attachment AI shall govern. In the event that the Commission issues a decision on the merits as to what constitutes a Transmission Facility under Attachment AI and that decision conflicts with the guidance document, the Commission decision shall govern.

E Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until EIA 412 balances are adjusted to reflect application of seven-factor test).

F Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

G Bond proceeds represent the amount of the 2014 debt issue for new projects that had not been expended at the end of each month. The bond proceeds on deposit have been included in the production plant since the vast majority of the proceeds are expected to utilized for additions to production plant. CWIP is included in the debt service allocator because the amounts included in CWIP were financed by bond proceeds and the annual debt service amount includes all bond proceeds, including those used to finance CWIP.

H "Direct Assign" and "DA & Allocated" items use the allocation noted in the referenced schedule; "Allocated" items are based off a Net or Gross Plant Allocator between SPP and MISO as calculated on Schedule 5, Page 5.

I Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

J Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including

Account Nos. 561.1, 561.2, 561.3, and 561.BA.

**Missouri River Energy Services**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1: SPP Directed ATRR
12 Months Ended December 31, 20XX

| Line No. | (1) Description | (2) Source | (3) UMZ (Zone 19) Transmission $ |
|---|---|---|---|
| 1 | Gross Transmission Plant (Note A) | Schedule 5, line 14, col 15,16 + Schedule 6 line, 14, col 8,9 | - |
| 2 | Transmission Plant Accumulated Depreciation | Schedule 5, line 28, col 15,16 | - |
| 3 | **Net Transmission Plant (Note B)** | **line 1 less line 2** | **-** |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 2, line 14, col 8 | #DIV/0! |
| 5 | Annual Allocation Factor for O&M | line 4 / line 1 | #DIV/0! |
| 6 | Total Other Taxes Allocated to SPP | Attach H, page 2, line 24, col 8 | #DIV/0! |

| | Transmission | | |
|---|---|---|---|
| 7 | Annual Allocation Factor for Other Taxes | line 6 / line 1 | #DIV/0! |
| **8** | **Annual Allocation Factor for Expense** | **line 5 + line 7** | **#DIV/0!** |
| 9 | Debt Service Plus Margin | Attach H, page 2, lines 17 and 26, col 8 | #DIV/0! |
| 10 | Annual Allocation Factor for Debt Service and Margin | line 9 / line 3 | #DIV/0! |



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed ATRR

12 Months Ended December 31, 20XX

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (10a) | (11) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Upgrade Name** | **Upgrade ID** | **Upgrade Gross Plant** | **Annual Allocation Factor for Expen** | **Annual Expense Charge** | **Upgrade Net Plant** | **Annual Allocation Factor for De** | **Annual Debt Service and Margi** | **Annual Revenue Requirement** | **True-Up Adjustment** | **Schedule 11 PTP Revenue** | **Net Revenue Requirement** |

| | | **se** | | | **bt Service & Margin** | **n Charge** | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | (Note C) | (Page 1 line 8) | (Col. 3 * Col. 4) | (Note D) | (Page 1 line 10) | (Col. 6 * Col. 7) | (Col. 5 + Col. 8) | (Note E) | Note (F) | (Col. 9 + Col. 10 - Col. 10 a) |
| 1 a | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! |
| 1 b | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! |
| 1 c | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! |
| 1 d | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! |
| 1 e | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | - | #DIV/0! |
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|---|---|---|---|---|---|---|---|---|---|
| 2 | **Total Revenue Req. for SPP Directed Projects** | **-** | **#DIV/0!** | **-** | **#DIV/0!** | **#DIV/0!** | **-** | **-** | **#DIV/0!** |

Notes:

it that

A Gross Transmission Plant is identified on Schedule 5, line 14, col 15 and is inclusive of all CWIP.

B Net Transmission Plant is identified on Schedule 5, line 42, col 15 and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 4, Col. 16

D Net Plant is derived from Schedule 4, Col. 16 and includes all CWIP

E True-Up Adjustment is included pursuant to a FERC approved methodology if applicable (see Schedule 12).

F Prior Year Sch 11 Point-to-Point Revenue as detailed on Schedule 10 is allocated on a prorata basis to all Base Plan Projects.

**Missouri River Energy Services**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 2: MISO Attachment MM ATRR
12 Months Ended December 31, 20XX

| Line No. | (1) Description | (2) Source | (3) MISO Transmission $ |
|---|---|---|---|
| 1 | Gross Transmission Plant (Note A) | Schedule 5, line 14, col 23 + Schedule 6, line 14, col 4,5,6,7,7a | - |
| 2 | Transmission Plant Accumulated Depreciation | Schedule 5, line 28, col 23 | - |
| 3 | **Net Transmission Plant (Note B)** | **Line 1 minus Line 2** | **-** |
| | **Transmission O&M Expense Expense** | | |
| 4 | Total O&M Allocated to MISO Transmission | Attach H, page 2, line 14, col 9 | #DIV/0! |

| | | | |
|---|---|---|---|
| 5 | Transmission O&M Allocated to MISO | Attach H, page 2, line 1 col 9 | #DIV/0! |
| 6 | Less: LSE Expenses included in above, if any | Attach H, page 2, line 2 col 9, if any | #DIV/0! |
| 7 | Less: Account 565 included in above, if any | Attach H, page 2, line 4 col 9 | #DIV/0! |
| 8 | **Adjusted Transmission O&M Expense** | **Line 5 less Lines 6, 7** | **#DIV/0!** |
| 9 | Annual Allocation Factor for Transmission O&M | (line 8 / line 2) | #DIV/0! |
| | **Other O&M Expense** | | |
| 10 | Other O&M Allocated to Transmission | Line 4 minus Line 8 | #DIV/0! |
| 11 | Annual Allocation Factor for Other O&M | (line 10 / line1) | #DIV/0! |
| **12** | **Annual Allocation Factor for Other Expense** | **Line 11** | **#DIV/0!** |
| | **Taxes Other Than Income Taxes** | | |
| 13 | Total Other | Attach H, page | #D |

| | | | |
|---|---|---|---|
| 3 | Taxes Allocated to MISO Transmission | 2, line 24 col 9 | IV/ 0! |
| 14 | Annual Allocation Factor for Other Taxes | (line 13 / line 1) | **#D IV/ 0!** |
| **15** | **Annual Allocation Factor for Other O&M and Taxes** | **(line 12 + line 14)** | **#D IV/ 0!** |
| | **Debt Service and Margin Allocated to MISO** | | |
| 16 | Debt Service and Margin (Note I) | Attach H, page 2, line 17 plus line 26 col 9 | #D IV/ 0! |
| 17 | Annual Allocation Factor for Debt Service and Margin | (line 16 / line 3) | #D IV/ 0! |



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: MISO Attachment MM ATRR

12 Months Ended December 31, 20XX

| **(1)** | **(2)** | **(3)** | **(4)** | **(5)** | **(6)** | **(7)** | **(8** | **(9)** | **(1** | **(1** | **(** | **(1** | **(1** | **(1** | **(1** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | ) | | 0) | 1) | 12) | 3) | 4) | 5) | 6) |
| Line No. | Project Name | MTEP Project Number | Project Gross Plant | Project Accumulated Depreciation | Transmission O&M Annual Allocation Factor | Annual Allocation for Transmission O&M Expense | Other Expense Annual Allocation Factor | Annual Allocation for Other O&M and Taxes | Annual Expense Charge | Project Net Plant | Annual Allocation Factor for Debt Service & Margin | Annual Return Charge | Project Depreciation Expense | Annual Revenue Requirement | True-Up Adjustment | MVP Annual Adjusted Revenue Requirement |
| | | | (Note C) | | (Page 1 line 9) | (Col 4 * Col 5) | (Page 1 line 15) | (Col 3 * Col 7) | (Col 6 + Col 8) | (Col 3 minus Col 4) | (Page 1 line 17) | (Col 11) | (Note E) | (Sum Col. 9, 12 & 13) | (Note F) | Sum Col. 14 & 15 (Note G) |
| | **Multi-Value Projects (MVP)** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/! | - | #DIV/0! | - | #DIV/0! |

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| 1b | Project 2 | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | - | #DIV/0! | - | #DIV/0! | #DIV/0! |
| 1c | Project 3 | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | - | #DIV/0! | - | #DIV/0! | #DIV/0! |
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| … | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - #DIV/0! | #DIV/0! | | #DIV/0! | | #DIV/0! |
| … | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - #DIV/0! | #DIV/0! | | #DIV/0! | | #DIV/0! |
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| … | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | | #DIV/0! | | #DIV/0! |
| … | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | | #DIV/0! | | #DIV/0! |
| … | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | | #DIV/0! | | #DIV/0! |
| … | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! | | #DIV/0! | | #DIV/0! |
| | | | | | | | | | | | |
| **2** | **MVP Total Annual Revenue Requirements (sum lines 1a-1xx)** | | | | | | | | **#DIV/0!** | **-** | **#DIV/0!** |

Notes:

A Gross Transmission Plant is identified on Schedule 5 and is inclusive of all CWIP.

B Net Transmission Plant is identified in Schedule 5 and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP.

D Note deliberately left blank.

E Project Depreciation

| | |
|---|---|
| | Expense is not applicable to the cash flow template. |
| F | True-Up Adjustment is included pursuant to a FERC approved methodology if applicable (see Schedule 12). |
| G | The MVP Annual Revenue Requirement is the value to be used in Schedule 26-A. |

**Missouri River Energy Services**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 3: MISO Attachment GG ATRR
12 Months Ended December 31, 20XX

| Line No. | (1) Description | (2) Reference | (3) MISO Transmission $ |
|---|---|---|---|
| 1 | Gross Transmission Plant (Note A) | Schedule 5, line 14, col 23 + Schedule 6, line 14, col 4,5,6,7,7a | - |
| 2 | Transmission Plant Accumulated Depreciation | Schedule 5, line 28, col 23 | - |
| 3 | **Net Transmission Plant (Note B)** | **Line 1 minus Line 2** | **-** |
| | **O&M Expense** | | |
| 4 | Total O&M Allocated to MISO Transmission | Attach H, page 2, line 14, col 9 | #DIV/0! |
| 5 | Annual Allocation Factor for O&M | (line 4 / line 1) | #DIV/0! |
| | **Taxes Other Than Income** | | |

| | | | |
|---|---|---|---|
| | **Taxes** | | |
| 6 | Total Other Taxes Allocated to MISO Transmission | Attach H, page 2, line 24 col 9 | #DIV/0! |
| 7 | Annual Allocation Factor for Other Taxes | (line 6 / line 1) | #DIV/0! |
| **8** | **Annual Allocation Factor for Expense** | **(line 5 + line 7)** | **#DIV/0!** |
| 9 | **Debt Service and Margin** | | |
| 10 | Debt Service Plus Margin | Attach H, page 2, line 17 plus line 26 col 9 | #DIV/0! |
| **11** | **Annual Allocation Factor for Debt Service and Margin** | **(line 10 / line 3)** | **#DIV/0!** |



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: MISO Attachment GG ATRR

12 Months Ended December 31, 20XX

| Line No | (1) Project Name | (2) MTEP Project Numb | (3) Project Gross Plant | (4) Annual Allocation Factor for Expe | (5) Annual Expense Cha | (6) Project Net Plant | (7) Annual Allocation | (8) Annual Debt Servic | (10) Annual Revenue Require | (11) True-Up Adjustment | (12) Annual Revenue |
|---|---|---|---|---|---|---|---|---|---|---|---|

| . | er | | nse | rge | | Factor for Debt Service & Margin | e and Margin Charge | ment | | Requirement, Including True-Up |
|---|---|---|---|---|---|---|---|---|---|---|
| | | (Note C) | (Page 1 line 8) | (Col. 3 * Col. 4) | (Note D) | (Page 1 line 11) | (Col. 6 * Col. 7) | (Sum Col. 5, 8 & 9) | (Note F) | Sum Col. 10 & 11 (Note G) |
| | **Network Upgrade Charge Projects** | | | | | | | | | |
| 1a | Project 1 | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| 1b | Project 2 | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| 1c | Project 3 | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| … | | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| … | | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| … | | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| … | | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
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| … | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
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| … | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
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| … | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
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| … | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| … | - | #DIV/0! | #DIV/0! | - | #DIV/0! | #DIV/0! | #DIV/0! | - | #DIV/0! |
| | | | | | | | | | |
| 2 | **Network Upgrade Total Annual Revenue Requirements (sum lines 1a-1xx)** | | | | | | **#DIV/0!** | **-** | **#DIV/0!** |

Notes:

A Gross Transmission Plant is identified on Schedule 5 and is inclusive of all CWIP.

B Net Transmission Plant is identified in Schedule 5 and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP. This value includes subsequent

capital investments required to maintain the facilities to their original capabilities.

D Project Net Plant for the cash flow template is the Project Gross Plant Identified in Note C.

E Reserved for future use.

F True-Up Adjustment is included pursuant to a FERC approved methodology if applicable (see Schedule 12).

G The Network Upgrade Charge is the value to be used in Schedules 26, 37 and 38.

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: SPP Directed Projects

13 Months Ended December 31, 20XX

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **13 Month Average** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | | - |
| ... | | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | | |
| 2 | **Total Gross Plant in Service** | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Accumulated Depreciati** | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **on** | | | | | | | | | | | | | |
| 3a | Project 1 | | | | | | | | | | | | | - |
| 3b | Project 2 | | | | | | | | | | | | | - |
| 3c | Project 3 | | | | | | | | | | | | | - |
| 3d | Project 4 | | | | | | | | | | | | | - |
| 3e | Project 5 | | | | | | | | | | | | | - |
| 3f | Project 6 | | | | | | | | | | | | | - |
| ... | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | |
| **4** | **Total Accumulated Depreciation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Net Plant in Service** | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - |
| ... | | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | |
| **6** | **Total Net Plant in Service** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 5: Plant Balances

13 Months Ended December 31, 20XX

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 5: Plant Balances

13 Months Ended December 31, 20XX

| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (15) | (16) | (17) | (18) | (19) | (20) | (21) | (22) | (23) | (24) | (25) | (26) | (27) | (28) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Transmission** | | | | | | | **Transmission Plant by Pricing Zone** | | | | | | | | | | | | | | **Trans. Plant Excluded from ISO rates** | | **Trans. Plant Included in OATT Ancillary Services** | |
| **Line No.** | **Month** | **Year** | **MBPP Production** | **Other Production** | W/O Incentives | With Incentives | **Distribution** | **General** | **Intangible** | **Common** | **Total Gross Plant in Service** | UMZ-Irv Simmons | UMZ-MBPP | UMZ-Other | **Total SPP UMZ** | SPP Direct Connected Projects | OTP Zone | Fargo 1 | Fargo 2 | Fargo 3 | Brookings | MISO-Other | **Total MISO** | **Total Fargo (Included)** | SPP | MISO | SPP | MISO |

| | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | September October | XX 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | November | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 13 | December | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 14 | **13 Month Average** | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 15 | December | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | January | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 17 | Febr | 20 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

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| | uary | XX | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 18 | March | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | April | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 20 | May | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 21 | June | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 22 | July | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 23 | August | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 24 | September | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | October | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 26 | November | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 27 | December | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 28 | **13 Month Avera** | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Net Plant in Service** | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 29 | December | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 30 | January | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 31 | February | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 32 | March | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 33 | April | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 34 | May | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 35 | June | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 36 | July | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 37 | August | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 38 | September | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 39 | October | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 40 | November | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 41 | December | 20XX | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 42 | **13 Month Average** | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |





| | Estimated 8-12/20XX Additions: | | Projected 20XX Additions * | | 7/31/20XX Balance | | 12/31/XX Balance | | Difference | | Projected 12/31/XX | | Depreciation Rates | | 20XX | Change in |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Total | Avera | Total | Avera | Plan | A/Dep | Plan | A/Dep | Plant | A/Dep | Plan | A/Dep | Annua | Month | Depre | A/Dep |

| | | | ge Monthly | l | ge Monthly | t | reciation | t | reciation | | reciation | t | reciation | l | ly | ciation | r. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | MBPP Production | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 2 | Worthington Wind | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 3 | Watertown | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 4 | Exira | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 5 | Marshall Wind Circuit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 6 | Marshall Wind Far | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 7 | mRedRockHydroProject | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 8 | IrvSimmonsMBPP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 9 | TransmissionUMZ | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 10 | OtherITAFacilities | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 11 | Fargo1 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 12 | Fargo2 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 13 | Fargo3 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 14 | | | | | | | | | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | Brookings | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 16 | MISO-Other | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 17 | SPP Directed Projects | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 18 | MRES General Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 19 | MBPP General | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 20 | WMMPA General Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 21 | MBP | $ - | $ - | $ | | $ | $ | $ | $ | $ - | $ - | $ - | $ - | - | - | $ | $ |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | P Intangible … | | - | | - | - | - | - | | | | | | - | - |
| 22 | Other Generation | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 23 | MBPP Generation | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 24 | Transmission | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 25 | General Plant | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 26 | Intangible | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | $ - | $ - |
| 27 | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | $ - | $ - |
| 28 | * = Based on capital | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | - | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | budget. | | | | | | | | | | | | | | |
| 29 | | | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | $ - | $ - |
| | Transmission plant excluded from ISO rates: | | | | | | | | | | | | | | |
| 30 | SPP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 31 | MISO | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| | Transmission plant included in OATT Ancillary Services: | | | | | | | | | | | | | | |
| 32 | SPP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |
| 33 | MISO | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - | - | $ - | $ - |



**Transmis**

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | **sion Plant Allocators** | | | | | |
| | | **SPP** | **SPP** | | **MISO** | | | | | |
| | | **UMZ** | **Directed** | **GG** | **MM** | **OTP Zone** | **Other** | | | |
| 1 | Transmission Gross Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 2 | Gross Plant % | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| 3 | Transmission CWIP | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 4 | Transmission Plant in | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | Service plus CWIP Transmission Gross Plant and CWIP % by zone | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| | | **SPP UMZ** | **SPP Directected** | **GG** | **MM** | **OTP Zone** | **Other** | **Total** | | |
| 6 | Transmission Net Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 7 | Net Plant % Transmission CWIP Transmission | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | |
| 8 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 9 | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Plant in Service plus CWIP | | | | | | | | | | | | | |
| 10 | Transmission Net Plant and CWIP % by zone | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | | | | | | |



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Construction Work in Progress

13 Months Ended December 31, 20XX

| Line No. | (1) Month | (2) Year | (3) Reference | (4) | (5) | (6) | (7) | (7a) | (8) | (9) | (10) | (11) | (12) | (13) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Transmission | | | | | | | | Production | | |
| | | | | MISO-Fargo 2-GG | MISO-Fargo 3-GG | MISO-Brookings-MM | MISO-OTP Zone | MISO-Other | SPP UMZ | SPP Directed Projects | Total Transmission CWIP | Red Rock Hydro Project | MBPP | Total Production CWIP |
| 1 | December | 20XX | | - | - | - | - | - | - | - | - | - | - | - |
| 2 | January | 20XX | | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | February | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 4 | March | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 5 | April | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 6 | May | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 7 | June | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 8 | July | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 9 | August | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | September | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | October | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 12 | November | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 13 | December | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 14 | **13 Month Average** | **(sum lines 1-13) / 13** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | |

**CWIP Balances,**

| | **Additions, and Closeouts** | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15 | Prior Year EOY CWIP Balance | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 16 | Prior Year EOY Plant Closeouts | 20XX | - | - | - | - | - | - | - | - | - | | - | |
| 17 | Projected Year CWIP Additions | 20XX | - | - | - | - | - | - | - | - | - | - | - | |
| 18 | Projected Year Plant Closeouts | 20XX | - | - | - | - | - | - | - | - | - | - | - | |

| | **WMMPA Share of Projected Capital Additions** | | **Fargo 2** | **Fargo 3** | **Brookings** |
|---|---|---|---|---|---|
| 19 | Prior Year | 20XX | - | - | - |
| 20 | Projected Year | 20XX | - | - | - |

| | **Total Projected CapX Fargo Costs** | | **Fargo 1** | **Fargo 2** | **Fargo 3** | **Total** |
|---|---|---|---|---|---|---|
| 21 | Total Projected Cost | 20XX | - | - | - | - |
| 22 | WMMPA % | | 11% | 11% | 11% | |
| 23 | WMMPA $ | 20XX | (line 21 * line 22) | - | - | - | - |
| 2 | WMMPA | 2 | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | Estimated Total With Internal Costs | 0 X X | - | - | - | - |
| 25 | Allocation Due to Alex Sub | 20 X X | - | - | - | - |

**Missouri River Energy Services**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 7: Bond Proceeds
13 Months Ended December 31, 20XX

| Line No. | (1) Month | (2) Reference | (3) $ Amount |
|---|---|---|---|
| | **Projected Bonds Proceeds on Deposit for New Generation (Note A):** | | |
| 1 | December | Internal Accounting Records | - |
| 2 | January | Internal Accounting Records | - |
| 3 | February | Internal Accounting Records | - |
| 4 | March | Internal Accounting Records | - |
| 5 | April | Internal Accounting Records | - |
| 6 | May | Internal Accounting Records | - |
| 7 | June | Internal Accounting Records | - |
| 8 | July | Internal Accounting Records | - |
| 9 | August | Internal Accounting Records | - |
| 10 | September | Internal Accounting Records | - |
| 11 | October | Internal Accounting Records | - |
| 12 | November | Internal Accounting Records | - |
| 13 | December | Internal Accounting Records | - |
| 14 | **13 month Average** | **(sum lines 1-13) / 13** | **-** |

Notes:

A Bond proceeds represent the amount of the 2014 debt issue for new projects that had not been expended at the end of each month. The bond proceeds on deposit have been

included
in the production plant since the vast majority of the proceeds are expected to be utilized for
additions to production plant. CWIP is included in the debt service allocator because the amounts included in CWIP were financed by bond proceeds and the annual debt service amount includes all bond proceeds, including those used to finance CWIP. The amounts shown in lines (1-13) will be updated in each year to reflect the remaining balance of the 2014 debt issue for new projects that has not been expended at the end of each month. When
all the proceeds of the 2014 debt issue have been expended, a zero balance will be shown on
lines 1 through 13.

**Missouri River Energy Services**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 8: Transmission Operation & Maintenance Expense
12 Months Ended December 31, 20XX

**Missouri River Energy Services**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 8: Transmission Operation & Maintenance Expense
12 Months Ended December 31, 20XX

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) | (9) | (10) | (11) | (12) | (13) | (14) | (14a) | (15) | (16) | (17) | (18) | (19) | (20) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | **Directly Assigned Transmission O&M Expenses** | | | | | **Allocated Transmission O&M Expenses (Note A)** | | | | | | **Total Transmission O&M Expenses)** | | | | | |
| **Line No.** | **Account #** | **Description** | **Reference** | **Company $** | Zone 19 (UMZ) Transmission | Attachment GG Plant | Attachment MM Plant | MISO (OTP) Zone | Other | **Total** (col 4 less col 5-9) | Zone 19 (UMZ) Transmission | Attachment GG Plant | Attachment MM Plant | MISO (OTP) Zone | Other | Zone 19 (UMZ) Transmission | Attachment GG Plant | Attachment MM Plant | MISO (OTP) Zone | Other | **Total** (sum lines 15-19) |
| 1 | | Gross Plant | Schedule 5, page 5, line 1 **(ratio share of line 1)** | | | | | | | - | - | - | - | - | | | | | | | |
| 2 | | **Gross Plant Allocator** | | | | | | | | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | | | | | | | |
| | | **Operation Expen** | | | | | | | | | | | | | | | | | | | |

| | | **ses** | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 560 | Operation Supervision and Engineering | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | 561 | Load Dispatching | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | 561.1 | Load Dispatch – Reliability | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | 561.2 | Load Dispatch – Monitor and Operate Transmission System | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | 561.3 | Load Dispatch – Transmission Service and Scheduling | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | 561.4 | Scheduling, System Control and Dispatch Services | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | 561.5 | Reliability, Planning and Standards Development | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 10 | 562 | Transm | Inte | | | | | | | | # | # | # | # | # | # | # | # | # | # | # | # |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 1.6 | ission Service Studies | rnal Accounting Records | - | - | - | - | - | - | - | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! | DIV/0! |
| 1 | 56 | Generation Interconnection | Internal Accounting Records | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 1 | 1.7 | Studies | | - | - | - | - | - | - | - | | | | | | | | | | | | |
| 1 | 56 | Reliability, Planning and Standards Development | Internal Accounting Records | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2 | 1.8 | Service | | - | - | - | - | - | - | - | | | | | | | | | | | | |
| 1 | 56 | Station Expenses | Internal Accounting Records | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | 2 | | | - | - | - | - | - | - | - | | | | | | | | | | | | |
| 1 | 56 | Overhead Lines Expenses | Internal Accounting Records | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | 3 | | | - | - | - | - | - | - | - | | | | | | | | | | | | |
| 1 | 56 | Underground Lines Expenses | Internal Accounting Records | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | 4 | | | - | - | - | - | - | - | - | | | | | | | | | | | | |
| 1 | 56 | Transmission of Electricity by Others | Internal Accounting Records | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | 5 | | | - | - | - | - | - | - | - | | | | | | | | | | | | |
| 1 | 56 | Miscellaneous Transmission Expenses | Internal Accounting Rec | | | | | | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | 6 | | | - | - | - | - | - | - | - | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | ords Internal Accounting Records | | | | | | | | | | | | | | | | | | | ! | ! | |
| 18 | 567 | Rents | | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| **19** | | **Total Operation Expenses** | **(sum lines 3-18)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** | **#DIV/0!** |
| | | **Maintenance Expenses** | | | | | | | | | | | | | | | | | | | | | | |
| 20 | 568 | Maintenance Supervision and Engineering | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 21 | 569 | Maintenance of Structures | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 22 | 569.1 | Maintenance of Computer Hardware | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 23 | 569.2 | Maintenance of Computer Software | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 24 | 569.3 | Maintenance of Communication Equipment | Internal Accounting Records | - | - | - | - | - | - | - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25 | 569.4 | Maintenance of Miscellaneous Regional Transmission Plant | Internal Accounting Records | - | - | - | - | - | - | - | | | | | | | | | | | | | | | | |
| 26 | 570 | Maintenance of Station Equipment | Internal Accounting Records | - | - | - | - | - | - | - | | | | | | | | | | | | | | | | |
| 27 | 571 | Maintenance of Overhead Lines | Internal Accounting Records | - | - | - | - | - | - | - | | | | | | | | | | | | | | | | |
| 28 | 572 | Maintenance of Underground Lines | Internal Accounting Records | - | - | - | - | - | - | - | | | | | | | | | | | | | | | | |
| 29 | 573 | Maintenance of Miscellaneous Transmission Plant | Internal Accounting Records | - | - | - | - | - | - | - | | | | | | | | | | | | | | | | |
| **30** | | **Total Maintenance Expenses** | **(sum lines 20-29)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | | | | | | | | | | | | | | | | |
| **31** | | **Total Transmission O&M Expense (Note B)** | **(line 19 + line 30)** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | | | | | | | | | | | | | | | | |
| 32 | | LSE Expenses | Internal Acc | - | - | - | - | - | - | - | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Included in Transmission O&M | Accounting Records | | | V/0! | V/0! | 0! | 0! | 0! | V/0! | V/0! | V/0! | V/0! | V/0! | 0! |

Notes:

A Non-direct assigned Transmission O&M costs are allocated on Transmission gross plant in each pricing zone.

B Total transmission O&M expenses agrees with EIA 412, Schedule 7, line 9, and the Combined Statements of Revenue, Expenses and Changes in Net Position in the MRES annual report



**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 9: Administrative & General Expense

12 Months Ended December 31, 20XX

| Line No. | Account No. | Description | Reference | (1) Total Company $ | (2) Directly Assigned MBPP A&G (Note A) | (3) Allocated Other A&G |
|---|---|---|---|---|---|---|
| | | **Administrative & General Expenses** | | | | |
| 1 | 920 | Administrative and General Salaries | Internal Accounting Records | - | - | - |
| 2 | 921 | Office Supplies and Expenses | Internal Accounting Records | - | - | - |
| 3 | 922 | Administrative Expenses Transferred Credit | Internal Accounting Records | - | - | - |
| 4 | 923 | Outside Services Employed | Internal Accounting Records | - | - | - |
| 5 | 924 | Property Insurance | Internal Accounting | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Records | | | |
| 6 | 925 | Injuries and Damages | Internal Accounting Records | - | - | - |
| 7 | 926 | Employee Pension and Benefits | Internal Accounting Records | - | - | - |
| 8 | 927 | Franchise Requirements | Internal Accounting Records | - | - | - |
| 9 | 928 | Regulatory Commission Expenses | Internal Accounting Records | - | - | - |
| 10 | 929 | Duplicate Charges Credit | Internal Accounting Records | - | - | - |
| 11 | 930.1 | General Advertising Expenses | Internal Accounting Records | - | - | - |
| 12 | 930.2 | Miscellaneous General Expenses | Internal Accounting Records | - | - | - |
| 13 | 931 | Rents | Internal Accounting Records | - | - | - |
| 14 | 935 | Maintenance of General Plant | Internal Accounting Records | - | - | - |
| 15 | | **Total Administrative and General Expenses (Note B)** | | **-** | **-** | **-** |
| | | **Other A&G Expense Information** | | | | |
| 16 | | FERC Annual Fees | Internal Accounting Records | - | | |
| 17 | | EPRI, Regulatory Commission Expenses, & Non-safety Advertising | Internal Accounting Records | - | | |
| 18 | | Transmission Related Regulatory Commission Expenses | Internal Accounting Records | - | | |
| 19 | | MBPP Production Plant | Schedule 5, Line 14, Column 3 | $ - | | |
| 20 | | MBPP Transmission Plant | Schedule 5, Line 14, Column 13 | $ - | | |
| 2 | | **Total MBPP Production &** | **(line 19 + line** | **$** | | |

| | | | |
|---|---|---|---|
| 1 | **Transmission Plant** | **20)** | **-** |
| 2 | | | |
| 2 | | | |
| 2 3 | MBPP Transmission Plant Percent | (line 20 / line 21) | **#DIV/0!** |
| 2 4 | Directly assigned MBPP transmission A&G | (line 15, col 4) * (line 23, col 3) | #DIV/0! |

Notes:

A MBPP A&G expense is allocated between MBPP production and transmission plant based on MBPP production and transmission gross plant. MBPP A&G expenses are obtained from internal accounting records.

B Total A&G expenses agrees to EIA 412, Schedule 7, line 14, and the Combined Statements of Revenue, Expenses and Changes in Net Position in the MRES annual report

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 10: Other Expenses and Income

12 Months Ended December 31, 20XX

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (7a) | (7b) | (7c) | (8) | (9) | (10) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Total Company $** | **Zone 19 (UMZ) Transmission** | **Attachment GG Plant** | **Attachment MM Plant** | **MISO-OTP Zone** | **MISO-Other** | **Distribution** | **Common** | **General & Intangible** | **Production** | **Total (sum col 4-9)** |
| 1 | Gross Plant in Service Balances | Schedule 5, Line 14 | - | - | - | - | - | - | - | - | - | - | - |
| 2 | Common Expenses | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Transmission Lease Payments | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| | **Taxes Other than Income Taxes** | | | | | | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | Payroll Taxes | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 5 | Highway and Vehicle Taxes | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| | Property Taxes (Note A) | | | | | | | | | | | | |
| 6 | Production and Transmission Property Taxes, excluding MBPP (Note B) | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 7 | MBPP Property Taxes (Note C) | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 8 | General Plant Property Taxes | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 9 | General Plant Property Taxes Allocated to Transmission and Production (Note D) | Internal Accounting Records | N/A | - | - | - | - | - | - | - | - | - | - |
| 10 | Total Property Taxes | (sum lines 6-9) | - | - | - | - | - | - | - | - | - | - | - |
| 11 | Gross Receipts Taxes | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 1 | Other Taxes | Intern | | | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | | al Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 13 | Payments in Lieu of Taxes | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 14 | **Total Taxes Other than Income Taxes** | | | | | | | | | | | | |
| 15 | Account 454, Rent from Electric Property (Note E) | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| | **Account 456.1, Other Electric Revenue (Note E)** | | | | | | | | | | | | |
| 16 | a. Transmission charges for transmission transactions | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 17 | b. Transmission charges for all transmission transactions included in charges to native load | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 18 | c. Transmission charges associated with Schedule 26 (Note H) | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 19 | d. Transmission charges | Internal Accou | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | associated with Schedule 26-A (Note I) | nting Records | | | | | | | | | | | |
| 19a | e. Transmission charges associated with Schedule 11 PTP (Note J) | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| 20 | **Total Account 456.1, Other Electric Revenue** | **Line 16 less lines 17, 18, 19, 19a** | **-** | **-** | **-** | **-** | **-** | **-** | | **-** | **-** | **-** | |
| 21 | Transmission expense included in OATT | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - |
| | **Wages and Salaries (Note F)** | | | | | | | | | | | | |
| 22 | Production | Internal Accounting Records | - | | | | | | | | | | |
| 23 | Transmission | Internal Accounting Records | - | | | | | | | | | | |
| 24 | Distribution | Internal Accounting Records | - | | | | | | | | | | |
| 25 | Other | Internal Accounting | - | | | | | | | | | | |

| | | | |
|---|---|---|---|
| 26 | **Total Wages and Salaries** | Records **(sum lines 22-25)** | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | Revenues from Grandfathered Interzonal Transactions | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - | - |
| 28 | Revenues from service provided by the ISO at a discount | Internal Accounting Records | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:

A The amounts on lines 6-9 are from internal accounting records. The Total of these lines (line 10) agrees with the Combined Statement of Revenue, Expenses and Changes in Net Position in the MRES Annual Report.

B These property taxes are allocated based on where the taxes paid in each taxing district where facilities are located.

C MBPP Property taxes are allocated between MBPP production and transmission plant based on MBPP production and transmission gross plant, as shown on Schedule 9.

D General plant property taxes are allocated between production and transmission based on the gross plant allocator. General plant property taxes allocated to transmission are allocated to transmission facilities based on transmission gross plant.

E Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

F Wages and Salaries are based on actual numbers from the following year:

| | |
|---|---|
| | 20XX |
| G | All amounts on lines 2-21 and 27-28 assume budgeted numbers unless listed below: |
| | |
| | |
| | |
| H | Removes from revenue credits revenues that are distributed pursuant to Schedules 26 and 37 of the Midwest ISO Tariff, since the Transmission Owner's Attachment O revenue requirements have already been reduced by the Attachment GG revenue requirements. |
| I | Pursuant to Attachment MM of the Midwest ISO Tariff, removes dollar amount of revenue requirements calculated pursuant to Attachment MM and recovered under Schedule 26-A of the Midwest ISO Tariff. |
| J | Prorated to each SPP Directed project on Schedule 1 |

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 11: Interest Rates

12 Months Ended December 31, 20XX

| Line No. | (1) Month | (2) Initial True-Up (May 20XX) FERC Rates* | (3) Forward Looking September 20XX) FERC Rates* |
|---|---|---|---|
| 1 | Jan-XX | | |
| 2 | Feb-XX | | |
| 3 | Mar-XX | | |
| 4 | Apr-XX | | |
| 5 | May-XX | | |
| 6 | Jun-XX | | |
| 7 | Jul-XX | | |
| 8 | Aug-XX | | |
| 9 | Sep-XX | | |
| 10 | Oct-XX | | |
| 11 | Nov-XX | | |
| 12 | Dec-XX | | |
| 13 | Jan-XX | | |
| 14 | Feb-XX | | |
| 15 | Mar-XX | | |
| 16 | Apr-XX | | |
| 17 | May-XX | | |
| 18 | Jun-XX | | |
| 19 | Jul-XX | | |
| 20 | Aug-XX | | |
| 21 | Sep-XX | | |
| 22 | Oct-XX | | |
| 23 | Nov-XX | | |
| 24 | Dec-XX | | |
| 25 | Average | #DIV/0! | #DIV/0! |

* = 18 CFR 35 19a (Per true-up procedures)
https://www.ferc.gov/interest-calculation-rates-and-methodology

The MRES protocols state that the average interest rates will be for the prior 16 months, e.g., January through April of the following year.

**Missouri River Energy Services**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 12: True-Up Adjustment

12 Months Ended December 31, 20XX

| Line No. | (1) Description | (2) Reference | (3) Zone 19 (UMZ) Transmission | (4) Attachment GG Plant | (5) Attachment MM Plant | (6) MISO-OTP Zone | (6a) MISO-Other | (7) SPP Directed Upgrades Regional Facilities |
|---|---|---|---|---|---|---|---|---|
| | **Annual Transmission Revenue Requirement (ATRR) True-Up:** | | | | | | | |
| 1 | Actual ATRR, excluding interest | | - | - | - | - | - | - |
| 2 | Projected ATRR/Revenue Received | | - | - | - | - | - | - |
| 3 | **ATRR True-Up, excluding Interest** | **(line 1 - line 2)** | - | - | - | - | - | - |
| | **Interest on Historic Year True-Up:** | | | | | | | |
| 4 | Average Monthly Rate (18 CFR 35.19a) (January 20XX-April 20XX) | **Schedule 11, Line 25** | - | - | - | - | - | - |
| 5 | Estimated Interest for 24 months (January 20XX-December 20XX) | (ln 4)/12 * 24 * (ln 3) | - | - | - | - | - | - |
| 6 | **Total True-Up** | **(line 3 + line 5)** | - | - | - | - | - | - |

Above amounts are for 20XX true-up included in 20XX rate year.

## IMPLEMENTATION PROTOCOLS

### Section 1. Annual True-Up and Projected Net Revenue Requirement

1. Beginning on or before June 1, 2016, and on or before each subsequent June 1, Missouri River Energy Services ("MRES") shall determine its Annual True-Up under this Attachment H-MRES and Section VI of these protocols, to derive a True-Up Adjustment to be included in MRES' projected net revenue requirement for the subsequent calendar year (the "Rate Year").
2. On or before June 1, 2016, and on or before each subsequent June 1, MRES shall provide its Annual True-Up, actual net revenue requirement, and True-Up Adjustment, and shall request such information to be posted on the SPP OASIS. The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the Federal Power Act.
3. On or before October 1, 2016, and on or before each subsequent October 1, MRES shall provide its projected net revenue requirement to SPP, shall request such information to be posted to the SPP OASIS, and shall notify Interested Parties via the SPP email exploder titled "Formula Rate Posting Information Notification" of the website address where such information is posted.
    a. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the OATT, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general ("Interested Parties"). Interested Parties can subscribe to the Formula Rate Posting Information Notification exploder.
    b. MRES shall provide electronic notice of Annual ATRR Update postings to all Interested Parties within 10 days of such posting through an email to the Formula Rate Posting Information Notification exploder maintained by SPP.
    c. As used in these Protocols, "Formula Rate Posting Information Notification exploder" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification exploder through the "Exploder List" link

on the SPP website. The Exploder List is titled "Formula Rate Posting Information Notification" and can be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include, but are not limited to, (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

4. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual True-Up occurs shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the projected net revenue requirement will result in an equivalent extension of time for the submission of Information Requests discussed in Section 3 of these protocols.
5. The Annual True-Up shall:
    a. Include a workable data-populated Formula Rate Template and underlying Work papers in native format with all formulas intact;
    b. Be based on MRES' audited financial statements for the prior calendar year;
    c. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the Annual True-Up that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the Annual True-Up results;
    d. Identify any changes in the formula references (page and line numbers);
    e. Identify all material adjustments made to the data in determining formula inputs,;
    f. Provide underlying data for formula rate inputs;
    g. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):
        i. Identify any Accounting Changes, including
            1. The initial implementation of an accounting standard or policy;
            2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;
4. The implementation of new estimation methods or policies that change prior estimates;
5. Changes to income tax elections (if applicable);

ii. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up;

iv. Provide, for each item identified pursuant to items Section 1, paragraph 5.g.i – 5.g.iii these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

6. The projected net revenue requirement shall:
   a. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas intact;
   b. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the projected net revenue requirement;
   c. Provide sufficient information to enable Interested Parties to replicate the calculation of the projected net revenue requirement;
   d. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):
      i. Identify any Accounting Changes, including:
         1. The initial implementation of an accounting standard or policy;
         2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
         3. Correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

4. The implementation of new estimation methods or policies that change prior estimates; and
5. Changes to income tax elections (if applicable).

ii. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement;

iv. Provide, for each item identified pursuant to items in Section 1, paragraph 6.c.i. – 6.c.v. of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

7. MRES shall hold an open meeting among Interested Parties ("Annual True-Up Meeting") between the Publication Date and September 1. No less than seven (7) days prior to such Annual True-Up Meeting, MRES shall provide notice on the SPP OASIS of the time, date, and location of the Annual True-Up Meeting. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall (i) permit MRES to explain and clarify its Annual True-Up and True-Up Adjustment and (ii) provide Interested Parties an opportunity to seek information and clarifications from MRES about the Annual True-Up and True-Up Adjustment. MRES shall provide an option for Interested Parties to remotely participate in this Annual True-Up Meeting (remote access options may include video conferencing, webinar, internet conferencing, or other appropriate remote access options as determined by MRES).
8. MRES shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") between the date that the projected net revenue requirement is posted to the SPP OASIS (as described in Section 1) and October 31. No less than seven (7) days prior to such Annual Projected Rate Meeting, MRES shall provide notice on the SPP OASIS of the time, date, and location of the Annual Projected Rate. The Annual Projected Rate Meeting shall (i) permit MRES to explain and clarify its projected net revenue

requirement and (ii) provide Interested Parties an opportunity to seek information and clarifications from MRES about the projected net revenue requirement.

9. Transmission Owners with transmission projects that utilize a regional cost sharing mechanism (including MRES, if applicable) shall endeavor to coordinate with other Transmission Owners in the SPP using formula rates to hold a joint informational meeting to enable all interested parties to understand how those Transmission Owners are implementing their formula rates for cost recovery of such projects. Such meeting shall occur by November 1 of each year (or the next business day if November 1 falls on a weekend or holiday recognized by FERC). Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to the Formula Rate Posting Information Notification exploder no less than seven (7) days prior to such meetings.

**Section 2. Information Exchange Procedures**

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until December 1 following the Publication Date (unless such period is extended with the written consent of MRES or by FERC order) to serve reasonable information and document requests on MRES ("Information Exchange Period"). If December 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:
    a. The extent or effect of an Accounting Change;
    b. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;
    c. The proper application of the formula rate and procedures in these protocols;
    d. The accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up or projected net revenue requirement;
    e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts; or
g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. MRES shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. MRES shall respond to all information and document requests by no later than January 10 following the Publication Date, unless the Information Exchange Period is extended by MRES or FERC.
3. MRES will cause to be posted on the SPP OASIS all information requests regarding MRES ATRR in SPP from Interested Parties and MRES' response(s) to such requests; except, however, if responses to information and document requests include material deemed by MRES to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by MRES and the requesting party.
4. MRES shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing MRES' Annual True-Up or projected net revenue requirement. However, MRES may require that Interested Parties execute a non-disclosure agreement to obtain access to material that MRES deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**Section 3. Changes to True-Up Adjustment or Projected Net Revenue Requirement**

Any changes to the data inputs, including but not limited to revisions as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any

refund or surcharge shall be calculated in accordance with the procedures outlined in Section 7 of these protocols.

**Section 4. Challenge Procedures**

1. Interested Parties shall have until January 31 following the Publication Date (unless such period is extended with the written consent of MRES or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify MRES in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up or projected net revenue requirement. The period of time from the Publication Date until January 31 shall be referred to as the Review Period. If January 31 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that Annual True-Up or projected net revenue requirement, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement.
2. A party submitting an Informal Challenge to MRES must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. MRES shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. MRES, and where applicable, the Transmission Provider, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If MRES disagrees with such challenge, MRES will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after January 31, and MRES must respond to all Informal Challenges by no later than February 28, unless the Review Period is extended by MRES or FERC.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.
    a. A Formal Challenge shall:
        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        ii. Explain how the action or inaction violates the filed rate formula or protocols;
        iii. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
            1. The extent or effect of an Accounting Change;
            2. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;
            3. The proper application of the formula rate and procedures in these protocols;
            4. The accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;
            5. The prudence of actual costs and expenditures;
            6. The effect of any change to the underlying Uniform System of Accounts; or
            7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.
        iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
        v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is

a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

b. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on MRES. Service to MRES must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on MRES's Informational Filing required under Section VI of these protocols.

4. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

5. MRES will cause to be posted all Informal Challenges from Interested Parties and MRES's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by MRES to be confidential information, such information will not be publicly posted but will be made

available to requesting parties pursuant to a confidentiality agreement to be executed by MRES and the requesting party.

6. Any changes or adjustments to the True-Up Adjustment or projected net revenue requirement resulting from the Information Exchange and Informal Challenge processes that are agreed to by MRES will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by MRES on or before December 1 will be reflected in the projected net revenue requirement for the upcoming Rate Year. Any changes or adjustments agreed to by MRES after December 1 will be reflected in the following year's Annual True-Up, as discussed in Section V of these protocols.
7. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of MRES to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on MRES on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as MRES's Informational Filing discussed in Section VI of these protocols. MRES shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.
8. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, MRES shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in this Attachment H. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.
9. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of MRES to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

10. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols and the Annual True-Up and projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.
11. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts, shall first raise the matter with MRES in accordance with this Section IV before pursuing a Formal Challenge.

**Section 5. Changes to True-Up Adjustment or Projected Net Revenue Requirement**

Except as provided in Section IV.6 of these protocols, any changes to the data inputs, including, or as the result of any FERC proceeding to consider the Annual True-Up or projected net revenue requirement, or as a result of the procedures set forth herein, shall be incorporated into the formula rate and the charges produced by the formula rate in the projected net revenue requirement for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols. If MRES makes a change to the actual ATRR, including but not limited to a change requiring correction to its audited financial statements or input data used for a Rate Year that would have affected the Annual True-Up for that Rate Year, MRES shall promptly (1) request that SPP notify via the Formula Rate Posting Information Notifications exploder; (2) file a change to the Annual Update with the Commission as an amended informational filing or compliance filing, as appropriate; and, (3) cause such information to be posted at a publicly accessible location on SPP's OASIS.

**Section 6. Informational Filings**

By March 15 of each year, MRES shall submit to FERC an informational filing ("Informational Filing") of its projected net revenue requirement for the Rate Year, including its Annual True-Up and True-Up Adjustment. MRES shall submit each year's Informational Filing in the same docket assigned to the initial informational filing of MRES (ER16-1137), subject to the determination of the FERC's Secretary. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly

recorded in any underlying work papers; (2) that MRES has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Any challenges to the implementation of the Attachment H formula rate must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing. MRES shall provide notification of each Informational Filing through notification to the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

**Section 7. Calculation of True-Up Adjustment.**

The True-Up Adjustment will be determined in the following manner:

1. Actual net revenue requirement (calculated in accordance with Page 1, Line 7 of Attachment H-MRES) for the previous year shall be compared to the projected net revenue requirement for the same year ("True-Up Year") to determine any excess or shortfall in the projected net revenue requirement that was used for billing purposes in the True-Up Year. The sum of the excess or shortfall due to the actual versus projected net revenue requirement will constitute the True-Up Adjustment. The True-Up Adjustment and related calculations will be posted on the SPP OASIS no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the MRES audited financial statements for the previous year, as set forth in Section 1 of these protocols.
2. Interest on any over or under recovery of the net revenue requirement will be determined based on the Commission's regulation at 18 C.F.R. § 35.19a. The interest payable will be calculated using an average interest rate for the prior sixteen (16) months (e.g. January – April) during which the over or under recovery in the net revenue requirement changes

exists. The interest amount (Page 1, Line 6i of Attachment H-MRES) will be included in the projected costs made available by October 1 in accordance with Section 2 above.

3. The net revenue requirement for transmission services for the following year shall be the sum of the projected net revenue requirement for the following year, plus or minus the True-Up Adjustment (sum of Page 1, Lines 6+6c+6d of Attachment H-MRES) from the previous year, if any, including interest as explained above.
4. MRES may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

## Appendix A: Example of Net Revenue and True-Up Calculations

1. Example True-Up of 2016 Net Revenue Requirement:
    a. Projected net ATRR was $7,000,000.
    b. Actual 2016 net ATRR calculated based on the Attachment H-MRES data available in June 2017 is $6,800,000.
2. True-Up Calculation:
    a. There is an over recovery of the net revenue requirement equal to $200,000 ($7,000,000 - $6,800,000 = $200,000).
    b. The total True-Up Adjustment amount would be a net over recovery of $200,000, which would be applied as a decrease to the 2018 projected ATRR beginning January 2018.

**ADDENDUM 25 TO ATTACHMENT H – Part 1**

**East River Electric Power Cooperative, Inc.**

# East River Electric Power Cooperative, Inc.
# Annual Transmission Revenue Requirement
# Budget Year Ending December 31, 2xxx

## INDEX


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| 4 | Worksheet C | Return Based on Rate of Return Method |
| 5 | Worksheet D | Coincident Peak Load |
| 6 | Worksheet E | Allocation Factors |
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Summary

**East River Electric Power Cooperative, Inc.**

**Summary**
**Budget Year Ending December 31, 2xxx**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total Company | E<br>Allocation Factor | F<br>Allocation % | G<br>Transmission |
|---|---|---|---|---|---|---|
| 1 | **A. Gross Revenue Requirement for Network Service** | | | | | |
| 2 | Gross Revenue Requirement | Worksheet B, Line 47, Cols F and I | | | | |
| 3 | 456 Revenue Credits-Operating | | | | | |
| 4 | Wheeling Existing | Workpaper M, Line 10, Col E | $ - | T-Tran Plant | 0.00% | $ - |
| 5 | Wheeling Point-to-Point Credits | Workpaper M, Line 10, Col F | $ - | Direct | 100.00% | $ - |
| 6 | Transmission Rents | Workpaper M, Line 10, Col G | $ - | Direct | 100.00% | $ - |
| 7 | Other Rents | Workpaper M, Line 10, Col H | $ - | T-Net Allocation | 0.00% | $ - |
| 8 | Production | Workpaper M, Line 10, Col I | $ - | | 0.00% | $ - |
| 9 | Revenue Credits-Operating | Subtotal | $ - | | | $ - |
| 10 | **Non-Operating Revenue Credits** | | | | | |
| 11 | Not used | Not used | $ - | Direct | 100.00% | $ - |
| 12 | Not used | Not used | $ - | Direct | 100.00% | $ - |
| 13 | Not used | Not used | $ - | Direct | 100.00% | $ - |
| 14 | Not used | Not used | $ - | Direct | 100.00% | $ - |
| 15 | Not used | Not used | $ - | Direct | 100.00% | $ - |
| 16 | Revenue Credits-Non-Operating | Subtotal | $ - | | | $ - |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total Company | E<br>Allocation Factor | F<br>Allocation % | G<br>Transmission |
|---|---|---|---|---|---|---|
| 17 | True-Up Adjustment | Workpaper V, Line 18, Col J | $ - | Direct | 100.00% | $ - |
| 18 | SPP Upgrades | Worksheet G, Line 14, Col O | | Direct | 100.00% | $ - |
| 19 | Revenue Requirement | Total: Line 2-Line 9-Line16+Line 17-Line 18 | | | | |
| 20 | **B. Point-To-Point Service (Divisor)** | | | | | |
| 21 | Network Transmission Load (kW) | Worksheet D, Line 15, Col E | | | | - |
| 22 | **C. Rates** | | | | | |
| 23 | Annual Point-to-Point Cost ($/kW-Yr) | Line 19 / Line 21 | | | | |
| 24 | Monthly Point-to-Point ($/kW-Mo) | Line 23 / 12 months | | | | |
| 25 | Weekly Point-to-Point ($/kW-Week) | Line 23 / 52 weeks | | | | |
| 26 | Daily On-Peak Point-to-Point ($/kW-Day) | Line 25 / 5 days | | | | |
| 27 | Daily Off-Peak Point-to-Point ($/kW-Day) | Line 25 / 7 days | | | | |
| 28 | Hourly On-Peak Point-to-Point ($/MWh) | (Line 26 / 16 hours) * 1,000 | | | | |
| 29 | Hourly Off-Peak Point-to-Point ($/MWh) | (Line 27 / 24 hours) * 1,000 | | | | |

Notes:

Worksheet A

## East River Electric Power Cooperative, Inc.

## Calculation of Rate Base
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Beginning of Year** | **End of Year** | **Total Company** | **Allocation Factor** | **Allocation %** | **Transmission** |
| 1 | **Plant in Service** | | | | Average | | | |
| 2 | 301-303 Total Intangible Plant | Worksheet F, Line 43, Cols D, E and F | $ - | $ - | $ - | T-Wages | | $ - |
| 3 | Total Production Plant | Worksheet F, Line 44, Cols D, E and F | $ - | $ - | $ - | Direct | 0.00% | $ - |
| 4 | 350 Land and Land Rights | Worksheet F, Line 45, Cols D, E and F | $ - | $ - | $ - | T-Tran Stations | | $ - |
| 5 | 352 Structures and Improvements | Worksheet F, Line 46, Cols D, E and F | $ - | $ - | $ - | T-Tran Stations | | $ - |
| 6 | 353 Station Equipment | Worksheet F, Line 47, Cols D, E and F | $ - | $ - | $ - | T-Tran Stations | | $ - |
| 7 | 354 thru 359.1 OH Lines Transmission Plant | Worksheet F, Line 48, Cols D, E and F | $ - | $ - | $ - | T-Length | | $ - |
| 8 | Transmission Plant | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 9 | 360 Distribution Land | Worksheet F, Line 49, Cols D, E and F | $ - | $ - | $ - | D-Network | | $ - |
| 10 | 362 Distribution Stations | Worksheet F, Line 50, Cols D, E and F | $ - | $ - | $ - | D-Network | 0.00% | $ - |
| 11 | Distribution Plant | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 12 | 380 thru 386 RTO/ISO Plant | Worksheet F, Line 51, Cols D, E and F | $ - | $ - | $ - | Direct | 100.00% | $ - |
| 13 | 389 thru 399.1 Total General Plant | Worksheet F, Line 52, Cols D, E and F | $ - | $ - | $ - | T-Wages | | $ - |
| 14 | Gross Electric Plant in Service | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 15 | 105 Electric Plant Held For Future Use | Worksheet F, Line 53, Cols D, E and F and Workpaper T, Line 13 Col G | $ - | $ - | $ - | Direct | | $ - |
| 16 | 106 Completed Construction Not Classified | Worksheet F, Line 54, Cols D, E and F and Workpaper U, Line 12 Col L | $ - | $ - | $ - | Direct | | $ - |
| 17 | 107 Construction Work in Progress | Worksheet F, Line 55, Cols D, E and F and Workpaper J, Line 40, Col L | $ - | $ - | $ - | Direct | | $ - |
| 18 | Utility Plant | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 19 | **Accumulated Depreciation** | | | | | | | |
| 20 | 108.1 Depr of Steam Plant | Worksheet F, Line 58, Cols D, E and F | $ - | $ - | $ - | | | |
| 21 | 108.4 Depreciation of Other Production Plant | Worksheet F, Line 59, Cols D, E and F | $ - | $ - | $ - | | | |
| 22 | 108.5 Depreciation of Transmission Plant | Worksheet F, Line 60, Cols D, E and F | $ - | $ - | $ - | T-Tran Plant | | |
| 23 | 108.6 Depreciation of Distribution Plant | Worksheet F, Line 61, Cols D, E and F | $ - | $ - | $ - | D-Network | | |
| 24 | 108.7 Depreciation of General Plant | Worksheet F, Line 62, Cols D, E and F | $ - | $ - | $ - | T-Wages | | |
| 25 | 108.8 Retirement Work in Progress | Worksheet F, Line 63, Cols D, E and F | $ - | $ - | $ - | T-Plant | | |
| 26 | 111 Amort of Electric Plant in Service | Worksheet F, Line 64, Cols D, E and F | $ - | $ - | $ - | T-Wages | | |
| 27 | Total Accumulated Depreciation | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 28 | **Total Net Plant in Service** | | | | | | | |
| 29 | 301-303 Net Total Intangible Plant | Line 2 | $ - | $ - | $ - | | | $ - |
| 30 | Net Production Plant | Line 3 - Line 20 - Line 21 | $ - | $ - | $ - | | | $ - |
| 31 | Net Transmission Plant | Line 8 + Line 12 - Line 22 | $ - | $ - | $ - | | | |
| 32 | Net Distribution Plant | Line 11 - Line 23 | $ - | $ - | $ - | | | |
| 33 | Net General Plant | Line 13 - Line 24 | $ - | $ - | $ - | | | |

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Beginning of Year** | **End of Year** | **Total Company** | **Allocation Factor** | **Allocation %** | **Transmission** |
| 34 | Electric Plant Held For Future Use | Line 15 | $ - | $ - | $ - | | | $ - |
| 35 | Completed Construction Not Classified | Line 16 | $ - | $ - | $ - | | | $ - |
| 36 | Construction Work in Progress | Line 17 | $ - | $ - | $ - | | | $ - |
| 37 | Retirement Work in Progress | Line 25 | $ - | $ - | $ - | | | $ - |
| 38 | Amort of Electric Plant in Service | Line 26 | $ - | $ - | $ - | | | $ - |
| 39 | Total Net Plant in Service | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 40 | Adjustments to Rate Base | | | | | | | |
| 41 | **Working Capital** | | | | | | | |
| 42 | Total O&M Costs | Worksheet B, Line 34, Cols F & I | | | | | | |
| 43 | Billing Lag in Days | Worksheet F, Line 2, Col F | | | 0 | | | 0 |
| 44 | Working Capital | Line 42 * Line 43 / 365 | | | | | | $ - |
| 45 | Prepayments | Worksheet F, Line 35, Cols D, E and F | $ - | $ - | $ - | T-Plant Allocation | | $ - |
| 46 | M&S Coal | Worksheet F, Line 66, Cols D, E and F | $ - | $ - | $ - | Direct | 0.00% | $ - |
| 47 | M&S Other Fuel | Worksheet F, Line 67, Cols D, E and F | $ - | $ - | $ - | Direct | 0.00% | $ - |
| 48 | M&S Production Plant Parts | Worksheet F, Line 68, Cols D, E and F | $ - | $ - | $ - | Direct | 0.00% | $ - |
| 49 | M&S Station Transformers & Equipment | Worksheet F, Line 69, Cols D, E and F | $ - | $ - | $ - | DT-Tran & Dist. Stn | | $ - |
| 50 | M&S Line Materials & Supplies | Worksheet F, Line 70, Cols D, E and F | $ - | $ - | $ - | T-Length | | $ - |
| 51 | M&S Other | Worksheet F, Line 71, Cols D, E and F | $ - | $ - | $ - | T-Plant Allocation | | $ - |
| 52 | Total Materials and Supplies | Subtotal | $ - | $ - | $ - | | | **$ -** |
| 53 | Rate Base | Total, Sum of Lines 39, 44, 45 and 52 | | | $ - | | | **$ -** |

Worksheet B

## East River Electric Power Cooperative, Inc.

## O&M, Depreciation and Other Expenses
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Total Company** | | | **Allocation Factor** | **Allocation %** | **Transmission** |
| 1 | **Transmission Operation & Maintenance Expenses** | | Lines | Stations | Total | | | |
| 2 | 560 Supervision and Engineering | Workpaper K, Line 1 Cols (a) and (b) | $ - | $ - | $ - | T-Tran Plant | | $ - |
| 3 | 561 Load Dispatching | Workpaper K, Line 2 Col (a) | $ - | | $ - | Direct | 100.00% | $ - |
| 4 | 562 Station Expenses | Workpaper K, Line 3 Cols (a) and (b) | $ - | $ - | $ - | T-Tran Stations | | $ - |
| 5 | 563 Overhead Line Expenses | Workpaper K, Line 4 Col (a) | $ - | | $ - | T-Length | | $ - |
| 6 | 564 Underground Line Expenses | Workpaper K, Line 5 Col (a) | $ - | | $ - | T-Length | | $ - |
| 7 | 566 Miscellaneous Expenses | Workpaper K, Line 6 Cols (a) and (b) | $ - | $ - | $ - | T-Tran Plant | | $ - |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total Company | E | F | G<br>Allocation Factor | H<br>Allocation % | I<br>Transmission |
|---|---|---|---|---|---|---|---|---|
| 8 | 565 Transmission of Electricity by Others | Workpaper K, Line 8 Col (a) | $ - | | $ - | Direct | 0.00% | $ - |
| 9 | 567 Rents | Workpaper K, Line 9 Cols (a) and (b) | $ - | $ - | $ - | T-Tran Stations | | $ - |
| 10 | 568 Supervision and Engineering | Workpaper K, Line 11 Cols (a) and (b) | $ - | $ - | $ - | T-Tran Plant | | $ - |
| 11 | 569 Structures | Workpaper K, Line 12 Col (b) | | $ - | $ - | T-Tran Stations | | $ - |
| 12 | 570 Station Equipment | Workpaper K, Line 13 Col (b) | | $ - | $ - | T-Tran Stations | | $ - |
| 13 | 571 Overhead Lines | Workpaper K, Line 14 Col (a) | $ - | | $ - | T-Length | | $ - |
| 14 | 572 Underground Lines | Workpaper K, Line 15 Col (a) | $ - | | $ - | T-Length | | $ - |
| 15 | 573 Miscellaneous Transmission Plant | Workpaper K, Line 16 Cols (a) and (b) | $ - | $ - | $ - | T-Tran Plant | | $ - |
| 16 | 575.1-575.8 RTO/ISO Expense - Operation | Workpaper X, Line 10, Cols E and G | | | $ - | Direct | 100.00% | $ - |
| 17 | 576.1-576.5 RTO/ISO Expense - Maintenance | Workpaper X, Line 10, Cols H and J | | | $ - | Direct | 100.00% | $ - |
| 18 | Transmission O&M | Subtotal | $ - | $ - | $ - | | | $ - |
| 19 | **Distribution Operation & Maintenance Expenses** | | Lines | Stations | Total | | | |
| 20 | 580-589 Distribution Expense - Operation | Workpaper K, Line 22 Cols (a) and (b) | $ - | $ - | $ - | D-Network | | $ - |
| 21 | 590-598 Distribution Expense - Maintenance | Workpaper K, Line 23 Cols (a) and (b) | $ - | $ - | $ - | D-Network | | $ - |
| 22 | Distribution O&M | Subtotal | $ - | $ - | $ - | | | $ - |
| 23 | **Customer Accounting, Service & Sales** | | | | | | | |
| 24 | 901-905 Op Exp-Consumer Accounts | Workpaper Y, Line 10, Col F | | | | Direct | 100.00% | |
| 25 | 901-905 Customer Accounting - Computer Support | Workpaper Y, Line 12, Col F | | | | Direct | 100.00% | |
| 26 | 907-910 Op Exp-Customer Service | Worksheet F, Line 17, Col F | | | $ - | Direct | 0.00% | $ - |
| 27 | 911-916 Op Exp-Sales | Worksheet F, Line 18, Col F | | | $ - | Direct | 0.00% | $ - |
| 28 | Customer Accounting, Service & Sales Expense | | | | $ - | | | $ - |
| | | | Total Company | Adjustment | Adjusted Total | | | |
| 29 | **Administrative & General Expense** | | | | | | | |
| 30 | 920-931 Op Exp-Admin and General | Worksheet F Line 19 Adj = Less Line 32 and Workpaper I, Lines 116, 117, 118, 119, 120, 121 Col D | $ - | $ - | $ - | T-Wage Allocation | | $ - |
| 31 | 932 Maint Exp-General Plant | Worksheet F, Line 24, Col F | $ - | $ - | $ - | T-Wage Allocation | | $ - |
| 32 | 928 Regulatory & Commission Expenses-SPP | Workpaper W, Line 10 Col F | | $ - | $ - | Direct | 100.00% | $ - |
| 33 | Total A&G Expenses | Subtotal | $ - | $ - | $ - | | | $ - |
| 34 | Subtotal O&M | | | | **$ -** | | | **$ -** |
| | | | Total Company | Adjustment | Adjusted Total | | | |
| 35 | **Depreciation Expense** | | | | | | | |
| 36 | Depreciation Expense-Production | Workpaper L Line 29 Col E | $ - | $ - | $ - | Direct | 0.00% | $ - |
| 37 | Depreciation Expense-Transmission Lines | Workpaper K, Line 26 Col (a) | $ - | $ - | $ - | T-Length | | $ - |
| 38 | Depreciation Expense-Transmission Stations | Workpaper K, Line 26 Col (b) | $ - | $ - | $ - | T-Tran Stations | | $ - |
| 39 | Depreciation Expense-Distribution | Workpaper L Line 29 Col G | $ - | $ - | $ - | D-Network | | $ - |
| 40 | Depreciation Expense-General | Workpaper L Line 29 Col H | $ - | $ - | $ - | T-Wage Allocation | | $ - |
| 41 | Amortization of Other Electric Plant | Workpaper L Line 29 Col I | $ - | $ - | $ - | T-Wage Allocation | | $ - |
| 42 | Total Depreciation & Amortization | Subtotal | $ - | $ - | $ - | | | $ - |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total Company | E | F | G<br>Allocation Factor | H<br>Allocation % | I<br>Transmission |
|---|---|---|---|---|---|---|---|---|
| 43 | 426 Other Deductions | Worksheet F, Line 29 Less Lines 5 thru 6 Note: Included in O&M, therefore zero | $ - | $ - | $ - | T-Wage Allocation | | $ - |
| 44 | Tax - Gross Receipts and Property Tax | here | | | $ - | T-Tax | 100.00% | $ - |
| 45 | Income Tax | N/A | | | | | | $ - |
| 46 | Return | Worksheet C, Line 9, Col J | | | | | | |
| 47 | Gross Revenue Requirement | | | | $ - | | | $ - |

Worksheet C

## East River Electric Power Cooperative, Inc.

## Return Based on Rate of Return Method
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| **Line No** | **Description** | **Reference** | **Total Co EoY** | **End of Year** | **Cap Str Weight** | **Settlement Structure Weight** | **Interest Expense** | **Cost of Capital** | **Weighted Rate of Return** |
| 1 | **Return** | | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Line 37, plus Lines 40 thru 42 less Line 74, Cols E, and F | $ - | $ - | | 65.00% | $ - | | 0.00% |
| 3 | Notes Payable | Worksheet F, Line 38, Cols E and F | $ - | $ - | | 0.00% | $ - | | 0.00% |
| 4 | Total Margins and Equities | Worksheet F, Line 36, Cols E and F | $ - | $ - | | 35.00% | | 10.10% | 3.54% |
| 5 | Total Capitalization | Subtotal | $ - | $ - | 0.00% | | $ - | | 3.54% |
| 6 | Interest on Long Term Debt | Worksheet F, Line 27, Col F | $ - | | | | | | |
| 7 | Other Interest Expense | Worksheet F, Line 28, Col F | $ - | | | | | | |
| 8 | Rate Base | Worksheet A, Line 53, Col F and I | | $ - | | | | | $ - |
| 9 | Return | Line 5, Col J * Line 8 | | $ - | | | | | **$ -** |

Note A:The base ROE of 9.6%, the incentive adder of 0.5%, and the "equity component" of the higher of actual or 35% are fixed pursuant to Settlement Agreement reached in Docket No. ER15-1976 and may not be changed without a filing at the Commission pursuant to Federal Power Act Sections 205 or 206. Such a filing may not be made before July 1, 2019.

Worksheet D

**East River Electric Power Cooperative, Inc.**

**Coincident Peak Load**
**Budget Year Ending December 31, 2xxx**

| A<br>Line No | B<br>Month | C<br>Member Demand (MW) | D<br>Other Customers (MW) | E<br>Total Demand (MW) |
|---|---|---|---|---|
| 1 | January | | | - |
| 2 | February | | | - |
| 3 | March | | | - |
| 4 | April | | | - |
| 5 | May | | | - |
| 6 | June | | | - |
| 7 | July | | | - |
| 8 | August | | | - |
| 9 | September | | | - |
| 10 | October | | | - |
| 11 | November | | | - |
| 12 | December | | | - |
| 13 | Total (MW-Mo) | 0 | 0 | - |
| 14 | Average (MW-Mo) | | | - |
| 15 | Average (kW-Mo) | | | - |

Worksheet E

**East River Electric Power Cooperative, Inc.**

**Allocation Factors**
**Budget Year Ending December 31, 2xxx**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total | E<br>Allocator | F<br>Allocated |
|---|---|---|---|---|---|
| 1 | Production Wages | Workpaper I Line 114 Col E | - | 0.00% | $ - |
| 2 | Transmission Supervision Wages | Workpaper I Line 114 Col F | - | | $ - |
| 3 | Transmission Station Wages | Workpaper I Line 114 Col G | - | | $ - |
| 4 | Transmission Line Wages | Workpaper I Line 114 Col H | - | | $ - |
| 5 | Distribution | Workpaper I Line 114 Col I | - | | $ - |
| 6 | Customer Accounting | Workpaper Y, Line 10, Col F | - | 100.00% | |
| 7 | Customer Service | Workpaper I Line 114 Col K | - | 0.00% | $ - |
| 8 | Sales | Workpaper I Line 114 Col L | - | 0.00% | $ - |
| 9 | Total Wages, excluding A&G | Sum of Line 1 through 8 | - | | $ - |
| 10 | **T-Wage Allocation** | | | | |
| 11 | 350-353 Total Transmission Substations | Worksheet F, Sum of Line 45 through 47, Col F, Less Lines 12 through 15 below | $ - | | $ - |
| 12 | 353 SCADA Master Station | Workpaper R, Line 17, Col C | $ - | 100.00% | $ - |
| 13 | 353 SCADA in Qualifying Stations | Workpaper R, Line 24, Col C Less Lines 12 and 14 | $ - | Direct | $ - |
| 14 | 353 Total SCADA in MOS | Workpaper R, Line 21, Col C | $ - | | |
| 15 | 353 Microwave Equipment | Workpaper N, Line 49, Col I | $ - | | $ - |
| 16 | Network Transmission Stations | Sum of Lines 11 through 16 | $ - | | $ - |
| 17 | **T-Tran Stations** | | | | |
| 18 | 350-353 Tran Qualified Substations | Workpaper P, Line 53, Col Y | | | $ - |
| 19 | 350-353 Tran Total Substations | Workpaper P, Line 54, Col Y | | | $ - |
| 20 | **T-Tran Substations** | | | | |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total | E<br>Allocator | F<br>Allocated |
|---|---|---|---|---|---|
| 21 | Network Distribution Stations | Workpaper Q, Line 2, Col X | | | $ - |
| 22 | Distribution Stations | Worksheet F, Line 49 through 50, Col F | | | $ - |
| 23 | **D-Network** | | | | |
| 24 | Network Stations | Sum of Lines 16 and 21, Col F | | | $ - |
| 25 | Transmission & Distribution Stations | Sum of Line 16, Col D, and Line 22, Col F | | | $ - |
| 26 | **DT-Tran & Dist. Stn** | | | | |
| 27 | Transmission Qualifying Plant | Worksheet A, Line 8, Col I | | | $ - |
| 28 | Total Transmission Plant | Worksheet A, Line 8, Col F | | | $ - |
| 29 | **T-Tran Plant** | | | | |
| 30 | Transmission & Distribution Qualifying Plant | Worksheet A, Sum of Line 8 and Line 11, Col I | | | $ - |
| 31 | Total Transmission & Distribution Plant | Worksheet A, Sum of Line 8 and Line 11, Col F | | | $ - |
| 32 | **T-TD Plant** | | | | |
| 33 | Gross Total Qualifying Plant in Service | Worksheet A, Line 14, Col I | | | $ - |
| 34 | Total Gross Plant in Service | Worksheet A, Line 14, Col F | | | $ - |
| 35 | **T-Plant Allocation** | | | | |
| 36 | Network Transmission Net Plant in Service | Worksheet A, Line 39, Col I | | | $ - |
| 37 | Excluded Transmission Net Plant | Sum Worksheet A, Lines 34-38, Col I | | | $ - |
| 38 | Total Net Plant in Service | Worksheet A, Line 39, Col F | | | $ - |
| 39 | **T-Net Allocation** | | | | |
| 40 | **T-Tax** | | | | **100.00%** |
| 41 | Qualified Circuit Feet | Workpaper S, Line 113, Col AB | | | 0 |
| 42 | Total Transmission Feet | Workpaper S, Line 115, Col I | | | 0 |
| 43 | **T-Length** | | | | |
| 44 | Microwave Qualifying Bandwidth | Workpaper O, Line 9, Col D | | | |

Worksheet F

**East River Electric Power Cooperative, Inc.**

**General Input Section**
**Budget Year Ending December 31, 2xxx**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Avg or YE |
|---|---|---|---|---|---|
| 1 | **Misc Inputs** | | Lines | Stations | |
| 2 | Billing Lag in days | Assumption | | | |
| 3 | Return on Equity | User Defined | | | 10.10% |
| 4 | Target Equity Minimum | Settlement (A) | | | 35% |
| 5 | 426.401-Exp for Legislative Act-Labor | Trial Balance, YTD Trans | | | |
| 6 | 426.402-Exp for Legislative Act-Expense | Trial Balance, YTD Trans | | | |
| 7 | **Data from Form-12** | | | | **Year End** |
| 8 | Electric Energy Revenue | Form 12, Part A, Sect A, L01b | | | |
| 9 | Income from Leased Property | Form 12, Part A, Sect A, L02b | | | |
| 10 | Op Exp-Production Excluding Fuel | Form 12, Part A, Sect A, L05b | | | |
| 11 | Op Exp-Production Fuel | Form 12, Part A, Sect A, L06b | | | |
| 12 | Op Exp-Other Power Supply | Form 12, Part A, Sect A, L07b | | | |
| 13 | Op Exp-Transmission | Workpaper K Line 10 Col's (a) and (b) | | | $ - |
| 14 | Op Exp-RTO/ISO | Form 12, Part A, Sect A, L09b | | | |
| 15 | Op Exp-Distribution | Form 12, Part A, Sect A, L10b | | | |
| 16 | 901-905 Op Exp-Consumer Accounts | Form 12, Part A, Sect A, L11b | | | |
| 17 | 907-910 Op Exp-Customer Service | Form 12, Part A, Sect A, L12b | | | |
| 18 | 911-916 Op Exp-Sales | Form 12, Part A, Sect A, L13b | | | |
| 19 | 920-931 Op Exp-Admin and General | Form 12, Part A, Sect A, L14b | | | |
| 20 | Maint Exp-Production | Form 12, Part A, Sect A, L16b | | | |
| 21 | Maint Exp-Transmission | Workpaper K Line 17 Col's (a) and (b) | | | $ - |
| 22 | Maint Exp-RTO/ISO | Form 12, Part A, Sect A, L18b | | | |
| 23 | Maint Exp-Distribution | Form 12, Part A, Sect A, L19b | | | |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Avg or YE |
|---|---|---|---|---|---|
| 24 | 932 Maint Exp-General Plant | Form 12, Part A, Sect A, L20b | | | |
| 25 | Depreciation & Amortization Expense | Form 12, Part A, Sect A, L22b | | | |
| 26 | Tax - Gross Receipts and Property Tax | Form 12, Part A, Sect A, L23b | | | |
| 27 | Interest on Long Term Debt | Form 12, Part A, Sect A, L24b | | | |
| 28 | Other Interest Expense | Form 12, Part A, Sect A, L26b | | | |
| 29 | 426 Other Deductions | Form 12, Part A, Sect A, L28b | | | |
| 30 | Operating Margin | Form 12, Part A, Sect A, L30b | | | |
| 31 | Interest Income | Form 12, Part A, Sect A, L31b | | | |
| 32 | Other Non Operating Income | Form 12, Part A, Sect A, L34b | | | |
| 33 | G&T Capital Credits Allocation | Form 12, Part A, Sect A, L35b | | | |
| | Other Capital Credits and Patronage | Form 12, Part A, Sect A, L36b | | | |
| 34 | Dividends Cash Payments | | | | |
| | | | | | **Average** |
| 35 | Prepayments | Form 12 for prior and current year, Part A, Section B, Line 25 | | | $ - |
| | | | | | **Year End** |
| 36 | Total Margins and Equities | Form 12, Part A, Section B, Line 39 | | | $ - |
| 37 | Total Long Term Debt | Form 12, Part A, Sect B, Line 46 | | | $ - |
| 38 | Notes Payable | Form 12, Part A, Sect B, Line 50 | | | $ - |
| 39 | Current Maturities LTD | Form 12, Part A, Sect B, Line 52 | | | $ - |
| 40 | Current Maturities LTD-Rural Devel | Form 12, Part A, Sect B, Line 53 | | | $ - |
| 41 | Current Maturities Capital Leases | Form 12, Part A, Sect B, Line 54 | | | $ - |
| 42 | **Plant in Service** | | | | **Average** |
| 43 | 301-303 Total Intangible Plant | Form 12, Suppl, Part H, Section A, Line 1 | | | $ - |
| 44 | Total Production Plant | Form 12, Suppl, Part H, Section A, Line 6 | | | $ - |
| 45 | 350 Land and Land Rights | Workpaper N, Line 46, Col D and H | $ - | $ - | $ - |
| 46 | 352 Structures and Improvements | Workpaper N, Line 47, Col D and H | $ - | $ - | $ - |
| 47 | 353 Station Equipment | Workpaper N, Line 48, Col D and H | $ - | $ - | $ - |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Avg or YE |
|---|---|---|---|---|---|
| 48 | 354 thru 359.1 Lines & Other Transmission Plant | Form 12, Suppl, Part H, Section A, Line 10 | | | $ - |
| 49 | 360 Distribution Land | Form 12, Suppl, Part H, Section A, Line 12 | | | $ - |
| 50 | 362 Distribution Stations | Form 12, Suppl, Part H, Section A, Line 16 | | | $ - |
| 51 | 380 thru 386 RTO/ISO Plant | Form 12, Suppl, Part H, Section A, Line 17 | | | $ - |
| 52 | 389 thru 399.1 Total General Plant | Form 12, Suppl, Part H, Section A, Line 18 | | | $ - |
| 53 | 105 Electric Plant Held For Future Use | Workpaper T, Line 21, Col E, F, and G | $ - | $ - | $ - |
| 54 | 106 Completed Construction Not Classified | Workpaper U, Line 12, Col J, K, and L | $ - | $ - | $ - |
| 55 | 107 Construction Work in Progress | Form 12, Suppl, Part H, Section A, Line 28 | | | $ - |
| 56 | Total CWIP Includable in Rate Base | Workpaper J, Line 40, Col L | | | $ - |
| 57 | **Depreciation and Amortization Reserves** | | | | **Average** |
| 58 | 108.1 Depr of Steam Plant | Form 12, Suppl, Part H, Section B, Line 1 | | | $ - |
| 59 | 108.4 Depreciation of Other Production Plant | Form 12, Suppl, Part H, Section B, Line 4 | | | $ - |
| 60 | 108.5 Depreciation of Transmission Plant | Form 12, Suppl, Part H, Section B, Line 5 | | | $ - |
| 61 | 108.6 Depreciation of Distribution Plant | Form 12, Suppl, Part H, Section B, Line 6 | | | $ - |
| 62 | 108.7 Depreciation of General Plant | Form 12, Suppl, Part H, Section B, Line 7 | | | $ - |
| 63 | 108.8 Retirement Work in Progress | Form 12, Suppl, Part H, Section B, Line 8 | | | $ - |
| 64 | 111 Amort of Electric Plant in Service | Form 12, Suppl, Part H, Section B, Line | | | $ - |

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Avg or YE |
|---|---|---|---|---|---|
| | | 12 | | | |
| 65 | **Materials and Supplies** | | | | **Average** |
| 66 | M&S Coal | Form-12, Part H, Section G, Line 1 | | | $ - |
| 67 | M&S Other Fuel | Form-12, Part H, Section G, Line 2 | | | $ - |
| 68 | M&S Production Plant Parts | Form-12, Part H, Section G, Line 3 | | | $ - |
| 69 | M&S Station Transformers & Equipment | Form-12, Part H, Section G, Line 4 | | | $ - |
| 70 | M&S Line Materials & Supplies | Form-12, Part H, Section G, Line 5 | | | $ - |
| 71 | M&S Other | Form-12, Part H, Section G, Line 6 | | | $ - |
| 72 | Materials and Supplies | Subtotal | $ - | $ - | $ - |
| | | | | | **Year End** |
| 73 | Total RUS Debt Service Billed | Form 12, Supplement H, Sect H, Line 1, Col d | | | |
| | | | | | **Year End** |
| 74 | RUS REDLG Loans | Form 12, Annual Supplement, Sect H, L5 | | | $ - |
| | | | | | **Year End** |
| 75 | Principal Payments on Debt | Form 12, Supplement H, Sect H, Line Total, Col c | | | |

Note A:The base ROE of 9.6%, the incentive adder of 0.5%, and the "equity component" of the higher of actual or 35% are fixed pursuant to Settlement Agreement reached in Docket No. ER15-1976 and may not be changed without a filing at the Commission pursuant to Federal Power Act Sections 205 or 206. Such a filing may not be made before July 1, 2019.

Worksheet G

**East River Electric Power Cooperative, Inc.**

**SPP Upgrades**
**Budget Year Ending December 31, 2xxx**

| A<br>Line<br>No. | B<br><br>Description | C<br><br>Reference | D<br>Company Total<br>Transmission Amount |
|---|---|---|---|
| 1 | Gross Transmission Plant | Worksheet A, Line 8, Col I | - |
| 2 | Accumulated Depreciation & Amortization | Worksheet A, Line 22, Col I | - |
| 3 | Net Transmission Plant | (line 1 minus line 2) | - |
| 4 | Transmission O&M | Worksheet B, Line 18, Col I | - |
| 5 | **Annual Allocation Factor for Transmission O&M** | (line 4 / line 1) | 0.00% |
| 6 | General Plant Depreciation Expense | Worksheet B, Line 40, Col I | - |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | (line 6 / line 1) | 0.00% |
| 8 | Return on Rate Base | Worksheet B, Line 46, Col I | - |
| 9 | **Annual Allocation Factor for Return** | (line 8 / line 3) | 0.00% |
| 10 | **Depreciation Rates** | | |
| 11 | Line | Worksheet H Average of Lines 17 and 18, Col D | 2.465% |
| 12 | Sub | Worksheet H Line 11, Col D | 1.670% |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Name and # | Type (Sub or Line) | Project Gross Plant (A) | Project Accumulated Depreciation | Transmission O&M Annual Allocation Factor | Allocation for Transmission O&M | General Plant Depreciation Annual Allocation Factor | Allocation for General Plant Depreciation | Annual Expense Charge | Project Net Plant (B) | Annual Allocation Factor for Return | Annual Return Charge | Project Depreciation and Amortization Expense (C) | Project ATRR |
| | | | | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | Col G + Col I | Col D - Col E | Line 9, Col D | Col K * Col L | | Col J + Col M + Col N |
| 13a | | Sub | - | | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 13b | | Line | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 13c | | Sub | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 13d | | Line | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 13e | | Sub | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 13f | | Line | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 13g | | Sub | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| … | | Line | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| … | | Sub | - | - | 0.00% | - | 0.00% | - | - | - | 0.00% | - | $ - | $ - |
| 14 | Total | | | | | | | | | | | | | $ - |

Note
Letter

A Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1.
This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

B Net Plant is the Gross Plant less the associated Accumulated Depreciation.

C Depreciation Expense is the depreciation amount associated with the specified line or sub.
Depreciation Expenses includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.

D For new facilities which are approved through the SPP planning process or otherwise added and satisfy Attachment AI criteria, the facilities and CWIP (up to the 50% level) can be included and added.
The related costs are subject to the annual update process, including the data review procedures, per the East River Implementation Protocols.

Worksheet H

**East River Electric Power Cooperative, Inc.**

**Depreciation Rates**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D |
|---|---|---|---|
| Line | RUS Account Number | Description | East River Depreciation / Amortization Rates (%)[1] |
| 1 | | **Intangible Plant** | |
| 2 | 303.01 | Intangible Plant - Transmission Station Equipment | 1.60% |
| 3 | 303.02 | Intangible Plant - Station Equipment -SCADA Radio | 6.04% |
| 4 | 303.03 | Intangible Plant - Poles & Fixtures | 2.47% |
| 5 | 303.04 | Intangible Plant - Overhead Conductor | 2.42% |
| 6 | | **Transmission Depreciation Rates** | |
| 7 | 352.00 | Transmission Structures and Improvements | 0.77% |
| 8 | 352.19 | Structures & Improvements | 0.77% |
| 9a | 352.20 | Structures & Improvements-Microwave-SD | 3.20% |
| 9b | 352.21 | Structures & Improvements-Microwave post 1993-SD | 3.51% |
| 10a | 352.30 | Structures & Improvements-Microwave-MN | 3.24% |
| 10b | 352.31 | Structures & Improvements-Microwave post 1993-MN | 3.80% |
| 11 | 353.00 | Transmission Station Equipment | 1.60% |
| 12 | 353.36 | Station Equipment | 1.60% |
| 13 | 353.40 | Station Equipment -SCADA Radio | 6.04% |
| 14 | 353.50 | Station Equipment - Microwave | 5.33% |
| 15 | 353.60 | Station Equipment - Microwave Towers | 2.43% |
| 16 | 354.00 | Towers & Fixtures | 2.75% |
| 17 | 355.00 | Poles & Fixtures | 2.47% |
| 18 | 356.00 | Overhead Conductor | 2.42% |
| 19 | 357.00 | Underground Conduit | 2.75% |
| 20 | 358.00 | Underground Conductors | 2.75% |

| A | B | C | D |
|---|---|---|---|
| Line | RUS Account Number | Description | East River Depreciation / Amortization Rates (%)[1] |
| 21 | 359.00 | Roads and Trails | 0.0% |
| 22 | | **Distribution Depreciation Rates** | |
| 23 | 361.00 | Distribution Plant Structures | 2.08% |
| 24 | 362.00 | Station Equipment | 2.08% |
| 25 | 362.10 | Station Equipment - Transformers | 1.89% |
| 26 | 362.20 | Station Equipment - Regulators | 2.27% |
| 27 | | **General Plant Depreciation Rates** | |
| 28 | 390.00 | Structures & Improvements | 2.00% |
| 29 | 390.02 | Structures & Leasehold Improvements | 6.72% |
| 30 | | **Office Furniture, Equipment** | |
| 31 | 391.01 | Office Furniture, Equipment Management | 6.00% |
| 32 | 391.02 | Office Furniture, Equipment Engineering | 6.00% |
| 33 | 391.03 | Office Furniture, Equipment Administration | 6.00% |
| 34 | 391.04 | Office Furniture, Equipment Member Services | 6.00% |
| 35 | 391.05 | Office Furniture, Equipment Transmission | 6.00% |
| 36 | 391.10 | Computer Equipment Directors | 33.33% |
| 37 | 391.11 | Computers and Copiers Management | 20.00% |
| 38 | 391.12 | Computers and Copiers Engineering | 20.00% |
| 39 | 391.13 | Computers and Copiers Administration | 20.00% |
| 40 | 391.14 | Computers and Copiers Member Services | 20.00% |
| 41 | 391.15 | Computers and Copiers Transmission | 20.00% |
| 42 | 391.16 | Computers and Copiers Minnesota | 20.00% |
| 43 | | **Transportation Equipment** | |
| 44 | 392.01 | Transportation Equipment Light Vehicles | 14.00% |
| 45 | 392.02 | Transportation Equipment Miscellaneous | 14.00% |
| 46 | 392.03 | Transportation Equipment Telecommunications | 14.00% |
| 47 | 392.04 | Transportation Equipment Meter/Relay | 14.00% |
| 48 | 392.05 | Transportation Equipment Aircraft | 14.00% |

| A | B | C | D |
|---|---|---|---|
| Line | RUS Account Number | Description | East River Depreciation / Amortization Rates (%)[1] |
| 49 | 392.10 | Transportation Equipment Unit Depreciation | 14.00% |
| 50 | 392.12 | Transportation Equipment Mileage | 14.00% |
| 51 | 392.13 | Transportation Equipment Hourly | 14.00% |
| 52 | 393.00 | Stores Equipment | 6.00% |
| 53 | 394.00 | Tools, Shop and Garage Equipment | 6.00% |
| 54 | 395.00 | Laboratory & Testing Equipment | 6.00% |
| 55 | 396.00 | Power Operated Equipment | 6.67% |
| 56 | 397.00 | Communications Equipment | 6.67% |
| 57 | 398.00 | Miscellaneous | 6.00% |

Note: 1 These depreciation / amortization rates will not change absent a filing under Section 205 or 206 of the Federal Power Act.

Workpaper I

## East River Electric Power Cooperative, Inc.

## Wages
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Account | Description | Total Expense | Wages-Prod | Wages-Tran Supervision & Misc | Wages-Tran Station | Wages-Tran Lines | Wages Distb | Wages Cust-Accting | Wages Cust-Service | Wages Cust-Sales |
| 1 | 560.101 | OPERATIONS SUPERVISION LABOR | | | $ - | | | | | | |
| 2 | 560.102 | OPERATIONS NON-PRODUCTIVE TIME | | | $ - | | | | | | |
| 3 | 560.103 | OPR - TELEPHONE UPDATES | | | $ - | | | | | | |
| 4 | 560.104 | M/W MONITOR FOREIGN USER | | | $ - | | | | | | |
| 5 | 560.105 | Tran.Serv.Cust/Key Accts-Labor | | | | $ - | | | | | |
| 6 | 561.101 | Dispatching For House Moves | | | $ - | | | | | | |
| 7 | 561.102 | SYSTEM DISPATCHING RADIO LABOR | | | $ - | | | | | | |
| 8 | 561.103 | SYSTEM DISPATCHING SWITCHING/WRT | | | $ - | | | | | | |
| 9 | 561.105 | SCADA SOFTWARE UPDATING LABOR | | | $ - | | | | | | |
| 10 | 561.106 | L/M SOFTWARE UPDATE LABOR | | | $ - | | | | | | |
| 11 | 562.101 | 115-23KV MOS INSPECTION LABOR | | | | $ - | | | | | |
| 12 | 562.102 | 115-230KV SUB INSPECTION LABOR | | | | $ - | | | | | |
| 13 | 562.103 | 115-230KV SUBSTATION MOWING LABR | | | | $ - | | | | | |
| 14 | 562.104 | 115-230KV DOBLE TESTING LABOR | | | | $ - | | | | | |
| 15 | 562.105 | 115-230KV RELAY TESTING LABOR | | | | $ - | | | | | |
| 16 | 562.106 | 115-230KV SCADA CONTR TEST LABOR | | | | $ - | | | | | |
| 17 | 562.107 | 115-230KV DGA OIL TESTING LABOR | | | | $ - | | | | | |
| 18 | 562.108 | L/M TESTING LABOR | | $ - | | | | | | | |
| 19 | 562.109 | L/M SIGNAL LEVEL TESTING LABOR | | $ - | | | | | | | |
| 20 | 562.110 | M/W ENGINEERING LABOR | | | | | $ - | | | | |
| 21 | 562.111 | M/W TESTING LABOR | | | | | $ - | | | | |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Account | Description | Total Expense | Wages-Prod | Wages-Tran Supervision & Misc | Wages-Tran Station | Wages-Tran Lines | Wages Distb | Wages Cust-Accting | Wages Cust-Service | Wages Cust-Sales |
| 22 | 562.112 | M/W RADIO TESTING LABOR | | | | | $ - | | | | |
| 23 | 562.113 | PowerSupply/LoadMan MSys Labor | | $ - | | | | | | | |
| 24 | 562.114 | RenewEnergy/Distrib.Gen-Labor | | $ - | | | | | | | |
| 25 | 562.115 | Tran.Serv.Cust/KeyAccnts-Labor | | | | | $ - | | | | |
| 26 | 562.116 | M/W TELEPHONE TESTING LABOR | | | | | $ - | | | | |
| 27 | 562.117 | SCADA RTU TESTING LABOR | | | | $ - | | | | | |
| 28 | 562.118 | M/W TOWER TESTING LABOR | | | | $ - | | | | | |
| 29 | 562.119 | M/W ANTENNA FEEDLINE TEST LABOR | | | | $ - | | | | | |
| 30 | 562.120 | M/W FIBER OPTICS TESTING LABOR | | | | $ - | | | | | |
| 31 | 562.121 | M/W CHANNEL BANK TESTING LABOR | | | | $ - | | | | | |
| 32 | 562.122 | M/W 1603 TESTING LABOR | | | | $ - | | | | | |
| 33 | 563.101 | 69 LINE MISC OPERERATIONS LABOR | $ - | | | | $ - | | | | |
| 34 | 563.102 | 69KV WALKING PATROL LABOR | $ - | | | | $ - | | | | |
| 35 | 563.103 | 69KV FLYING PATROL LABOR | $ - | | | | $ - | | | | |
| 36 | 563.104 | House Move Labor | $ - | | | | $ - | | | | |
| 37 | 563.105 | STORM DAMAGE ASSIST LABOR | $ - | | | | $ - | | | | |
| 38 | 563.106 | 115-230KV LINE MISC OPERATIONS L | $ - | | | | $ - | | | | |
| 39 | 563.107 | 115-230KV WALK PATROL LABOR | $ - | | | | $ - | | | | |
| 40 | 566.101 | MISC OP-OFFICE & DRAFTING LABOR | $ - | | $ - | | | | | | |
| 41 | 566.102 | MISC OPS-WHSE SNOW REMOVAL LABOR | $ - | | $ - | | | | | | |
| 42 | | Subtotal | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 43 | MAINTENANCE EXPENSE-TRANSMISSION-LINE 17 | | | | | | | | | | |
| 44 | 568.101 | MTC SPRVR CHECKING LINES LABOR | | | $ - | | | | | | |
| 45 | 569.101 | MTC M/W BLDG & SITE LABOR | | | | $ - | | | | | |
| 46 | 569.102 | MNT CONTROL BUILDING-LABOR | | | | $ - | | | | | |
| 47 | 570.101 | 115-230KV SUB MAINTENANCE LABOR | | | | $ - | | | | | |
| 48 | 570.102 | 115-230KV RELAY MTC LABOR | | | | $ - | | | | | |
| 49 | 570.103 | 115-230KV METER MTC | | | | $ - | | | | | |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Account | Description | Total Expense | Wages-Prod | Wages-Tran Supervision & Misc | Wages-Tran Station | Wages-Tran Lines | Wages Distb | Wages Cust-Accting | Wages Cust-Service | Wages Cust-Sales |
| | | LABOR | | | | | | | | | |
| 50 | 570.104 | 115-230KV Battery MTC Labor | | | | $ - | | | | | |
| 51 | 570.105 | MOS MTC LABOR | | | | $ - | | | | | |
| 52 | 570.106 | L/M INJECTOR MTC LABOR | | | | $ - | | | | | |
| 53 | 570.107 | L/M IRRI CONTROLLER MTC LABOR | | | | $ - | | | | | |
| 54 | 570.108 | L/M ASSISTANCE TO COOP-LABOR | | | | $ - | | | | | |
| 55 | 570.109 | L/M MASTER MTC LABOR | | | | $ - | | | | | |
| 56 | 570.110 | M/W MTC LABOR | | | | $ - | | | | | |
| 57 | 570.111 | M/W RADIO MTC LABOR | | | | $ - | | | | | |
| 58 | 570.112 | M/W MULTIPLEX MTC LABOR | | | | $ - | | | | | |
| 59 | 570.113 | M/W BATTERY/CHARGER MTC LABOR | | | | $ - | | | | | |
| 60 | 570.114 | M/W OW/ALARM SYSTEM MTC LABOR | | | | $ - | | | | | |
| 61 | 570.115 | SCADA UPDATES LABOR | | | | $ - | | | | | |
| 62 | 570.116 | M/W TELEPHONE MTC LABOR | | | | $ - | | | | | |
| 63 | 570.117 | M/W TOWER MTC LABOR | | | | $ - | | | | | |
| 64 | 570.118 | M/W ANTENNA/FEEDLINE MTC LABOR | | | | $ - | | | | | |
| 65 | 570.119 | M/W FIBER OPTICS MTC LABOR | | | | $ - | | | | | |
| 66 | 570.120 | SCADA MASTER MTC LABOR | | | | $ - | | | | | |
| 67 | 570.121 | SCADA RTU MAINTENANCE | | | | $ - | | | | | |
| 68 | 570.122 | SCADA MAINTENANCE LABOR | | | | $ - | | | | | |
| 69 | 570.123 | SCADA RADIO MTC LABOR | | | | $ - | | | | | |
| 70 | 570.124 | GIS Labor | | | | $ - | | | | | |
| 71 | 570.125 | STANDBY GENERATOR MTC LABOR | | | | $ - | | | | | |
| 72 | 570.130 | SCADA MASTER MTNC-RUSHMORE LABO | | | | $ - | | | | | |
| 73 | 571.101 | 69KV LINE MNTC GENERAL LABOR | | | | | $ - | | | | |
| 74 | 571.102 | MTC 69KV LINE TREAT & WRAP LABR | | | | | $ - | | | | |
| 75 | 571.103 | MTC 69KV LINE HDWR TIGHTEN LABR | | | | | $ - | | | | |
| 76 | 571.104 | 69KV LINE TREE TRIMMING LAB | | | | | $ - | | | | |
| 77 | 571.105 | MTC 69KV LINE STRAIGHTEN & TAMP | | | | | $ - | | | | |
| 78 | 571.106 | MTC 69KV LINE POLE BANDING LABR | | | | | $ - | | | | |
| 79 | 571.107 | MTC 69KV LINE CONDUCTOR | | | | | $ - | | | | |

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Account | Description | Total Expense | Wages-Prod | Wages-Tran Supervision & Misc | Wages-Tran Station | Wages-Tran Lines | Wages Distb | Wages Cust-Accting | Wages Cust-Service | Wages Cust-Sales |
| | | DEVICES | | | | | | | | | |
| 80 | 571.108 | MTC 69KV LINE INSULATOR CHANGES | | | | | $ - | | | | |
| 81 | 571.109 | MTC 69KV LINE ANCHOR ROD REPLAC | | | | | $ - | | | | |
| 82 | 571.110 | 115-230KV MAINT POLE & FIXTURES | | | | | $ - | | | | |
| 83 | 571.112 | MTC 115-230KV TREAT WRAP LABOR | | | | | $ - | | | | |
| 84 | 571.114 | 115-230KV TREE TRIMMING LAB | | | | | $ - | | | | |
| 85 | 571.115 | MTC 115-230KV STRAIGHTEN & TAMP | | | | | $ - | | | | |
| 86 | 571.117 | Fiber Line Maint Labor | | | | | $ - | | | | |
| 87 | | Subtotal | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 88 | OPERATING EXPENSE-DISTRIBUTION -LINE 10 | | | | | | | | | | |
| 89 | 580.101 | SUPERVISION DIST OPS LABOR | | | | | | $ - | | | |
| 90 | 580.102 | POWER QUALITY LABOR | | | | | | $ - | | | |
| 91 | 580.201 | SUPERVISION DIST OPS EXPENSES | | | | | | | | | |
| 92 | 582.101 | 69KV SUB OPERATIONS LABOR | | | | | | $ - | | | |
| 93 | 582.102 | 69KV SUB INSPECTION LABOR | | | | | | $ - | | | |
| 94 | 582.103 | 69KV SUB SPRAYING & MOWING | | | | | | $ - | | | |
| 95 | 582.105 | 69KV PCB TESTING LABOR | | | | | | $ - | | | |
| 96 | 582.106 | 69KV OCR CONTROLS TESTING LABOR | | | | | | $ - | | | |
| 97 | 582.107 | 69KV POWER QUALITY LABOR | | | | | | $ - | | | |
| 98 | 582.108 | 69KV DGA OIL TESTING LABOR | | | | | | $ - | | | |
| 99 | | Subtotal | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 100 | MAINTENANCE EXPENSE-DISTRIBUTION-LINE 19 | | | | | | | | | | |
| 101 | 590.101 | SUPERVISION DIST MTC LABOR | | | | | | $ - | | | |
| 102 | 592.101 | 69KV SUB MNTC LABOR | | | | | | $ - | | | |
| 103 | 592.102 | 69KV METER MTC LABOR | | | | | | $ - | | | |
| 104 | 592.103 | 69KV RECORDER MTC LABOR | | | | | | $ - | | | |
| 105 | 592.104 | 69KV LRG LOAD RECORDER MTC LABR | | | | | | $ - | | | |
| 106 | 592.105 | 69KV SURVEY RECORDER | | | | | | $ - | | | |

| A<br>Line | B<br>Account | C<br>Description | D<br>Total Expense | E<br>Wages-Prod | F<br>Wages-Tran Supervision & Misc | G<br>Wages-Tran Station | H<br>Wages-Tran Lines | I<br>Wages Distb | J<br>Wages Cust-Accting | K<br>Wages Cust-Service | L<br>Wages Cust-Sales |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | MTC LABOR | | | | | | | | | |
| | | 34.5-69KV SCADA CONTROL | | | | | | | | | |
| 107 | 592.106 | MTC LABO | | | | | | $ - | | | |
| | | 34.5-69KV BATTERY MTC | | | | | | | | | |
| 108 | 592.107 | LABOR | | | | | | $ - | | | |
| 109 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | CONSUMER ACCOUNTS LINE | | | | | | | | | |
| 110 | | 11 | | | | | | | | | |
| | | SUPV METER READING | | | | | | | | | |
| 111 | 901.101 | LABOR | | | | | | | $ - | | |
| | | CUST METER TRANSLATION | | | | | | | | | |
| 112 | 903.101 | LABOR | | | | | | | $ - | | |
| 113 | | Subtotal | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | | Grand Total Wages excluding | | | | | | | | | |
| 114 | | A&G | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| | Line 14 on Administrative & | | | | | | | | | | |
| 115 | General Exp. | | | | | | | | | | |
| | | DONATIONS/CONTIB/GOOD | | | | | | | | | |
| 116 | 930.801 | WILL | | | | | | | | | |
| 117 | 930.803 | MARKETING INFO/MATERIAL | | | | | | | | | |
| 118 | 930.804 | EXHIBITS/BOOTHS AT FAIRS | | | | | | | | | |
| 119 | 930.808 | YOUTH TOUR | | | | | | | | | |
| 120 | 930.810 | SCHOLARSHIPS | | | | | | | | | |
| | | DONATIONS-EMPLOYEE | | | | | | | | | |
| 121 | 930.811 | MATCH FUND | | | | | | | | | |
| 122 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note
Letter

A The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
Additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

Workpaper J

## East River Electric Power Cooperative, Inc.

## Construction Work in Progress
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Project Description** | **Approval Docket No.** | **% Recovery Approved (Note A)** | **Pricing Zone (Note B)** | **Project ID** | **Construction Start Date** | **In-Service Date (Estimated)** | **EoY Balance Dec. 31 20xx** | **EoY Balance Dec. 31 20xx** | **Average Balance** (Col I + J) /2 | **Includable in Rate Base** (Note C) (Col D * Col K) |
| 1 | | | 50.00% | Zone 19 | | | | | | - | - |
| 2 | | | 50.00% | Zone 19 | | | | | | - | - |
| 3 | | | 50.00% | Zone 19 | | | | | | - | - |
| 4 | | | 50.00% | Zone 19 | | | | | | - | - |
| 5 | | | 50.00% | Zone 19 | | | | | | - | - |
| 6 | | | 50.00% | Zone 19 | | | | | | - | - |
| 7 | | | 50.00% | Zone 19 | | | | | | - | - |
| 8 | | | 50.00% | Zone 19 | | | | | | - | - |
| 9 | | | 50.00% | Zone 19 | | | | | | - | - |
| 10 | | | 50.00% | Zone 19 | | | | | | - | - |
| 11 | | | 50.00% | Zone 19 | | | | | | - | - |
| 12 | | | 50.00% | Zone 19 | | | | | | - | - |
| 13 | | | 50.00% | Zone 19 | | | | | | - | - |
| 14 | | | 50.00% | Zone 19 | | | | | | - | - |
| 15 | | | 50.00% | Zone 19 | | | | | | - | - |
| 16 | | | 50.00% | Zone 19 | | | | | | - | - |
| 17 | | | 50.00% | Zone 19 | | | | | | - | - |
| 18 | | | 50.00% | Zone 19 | | | | | | - | - |
| 19 | | | 50.00% | Zone 19 | | | | | | - | - |
| 20 | | | 50.00% | Zone 19 | | | | | | - | - |
| 21 | | | 50.00% | Zone 19 | | | | | | - | - |
| 22 | | | 50.00% | Zone 19 | | | | | | - | - |
| 23 | | | 50.00% | Zone 19 | | | | | | - | - |
| 24 | | | 50.00% | Zone 19 | | | | | | - | - |
| 25 | | | 50.00% | Zone 19 | | | | | | - | - |
| 26 | | | 50.00% | Zone 19 | | | | | | - | - |
| 27 | | | 50.00% | Zone 19 | | | | | | - | - |
| 28 | | | 50.00% | Zone 19 | | | | | | - | - |
| 29 | | | 50.00% | Zone 19 | | | | | | - | - |
| 30 | | | 50.00% | Zone 19 | | | | | | - | - |
| 31 | | | 50.00% | Zone 19 | | | | | | - | - |
| 32 | | | 50.00% | Zone 19 | | | | | | - | - |
| 33 | | | 50.00% | Zone 19 | | | | | | - | - |
| 34 | | | 50.00% | Zone 19 | | | | | | - | - |
| 35 | | | 50.00% | Zone 19 | | | | | | - | - |
| 36 | | | 50.00% | Zone 19 | | | | | | - | - |
| 37 | | | 50.00% | Zone 19 | | | | | | - | - |
| 38 | | | | | | | | | | - | - |
| 39 | | | | | | | | | | - | - |
| 40 | Total CWIP Includable in Rate Base | | | | | | | - | - | - | - |

Notes: A. Percentage recovery cannot be added or changed absent approval from FERC

B. CWIP amounts should be directly assigned to pricing zones on Summary

C. AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization. Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years.
Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
For inclusion of CWIP for new facilities, East River will seek any necessary Commission authorization that is applicable. Otherwise, additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

E. For new facilities which are approved through the SPP planning process or otherwise added and satisfy Attachment AI criteria, the facilities and CWIP (up to the 50% level) can be included and added.
The related costs are subject to the annual update process, including the data review procedures, per the East River Implementation Protocols.

Workpaper K

## East River Electric Power Cooperative, Inc.

## O&M Input - RUS Form 12
## Budget Year Ending December 31, 2xxx

| SECTION A. EXPENSES AND COSTS | | | | |
|---|---|---|---|---|
| ITEM | | ACCOUNT NUMBER | LINES (a) | STATIONS (b) |
| **Transmission Operations** | | | | |
| 1 | Supervision and Engineering | 560 | | |
| 2 | Load Dispatching | 561 | | |
| 3 | Station Expenses | 562 | | |
| 4 | Overhead Line Expenses | 563 | | |
| 5 | Underground Line Expenses | 564 | | |
| 6 | Miscellaneous Expenses | 566 | | |
| **7** | **Subtotal (1 thru 6)** | | - | - |
| 8 | Transmission of Electricity by Others | 565 | | |
| 9 | Rents | 567 | | |
| **10** | **Total Transmission Operations (7 thru 9)** | | - | - |
| **Transmission Maintenance** | | | | |
| 11 | Supervision and Engineering | 568 | | |
| 12 | Structures | 569 | | |
| 13 | Station Equipment | 570 | | |
| 14 | Overhead Lines | 571 | | |
| 15 | Underground Lines | 572 | | |
| 16 | Miscellaneous Transmission Plant | 573 | | |
| **17** | **Total Transmission Maintenance (11 thru 16)** | | - | - |
| **18** | **Total Transmission Expense (10+17)** | | - | - |
| 19 | RTO/ISO Expense - Operation | 575.1-575.8 | | |
| 20 | RTO/ISO Expense - Maintenance | 576.1-576.5 | | |
| **21** | **Total RTO/ISO Expense (19+20)** | | - | - |
| 22 | Distribution Expense - Operation | 580-589 | | |
| 23 | Distribution Expense - Maintenance | 590-598 | | |
| **24** | **Total Distribution Expense (22+23)** | | - | - |
| **25** | **Total Operation and Maintenance (18+21+24)** | | - | - |

| SECTION A. EXPENSES AND COSTS | | | | |
|---|---|---|---|---|
| | **ITEM** | **ACCOUNT NUMBER** | **LINES (a)** | **STATIONS (b)** |
| **Fixed Costs** | | | | |
| 26 | Depreciation - Transmission | 403.5 | | |
| 27 | Depreciation - Distribution | 403.6 | | |
| 28 | Interest - Transmission | 427.0 | | |
| 29 | Interest - Distribution | 427.0 | | |
| **30** | **Total Transmission (18+26+28)** | | - | - |
| **31** | **Total Distribution (24+27+29)** | | - | - |
| **32** | **Total Lines and Stations (21+30+31)** | | - | - |

Note: A. Lines can be added or removed from this Workpaper only if there are corresponding changes in the RUS Form 12 Format.

Workpaper L

**East River Electric Power Cooperative, Inc.**

**Depreciation and Amortization**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line** | **Account** | **Description** | **Total Expense** | **Production** | **Transmission** | **Distribution** | **General** | **Amort** |
| 1 | 403.01 | DEPR TRANSMISSION PLANT SD | | | $ - | | | |
| 2 | 403.02 | DEPR OF DISTRIBUTION PLANT SD | | | | $ - | | |
| 3 | 403.03 | DEPR GP STRUCTURE & IMP OPER CEN | | | | | $ - | |
| 4 | 403.09 | DEP GP HIGHLAND-SD-SUB MAINT DPT | | | | | $ - | |
| 5 | 403.11 | DEPR GP STRUCTURE & IMP HDQTR | | | | | $ - | |
| 6 | 403.12 | DEPR GEN PL-HIGHLAND#2 | | | | | $ - | |
| 7 | 403.13 | DEPR GEN PL-OUTPOST WHSES | | | | | $ - | |
| 8 | 403.16 | DEPR GP MADISON HANGAR | | | | | $ - | |
| 9 | 403.18 | DEPR GP MARSHALL WHSE-MINN | | | | | $ - | |
| 10 | 403.19 | DEPR ANNEX III BLDG | | | | | $ - | |
| 11 | 403.21 | DEPR OFFICE FURN EQ-MAN DIV | | | | | $ - | |
| 12 | 403.22 | DEPR GP OFFICE EQUIPMENT | | | | | $ - | |
| 13 | 403.23 | DEPR GP OFFICE EQUIPMENT | | | | | $ - | |
| 14 | 403.24 | DEPR OFFICE F MEMBER SERV | | | | | $ - | |
| 15 | 403.25 | DEPR GP OFFICE EQUIPMENT | | | | | $ - | |
| 16 | 403.26 | DEPR GP COMPUTER EQUIPMENT | | | | | $ - | |
| 17 | 403.50 | DEPR GP TOOLS | | | | | $ - | |
| 18 | 403.52 | DEPR GP TOOLS | | | | | $ - | |
| 19 | 403.55 | DEPR GP TOOLS | | | | | $ - | |
| 20 | 403.62 | DEPR GP TESTING EQUIPMENT | | | | | $ - | |
| 21 | 403.65 | DEPR GP TESTING EQUIPMENT | | | | | $ - | |
| 22 | 403.82 | DEPR GP-VOICE RADIO-TEL DEPT | | | | | $ - | |
| 23 | 403.91 | DEPR GEN PL-MISC EQ MAN DIV | | | | | $ - | |
| 24 | 403.92 | DEPR GP MISC EQUIPMENT | | | | | $ - | |
| 25 | 403.93 | DEPR GP MISC EQUIPMENT | | | | | $ - | |
| 26 | 403.94 | DEPR GEN PL MIS EQ MEMB SERV | | | | | $ - | |
| 27 | 403.95 | DEPR GP MISC EQUIPMENT | | | | | $ - | |

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line** | **Account** | **Description** | **Total Expense** | **Production** | **Transmission** | **Distribution** | **General** | **Amort** |
| 28 | 404.01 | AMORT LIMITED TERM PLANT | | | | | | $ - |
| 29 | | **Total** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

Note: A. Lines representing detail and sub-accounts can be added only at the same depreciation rates shown in the groupings originally listed.

Workpaper M

**East River Electric Power Cooperative, Inc.**

**Other Revenue**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line** | **Account** | **Description** | **Total Company** | **Wheeling Existing** | **Wheeling SPP P2P** | **Transmission Rents** | **Other Rents** | **Production** |
| 1 | 412.00 | Revenue from Leased Elect Plant | | | | $ - | | |
| 2 | 447.11 | SALES FOR RESALE-RUS BORROW-MINN | | | | | | |
| 3 | 447.31 | SALES MN WINDPOWER | | | | | | $ - |
| 4 | 454.00 | RENTS ELECTRIC PROPERTY SD | | | | | $ - | |
| 5 | 454.01 | RENTS ELECTRIC PROPERTY MN | | | | $ - | | |
| 6 | 454.11 | RENTS DOME PIPELINE SUB | | | | $ - | | |
| 7 | 456.00 | OTHER ELECT REVENUE WHEELING SD | | $ - | | | | |
| 8 | 456.02 | OTHER ELECT REVENUE WHEELING MN | | $ - | | | | |
| 9 | 456.03 | OTHER ELECT REVENUE WHEELING P2P | | | $ - | | | |
| 10 | | Total | $ - | $ - | $ - | $ - | $ - | $ - |

Note: The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
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Workpaper N

## East River Electric Power Cooperative, Inc.

## 350-353 Transmission Plant
## Budget Year Ending December 31, 2xxx

| A<br>Line | B<br>Account | C<br>Description | D<br>Balance Forward | E<br>YTD Trans | F<br>Debit | G<br>Credit | H<br>Year End | I<br>Microwave | J<br>Common/<br>SCADA |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 350.00 | L & LR TRANSMISSION | | | | | $ - | | |
| 2 | 350.01 | L & LR TRANS SUBS SD | | | | | $ - | | |
| 3 | 350.10 | L & LR RAILROAD R/O/W | | | | | $ - | | |
| 4 | 350.19 | L & LR TRANS SUBS HCPD | | | | | $ - | | |
| 5 | 350.20 | L & LR TRANS COMPLETED BY WO | | | | | $ - | | |
| 6 | 350.29 | L & LR TRANS BY WO HCPD | | | | | $ - | | |
| 7 | 350.30 | L & LR TRANS WORK IN PROGRESS | | | | | $ - | | |
| 8 | 350.40 | L & LR TRANS SUBS MN | | | | | $ - | | |
| 9 | 350.49 | LAND&LAND R-TR-SUB SITE-MN-HCPD | | | | | $ - | | |
| 10 | 350.50 | LAND&LAND R-TRANS-MINN | | | | | $ - | | |
| 11 | 350.59 | LAND&LAND R-TRAN-MN-WO-HCPD | | | | | $ - | | |
| 12 | 350.60 | LAND&LAND R-TRANS-M/W TOWERS-SD | | | | | $ - | $ - | |
| 13 | 352.00 | STRUCTURES&IMP-TRANS-SD | | | | | $ - | | |
| 14 | 352.01 | STRUCT.&IMP-TRANS-MINN | | | | | $ - | | |
| 15 | 352.09 | STRUCT.&IMP-TRANS-SD-HCPD | | | | | $ - | | |
| 16 | 352.19 | STRUCT&IMP-TRANS-MN-HCPD | | | | | $ - | | |
| 17 | 352.20 | STRUCT.&IMP-M/W BLDGS-SD | | | | | $ - | $ - | |
| 18 | 352.21 | STRUCT.&IMP-M/W BLDGS-SD-AFT.'93 | | | | | $ - | $ - | |
| 19 | 352.30 | STRUCT.&IMP-M/W BUILDINGS-MINN | | | | | $ - | $ - | |
| 20 | 352.31 | STRUCT.&IMP-M/W BLD-MN-AFT'93 | | | | | $ - | $ - | |
| 21 | 352.39 | STRUCT.&IMP-M/W BUILDING-MN-HCPD | | | | | $ - | $ - | |
| 22 | | STATION EQUIPMENT | | | | | $ - | | |
| 23 | 353.00 | STATION EQUIP.-TRANSMISS-SD | | | | | $ - | | |
| 24 | 353.01 | STAT.EQUIP.TR-CONTR.CTY VERMILL | | | | | $ - | | |
| 25 | 353.02 | STAT.EQUIP.-TRANSMISSION-MINN | | | | | $ - | | |
| 26 | 353.09 | STATION EQUIP.-TRANS-SD-HCPD | | | | | $ - | | |
| 27 | 353.19 | STAT.EQUIP.-TRANS-MN-HCPD | | | | | $ - | | |
| 28 | 353.30 | STAT.EQ.-REACTORS-USBR 115SBS-SD | | | | | $ - | | |
| 29 | 353.31 | STAT.EQ.REACTRS-USBR-115KV-MINN | | | | | $ - | | |
| 30 | 353.34 | STAT.EQ.41-69KV INTERC-SUBS-SD | | | | | $ - | | |
| 31 | 353.35 | STAT.EQ.41-69KV BREAKER STA-SD | | | | | $ - | | |
| 32 | 353.36 | STAT.EQ.69KV BREAKER STAT.SD | | | | | $ - | | |
| 33 | 353.40 | STAT.EQ.RADIO-MOS/BRKER-TR.SUB | | | | | $ - | | $ - |
| 34 | 353.41 | STAT.EQ.RADIO/MOS/BRKER-SUB-MINN | | | | | $ - | | $ - |
| 35 | 353.49 | STAT.EQUIP-RAD/MOS/BRKR-SD-HCPD | | | | | $ - | | $ - |

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line | Account | Description | Balance Forward | YTD Trans | Debit | Credit | Year End | Microwave | Common/ SCADA |
| 36 | 353.49 | STAT.EQ.RAD/MOS/BRK-MN-HCPD | | | | | $ - | | $ - |
| 37 | 353.50 | STAT.EQ.M/W SD | | | | | $ - | $ - | |
| 38 | 353.51 | STAT.EQ.M/W-MINN | | | | | $ - | $ - | |
| 39 | 353.52 | STAT.EQ.M/W-LIMITED TERM AGREEM | | | | | $ - | $ - | |
| 40 | 353.58 | STAT.EQ.-M/W-SD-HCPD | | | | | $ - | $ - | |
| 41 | 353.59 | STAT.EQUIP-M/W-MINN-HCPD | | | | | $ - | $ - | |
| 42 | 353.60 | STAT.EQ.M/W TOWERS-SD | | | | | $ - | $ - | |
| 43 | 353.61 | STAT.EQ.M/W TOWERS-MINN | | | | | $ - | $ - | |
| 44 | 353.68 | STAT.EQ.-M/W TOWERS-SD-HCPD | | | | | $ - | $ - | |
| 45 | 353.69 | STAT.EQ.-M/W TOWER-MINN-HCPD | | | | | $ - | $ - | |
| 46 | 350.00 | Land | $ - | $ - | | | $ - | $ - | $ - |
| 47 | 352.00 | Structures | $ - | $ - | | | $ - | $ - | $ - |
| 48 | 353.00 | Station Equipment | $ - | $ - | | | $ - | $ - | $ - |
| 49 | | **Total Substations** | **$ -** | **$ -** | | | **$ -** | **$ -** | **$ -** |

Note: A. Lines representing detail and sub-accounts can be added only at the same depreciation rates shown in the groupings originally listed.

**ADDENDUM 25 TO ATTACHMENT H - Part 2**

**East River Electric Power Cooperative**

Workpaper O

**East River Electric Power Cooperative, Inc.**

**Derivation of Microwave Qualified Bandwidth**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D |
|---|---|---|---|
| | | | % of |
| Line | Classification | Channels | Occupied BW |
| 1 | SCADA (Substation and Motor Switch RTU's, Master T1's) | | |
| 2 | Metering (load data, on-line load data and reading) | | |
| 3 | Relaying | | |
| 4 | Load Management | | |
| 5 | Edacs | | |
| 6 | Alarm RTU's | | |
| 7 | Voice (OPX and Fax) | | |
| 8 | Total | 0 | |
| 9 | Qualifying for SPP | 0 | |
| 10 | Note: Bandwidth excludes Load Management | | |

Note: A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years.
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Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

Workpaper P

# East River Electric Power Cooperative, Inc.

## Determination of Qualifying Transmission Substations Budget Year Ending December 31, 2xxx

| A | B | C | D | F | E | G | H | I | J | L | M | N | O | P | Q | R | S | T | W | U | V |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 30.13.1 | | | | | | | K | | | | | | | | | | | | | |
| | 32 | | | | | | | | | | | | | | | | | | | | |
| | Transmission | Transmission | | Voltage | | | | Transmission | Applicable | Criteria 1 | | | | Criteria 2 | Criteria 3 | Criteria 4 | | Criteria 5 | Criteria 6 | Exclusion 1 | Exclusion 2 |
| | Facility | | | Level(s) | | Capacity | Owner | Facility | One- | | | Two or More | | Interconnect | Control/Protection | Substation | | | Below 60 kV Meet 7 | Direct Assignment | Inclusion |
| Line | Name | | | (kV) | | (MVA) | ship | Under | Line | Above 60 kV | Non-Radial | Eligible Customers | Name of Customers | Zones | | 60 kV+ | to | | | | |
| 1 | | | | | | | | | Diagra | | | | | Surrounding Entities | Equipment 60 kV- | | | | | | |
| 2 | | | | | | | | | Construction | | | | | | | | | | | | |
| 3 | | | | | | | % | Location | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | | | | | | | | |
| 6 | | | | | | | | | | | | | | | | | | | | | |
| 7 | | Facility | | | | | | | | | | | | | | | | | | | Yes |
| 8 | | | | | | | | | | | | | | | | | | | | | |
| 9 | | | | | | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | | | | | | |
| 10.1 | | gm Owner | Sent | | Date | | | | | | | | | | | | | | | | |
| 11 | | | | | | | | | | | | | | | | | | | | | |
| 12 | | | | | | | | | | | | | | | | | | | | | |
| 13 | | | | | | | | | | | | | | | | | | | | | |
| 14 | | | | | | | | | | | | | | | | | | | | | |
| 15 | | | | | | | | | | | | | | | | | | | | | |
| 16 | | | | | | | | | | | | | | | | | | | | | |
| 17 | | | | | | | | | | | | | | | | | | | | | |
| 18 | | | | | | | | | | | | | | | | | | | | | |
| 19 | | | | | | | | | | | | | | | | | | | | | |
| 20 | | | | | | | | | | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | | | | | | | | | | |
| 21.1 | | | | | | | | | | | | | | | | | | | | | |
| 21.2 | | | | | | | | | | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | | | | | | | | | | |
| 23.1 | | | | | | | | | | | | | | | | | | | | | |
| 23.2 | | | | | | | | | | | | | | | | | | | | | |
| 24 | | | | | | | | | | | | | | | | | | | | | |
| 25 | | | | | | | | | | | | | | | | | | | | | |
| 26 | | | | | | | | | | | | | | | | | | | | | |
| 27 | | | | | | | | | | | | | | | | | | | | | |
| 28 | | | | | | | | | | | | | | | | | | | | | |
| 29 | | | | | | | | | | | | | | | | | | | | | |
| 30 | | | | | | | | | | | | | | | | | | | | | |

**Y**
**Totals to be Included into SPP**

**Gross Plant**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Transmission | Transmission | | | Voltage | | | Transmission | Applicable | | Criteria 1 | | | | Criteria 2 | Criteria 3 | Criteria 4 | Criteria 5 | Criteria 6 | Exclusion 1 | Exclusion 2 | Exclusion 3 | Eligible for Inclusion | Totals to be Included into SPP |
| Line | Facility Name | Facility Owner | Segment | As built Date | Level(s) (kV) | Capacity (MVA) | Ownership % | Facility Location | One-Line Diagram | Under Construction | Above 60 kV | Non-Radial | Two or More Eligible Customers | Name of Customers | Interconnect Zones Surrounding Entities | Control/Protection Equipment 60 kV- | Substation 60 kV+ to ection | DC Interconn | Below 60 kV Meet 7 Factor Test | Generator Step-Up | Generator Tie Line | Direct Assignment Facilities | Yes/No | Gross Plant |
| 33 | | | | | | | | | | | | | | | | | | | | | | | | |
| 34 | | | | | | | | | | | | | | | | | | | | | | | | |
| 35 | | | | | | | | | | | | | | | | | | | | | | | | |
| 36 | | | | | | | | | | | | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | | | | | | | | | | | |
| 38 | | | | | | | | | | | | | | | | | | | | | | | | |
| 39 | | | | | | | | | | | | | | | | | | | | | | | | |
| 40 | | | | | | | | | | | | | | | | | | | | | | | | |
| 40.1 | | | | | | | | | | | | | | | | | | | | | | | | |
| 40.2 | | | | | | | | | | | | | | | | | | | | | | | | |
| 40.3 | | | | | | | | | | | | | | | | | | | | | | | | |
| 41 | | | | | | | | | | | | | | | | | | | | | | | | |
| 42 | | | | | | | | | | | | | | | | | | | | | | | | |
| 43 | | | | | | | | | | | | | | | | | | | | | | | | |
| 44 | | | | | | | | | | | | | | | | | | | | | | | | |
| 45 | | | | | | | | | | | | | | | | | | | | | | | | |
| 46 | | | | | | | | | | | | | | | | | | | | | | | | |
| 46.1 | | | | | | | | | | | | | | | | | | | | | | | | |
| 47 | | | | | | | | | | | | | | | | | | | | | | | | |
| 48 | | | | | | | | | | | | | | | | | | | | | | | | |
| 49 | | | | | | | | | | | | | | | | | | | | | | | | |
| 50 | | | | | | | | | | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | | | | | | | | | |
| 51.1 | | | | | | | | | | | | | | | | | | | | | | | | |
| 52 | | | | | | | | | | | | | | | | | | | | | | | | |
| 53 | Total | | | | | | | | | | | | | | | | | | | | | | | $ - |
| 54 | General Ledger total | | | | | | | | | | | | | | | | | | | | | | | |

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**ADDENDUM 25 TO ATTACHMENT H - Part 3**

**East River Electric Power Cooperative**

Workpaper Q

## East River Electric Power Cooperative, Inc.

## Determination of Qualifying Distribution Substations
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Transmission Facility | Transmission Facility | | Voltage Level(s) | Capacity | Transmission Facility | Applicable One-Line | | Criteria 1 | | | | Criteria 2 | Criteria 3 | Criteria 4 | Criteria 5 | Criteria 6 | Exclusion 1 | Exclusion 2 | Exclusion 3 | Eligible for Inclusion | Totals to be Included into SPP | |
| | | | As built | | | | | Under | | | Two or More | Name | Interconnect Zones | Control/Protection | Substation | | Below 60 kV | | | Direct Assignment | | | Gross |
| Line | Name | Owner | | (kV) | (kVA) | Location | Diagram | Construction | Above 60 kV | Non-Radial | Eligible Customers | of Customers | Surrounding Entities | Equipment | 60 kV+ to 60 kV- | DC Interconnection | Meet 7 Factor Test | Generator Step-Up | Generator Tie Line | Facilities | Yes/No | Subs | Plant |
| 1a | | | | | | | | | | | | | | | | | | | | | | | |
| 1b | | | | | | | | | | | | | | | | | | | | | | | |
| 1c | | | | | | | | | | | | | | | | | | | | | | | |
| 1d | | | | | | | | | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | | | | | | | | | |
| 3 | Totals | | | | | | | | | | | | | | | | | | | | | - | - |
| 4 | | | | | | | | | | | | | | | | | | | | | | | |
| 5 | | | | | | | | | | | | | | | | | | | | | | | |

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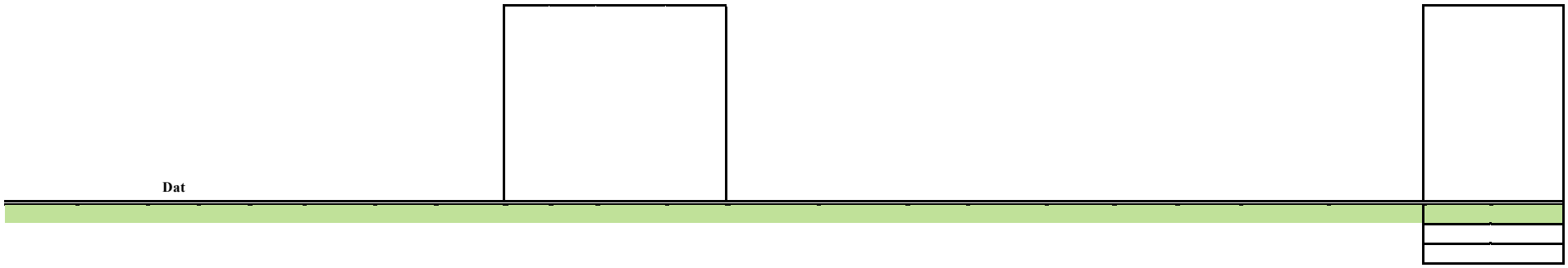

Workpaper R

**East River Electric Power Cooperative, Inc.**

**Derivation of Qualified SCADA Substation Plant**
**Budget Year Ending December 31, 2xxx**

| A<br>Line | B<br>Substation | C<br>SCADA Equipment | D<br>Accum. Depr | E<br>Net SCADA Equipment |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | | | | |
| 18 | **Total Qualifying** | **$ -** | | |
| 19 | **SCADA at Motor Operated Switch Sites Data** | | | |
| 20 | | SCADA Equipment | Accum. Depr | Net SCADA Equipment |
| 21 | MOS SCADA Total | | | |
| 22 | % Qualifying Line | | | |
| 23 | **Qualifying MOS SCADA** | | | |
| 24 | Total SCADA (Workpaper N, Line 49, Col J) | | | |

| | | |
|---|---|---|
| 25 | Total SCADA Accum. Depr | |
| 26 | % SCADA Qualifying from Above | |
| 27 | % MOS to SCADA | |
| 28 | Qualifying SCADA Accum Depr. | |



| | |
|---|---|
| 29 | MOS SCADA Accum Depr Total |

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Workpaper S

# East River Electric Power Cooperative, Inc.

## Determination of Qualifying Lines
## Budget Year Ending December 31, 2xxx

| A | B | C | D | E | F | G | H | L | I | M | N | O | K | P | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Transmission Facility | Transmission Facility | Transmission Facility | | | Voltage Level(s) | | Applicable | Line | | Criteria 1 | | Transmission | | | | | Criteria 4 | Criteria 5 | Criteria 6 | Exclusion 1 | Exclusion 2 |
| Line | Name | Owner | Description | Segment | As Conduit Date | Line Lenctor (kV) | gth | One-nder Line Diagronstrutionam | ship | U C c | Owner Ab Facility nove 60 d kV % | No Local Ratio | Two More Eligible Customers | or | Name of Customers | Criteria 2 Interconnecubst t Zones 60 Surroundin kV+ g Entities to 60 | Criteria 3 Control/Protection ation Equipment | S kV- | DC Interconnection | Below 60 kV Meet 7 Factor Test | Generator Step-Up | Generator Tie Line |

| Y | Z | AA | AB |
|---|---|---|---|
| | | | Totals to be Included |
| Exclusion 3 | into SPP Inc | Eligible for | Line |
| lusion Direct Assignmen Length t | | | |
| | | No | |
| Facilities | Yes/No | tes | (Ft) |

| A | B | C | D | E | F | G | H | L | I | M | N | O | K | P | Q | R | S | T | U | V | W | X |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Transmission Facility | Transmission Facility | Transmission Facility | | | Voltage Level(s) | | Applicable Ownership | Line Ownership | Criteria 1 | | | Transmission Two or More | | | Criteria 2 | Criteria 3 | Criteria 4 | Criteria 5 | Criteria 6 | Exclusion 1 | Exclusion 2 |
| Line | Name | Owner | Description | Segment | As Conduit built | Voltage Level(s) | Length | Applicable Ownership | Line Ownership | Facility Undergrounded | | | Transmission Two or More Eligible Customers | | Name of Customers | Interconnected Substation Zones 60 kV+ | Control/Protection Equipment | Criteria 4 | DC Interconnection | Below 60 kV Factor Test Meet 7 | Generator Step-Up | Generator Tie Line |
| 49 | | | | | | | | | | | | | | | | | | | | | | |
| 50 | | | | | | | | | | | | | | | | | | | | | | |
| 51 | | | | | | | | | | | | | | | | | | | | | | |
| 52 | | | | | | | | | | | | | | | | | | | | | | |
| 53 | | | | | | | | | | | | | | | | | | | | | | |
| 54 | | | | | | | | | | | | | | | | | | | | | | |
| 55 | | | | | Date | (kV) | | Diagram (Ft) | Construction | | 60 kV | Radial % | | | Customers | 60 kV- Surrounding Entities | Equipment | to | | | | |
| 56 | | | | | | | | | | | | | | | | | | | | | | |
| 57 | | | | | | | | | | | | | | | | | | | | | | |
| 58 | | | | | | | | | | | | | | | | | | | | | | |
| 59 | | | | | | | | | | | | | | | | | | | | | | |
| 60 | | | | | | | | | | | | | | | | | | | | | | |
| 61 | | | | | | | | | | | | | | | | | | | | | | |
| 62 | | | | | | | | | | | | | | | | | | | | | | |
| 63 | | | | | | | | | | | | | | | | | | | | | | |
| 64 | | | | | | | | | | | | | | | | | | | | | | |
| 65 | | | | | | | | | | | | | | | | | | | | | | |
| 66 | | | | | | | | | | | | | | | | | | | | | | |
| 67 | | | | | | | | | | | | | | | | | | | | | | |
| 68 | | | | | | | | | | | | | | | | | | | | | | |
| 69 | | | | | | | | | | | | | | | | | | | | | | |
| 70 | | | | | | | | | | | | | | | | | | | | | | |
| 71 | | | | | | | | | | | | | | | | | | | | | | |
| 72 | | | | | | | | | | | | | | | | | | | | | | |
| 73 | | | | | | | | | | | | | | | | | | | | | | |
| 74 | | | | | | | | | | | | | | | | | | | | | | |
| 75 | | | | | | | | | | | | | | | | | | | | | | |
| 76 | | | | | | | | | | | | | | | | | | | | | | |
| 77 | | | | | | | | | | | | | | | | | | | | | | |
| 78 | | | | | | | | | | | | | | | | | | | | | | |
| 79 | | | | | | | | | | | | | | | | | | | | | | |
| 80 | | | | | | | | | | | | | | | | | | | | | | |
| 81 | | | | | | | | | | | | | | | | | | | | | | |
| 82 | | | | | | | | | | | | | | | | | | | | | | |
| 83 | | | | | | | | | | | | | | | | | | | | | | |
| 84 | | | | | | | | | | | | | | | | | | | | | | |
| 85 | | | | | | | | | | | | | | | | | | | | | | |
| 86 | | | | | | | | | | | | | | | | | | | | | | |
| 87 | | | | | | | | | | | | | | | | | | | | | | |
| 88 | | | | | | | | | | | | | | | | | | | | | | |
| 89 | | | | | | | | | | | | | | | | | | | | | | |
| 90 | | | | | | | | | | | | | | | | | | | | | | |
| 91 | | | | | | | | | | | | | | | | | | | | | | |
| 92 | | | | | | | | | | | | | | | | | | | | | | |
| 93 | | | | | | | | | | | | | | | | | | | | | | |
| 94 | | | | | | | | | | | | | | | | | | | | | | |
| 95 | | | | | | | | | | | | | | | | | | | | | | |
| 96 | | | | | | | | | | | | | | | | | | | | | | |
| 97 | | | | | | | | | | | | | | | | | | | | | | |
| 98 | | | | | | | | | | | | | | | | | | | | | | |
| 99 | | | | | | | | | | | | | | | | | | | | | | |
| 10 | | | | | | | | | | | | | | | | | | | | | | |

| Y | Z | AA | AB |
|---|---|---|---|
| Exclusion 3 | into SPP In | Eligible for | Totals to be Included Line |
| clusion Direct Assignmen Length t | | | |
| | | No | |
| Facilities | Yes/No | tes | (Ft) |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y | Z | AA | AB |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Transmission Facility | Transmission Facility | Transmission Facility | | As built | Voltage Level(s) | Conductor | Line Length | Ownership | Transmission Facility Location | Applicable One-Line Diagram | Under Construction | Criteria 1 Above 60 kV | Criteria 1 Non-Radial | Two or More Eligible Customers | Name of Customers | Criteria 2 Interconnect Zones 60 Surrounding Entities kV- | Criteria 3 Control/Protection Equipment | Criteria 4 Substation kV+ to 60 | Criteria 5 DC Interconnection | Criteria 6 Below 60 kV Meet 7 Factor Test | Exclusion 1 Generator Step-Up | Exclusion 2 Generator Tie Line | Exclusion 3 Direct Assignment Facilities | Eligible for Inclusion Yes/No | | Totals to be Included into SPP Line Length (Ft) |
| Line | Name | Owner | Description | Segment | Date | (kV) | | (Ft) | % | n | am | ction | 60 kV | Radial | Customers | Customers | g Entities kV- | Equipment | to 60 | ection | Test | Up | Line | Facilities | Yes/No | tes | (Ft) |
| 105 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 106 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 107 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 108 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 109 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 110 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 111 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 112 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 113 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 114 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 115 | Total East River System Line Length | | | | | | | | | | | | | | | | | | | | | | | | | | #DIV/0! Ratio |

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Workpaper T

**East River Electric Power Cooperative, Inc.**

**Plant Held for Future Use**
**Budget Year Ending December 31, 2xxx**

| A<br>Line | B<br>Facility No. | C<br>Asset No. | D<br>Description | E<br>BoY Investment $ | F<br>EOY Investment $ | G<br>Average Investment $ |
|---|---|---|---|---|---|---|
| 1 | | | | | | $ - |
| 2 | | | | | | $ - |
| 3 | | | | | | $ - |
| 4 | | | | | | $ - |
| 5 | | | | | | $ - |
| 6 | | | | | | $ - |
| 7 | | | | | | $ - |
| 8 | | | | | | $ - |
| 9 | | | | | | $ - |
| 10 | | | | | | $ - |
| 11 | | | | | | $ - |
| 12 | | | | | | $ - |
| 13 | | | Subtotal Transmission Future Use Assets | $ - | $ - | $ - |
| 14 | | | | | | |
| 15 | | | Distribution Future Use Assets | $ - | $ - | $ - |
| 16 | | | | | | |
| 17 | | | General Plant Future Use Assets | $ - | $ - | $ - |
| 18 | | | | | | |
| 19 | | | Intangible Plant Future Use Assets | $ - | $ - | $ - |
| 20 | | | | | | |
| 21 | | | Total Plant Held for Future Use | $ - | $ - | $ - |

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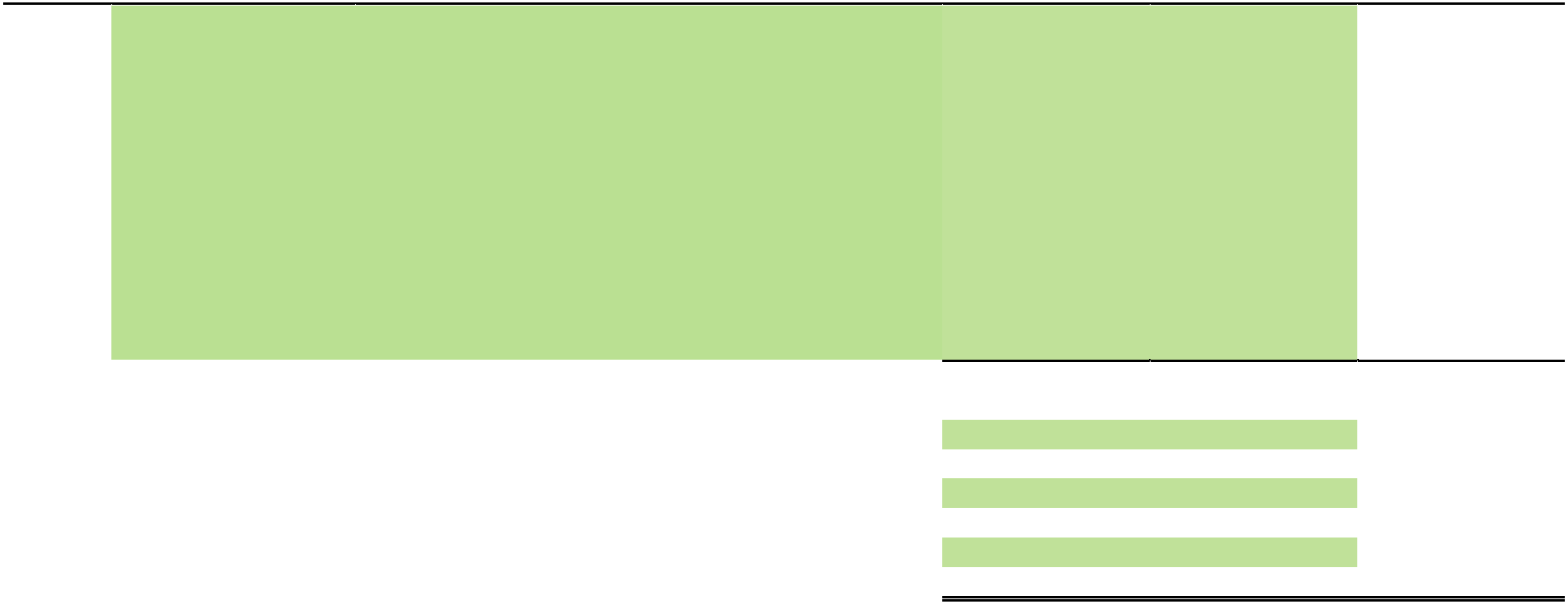
Additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.



Workpaper U

**East River Electric Power Cooperative, Inc.**
**SPP Completed Not Classified**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Fac ID | Work Order | Project | BoY Balance | EoY Balance | SPP 106 | Facility | % SPP Eligible: | BoY Amount | EoY Amount | Average | Comments |
| 1 | | | | | | | | | $0 | $0 | $0 | |
| 2 | | | | | | | | | $0 | $0 | $0 | |
| 3 | | | | | | | | | $0 | $0 | $0 | |
| 4 | | | | | | | | | $0 | $0 | $0 | |
| 5 | | | | | | | | | $0 | $0 | $0 | |
| 6 | | | | | | | | | $0 | $0 | $0 | |
| 7 | | | | | | | | | $0 | $0 | $0 | |
| 8 | | | | | | | | | $0 | $0 | $0 | |
| 9 | | | | | | | | | $0 | $0 | $0 | |
| 10 | | | | | | | | | $0 | $0 | $0 | |
| 11 | | | | | | | | | $0 | $0 | $0 | |
| 12 | | | Total | | | | | | $ - | $ - | $ - | |

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Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
Additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

Workpaper V

**East River Electric Power Cooperative, Inc.**

**Calculation of Interest applied to True-Up Calculations**
**Budget Year Ending December 31, 2xxx**

**Calculation**

| | | Annual Amount | Quarterly Amount |
|---|---|---|---|
| 1 | | | |
| 2 | ATRR Actual | | |
| 3 | ATRR Estimated | | |
| 4 | Difference | $ - | $ - |

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| | Period Start | Period Ending | Year description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance | |
| 5 | | | | | | | | | |
| 6 | | | Rate Year | | $ - | | $ - | $ - | |
| 7 | | | Rate Year | $ - | $ - | | $ - | $ - | |
| 8 | | | Rate Year | $ - | $ - | | $ - | $ - | |
| 9 | | | Rate Year | $ - | $ - | | $ - | $ - | |
| 10 | | | | $ - | | | $ - | $ - | |
| 11 | | | | $ - | | | $ - | $ - | |
| 12 | | | | $ - | | | $ - | $ - | |
| 13 | | | | $ - | | | $ - | $ - | |
| 14 | | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 15 | | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 16 | | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 17 | | | True-Up Year | $ - | $ - | | $ - | $ - | |
| 18 | | | **True-up Adjustment, "Summary"** | | | | | | $ - |

Workpaper W

**East River Electric Power Cooperative, Inc.**

**Regulatory and Commission Expenses**
**Budget Year Ending December 31, 2xxx**

| A<br>Line | B<br>Account 928 | C<br>Description | D<br>Total Company | E<br>Non-SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | Total | $ - | $ - | $ - |

Note: A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years.
Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
Additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

Workpaper X

**East River Electric Power Cooperative, Inc.**

**RTO/ISO Expenses - Operation & Maintenance**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line (A) | Account 575-576 | Description | Total Company | 575.1-575.8 Total Company Expenses | 575.1-575.8 Non-SPP Expenses | 575.1-575.8 SPP Expenses | 576.1-576.5 Total Company Expenses | 576.1-576.5 Non-SPP Expenses | 576.1-576.5 SPP Expenses (B) |
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Note: A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years.
Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

B. Amounts listed on lines 1 through 9 are only eligible for inclusion in SPP Zone 19 ATRR following a change in accounting procedures to the RUS Form 12 or Uniform System of Accounts, which would classify amounts in these accounts as eligible for transmission rate recovery. To the extent that East River recovers any of these amounts in SPP Zone 19 ATRR, it will provide details of the applicable accounting procedure changes during the annual update.

Workpaper Y

**East River Electric Power Cooperative, Inc.**

**Customer Accounting**
**Budget Year Ending December 31, 2xxx**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line** | **Account 901-905** | **Description** | **Total Company** | **T-TD Plant Allocator (Note B)** | **SPP Expenses** |
| 1 | | | | 0.00% | $ - |
| 2 | | | | 0.00% | $ - |
| 3 | | | | 0.00% | $ - |
| 4 | | | | 0.00% | $ - |
| 5 | | | | 0.00% | $ - |
| 6 | | | | 0.00% | $ - |
| 7 | | | | 0.00% | $ - |
| 8 | | | | 0.00% | $ - |
| 9 | | | | 0.00% | $ - |
| 10 | | Total Wages (Less Distribution Costs) | $ - | | $ - |
| 11 | | | | | |
| 12 | | | | 0.00% | $ - |
| 13 | | | | | |
| 14 | | | | | |
| 15 | | Total | $ - | 0.00% | $ - |
| 16 | | | | | |

Note: A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years.
Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
Additional line items or line deletions will not require FPA Section 205 or 206 filings. East River will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in East River's Implementation Protocols. East River may not change the columns or the formulas included in these Work Papers during the Annual Update.

B. T-TD Plant Allocator reference Worksheet E, Line 32 Col F.



# East River Electric Power Cooperative, Inc.

## Transmission Formula Rate Implementation Protocols

The transmission Formula Rate Template of East River Electric Power Cooperative, Inc. (East River) and these Transmission Formula Rate Implementation Protocols (Protocols) together comprise the filed rate (Formula Rate) for transmission service in transmission pricing zone, Zone 19, of the Southwest Power Pool, Inc. (SPP). East River must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement (ATRR) and the rates for Network Integration Transmission Service (NITS) and Point-to-Point (PTP) Transmission Service in Zone 19.

The initial ATRR and the initial rates will be in effect for a partial year from the effective date of transfer of functional control of East River's transmission facilities to SPP through December 31, 2015. The Formula Rate shall be recalculated each year with the resulting rates to become effective on and after January 1 of each year through December 31 of such year (Rate Year). The resulting rates implemented each January 1 will be subject to review and true-up as further provided in the Protocols.

## Section 1. Annual Updates

1. No later than 10 days after the Federal Energy Regulatory Commission (Commission) accepts for filing the Formula Rate, East River shall post its Annual Update for the following 2016 Rate Year. Beginning in 2016, the Annual Update shall include the True-up Adjustment for the preceding Rate Year, as applicable.
2. No later than September 10 of each year (Publication Date), East River, upon approval of East River's Board of Directors, shall populate the Formula Rate Template. The Annual Update shall include the populated Formula Rate Template and underlying data and calculations with sufficient detail that Interested Parties can replicate the calculations. In accordance with the Protocols East River will request that SPP post the Annual Update by September 10 of each year on the SPP OASIS. Contemporaneously, East River shall provide notice to the Interested Parties of the availability of the Annual Update along with the

time, date, location and remote access information for the Annual Meeting. The notice to Interested Parties shall be served electronically upon the Formula Rate Posting Information Notification List.[1]

3. Commencing September 11 of each year, such parties may submit written Information Requests and East River shall make a good faith effort to provide answers within ten (10) Business Days following receipt of such requests. East River will request that SPP post on the SPP OASIS responses to any such Information Requests and information regarding frequently asked questions.
4. No earlier than September 17 and no later than September 20 of each year, East River will hold an Annual Meeting with Interested Parties to explain the Formula Rate input projections and True-up Adjustments, and provide an opportunity for oral and written comments. East River shall provide in-person and remote access for participation in the Annual Meeting by Interested Parties.
5. Written comments from Interested Parties regarding both Informal Challenges and Formal Challenges must be submitted no later than November 10 and December 5, respectively. No later than December 20 of each year, East River will provide a final posting addressing all resolved issues to SPP for posting on the SPP OASIS. East River will also request SPP to post on the SPP OASIS the final Formula Rate Template and resulting ATRR to become effective January 1 of the following Rate Year. In addition, East River will provide an Informational Filing to the Commission by December 20 of each year.
6. Any modification to the Formula Rate will require filing under Section 205 or 206 of the Federal Power Act (FPA).

[1] As used in these Protocols, "Formula Rate Posting Information Notification List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification List through the "Exploder List" link on the SPP website. As of June 2016, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

## Section 2. True-up Adjustments

1. On or before September 10 of each year, East River will calculate the True-up Adjustment with supporting data inputs in sufficient detail to identify the projected and actual cost of each element of East River's ATRR and actual revenues. East River will reflect the True-up Adjustment as a line item in its Formula Rate included with the Annual Update which will be noticed on or before September 10 of each year. The True-up Adjustment will be determined as described below.

2. The actual ATRR shall be calculated in accordance with the Formula Rate Template using actual data from the previous year. For each Rate Year, East River will complete and make available for review, on the SPP OASIS, actual data as recorded in accordance with the Rural Utilities Service (RUS) Uniform Service of Accounts, including underlying data and calculations not included in East River's audited financial statements. The information provided shall include sufficient detail such that Interested Parties may replicate the calculation. An affidavit from the Manager of Finance and Accounting of East River (or a similar successor position, if applicable) attesting to the accuracy of the cost and revenue data set forth therein will also be provided. In addition, East River shall disclose and provide an explanation of any change in accounting policies and practices (including those resulting from mergers or reorganizations) that East River employed during the Rate Year that affect transmission accounts or the allocation of common costs to transmission. Actual costs incurred during the applicable Rate Year will be compared to actual revenues recovered during such period to determine whether there was any under-recovery or over-recovery. The True-up Adjustment and related calculations shall be posted no later than September 10 on the SPP OASIS.

3. Commencing September 11 of each year, any Interested Party may submit Information Requests and East River shall make a good faith effort to provide responses within ten (10) Business Days. East River will request that SPP post on the SPP OASIS responses to any such Information Requests and information regarding frequently asked questions. Written comments related to Informal Challenges and Formal Challenges must be submitted no later than November 10 and December 5, respectively, of each year. East River will request that SPP post on the SPP OASIS, the final True-up Adjustment no later

than December 20 of each year. East River will provide an Informational Filing to the Commission by December 20 of each year.

4. Interest on any over-recovery or under-recovery of the ATRR shall be based on the applicable interest rate set forth in 18 C.F.R. §35.19a of the Commission's regulations.
5. The ATRR for transmission services for the Rate Year shall be the sum of the projected ATRR for the Current Rate Year and a True-up Adjustment for the Prior Rate Year, including interest as explained above.

## Section 3. Information Requests

1. Interested Parties may begin submitting Information Requests immediately following the Posting Date of the Annual Update and will have until sixty (60) days of the date of the posting to serve reasonable Information Requests on East River for information and work papers supporting the Annual Update. Such Information Requests shall be limited to what is necessary to determine:
    a. The extent or effect of an accounting change;
    b. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;
    c. The proper application of the Formula Rate and procedures in these Protocols;
    d. The accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;
    e. The prudence of projected costs and expenditures;
    f. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Template; or
    g. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.
2. The Information Requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable.
3. East River shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within ten (10) Business Days.
4. Any delay in the timing of the Publication Date or Annual Meeting will result in an equivalent extension of time for submission of Information Requests.
5. If a deadline for Interested Parties specified in the Protocols falls on a weekend or a holiday recognized by the Commission, the deadline will be extended to the next Business Day.

6. East River shall request SPP to post on the SPP OASIS all Information Requests from Interested Parties and East River's response(s) to such

requests. If responses to Information Requests contain information deemed by East River to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and East River.

7. East River shall not claim that responses to Information Requests provided pursuant to these Protocols are subject to any settlement confidentiality privilege in any subsequent Commission proceeding addressing East River's Annual Update; however, East River may require that Interested Parties execute a non-disclosure agreement to obtain access to material that East River deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR § 388.113(c)(1).

## Section 4. Informal Challenges

1. Interested Parties shall have until November 10 (or the first Business Day after November 10 if November 10 falls on a weekend or holiday) to notify East River in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocation calculations, or other information to which the Interested Party objects and provide a sufficient explanation and documents to support its Informal Challenge. East River will make a good faith effort to respond to any Informal Challenge within ten (10) Business Days of notification of such Informal Challenge. East River, and if appropriate, SPP shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.
2. East River will request SPP to post on the SPP OASIS all Informal Challenges from Interested Parties and East River's responses to the Informal Challenges. If responses to Information Requests contain information deemed by East River to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and East River.
3. Any Informal Challenge that can be reconciled prior to, and included in the implementation of the Current Rate Year will be included in the Current Rate Year ATRR.
4. Any changes or adjustments to the Annual Update resulting from the Information Request and Informal Challenge procedures that are agreed to by East River and resolved prior to the Informational Filing shall be reported in the Informational Filing made with the Commission by East River and will be

reflected in the Annual Update for the following Rate Year if not already included in the Current Rate Year.

## Section 5. Formal Challenges

1. Formal Challenges shall:
    a. Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;
    b. Explain how the action or inaction violates the filed Formula Rate or Protocols;
    c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
        i. The extent or effect of an Accounting Change;
        ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;
        iii. The proper application of the Formula Rate and procedures in these Protocols;
        iv. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;
        v. The prudence of costs and expenditures;
        vi. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Template; or
        vii. Any other information that may reasonably have a substantive effect on the calculation of the ATRR pursuant to the Formula Rate.
    d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;
    e. State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;
    f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;
    g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and
    h. State whether the filing party utilized the Informal Challenge

procedures described in these Protocols with regard to any issue.

2. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on East River. Service to East River must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f) (3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on East River's Informational Filing required under these Protocols.
3. Any Formal Challenge must be presented by December 5 (or the next Business Day if December 5 falls on a weekend or holiday) . East River will provide a response to the Formal Challenge no later than December 15.

## Section 6. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols, and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a FPA Section 205 or Section 206 filing.
2. A change to the Formula Rate Stated Values may not be made absent the appropriate filing with the Commission pursuant to the FPA, Sections 205 or 206.
3. If East River makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the SPP Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.
4. Any changes to the data inputs or as the result of an Informal Challenge or a Commission proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the SPP Tariff, and the Commission interest rate.

## Section 7. Informational Filing

By December 20 of each year, East River shall provide to the Commission an

Informational Filing of its Annual Update under a separate docket number.

1. This Informational Filing must include the information that is reasonably necessary to determine:
    a. That input data under the Formula Rate is properly recorded in any underlying work papers.
    b. That East River has properly applied the Formula Rate and these procedures;
    c. The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and
    d. The extent of accounting changes that affect Formula Rate inputs.
2. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.
3. Contemporaneous with the making of such Informational Filing, East River shall provide notice of the Informational Filing and the associated docket number to the Interested Parties through Formula Rate Posting Information Notification List to be maintained by SPP. East River will also request that SPP post the notice and final Annual Update and True-up Adjustments on the SPP OASIS.

## Section8. Joint SPP Transmission Owners' Meeting

As applicable, each year East River shall endeavor to coordinate with other SPP transmission owners using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and transmission owners that own inter-regional projects whose costs are allocated in part to SPP members, and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

## Section 9. Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

a. "Annual Transmission Revenue Requirement" (ATRR) means the net revenue requirement for the transmission services calculated in accordance with the Formula Rate, filed for informational purposes

with the Commission,posted on the SPP OASIS on or before the annual Publication Date, and subject to review pursuant to the provisions of these Protocols.

b. "Annual Meeting" means the meeting hosted by East River for the purpose of exchanging information with Interested Parties regarding the Annual Update and True-up Adjustment.

c. "Annual Update" means East River's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

d. "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and holidays recognized by the Commission.

e. "Calendar Year" means January 1 through December 31 of a given year.

f. "Current Calendar Year" means the Calendar Year in which the Annual Update is filed (e.g., if the Annual Update is filed on September 10, 2017, the Current Calendar Year is 2017).

g. "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and filed with the Commission (e.g., if the Annual Update is filed on September 10, 2016, the Current Rate Year is January 1, 2017 through December 31, 2017).

h. "Customer(s)" or "Transmission Customer(s)" means the East River customers taking NITS service, service under Grandfathered Agreements, or PTP service.

i. "Commission" means the Federal Energy Regulatory Commission.

j. "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with the Commission, and served on East River by electronic service on the date of such filing.

k. "Formula Rate Template" means the East River transmission formula rate template set forth in Addendum 25 to Attachment H, , to the SPP Tariff.

l. "Formula Rate" means the East River Implementation Protocols together with the Formula Rate Template.

m. "FPA" means Federal Power Act.

n. "Informal Challenge" means written notification by an Interested Party to East River, during the Review Period, of any specific challenge to the Annual Update.

o. "Information Request" means a written request submitted by an Interested Party to East River.

p. "Informational Filing" means East River's annual filing at the Commission with the information stipulated in these Protocols.

q. "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a) (2) (iii), or successor regulation.

r. "Interested Party" includes but is not limited to, customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

s. "Interested Parties Review Period" means a period of up to sixty (60) days after each annual Publication Date (unless such period is extended with the written agreement of East River) during which Interested Parties may serve reasonable Information Requests on East River.

t. "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

u. "OASIS" means Open Access Same-Time Information System.

v. " SPP Tariff" means SPP's Open Access Transmission Tariff.

w. "Prior Calendar Year" means the year preceding the Current Calendar Year (e.g., if the Annual Update is filed on September 10, 2017, the Prior Calendar Year is 2016).

x. "Prior Rate Year" means the Rate Year prior to the Current Rate Year (e.g., if the Current Rate Year is January 1, 2017 through December 31, 2017, then the Prior Rate Year is January 1, 2016 through December 31, 2016).

y. "PTP Rates" means the point-to-point rates derived from the Formula Rate.

z. "Publication Date" means the date on which East River posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2016 shall be no later than September 10, provided however, that if September 10 should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

aa. "Rate Year" means January 1 through December 31 of a given year.

bb. "Review Period" means unless otherwise extended in writing by East River, sixty (60) days after the Publication Date.

cc. "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated Values include: (i) the authorized return on equity (ROE)percentage; (ii) the target equity minimum percentage; (iii) depreciation and amortization rates; and(iv) CWIP percentage recovery, and (v) direct allocation factors. Stated Values may be changed only pursuant to FPA Section 205 or 206.

dd. "True-up Adjustments" means the calculated difference between the

projected and actual ATRR for a Rate Year.

ee. "USoA" means the Rural Utilities Service Uniform System of Accounts.

| EAST RIVER EXAMPLE IMPLEMENTATION PROTOCOL SCHEDULE | | | | |
|---|---|---|---|---|
| | | | | |
| | Start | Stop | Days in Task | Days Since Posting |
| Initial Posting of ATRR Estimate | | 9/10/2016 | | |
| Annual Interested Parties Meeting | | 9/20/2016 | - | 10 |
| Information Request Period | 9/11/2016 | 10/26/2016 | 45 | 46 |
| Interested Party Review | 9/11/2016 | 11/10/2016 | 60 | 61 |
| Informal Challenge Due | 9/11/2016 | 11/10/2016 | 60 | 61 |
| Informal Challenge Resolution | 11/10/2016 | 11/25/2016 | 15 | 76 |
| Formal Challenge | 11/25/2016 | 12/5/2016 | 10 | 86 |
| Formal Challenge Response | 12/5/2016 | 12/15/2016 | 10 | 96 |
| Recalculation of ATRR | 12/15/2016 | 12/20/2016 | 5 | 101 |
| Final Posting of ATRR Estimates | | 12/20/2016 | - | 101 |
| Informational Filing | | 12/20/2016 | - | 101 |
| Rate Year | 1/1/2017 | 12/31/2017 | | |
| | | | | |
| | | | | |
| TU-Initial Posting ATRR | | 9/10/2018 | | |
| TU-Annual Interested Parties Meeting | | 9/20/2018 | - | 10 |
| TU-Information Request Period | 9/11/2018 | 10/26/2018 | 45 | 46 |
| TU-Interested Party Review | 9/11/2018 | 11/10/2018 | 60 | 61 |
| TU-Informal Challenge Review | 9/11/2018 | 11/10/2018 | 60 | 61 |
| TU-Informal Challenge Resolution | 11/10/2018 | 11/25/2018 | 15 | 76 |
| TU-Formal Challenge | 11/25/2018 | 12/5/2018 | 10 | 86 |
| TU-Formal Challenge Response | 12/5/2018 | 12/15/2018 | 10 | 96 |
| TY-Recalculation of ATRR Difference | 12/15/2018 | 12/20/2018 | 5 | 101 |
| Final Posting of ATRR Estimates | | 12/20/2018 | - | 101 |
| Informational Filing | | 12/20/2018 | - | 101 |
| True-Up Year | 1/1/2019 | 12/31/2019 | | |

# ADDENDUM 26 TO ATTACHMENT H - Part 1

## Corn Belt Power Cooperative



**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Index and Annual Update Timeline

12 Months Ended 12/31/20XX

| Line No. | Schedule/Workpaper | Description | Contents | Notes |
|---|---|---|---|---|
| | (a) | (b) | 12 Support II | Schedule 12 Cost |
| 1 | Schedule 1 | Formula Rate Template (Attachment H) | | |
| 2 | Schedule 2 | SPP Projects ATRR | | |
| 3 | Schedule 3 | Incentive ROE Calculation | | |
| 4 | Schedule 4 | Depreciation Rates | | |
| 5 | Schedule 5 | Wages & Salaries | | |
| 6 | Schedule 6 | Reconciliation | | |
| 7 | Schedule 7 | Project True-Up | | |
| 8 | Schedule 8 | CWIP | | |
| 9 | Schedule 9 | Abandoned Plant & Regulatory Assets | | |
| 10 | Schedule 10 | Communication Assets | | |
| 11 | Schedule 11 | Cost Support I | | |

| (c) | (d) |
|---|---|
| Main calculation of Corn Belt ATRR Project-specific ATRRs for SPP base plan, economic, and requested upgrades | |
| Calculates incentive return for 100 basis point ROE | |
| Stated depreciation rates for assets Monthly wages & salaries data | |
| Reconciliation for prior year errors True-up adjustment for SPP base plan, economic, and requested upgrades | |
| 13-month breakout of Construction Work in Progress | |
| 13-month breakout of regulatory assets and abandoned plant (unamortized balances and annual amortization expense) | |
| Development of CA allocator and allocation of transmission and distribution communication assets Common Plant Balances, Plant included in OATT Ancillary Services, FERC Annual Fees, EPRI/Regulatory Commission Expense, Other Transmission Amortization, Land Held for Future Use, Materials & Supplies | |
| Taxes Other than Income Taxes, Transmission Lease Payments/(Receipts) | |

| | | | |
|---|---|---|---|
| 13 | Schedule 13 | Cost Support III | 561/LSE Costs, Schedule 1 Revenue Requirements, NIMECA Revenue Requirements, 454 and 456 Revenues |
| 14 | Schedule 14 | Cost Support IV | Grandfather Interzonal Transaction Revenues, NIMECA Share of O&M Payment |
| 15 | Schedule 15 | Return on Rate Base | Calculates Return on Rate Base |
| 16 | Schedule 16 | SPP Assets | Total SPP Transmission Assets Included in Rate Base |
| 17 | Schedule 16a | Transmission Asset List | Asset Cost Detail |
| 18 | Schedule 16b | Transmission Asset List BOY | Asset Cost Detail - BOY |
| 19 | Schedule 17 | SPP Line Investments | Line assets included in SPP rates |
| 20 | Schedule 18 | SPP Substation Investments | Substation assets included in SPP rates |
| 21 | Schedule 19 | SPP MOS Investments | MOS assets included in SPP rates |

**PROCESS (PER PROTOCOLS) - EXAMPLE YEAR**

| | | |
|---|---|---|
| 1 | **June 1 each year** | ATRR is Posted on SPP OASIS and implemented using actual costs from prior calendar year (publication date) |
| 2 | **July 1 - September 1** | Corn Belt holds Annual Meeting for Interested Parties |
| 3 | **Pub date - September 15** | Interested Parties can send data requests to Corn Belt on the annual upate |
| 4 | **Pub Date - November 15** | Review Period |
| 5 | **November 15** | Deadline for Informal Challenge by interested party |
| 6 | **December 15** | Corn Belt responds to Informal Challenge |
| 7 | **January 15** | Corn Belt shall submit an informational filing at FERC |
| 8 | **March 1** | Deadline to resolve Informal Challenge and for interested parties to file Formal Challenge at FERC |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1 (Utilizing RUS Form 12 Data)

12 Months Ended 12/31/20XX

Shaded cells indicate inputs

| Line No. | Description | Source | Company Total | Allocator | SPP Transmission Amount |
|---|---|---|---|---|---|
| | (a) | | (b) | | |
| A | **NETWORK SERVICE** | | | | |
| 1 | GROSS REVENUE REQUIREMENT | Page 3, line 25, col. E | | | |
| | **REVENUE CREDITS** | | | | |
| 2 | Account No. 454 | Schedule 13, page 3, line 13, col. C | - | | |
| 3 | Account No. 456 | Schedule 13, page 3, line 13, col. E | - | | |
| 4 | Schedule 7 & 8 PTP Revenues | Schedule 13, page 1, line 13, col. F | - | | |
| 5 | Revenues from Grandfathered Interzonal Transactions | Schedule 14, page 1, line 27, col. F | - | | |
| 6 | NIMECA's share of Combined Trans System O&M | Schedule 14, page 2, line 13, col. H | - | | |
| 6a | Lease Revenue from Basin Electric Power Cooperative BEPC | RUS 12H.H.1.c | | | |
| 6b | Adjustment to BEPC Lease Revenue (Note A) | (line 6b) | - | | |
| 6c | Transmission Lease Receipts | Schedule 12, line 3a, col F | | page 2, | |
| 7 | **TOTAL REVENUE CREDITS** | sum lines (2 - 6a) - 6b + 6c | - | | |
| | **Adjustments for Upgrades** | | | | |
| 8 | Less: Base Plan Upgrades (w/o incentives) | Schedule 2, line 21, col. 21 | | page 4, | |
| 9 | Less: Economic Upgrades (w/o incentives) | Schedule 2, line 22, col. 21 | | page 4, | |
| 10 | Less: Requested Upgrades (w/o incentives) | Schedule 2, line 23, col. 21 | | page 4, | |
| 11 | True-up for Corn Belt Regional Facilities including interest | Schedule 7, line 2, col. I | | page 1, | |

(sum lines 8-11)

| | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 13 | Reconciliation - Adjustments to ATRR for Prior Year Corrections | Schedule 6, page 1, line 6, col. I | | | | - |
| 14 | **SUBTOTAL SPP ZONAL REVENUE REQUIREMENT** | (line 1 - 7 - 12 + 13) | | | | #DIV/0! |
| 15 | NIMECA Annual Transmission Revenue Requirements | Schedule 13, page 2, line 11, col. C | | | | - |
| 16 | Docket No. ER15-2028 Settlement Adjustment (Note D) | Note D | - | T P | 0.7141 06458 | 0 |
| 17 | **NET SPP ZONAL REVENUE REQUIREMENT** | (line 14 + line 15) | | | | #DIV/0! |
| B | **SCHEDULE 1** | | | | | |
| 18 | Schedule 1 Revenue Requirement | Sch 13, page 1, line 21 col c | - | T E | #DIV/0 ! | #DIV/0! |
| 19 | Reconcilliation - Adj Schedule 1 Revenue Requirement | Sch 6, page 1, line 14, col i | | | | - |
| 20 | **NET SPP SCHEDULE 1 REVENUE REQUIREMENT** | | | | | #DIV/0! |
| C | **SPP REGIONAL SERVICE** | | | | | |
| 21 | Base Plan Upgrades ATRR for SPP Collection under Schedule 11 | Schedule 2, page 4, line 21, col. 21 | | | | - |
| 22 | ATRR for Economic and Requested Upgrades | Schedule 2, page 4, lines 22 & 23, col. 21 | | | | - |
| 23 | Reconciliation - Adjs to ATRR for prior year corrections - Regional | Schedule 6, page 1, line 12, col. I | | | | - |
| 24 | | | | | | |
| 25 | **Total SPP Regional Service** | (sum lines 18-20) | | | | - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1 (Utilizing RUS Form 12 Data)

12 Months Ended 12/31/2014

| Line No. | Description | Source | Company Total | Allocator | | SPP Transmission Amount |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | | (e) |
| | **RATE BASE** | | | | | |
| | GROSS PLANT IN SERVICE | | | | | |
| 1 | Production | (RUS 12H.A.6 a + e)/2 | - | NA | 0.00 % | - |
| 2 | Transmission | (RUS 12H.A.11 a + e)/2 | - | TP | 0.00 % | - |
| 3 | Distribution | (RUS 12H.A.16 a + e)/2 | - | NA | 0.00 % | - |
| 4 | General | (RUS 12H.A.18 a + e)/2 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Intangible | (RUS 12H.A.1 a + e)/2 | - | W/S | #DIV/0! | #DIV/0! |
| 6 | Common | Schedule 11, page 1, line 14, col. E | - | CE | 0.00 % | - |
| 7 | SUBTOTAL GROSS PLANT IN SERVICE | (sum lines 1-6) | - | **GP 1=** | **0.00 %** | #DIV/0! |
| 8 | Communication/Microwave System (Note B) | (RUS 12H.A.17 a + e)/2 | - | CA | #DIV/0! | #DIV/0! |
| 9 | TOTAL GROSS PLANT IN SERVICE | (line 7 + line 8) | - | **GP 2=** | **0.00 %** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note C) | | | | | |
| 10 | Production | (RUS 12H.B.1-4 b + f)/2 | - | NA | 0.00 % | - |
| 11 | Transmission | (RUS 12H.B.5 b + f)/2 | - | TP | 0.00 % | - |
| 12 | Distribution | (RUS 12H.B.6 b + f)/2 | - | NA | 0.00 % | - |
| 13 | General | (RUS 12H.B.7 b + f)/2 less line 17 | - | W/S | #DIV/0! | #DIV/0! |
| 14 | Intangible | (RUS 12H.B.12 b + f)/2 | - | W/S | #DIV/0! | #DIV/0! |
| 15 | Common | Schedule 11, page 1, line 28, col. E | - | CE | 0.00 % | - |
| | SUBTOTAL ACCUMULATED | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 16 | DEPRECIATION | (sum lines 10-15) | - | | | #DIV/0! |
| 17 | Communication/Microwave System | Schedule 10, page 1, line 21b, col. H | - | CA | #DIV /0! | #DIV/0! |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 18 | TOTAL ACCUMULATED DEPRECIATION | (line 16 + line 17) | - | | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | | |
| 19 | Production | (line 1 - line 10) | - | | | - | |
| 20 | Transmission | (line 2 - line 11) | - | | | - | |
| 21 | Distribution | (line 3 - line 12) | - | | | - | |
| 22 | General | (line 4 - line 13) | - | | | | #DIV/0! |
| 23 | Intangible | (line 5 - line 14 | - | | | | #DIV/0! |
| 24 | Common | (line 6 - line 15) | - | | | - | |
| 25 | SUBTOTAL NET PLANT IN SERVICE | (sum lines 19-24) | - | | | | #DIV/0! |
| 26 | Communication/Microwave System | (line 8 - line 17) | - | | | | #DIV/0! |
| 27 | TOTAL NET PLANT IN SERVICE | (line 25 + line 26) | - | | | | #DIV/0! |
| | RATE BASE ADJUSTMENTS | | | | | | |
| 28 | Construction Work in Progress | Schedule 8, line 2, col. U | - | DA | 100 % | - | |
| 29 | Regulatory Assets | Schedule 9, line 3, col. X | - | DA | 100 % | - | |
| 30 | Unamortized Abandoned Plant | Schedule 9, line 4, col. X | - | DA | 100 % | - | |
| 31 | TOTAL RATE BASE ADJUSTMENTS | (sum lines 28-30) | - | | | - | |
| 32 | Land Held for Future Use | Schedule 11, page 2, line 11, col. D | - | TP | 0.00 % | - | |
| | WORKING CAPITAL | | | | | | |
| 33 | Cash Working Capital | (page 3, line 9 * 1/8) | - | | | | #DIV/0! |
| 34 | Materials & Supplies | Schedule 11, page 3, line 12, col. E | #DIV/0! | TE | #DIV /0! | | #DIV/0! |
| 35 | Prepayments | (RUS 12A.B.25) | | GP 2 | 0.00 % | - | |
| 36 | TOTAL WORKING CAPITAL | (sum lines 33-35) | #DIV/0! | | | | #DIV/0! |
| 37 | **TOTAL RATE BASE** | (sum lines 27, 31, 32, 36) | #DIV/0! | | | | #DIV/0! |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1 (Utilizing RUS Form 12 Data)

12 Months Ended 12/31/2014

| Line No. | Description | Source | Company Total | Allocator | SPP Transmission Amount |
|---|---|---|---|---|---|
| | (a) | | 17 | (b) | |
| | **O&M EXPENSE** | | Amortization of Regulatory Assets | | |
| 1 | Transmission | | (RUS 12.A A.17.b) | | A.8.b + |
| 2 | Less Property Taxes functionalized in O&M | | Schedule 12 | | |
| 3 | Less Account 561 and LSE Related Costs | | Schedule 13, page 1, line 20a, col. C | - | |
| 4 | Less Account 565 (Transmission of Electricity by Others) | | (RUS | | 12.I.A.8.a) |
| 5 | A&G | | (RUS 12.A A.14.b + A.20.b) | | |
| 6 | Less Property Taxes functionalized in A&G | | Schedule 12 | | |
| 7 | Less FERC Annual Fees | | Schedule 11, page 2, line 4, col. D | - | |
| 8 | Less EPRI and Regulatory Commission Expense | | Schedule 11, page 2, line 6, col. D | - | |
| 9 | Plus Transmission Related Regulatory Commission Expense | | Schedule 11, page 2, line 7, col. D | - | |
| 10 | Transmission Lease Payments | | Schedule 12, page 2, line 5, col. D | - | |
| 11 | **TOTAL O&M EXPENSE** | | (line 1 - 2 - 3 - 4 + 5 - 6 - 7 - 8+9+10) | - | |
| | **DEPRECIATION EXPENSE (Note C)** | | | | |
| 12 | Transmission | | (RUS 12.H.B.5.c) | | |
| 13 | Other Transmission Amortization | | Schedule 11, page 2, line 9, col. D | - | |
| 14 | General | | (RUS 12.H.B.7.c) less line 13 | | |
| 15 | Communication/Microwave System | | Schedule 10, page 1, line 21, col. I | - | |
| 16 | **TOTAL DEPRECIATION EXPENSE** | | (sum lines 10 - 13) | - | |

Schedule 9, line 3, col. l -

| | (c) | | (d) | | (e) |
|---|---|---|---|---|---|
| | | TE | #DIV/0! | | #DIV/0! |
| | - | TE | #DIV/0! | | #DIV/0! |
| | | TE | #DIV/0! | | #DIV/0! |
| | | TE | #DIV/0! | | #DIV/0! |
| | | TE | #DIV/0! | | #DIV/0! |
| | - | W/S | #DIV/0! | | #DIV/0! |
| | | W/S | #DIV/0! | | #DIV/0! |
| | | W/S | #DIV/0! | | #DIV/0! |
| | | TE | #DIV/0! | | #DIV/0! |
| | | D | 100 % | - | |
| | | | | | #DIV/0! |
| | | TP | 0.00 % | - | |
| | | TP | 0.00 % | - | |
| | | W/S | #DIV/0! | | #DIV/0! |
| | | CA | #DIV/0! | | #DIV/0! |
| | | | | | #DIV/0! |
| | | D | | | |
| | | 100 | | | |
| | | A | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 18 | Amortization of Abandoned Plant | Schedule 9, line 4, col. I | - | D A | 100 % | - |
| | **TAXES OTHER THAN INCOME TAXES** | | | | | |
| | LABOR RELATED | | | | | |
| 19 | Payroll | Schedule 12, page 1, line 2, col. D | - | W /S | #DIV /0! | #DIV/0! |
| 20 | Highway and Vehicle | Schedule 12, page 1, line 4, col. D | - | W /S | #DIV /0! | #DIV/0! |
| | PLANT RELATED | | | | | |
| 21 | Property tax transmission | Schedule 12 | - | D A | 100. 00% | - |
| 22 | Property tax A&G | Schedule 12 | - | W /S | #DIV /0! | #DIV/0! |
| 23 | Gross Receipts | Schedule 12, page 1, line 8, col. D | - | D A | 100 % | - |
| 24 | Other | Schedule 12, page 1, line 10, col. D | - | G P1 | 0.00 % | - |
| 25 | Payments in Lieu of Taxes | Schedule 12, page 1, line 12, col. D | - | G P1 | 0.00 % | - |
| 26 | **TOTAL TAXES OTHER THAN INCOME TAXES** | (sum lines 17 - 22) | - | | | #DIV/0! |
| 27 | Return on Rate Base | Schedule 15, page 1, lines 8 & 10, col. C | #DIV/0! | | | #DIV/0! |
| 28 | **GROSS REVENUE REQUIREMENT** | (line 9 + 14 + 14 + 15 + 16 +23) | #DIV/0! | | | #DIV/0! |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1 (Utilizing RUS Form 12 Data)

12 Months Ended 12/31/2014

| Line No. | Description | Source | $ Amount | % | |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | |
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | |
| 1 | Total transmission plant | Page 2, line 2, col. C | - | | |
| 2 | Less transmission plant excluded from ISO rates | Schedule 16, page 2, line 16b, col. C | #DIV/0! | | |
| 3 | Less transmission plant included in OATT Ancillary Services | Schedule 11, page 2, line 2, col. D | - | | |
| 4 | Transmission plant included in ISO rates | (line 1 - line 2 - line 3) | #DIV/0! | | |
| 5 | Percentage of Transmission Plant Included in ISO Rates | (line 4 / line 1) | | **0.00 %** | **= TP** |
| | TRANSMISSION EXPENSES INCLUDED IN ISO RATES | | | | |
| 6 | Total transmission expenses | Page 3, line 1, col. C - line 2, col. C | - | | |
| 7 | Less transmission expenses included in OATT Ancillary Services | Schedule 13, page 1, line 21, col. C | - | | |
| 8 | Included Transmission Expenses | (line 6 - line 7) | - | | |
| 9 | Percentage of transmission expenses after adjustment | (line 8 / line 6) | | #DIV/0! | |
| 10 | Percentage of transmission plant included in ISO Rates | line 5 | | 0.00 % | |
| 11 | Percentage of transmission expenses included in ISO Rates | (line 9 * line 10) | | **#DIV/0!** | **= TE** |
| | WAGES & SALARIES ALLOCATOR (W&S) | | | | |
| | | | | | **Transmission** |

| | | | $ Amount | TP | Amount | | W/S Allocator |
|---|---|---|---|---|---|---|---|
| 12 | Production | Schedule 5, page 1, line 1, col. O | - | 0.00 % | - | | |
| 13 | Transmission | Schedule 5, page 1, line 2, col. O | - | 0.00 % | - | | |
| 14 | Distribution | Schedule 5, page 1, line 3, col. O | - | 0.00 % | - | | |
| 15 | Customer Accounts, Service & Info, and Sales | Schedule 5, page 1, lines 4, 5, 6, col. O | - | 0.00 % | - | | |
| 16 | **Total Labor (Excluding A&G)** | (sum lines 12-15) | - | | - | = | **#DIV/0!** |

COMMON PLANT ALLOCATOR (CE)

| | | | $ Amount | W/S | Transmission Amount | | CE Allocator |
|---|---|---|---|---|---|---|---|
| 17 | Electric Common Plant | Schedule 11, page 1, line 14, col. B | - | #DIV/0! | #DIV/0! | | |
| 18 | Gas Common Plant | Schedule 11, page 1, line 14, col. C | - | 0.00 % | - | | |
| 19 | Water Common Plant | Schedule 11, page 1, line 14, col. D | - | 0.00 % | - | | |
| 20 | Total Common Plant | (sum line 17-19) | - | | #DIV/0! | = | **0.00%** |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1 (Utilizing RUS Form 12 Data)

12 Months Ended 12/31/2014

Notes:

This settlement adjustment (Docket No. ER15-2028) only applies to the Corn Belt 2015 and A 2016 ATRR and will expire following the 2016 rate year, at which time the amount listed on lines 6b and 6c will be 0 going forward.

B Communication and Microwave equipment is allocated between Transmission and Non-Transmission on Schedule 10. "CA" allocator is Transmission Allocator calculated on Schedule 10, line 28.

C Depreciation Rates are shown in Schedule 4 and will not be changed absent an Order from the FERC

D One-time settlement adjustment for the 2018 rate year (the year utilizing historical data from the 12 months ended 12/31/2017). For the 2018 rate year, the total company settlement adjustment will be -$119,743 per the settlement in Docket No. ER15-2028. This amount will be multiplied by the TP allocator to derive the SPP Zone 19 amount. The result will be a reduction in Corn Belt's net zonal revenue requirement. For every year other than the 2018 rate year, the total company amount will be populated with a zero, resulting in no change to the revenue requirement.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Project ATRR

12 Months Ended 12/31/20XX

| Line No | Description | Source | SPP Transmission Total | Allocator |
|---|---|---|---|---|
| | (a) | | (b) | |
| | **RATE BASE ITEMS** | | | |
| 1 | Gross Plant in Service - Transmission | | Schedule 1, page 2, line 2, col e | - |
| 2 | Accumulated Depreciation - Transmission | | Schedule 1, page 2, line 11, col e | - |
| 3 | Adjustments to Rate Base | | Schedule 1, page 2, line 31, col e | - |
| 4 | **Net Transmission Plant with Adjustments to Rate Base** | | (line 1 - line 2 + line 3) | - |
| | **O&M** | | | |
| 5 | Total O&M Allocated to Transmission | | Schedule 1, page 3, line 9, col e | |
| 6 | Transmission O&M | | Schedule 1, page 3, line 1, col e | |
| 7 | Less Account 561 and LSE related costs | | Schedule 1, page 3, line 2, col e | |
| 8 | Less Account 565 (trans of elec by others) | | Schedule 1, page 3, line 3, col e | |
| 9 | **Adjusted Transmission O&M** | | (line 6 - line 7 - line 8) | |
| 10 | Annual Allocation Factor for Transmission O&M | | (line 9 / line 1) | |
| 11 | A&G Allocated to Transmission | | (line 5 - line 9) | |
| 12 | Annual Allocation Factor for A&G | | (line 11 / line 1) | |
| | **OTHER DEPRECIATION EXPENSE** | | | |
| 13 | Other Transmission Amortization | | Schedule 1, page 3, line 11, col e | - |

14 General Allocated to Transmission Transmission Related Communications 15 Depreciation

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 12, col e Schedule | 1, | page | 3, | line | (c) | (d) | 0! | |
| 13, col e | | | | | | | #DIV/0! | |
| | | | | | | | #DIV/0! | |
| | | | | | | | | 0.00% |
| | | | | | | | #DIV/0! | |
| | | | | | | | | 0.00% |

#DIV/0!

#DIV/0!

#DIV/0!

| | | | | |
|---|---|---|---|---|
| 16 | **Total Other Transmission & General Depr & Amort** | (sum lines 13-15) | #DIV/0! | |
| 17 | Annual Allocation Factor for Other Depr & Amort | (line 16 / line 1) | | 0.00% |
| 18 | Total Other Taxes | Schedule 1, page 3, line 23, col e | #DIV/0! | |
| 19 | Annual Allocation Factor for Other Taxes | (line 18 / line 1) | | 0.00% |
| 20 | Annual Allocation Factor for Other Expense | (line 12 + line 17 + line 19) | | 0.00% |
| 21 | Return on Rate Base | Schedule 1, page 3, line 24, col e | #DIV/0! | |
| 22 | Annual Allocation Factor for Return on Rate Base | (line 21 / line 4) | | 0.00% |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Project ATRR

12 Months Ended 12/31/2014

| | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| **Line No.** | **Project Name and #** | **Type** | **Project Gross Plant** | **Project Accumulated Depreciation** | **Transmission O&M Annual Allocation Factor** |
| | | | (Note A) | | Page 1 line 10 |
| 1 | | | | | - |
| 2 | | | | | - |
| 3 | | | | | - |
| 4 | | | | | - |
| 5 | | | | | - |
| 6 | | | | | - |
| 7 | | | | | - |
| 8 | | | | | - |
| 9 | | | | | - |
| 10 | | | | | - |
| 11 | | | | | - |
| 12 | | | | | - |
| 13 | | | | | - |
| 14 | | | | | - |
| 15 | | | | | - |
| 16 | | | | | - |
| 17 | | | | | - |
| 18 | | | | | - |
| 19 | | | | | - |
| 20 | Total | | $ - | $ - | |

21

22

23





**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Project ATRR

12 Months Ended 12/31/20XX

| (6) Annual Allocation for Transmission O&M Expense | (7) Other Expense Annual Allocation Factor | (8) Annual Allocation for Other Expense | (9) Annual Expense Charge | (10) Project Net Plant | (11) Annual Allocation Factor for Return | (12) Annual Return Charge | (13) Project Depreciation/ Amortization Expense | (14) Annual Revenue Requirement |
|---|---|---|---|---|---|---|---|---|
| Col. 3 * Col. 5 | Page 1 line 20 | Col. 3 * Col. 7 | Col. 6 + Col. 8 | (Note B) | Page 1 line 22 | Col. 10 * Col. 11 | (Note C) | Sum Col. 9, 12 & 13 |
| $ - | - | $ - | $ - | $ - | - | $ - | | $ -

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
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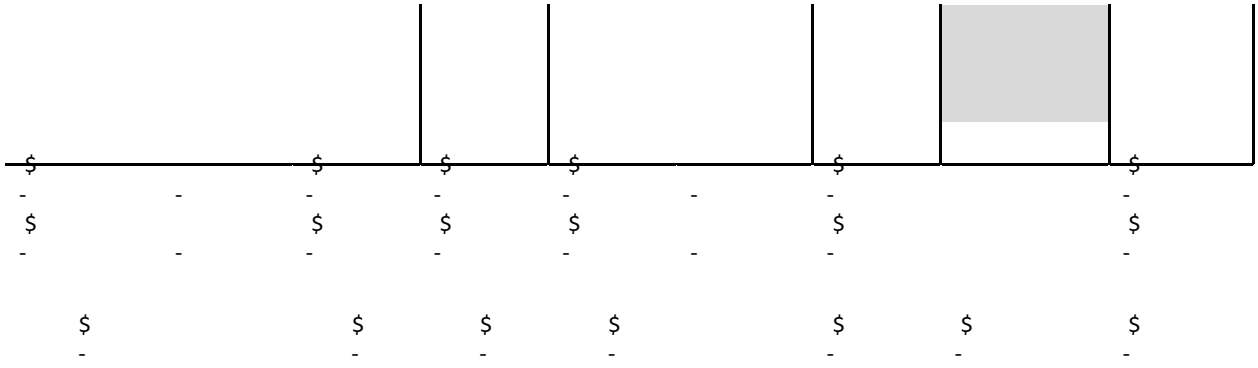

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Project ATRR

12 Months Ended 12/31/20XX

| (15) Incentive Return in basis Points | (16) Incentive Return (Schedule 3, line 9 * (Col. 15/100)) x Col. 10 | (16a) Ceiling Rate | (17) Competitive Bid Concession | (18) Total Annual Revenue Requirement | (19) True-Up Adjustment | (20) Schedule 11 PTP Revenue Credits allocated to project | (21) Net Revenue Requirement |
|---|---|---|---|---|---|---|---|
| Per FERC order (Note D) | | Sum Col. 14 & 16 | (Note E) (Enter Negative) | Sum Col. 14, 16 & 17 | (Note F) | (Note G) | Sum Col. 18 & 19, less Col. 20 |
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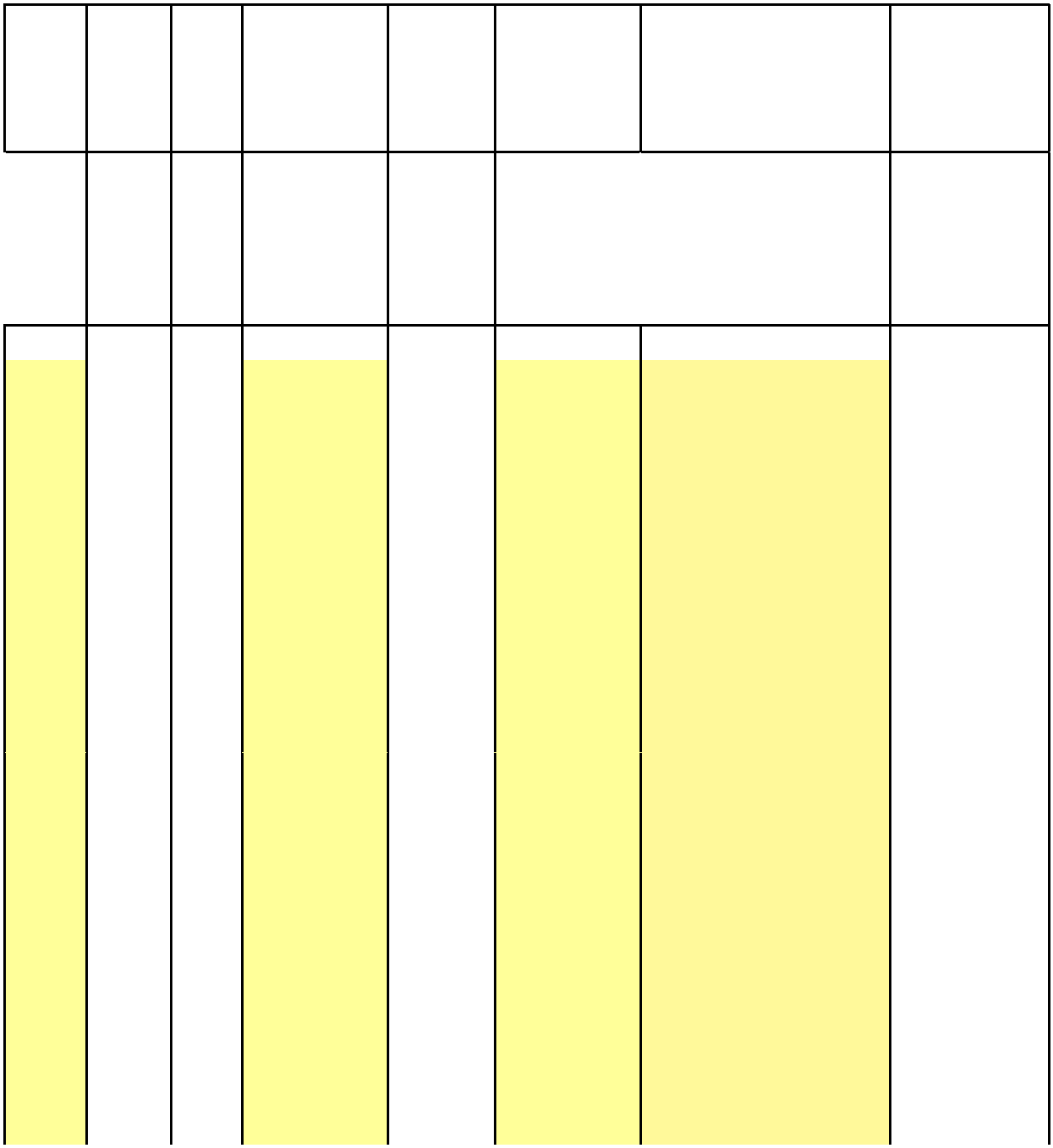

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| | |
|---|---|
| Total Base Plan Upgrades (Note H): | $ - |
| Total Economic Upgrades (Note H): | $ - |
| Total Requested Upgrades (Note H): | $ - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Project ATRR

12 Months Ended 12/31/2014

Notes

This value includes subsequent capital investments reqired to maintain the facilities to their original capabilities.
Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

B Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation in column 4.
Net Plant includes CWIP, Unamortized Abandoned Plant and any FERC approved Regulatory Asset.

C Project Depreciation Expense is the amount in Schedule 1, Page 3, line 11 that is associated with the specified project per the annual deprciation rate specified in Schedule 4.
Project Depreciation Expenses includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.
However, if FERC grants accelerated depreciation for a project the depreciation rate authorized by FERC will be used instead of the rates shown on Schedule 4 for all other projects.

D Requires approval by FERC of incentive return applicable to the specified project(s)

E Competitive Bid Concession, if any, will reflect outcome of SPP competitive developer selection process and will be computed on a workpaper that will be provided as supporting documentation for each Annual Update and will be zero or a reduction to the revenue requirement.
Additionally, the value and form of the rate reduction will be refected in a project sponsor agreement between Corn Belt Power Cooperative and SPP.

F True-Up Adjustment is calculated on Schedule 8

G Schedule 11 PTP revenue credits allocated to each project by SPP

H The sum of lines 21, 22, and 23 must equal the amount listed on line 20

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Incentive ROE

12 Months Ended 12/31/20XX

| Line No. | Description | Reference | $ Amount | % | Cost | Weighted |
|---|---|---|---|---|---|---|
| | (a) | (b) | (line 7 / line 8) | | | |
| 1 | Rate Base | Schedule 1, page 2, line 37, Col. E | | | | |
| | **100 Basis Point Incentive Return** | | | | | |
| 2 | Long Term Debt | Schedule 15, page 1, line 4 | - | | | |
| 3 | Common Stock | Schedule 15, page 1, line 5 | - | | | |
| 4 | Total | (line 2 + line 3) | - | | | |
| 5 | 100 Basis Point Incentive Return multiplied by Rate Base | (line 1 * line 4) | | | | |
| 6 | Return | Schedule 1, page 3, line 24, col. E | | | | |
| 7 | Incremental Return for 100 Basis Point Increase in ROE | (line 5 less line 6) | | | | |
| 8 | Rate Base | line 1 | | | | |
| 9 | Incremental Return for 100 basis point increase in ROE divided by Rate Base | | | | | |

| (c) | (d) | (e) | (f) |
|---|---|---|---|
| #DIV/0! | | | |
| | #DIV/0! | #DIV/0! | #DIV/0! |
| | #DIV/0! | 11.10% | #DIV/0! |
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Notes:

A Line 3 includes a 100 basis point increase in ROE that is used only to determine the increase in return associated with a 100 basis point increase in ROE. Any actual incentive calculated on Schedule 3 must be approved by the Commission.

Corn Belt Power Cooperative

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Depreciation Rates

12 Months Ended 12/31/20XX

| Line No | RUS Account Number | Description | Prior to Settlement Accept Depreciation Rate (Note A) | On and After Settlement Accept Depreciation Rate (Note A) |
|---|---|---|---|---|
| | (a) | (b) | | |
| | | **Transmission Depreciation Rates** | | |
| 1 | 352 | Transmission Structures and Improvements | | |
| 2 | 353 | Transmission Station Equipment | | |
| 3 | 354 - 359.1 | Other Transmission Plant | | |
| | | **Regional Transmission & Market Operation Depreciation Rates** | | |
| 4 | 381100 | Structures & Improvements - Microwave | | |
| 5 | 382100 | Computer Hardware - Microwave | | |
| 6 | 382150 | Computer Hardware - Microwave | | |
| 7 | 383150 | Computer Software - Microwave | | |
| 8 | 384100 | Communication Equipment-Microwave | | |
| | | **General Plant Depreciation Rates** | | |
| 9 | 390000 | Structures and Improvements | | |
| 10 | 390100 | Structures and Improvements-15 year property | | |
| 11 | 391000 | Office Furnishings - Except Computers | | |
| 12 | 391150 | Office Furnishings - 7 year property | | |
| 13 | 391200 | Office Furnishings - Computers | | |
| 14 | 391250 | Office Furnishings - Laptops | | |
| 15 | 392100-392150 | Transportation Equipment-Heavy Truck & Trailers | | |
| 16 | 392200-392250 | Transportation Equipment-Car/Light Truck | | |
| 17 | 393000 | Stores Equipment | | |
| 18 | 394000-394250 | Tools, Shop, and Garage Equipment-Trans/Elect | | |
| 19 | 394300 | Tools, Shop, and Garage Equipment-Eng/Office | | |
| 20 | 395000 | Laboratory Equipment | | |
| | | | 21 | 396000 Pow |
| | | | 22 | 397100 Com |

| (c) | (d) |
|---|---|
| 2.75% | 2.63% |
| 2.75% | 2.63% |
| 2.75% | 2.63% |
| | |
| 8.00% | 8.00% |
| 8.00% | 8.00% |
| 16.00% | 16.00% |
| 16.00% | 16.00% |
| 8.00% | 8.00% |
| | |
| 2.00% | 2.00% |
| 6.67% | 6.67% |
| 6.00% | 6.00% |
| 14.29% | 14.29% |
| 20.00% | 20.00% |
| 33.33% | 33.33% |
| 10.00% | 10.00% |
| 17.65% | 17.65% |
| 6.00% | 6.00% |
| 10.00% | 10.00% |
| 14.29% | 14.29% |
| 6.00% | 6.00% |
| 11.01% | 11.01% |
| 8.00% | 8.00% |

| | | | | |
|---|---|---|---|---|
| 23 | 397150 | Communication Equipment-Microwave Computer | 16.00% | 16.00% |
| 24 | 397300 | Communication Equipment - Radio 12.5 | 8.00% | 8.00% |
| 25 | 397350 | Communication Equipment - Video | 20.00% | 20.00% |
| 26 | 397355 | Communication Equipment - Radio 7 yr | 14.29% | 14.29% |
| 27 | 398000-398100 | Miscellaneous Equipment | 6.00% | 6.00% |
| 28 | 398200 | Miscellaneous Equipment-High Tech | 20.00% | 20.00% |

Notes:

A These depreciation rates will not change absent a filing under Section 205 or 206 of the Federal Power Act. Rates are per settlement in Docket No. ER15-2028

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 5: Wages & Salaries

12 Months Ended 12/31/20XX

| Line No | FERC Account No. (if applicable) | Description (Note A) | End-of-Month Payroll Amounts | | | | | | | | | | | | Annual Amount (sum cols. C-N) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | |
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | 500-557 | Generation | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | 560-577 | Tranmission | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | 580-598 | Distribution | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | 900-905 | Customer Accounts | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5 | 906-910 | Customer Service and Info | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 6 | 911-917 | Sales | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | 920-933 | A&G | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 8 | | **Total Expensed Labor (sum lines 1-7)** | - | - | - | - | - | - | - | - | - | - | - | - | - |

Notes:

-

| | |
|---|---|
| A | Sources for payroll amounts are company records |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Reconciliation Items, Refunds, and Surcharges

12 Months Ended 12/31/20XX

| Line No | Error Identification | Formula Reference | Rate Year (Note A) | Incorrect Amount | Correct Amount | Difference (Credit)/Chg | Impact on ATRR | Calculated Interest (Note B) | Total Adjustment to ATRR (col. G + col. H) |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **ADJUSTMENTS TO GROSS ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:** | | | | | | | | |
| 1 | | | | | | | | | - |
| 2 | | | | | | | | | - |
| 3 | | | | | | | | | - |
| 4 | | | | | | | | | - |
| 5 | | | | | | | | | - |
| 6 | **Total Adjustment to Gross ATRR (sum lines 1-5)** | | | - | - | - | - | - | - |
| | **ADJUSTMENTS TO SPP REGIONAL PROJECTS' ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:** | | | | | | | | |
| 7 | | | | | | | | | - |
| 8 | | | | | | | | | - |
| 9 | | | | | | | | | - |
| 10 | | | | | | | | | - |
| 11 | | | | | | | | | - |
| 12 | **Total Adjustment to Regional Projects' ATRR (sum lines 7-11)** | | | - | - | - | - | - | - |
| | **ADJUSTMENTS TO SPP SCHEDULE 1 ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:** | | | | | | | | |

13 -

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 14 | **Total Adjustment to Schedule 1 (sum line 13)** | - | - | - | - | - | - |

Notes:

A Rate Year in which the error occurred and affected the ATRR and rates paid by customers.

B Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: SPP Regional Project True-Up

12 Months Ended 12/31/20XX

| Line No | Project Name | Project Number | Actual Revenues from SPP (RUS Form 12) | Actual Net Revenue Requirement | True-Up Adjustment Principal Under/(Over) (col. D - col. C) | Prior Period Adjustment (Note A) (line 3a-3xx, col. E) | Applicable Interest Rate (Note B) (page 2, line 22) | True-Up Adjustment Interest (col. E + col. F) x col. G x 24 | Total True-Up Adjustment col. E + col. F + col. H |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| | **Under/(Over) Recovery True-Up Adjustment** | | | | | | | | |
| 1a | | | - | - | - | - | 0.00% | - | - |
| 1b | | | - | - | - | - | 0.00% | - | - |
| 1c | | | - | - | - | - | 0.00% | - | - |
| 1d | | | - | - | - | - | 0.00% | - | - |
| ... | | | - | - | - | - | 0.00% | - | - |
| ... | | | - | - | - | - | 0.00% | - | - |
| 2 | **Total Under/(Over) Recovery (sum lines 1a - 1xx)** | | | | | | | | - |

| Project Name | Description of Adjustment | Amount in Dollars | Interest (Note B) | Total Adjustment (col. C + col. D) |
|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) |

| | Prior Period Adjustments | | |
|---|---|---|---|
| 3 | | | |
| a | - | - | - |

| | | | | |
|---|---|---|---|---|
| 3b | | - | - | - |
| 3c | | - | - | - |
| ... | | - | - | - |
| ... | | - | - | - |
| 4 | **Total Prior Period Adjustments (sum lines 3a - 3xx)** | | | - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: SPP Regional Project True-Up

12 Months Ended 12/31/2014

| Line No. | Month (Note B) | Year | Interest Rates Under Section 35.19(a) |
|---|---|---|---|
| 1 | June | | 0.00% |
| 2 | July | | 0.00% |
| 3 | August | | 0.00% |
| 4 | September | | 0.00% |
| 5 | October | | 0.00% |
| 6 | November | | 0.00% |
| 7 | December | | 0.00% |
| 8 | January | | 0.00% |
| 9 | February | | 0.00% |
| 10 | March | | 0.00% |
| 11 | April | | 0.00% |
| 12 | May | | 0.00% |
| 13 | June | | 0.00% |
| 14 | July | | 0.00% |
| 15 | August | | 0.00% |
| 16 | September | | 0.00% |
| 17 | October | | 0.00% |
| 18 | November | | 0.00% |
| 19 | December | | 0.00% |
| 20 | January | | 0.00% |
| 21 | February | | 0.00% |
| 22 | **Average Monthly FERC Rate** | | 0.00% |

Notes:

A Prior Period Adjustments are when an error is discovered relating to a prior true-up or refunds/surcharges ordered by FERC. Prior period adjustment amounts listed must be supported in lines 3a-3xx for the corresponding project name.

B The interest on the Prior Period Adjustment excludes interest for the current true up period, because that interest is included in

Row 1x column (i).

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Transmisison Construction Work in Progress

13 Months ended 12/21/2014

| Line No | Project Description (Note A) | In-Service Approval Docket No | % Recovery Approved (Note B) | Project ID | Construction Start Date | Date (Estimated) | Dec. 2013 | Jan 2014 | Feb 2014 |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| 1a | | | | | | | | | |
| 1b | | | | | | | | | |
| 1c | | | 0.00% | | | | - | - | - |
| ... | | | 0.00% | | | | - | - | - |
| ... | | | 0.00% | | | | - | - | - |
| ... | | | 0.00% | | | | - | - | - |
| | | | 0.00% | | | | - | - | - |

**13 End-of-Month Balances for Rate Year**

| Mar. | Apr | May | Jun | Jul. | Aug. | Sep. | Oct | Nov. | Dec. | 13-Month Avg. Balance | Includable in Rate Base (Note C) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | | | | (col. g through s)/13 | (col. c * col. t) |
| (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) |
| - | - | - | - | - | - | - | | | | | |
| - | - | - | - | - | - | - | | | | | |
| - | - | - | - | - | - | - | | | | | |
| - | - | - | - | - | - | - | | | | | |
| - | - | - | - | - | - | - | | | | | |
| - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | - | - | - | - | - |
| | | | | | | | - | - | - | - | - |
| | | | | | | | - | - | - | - | - |
| | | | | | | | - | - | - | - | - |
| | | | | | | | - | - | - | - | - |
| | | | | | | | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | 0.00 | | | | | | | | | | | | | | | | |
| ... | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | 0.00 | | | | | | | | | | | | | | | | |
| ... | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | 0.00 | | | | | | | | | | | | | | | | |
| ... | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | 0.00 | | | | | | | | | | | | | | | | |
| ... | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | | 0.00 | | | | | | | | | | | | | | | | |
| ... | | % | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |
| | Total CWIP Includable in Rate | | | | | | | | | | | | | | | | | |
| 2 | Base | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | |

Notes:

A: Only include projects approved for SPP Zone 19 (UMZ) transmission cost recovery

B: Percentage recovery cannot be added or changed absent approval from FERC

C: AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization. Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 9: Regulatory Assets and Abandoned Plant

13 Months Ended 12/31/2014

| Line No. | Project Description (Notes A and F) | Project ID | Approval Docket No. | % Recovery Approved (Note B) | Total Project Amount (Note B) | Recovery Period (Months) (Note B) | Monthly Amort. Expense (col. e / col. f) | Rate Year Amort. Periods (Months) | Rate Year Amort. Expense (col. d * col. g * col. h) |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| 1a | | | | 0.00% | - | | - | | - |
| 1b | | | | 0.00% | - | | - | | - |
| 1c | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |
| ... | | | | 0.00% | - | | - | | - |

| | | | |
|---|---|---|---|
| ... | 0.00% | - | - |

| | | | | | |
|---|---|---|---|---|---|
| ... | | 0.00% | - | - | - |
| ... | | 0.00% | - | - | - |
| ... | | 0.00% | - | - | - |
| ... | | 0.00% | - | - | - |

| | | |
|---|---|---|
| 2 | Total Regulatory Asset and Abandoned Plant Amortization Expense for Rate Year (Notes D and E): | - |
| 3 | Annual Amortization of Regulatory Assets (Note C): | - |
| 4 | Annual Amortization of Abandoned Plant (Note C): | - |

Notes:

A Only include projects approved for SPP Zone 19 (UMZ) transmission cost recovery

B Regulatory Assets and/or Abandoned Plant cannot be included absent FERC approval. Amounts, percentages includable, and amortization periods cannot be added or changed absent FERC approval.

C The totals of lines 3 and 4 must equal the amounts on line 2

D Recovery of Regulatory Asset permitted only for pre-commercial and formation expenses related to projects and are subject to FERC approval before any Regulatory Asset amounts are included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal equal to the AFUDC rate will be applied to the Regulatory Asset prior to the rates becoming effective.

E Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.

Recovery of Abandoned Plant Cost permitted only subject to FERC F approval before any Abandoned Plant Costs are included in rates

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 9: Regulatory Assets and Abandoned Plant

13 Months Ended 12/31/2014

| 13 End-of-Month Unamortized Balances for Rate Year | | | | | | | | | | | | | 13-Month | Includable in |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dec. | Jan. | Feb. | Mar. | Apr. | May | Jun. | Jul. | Aug. | Sep. | Oct. | Nov. | Dec. | Avg. Balance | Rate Base (col. d * col. w) |
| 2013 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | 2014 | (col. j through v) /13 | |
| (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) | (v) | (w) | (x) |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

Total Unamortized Regulatory Assets and Abandoned Plant Includable in Rate Base (Notes D and E): -

Total Unamortized Regulatory Assets (Note C): -

Total Unamortized Abandoned Plant (Note C): -

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 10: Communication Assets

12 Months Ended 12/31/20XX

| Line No. | Description (Note A) | Source/Calculation | Account No. | Not in SPP | In SPP | Must Be Allocated | Total | Accumulated Depreciation | Annual Depr. Expense |
|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) |
| 1 | Switching Equipment | Company Records | 382 | | | | - | | |
| 2 | Switching Equipment | Company Records | 384 | | | | - | | |
| 3 | Warehouses - Other | Company Records | 384 | | | | - | | |
| 4 | Warehouses - Control Center | Company Records | 382 | | | | - | | |
| 5 | Warehouses - Control Center | Company Records | 383 | | | | - | | |
| 6 | Other (part of control center) | Company Records | 381 | | | | - | | |
| 7 | Other (part of control center) | Company Records | 382 | | | | - | | |
| 8 | Other (part of control center) | Company Records | 384 | | | | - | | |
| 9 | Control Center | Company Records | 382 | | | | - | | |
| 10 | Control Center | Company Records | 383 | | | | - | | |
| 11 | Control Center | Company Records | 384 | | | | - | | |
| 12 | Yukon Load control system for subs | Company Records | 383 | | | | - | | |
| 13 | Yukon Load control system for subs | Company Records | 384 | | | | - | | |
| 14 | Microwave Sites | Company Records | 380 | | | | - | | |
| 15 | Microwave Sites | Company Records | 381 | | | | - | | |
| 16 | Microwave Sites | Company Records | 382 | | | | - | | |
| 17 | Microwave Sites | Company Records | 383 | | | | - | | |
| 18 | Microwave Sites | Company Records | 384 | | | | - | | |
| 19 | | Company | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 9 | Substations | Records | 382 | - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20 | Substations | Company Records | 384 | | | | - | | |
| 21 | **Total Communications Assets** | (sum lines 1-20) | | - | - | - | - | - | - |
| 21a | | | | | Amount from Prior Year | | | | |
| 21 b | **Allocation of Communication Assets to SPP** | | | | | B/E Yr. Avg | - | - | (RUS 12H.A.17 a + e)/2 |
| 22 | Other (part of control center) | (lines 6-8 * T1) | | | #DIV/0! | | | | |
| 23 | Communication Assets (excluding Other (part of control center)) | ((lines 1-5 + lines 9-20) * T2) | | | #DIV/0! | | | | |
| 24 | **Total Communication Assets Allocated to SPP** | (sum lines 22-23) | | | #DIV/0! | | | | |
| 25 | **Total Communication Assets Includable in SPP** | (line 21 + line 24) | | | #DIV/0! | | | | |
| 26 | Percentage of Total Communication Assets | (line 25 / line 21, col. G) | | | #DIV/0! | | | | |
| 27 | TP Allocator | Schedule 1, page 4, line 5, col. D | | | 0.00% | | | | |
| 28 | Communication Assets Allocator ("CA") | (line 26 * line 27) | | | **#DIV/0!** | **= CA** | | | |

| | | | **$ Amount** | **%** | | **% (w/ generation)** | |
|---|---|---|---|---|---|---|---|
| 29 | Generation Plant (Note B) | | | **0.00 %** | **= G1** | **5.00%** | **= G2** |
| 30 | Transmission Plant (Note C) | Company Records | | **#DIV/0!** | **= T1** | **#DIV/0!** | **= T2** |
| 31 | Distribution Plant | Schedule 1, page 2, line 3, col. C | - | **#DIV/0!** | **= D1** | **#DIV/0!** | **= D2** |
| 32 | **Total Plant** | | - | #DIV/0! | | #DIV/0! | |

Notes:

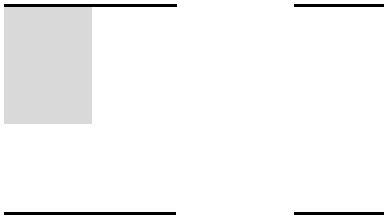
A Communication asset amounts based on average BOY/EOY balances. Corn Belt does not often dispatch

generation from the control center. 5

B percent allocation factor assumed.







| | |
|---|---|
| C | Excludes transmission assets at jointly owned plants where the majority owner does the telemetry, not Corn Belt |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 11: Cost Support I

12 Months Ended 12/31/2014

| Line No | Month | Electric Common Plant | Gas Common Plant | Water Common Plant | Total Common Plant |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **Common Plant Gross Plant in Service (Note A)** | | | | |
| 1 | December | - | - | - | - |
| 2 | January | - | - | - | - |
| 3 | February | - | - | - | - |
| 4 | March | - | - | - | - |
| 5 | April | - | - | - | - |
| 6 | May | - | - | - | - |
| 7 | June | - | - | - | - |
| 8 | July | - | - | - | - |
| 9 | August | - | - | - | - |
| 10 | September | - | - | - | - |
| 11 | October | - | - | - | - |
| 12 | November | - | - | - | - |
| 13 | December | - | - | - | - |
| 14 | **Total (sum lines 1 through 13)** | - | - | - | - |
| | **Common Plant Accumulated Depreciation (Note A)** | | | | |
| 15 | December | - | - | - | - |
| 16 | January | - | - | - | - |
| 17 | February | - | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 18 | March | - | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 19 | April | - | - | - | - |
| 20 | May | - | - | - | - |
| 21 | June | - | - | - | - |
| 22 | July | - | - | - | - |
| 23 | August | - | - | - | - |
| 24 | September | - | - | - | - |
| 25 | October | - | - | - | - |
| 26 | November | - | - | - | - |
| 27 | December | - | - | - | - |
| 28 | **Total (sum lines 15 through 27)** | - | - | - | - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 11: Cost Support I

12 Months Ended 12/31/2014

| Line No. | Description | Account No. (if applicable) | Source | $ Amount |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | **Transmission Plant Included in OATT Ancillary Services (Note A) (Note B)** | | | |
| 1a | Description | XXX | Source Reference | - |
| 1b | | | | - |
| 1c | | | | - |
| … | | | | - |
| … | | | | - |
| 2 | **Total Transmission Plant Included in OATT Ancillary Services** | | (sum lines 1a-1xx) | - |
| | **FERC Annual Fees** | | | |
| 3a | Description | XXX | Source Reference | - |
| 3b | | | | - |
| 3c | | | | - |
| … | | | | - |
| … | | | | - |
| 4 | **Total FERC Annual Fees** | | (sum lines 3a-3xx) | - |
| | **EPRI and Regulatory Commission Expense (Note C)** | | | |
| 5a | Description | XXX | Source Reference | - |
| 5b | | | | - |
| 5c | | | | - |
| … | | | | - |

...

-

| | | | | |
|---|---|---|---|---|
| 6 | **Total EPRI Regulatory Commission Expense** | | (sum lines 5a-5xx) | - |
| 7 | Total Transmission Related Regulatory Commission Expense | XXX | Source Reference | - |
| | **Other Transmission Amortization** | | | |
| 8a | | | Company Records | |
| 8b | | | | |
| 8c | | | | |
| … | | | | |
| … | | | | |
| 9 | **Total Other Transmission Amortization** | | (sum lines 8a-8xx) | - |
| | **Land Held for Future Use (Note A) (Note D)** | | | |
| 10a | Description | XXX | Source Reference | - |
| 10b | | | | - |
| 10c | | | | - |
| … | | | | - |
| … | | | | - |
| 11 | **Total Land Held for Future Use** | | (sum lines 10a-10xx) | - |



**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 11: Cost Support I

12 Months Ended 12/31/20XX

| **Line No.** | **Description** | **Source** | **Beginning of Year Balance** (RUS 12H.G.a) | **End of Year** (RUS 12H.G.d) | **Average BOY/EOY Balance** (col. B + C) / 2 |
|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) |
| | **Materials & Supplies** | | | | |

| | | |
|---|---|---|
| 1 | Coal | - |

| | | | | | |
|---|---|---|---|---|---|
| 2 | Other Fuel | | | | - |
| 3 | Production Plant Parts and Supplies | | | | - |
| 4 | Station Transformers and Equipment | | | | - |
| 5 | Line Materials and Supplies | | | | - |
| 6 | Other Materials and Supplies | | | | - |
| 7 | **Total Materials & Supplies (sum lines** | (sum lines 1-6) | - | - | - |
| 8 | Transmission & Distribution Materials & Supplies | (line 4 + line 5) | - | - | - |
| | | | **$** | **%** | |
| 9 | Transmission Plant Investment | Schedule 1, page 2, line 2 | - | #DIV/0! | **= T/D** |
| 10 | Distribution Plant Investment | Schedule 1, page 2, line 3 | - | #DIV/0! | |
| 11 | Total Transmission & Distribution Plant Investment | (line 9 + line 10) | - | #DIV/0! | |
| 12 | Materials & Supplies Allocable to Transmission | (line 8, col. E * T/D) | | | #DIV/0! |

Notes:

A Balances listed must be the average of the BOY and EOY balances for the historic year used.

B To the extent any investment in transmission plant is recovered in ancillary services, report the investment here

C Specify if the regulatory commission expense is transmission-related. Transmission-related regulatory commission expenses should be totaled together on page 2, line 7.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 12: Cost Support II

12 Months Ended 12/31/20XX

| Line No. | Description | Tax Rate (if applicable) | Source | $ Amount |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | **Payroll Taxes (Note A)** | | | |
| 1a | Description | XXX | Source Reference | - |
| 1b | | | | - |
| 1c | | | | - |
| … | | | | - |
| … | | | | - |
| 2 | **Total Payroll Taxes** | | (sum lines 1a-1xx) | - |
| | **Highway and Vehicle Taxes (Note A)** | | | |
| 3a | Description | XXX | Source Reference | - |
| 3b | | | | - |
| 3c | | | | - |
| … | | | | - |
| … | | | | - |
| 4 | **Total Highway and Vehicle Taxes** | | (sum lines 3a-3xx) | - |
| | **Property Taxes (Note A)** | | | |
| 5a | Transmission Property tax (Non SPP Assets Only) | N/A | G/L less Sch 17 | |
| 5b | Transmission Property tax (SPP Assets Only) | | Schedule 17 | |
| 5c | Reconcilliation (over payment in prior year) | | G/L | |
| 5d | Subtotal Transmission Property Tax inlcuded in O&M | | (sum lines 5a-5c) | - |
| 5e | A&G Property tax | | G/L | |
| … | | | | |
| 6 | **Property Taxes** | | (sum lines 5d-5xx) | - |
| | **Gross Receipts Taxes (Note A)** | | | |
| 7a | Description | XXX | Source Reference | - |
| 7b | | | | - |

| | |
|---|---|
| 7c | - |
| ... | - |

| | | | | |
|---|---|---|---|---|
| ... | | | | - |
| 8 | **Total Gross Receipts Taxes** | | (sum lines 7a-7xx) | - |
| | **Other Taxes (Note A)** | | | |
| 9a | Description | XXX | Source Reference | - |
| 9b | | | | - |
| 9c | | | | - |
| ... | | | | - |
| ... | | | | - |
| 10 | **Total Other Taxes** | | (sum lines 9a-9xx) | - |
| | **Payments in Lieu of Taxes (Note A)** | | | |
| 11a | Description | XXX | Source Reference | - |
| 11b | | | | - |
| 11c | | | | - |
| ... | | | | - |
| ... | | | | - |
| 12 | **Total Payments in Lieu of Taxes** | | (sum lines 11a-11xx) | - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 12: Cost Support II

~~12 Months Ended 12/31/2014~~

| Line No. | Description | 3rd Party (if applicable) | Source | $ Amount |
|---|---|---|---|---|
| | (a) | (b) | (c) | (d) |
| | **Transmission Lease Payments** | | | |
| 1a | Description | XXX | Source Reference | - |
| 1b | | | | - |
| 1c | | | | - |
| … | | | | - |
| … | | | | - |
| 2 | **Total Transmission Lease Payments** | | (sum lines 1a-1xx) | - |
| | **Transmission Lease Receipts** | | | |
| 3a | Pre-existing transmission lease agreement | Alliant Energy/IPL | Company Records | |
| 3b | | | | - |
| 3c | | | | - |
| … | | | | - |
| … | | | | - |
| 4 | **Total Transmission Lease Receipts** | | (sum lines 3a-3xx) | - |
| 5 | Total Transmission Lease Payments & Receipts | | (line 2 less line 4) | - |

Notes:

A Property Taxes that are functionalized and included in O&M RUS repoting are removed from O&M on Schedule 1.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 13: Cost Support III

12 Months Ended 12/31/20XX

| Line No. | Month | Expenses Account 561 | MAPP MAPCOR Exp | MRO NERC Exp | Line Rental Exp | Schedules 7 & 8 PtP Revenues |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | January | | | | | |
| 2 | February | | | | | |
| 3 | March | | | | | |
| 4 | April | | | | | |
| 5 | May | | | | | |
| 6 | June | | | | | |
| 7 | July | | | | | |
| 8 | August | | | | | |
| 9 | September | | | | | |
| 10 | October | | | | | |
| 11 | November | | | | | |
| 12 | December | | | | | |
| 13 | **Total (sum lines 1-12)** | - | - | - | - | - |

| Line No. | Description | Source | $ Amount |
|---|---|---|---|
| | (a) | (b) | (c) |
| | **Adjustments to Transmission Expense to Reflect LSE Cost Responsibility in Accounts Other than Account 561** | | |
| 14a | Direct Assignment Charge | | - |

1

4

b Sponsored (Requested or Economic) Upgrades Charge -

| | | | | |
|---|---|---|---|---|
| 14c | Firm and Non-Firm Point-To-Point Charges | | - | |
| 14d | Base Plan Charges | | - | |
| 14e | Schedule 9 Charges | | - | |
| 14f | SPP Schedule 1-A | | - | |
| 14g | SPP Annual Assessment | | - | |
| 14h | NERC Assessment | | - | |
| 14i | Ancillary Services Expenses | | - | |
| ... | | | - | |
| ... | | | - | |
| 15 | **Total Adjustments** | (sum lines 14a - 14xx) | - | |
| | **Adjustments to Acct. 561 and Ancillary Schedule 1 Revenue Requirements** | | | |
| 16 | Account 561 | line 13, col. B | - | |
| 17 | Less LSE Related Costs in 561 | line 15, col. C | - | |
| 18 | Less MAPP MAPCOR | line 13, col. C | - | |
| 19 | Less MRO-NERC | line 13, col. D | - | |
| 20 | Less Line Rentals | line 13, col. E | - | |
| 20a | Total Adjustments to Acct. 561 | sum lines 17 - 20 | - | to Sch 1, page 3, line 2, col. C |
| 21 | **Total Ancillary Schedule 1 Revenue Requirement** | (line 16 less line 20a) | - | to Sch 1, page 1, line 17, col. C |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 13: Cost Support III

12 Months Ended 12/31/2014

| Line No. | Month | Source | Account 454 (Note B) | Source | Account 456 | Total Accounts 454 & 456 |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | January | Company Records | - | Company Records | - | - |
| 2 | February | Company Records | - | Company Records | - | - |
| 3 | March | Company Records | - | Company Records | - | - |
| 4 | April | Company Records | - | Company Records | - | - |
| 5 | May | Company Records | - | Company Records | - | - |
| 6 | June | Company Records | - | Company Records | - | - |
| 7 | July | Company Records | - | Company Records | - | - |
| 8 | August | Company Records | - | Company Records | - | - |
| 9 | September | Company Records | - | Company Records | - | - |
| 10 | October | Company Records | - | Company Records | - | - |
| 11 | November | Company Records | - | Company Records | - | - |
| 12 | December | Company Records | - | Company Records | - | - |
| 13 | Total | (sum lines 1-12) | - | (sum lines 1-12 | - | - |

Notes:

A New NIMECA members may not be added absent a Section 205 filing with the Commission.

B Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 14: Cost Support IV

12 Months Ended 12/31/20XX

| Line No | Historic Month (Note A) | kWh | Loss Factor | kWh Grossed Up for Losses | Contract Charge | Adjustment | Monthly Revenues |
|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | | (f) |
| | **GRANDFATHERED INTERZONAL TRANSACTION REVENUES (Note B)** | | | | | | |
| | **Substation V** | | | | | | |
| 1 | January | | | - | | | $ - |
| 2 | February | | | - | | | $ - |
| 3 | March | | | - | | | $ - |
| 4 | April | | | - | | | $ - |
| 5 | May | | | - | | | $ - |
| 6 | June | | | - | | | $ - |
| 7 | July | | | - | | | $ - |
| 8 | August | | | - | | | $ - |
| 9 | September | | | - | | | $ - |
| 10 | October | | | - | | | $ - |
| 11 | November | | | - | | | $ - |
| 12 | December | | | - | | | $ - |
| 13 | **Total Substation V Revenues** | - | | - | | | $ - |
| | **Substation R** | | | | | | |
| 14 | January | | | - | | | $ - |
| 15 | February | | | - | | | $ - |
| 16 | March | | | - | | | $ - |

| | | | $ |
|---|---|---|---|
| 17 | April | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 18 | May | | - | | $ - |
| 19 | June | | - | | $ - |
| 20 | July | | - | | $ - |
| 21 | August | | - | | $ - |
| 22 | September | | - | | $ - |
| 23 | October | | - | | $ - |
| 24 | November | | - | | $ - |
| 25 | December | | - | | $ - |
| 26 | **Total Substation V Revenues** | - | - | | - |
| 27 | **Total Substation V and R Revenues (sum lines 13 and 26, col. F)** | | | | $ - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 14: Cost Support IV

12 Months Ended 12/31/2014

| Line No. | Historic Month | Trans. Usage kWh | Trans. Usage Rate | Trans. Usage Charge | Dispatch kWh | Dispatch Rate | Dispatch Charge | Subtotal |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| | **NIMECA Payments to Corn Belt for Share of O&M (Note C)** | | | | | | | |
| 1 | January | | | $ - | | | $ - | $ - |
| 2 | February | | | $ - | | | $ - | $ - |
| 3 | March | | | $ - | | | $ - | $ - |
| 4 | April | | | $ - | | | $ - | $ - |
| 5 | May | | | $ - | | | $ - | $ - |
| 6 | June | | | $ - | | | $ - | $ - |
| 7 | July | | | $ - | | | $ - | $ - |
| 8 | August | | | $ - | | | $ - | $ - |
| 9 | September | | | $ - | | | $ - | $ - |
| 10 | October | | | $ - | | | $ - | $ - |
| 11 | November | | | $ - | | | $ - | $ - |
| 12 | December | | | $ - | | | $ - | $ - |
| 13 | **Total NIMECA O&M Payments** | - | | $ - | - | | $ - | $ - |

Notes:

Shaded area indicates input

A value from Corn Belt

B Revenue received by Corn Belt for MEC loads in WAUE Control Area--SPP GFA #779

C Calculated per agreement between Corn Belt and NIMECA

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 15: Return on Rate Base

12 Months Ended 12/31/20XX

| Line No. | Description | Source | | $ Amount | Actual % | Higher of 35% or Actual Equity (Note A) | Cost (Note B) | Weighted Cost |
|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | | (c) | (d) | (e) | (f) | (g) |
| | COST OF LONG TERM DEBT | | | | | | | |
| 1 | Long Term Debt | (RUS 12A.B.46) | | | | | | |
| 2 | Long Term Interest | (RUS 12A.A.24.b) | | | | | | |
| 3 | Cost of Long Term Debt | (line 2 / line 1) | | #DIV/0! | | | | |
| | WEIGHTED AVERAGE COST OF CAPITAL | | | | | | | |
| 4 | Long Term Debt | (RUS 12A.B.46) | | | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | Proprietary Capital | (RUS 12A.B.39) | | | #DIV/0! | #DIV/0! | 10.10% | #DIV/0! |
| 6 | Total | (line 4 + line 5) | - | | #DIV/0! | #DIV/0! | **WACC=** | **#DIV/0!** |
| 7 | Total Company Rate Base | Schedule 1, pg 2, line 37, col. C | | #DIV/0! | | | | |
| 8 | Return on Total Company Rate Base | (line 7 * WACC) | | #DIV/0! | | | | |
| 9 | SPP Transmission Rate Base | Schedule 1, pg 2, line 37, col. E | | #DIV/0! | | | | |
| 10 | Return on SPP Transmission Rate Base | (line 9 * WACC) | | #DIV/0! | | | | |

Notes:

A The cost of long term debt is calculated on line 3, column c. Per Docket No. ER15-2028-000 the higher of equity component applicable only to Rate Years prior to 2021.
A base ROE of 9.6% and an SPP incentive adder of 50 basis points. This amount will not be changed absent a Section 205 or 206 filing with FERC.

No party to this proceeding may submit a filing under section 205 or 206 of the Federal Power Act (FPA) prior to September 1, 2022

to change the base ROE, nor may any party to this proceeding support such a request by another entity. Corn Belt shall use the base ROE of 9.6% in any section 205 filing made before September 1, 2022 that requires an ROE component and the other parties will not challenge the use of such base ROE in those filings.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 16: SPP Transmission Line Assets

12 Months Ended 12/31/20XX

| Line No. | Account No. (Description) (a) | Gross Transmission (b) | NIMECA CTS (c) | GC LW | |
|---|---|---|---|---|---|
| | **ACT 350** | | $ - | | |
| 1 | Lines | $ - | $ - | | |
| 2 | JOUs | $ - | $ - | $ - | |
| 3 | JOU - DAEC | $ 1 | $ - | | |
| 4 | Switches | $ - | $ - | | |
| 5 | **TOTAL ACT 350** | $ 1 | $ - | $ - | $ (1) |
| | **ACT 352** | | $ - | | |
| 6 | JOUs | $ - | $ - | $ - | |
| 7 | JOU - DAEC | $ - | $ - | | |
| 8 | **TOTAL ACT 352** | $ - | $ - | $ - | $ - |
| | **ACT 353** | | $ - | | |
| 9 | Lines | $ - | #DIV/0! | | |
| 10 | Switches | $ - | #DIV/0! | | |
| 11 | JOUs | $ - | $ - | $ - | |
| 12 | JOU - DAEC | $ - | #DIV/0! | | |
| 13 | Wisdom II | $ - | #DIV/0! | | |
| 14 | MOS | $ - | #DIV/0! | | |
| 15 | **TOTAL ACT 353** | $ - | #DIV/0! | $ - | #DIV/0! |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 16: SPP Transmission Line Assets

12 Months Ended 12/31/20XX

| Line No. | Account No. (Description) (a) | Gross Transmission (b) | NIMECA CTS (c) | GC LW | |
|---|---|---|---|---|---|
| | **ACT 350** | | $ - | | |
| 1 | Lines | $ 3,558,718 | $ - | | |
| 2 | JOUs | $ - | $ - | 0 | |
| 3 | JOU - DAEC | $ - | $ - | | |
| 4 | Switches | $ - | $ - | | |
| 5 | **TOTAL ACT 350** | $ 3,558,718 | $ - | 0 | $ 0 |
| | **ACT 352** | | $ - | | |
| 6 | JOUs | $ - | $ - | 0 | |
| 7 | JOU - DAEC | $ - | $ - | | |
| 8 | **TOTAL ACT 352** | $ - | $ - | 0 | $ - |
| | **ACT 353** | | $ - | | |
| 9 | Lines | $ 17,868 | $ - | | |
| 10 | Switches | $ - | $ - | | |
| 11 | JOUs | $ - | $ - | 1 | |
| 12 | JOU - DAEC | $ - | $ - | | |
| 13 | Wisdom II | $ - | $ - | | |
| 14 | MOS | $ - | $ - | | |
| 15 | **TOTAL ACT 353** | $ 17,868 | $ - | 1 | $ (1) |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | $ | | | | | | | $ | | | | |
| | **ACT 354** | | - | | | | | **ACT 354** | | - | | | | |
| | | $ | $ | $ | | $ | | | $ | $ | | | | |
| 16 | JOUs | - | - | - | | 16 | | JOUs | - | - | | 0 | | |
| | JOU - | $ | $ | | | $ | | JOU - | $ | $ | | | | |
| 17 | DAEC | - | - | | | 17 | | DAEC | - | - | | | | |
| | **TOTAL** | $ | $ | $ | $ | $ | | **TOTAL** | $ | $ | | | $ | |
| 18 | **ACT 354** | - | - | - | - | 18 | | **ACT 354** | - | - | | 0 | - | |
| | | | $ | | | | | | | $ | | | | |
| | **ACT 355** | | - | | | | | **ACT 355** | | - | | | | |
| | | $ | | | | $ | | | $ | $ | | | | |
| 19 | Lines | - | #DIV/0! | | | 19 | | Lines | 27,265,626 | - | | | | |
| | | $ | $ | $ | | $ | | | $ | $ | | | | |
| 20 | JOU's | - | - | - | | 20 | | JOU's | - | - | | 0 | | |
| | JOU- | $ | | | | $ | | JOU- | $ | $ | | | | |
| 21 | DAEC | - | #DIV/0! | | | 21 | | DAEC | - | - | | | | |
| | **TOTAL** | $ | | $ | #DIV/ | $ | | **TOTAL** | $ | $ | | | $ | |
| 22 | **ACT 355** | - | #DIV/0! | - | 0! | 22 | | **ACT 355** | 27,265,626 | - | | 0 | (0) | |
| | | | $ | | | | | | | $ | | | | |
| | **ACT 356** | | - | | | | | **ACT 356** | | - | | | | |
| | | $ | $ | | | $ | | | $ | | | | | |
| 23 | Lines | - | - | | | 23 | | Lines | - | #DIV/0! | | | | |
| | | $ | $ | $ | | $ | | | $ | $ | | | | |
| 24 | JOU's | - | - | - | | 24 | | JOU's | - | - | | 0 | | |
| | JOU- | $ | $ | | | $ | | JOU- | $ | | | | | |
| 25 | DAEC | (1) | - | | | 25 | | DAEC | - | #DIV/0! | | | | |
| | **TOTAL** | $ | $ | $ | $ | $ | | **TOTAL** | $ | | | | #DIV/0 | |
| 26 | **ACT 356** | (1) | - | - | 1 | 26 | | **ACT 356** | - | #DIV/0! | | 0 | ! | |
| | | $ | | $ | | $ | | | $ | | | | | |
| 27 | **TOTAL** | - | #DIV/0! | - | | 27 | | **TOTAL** | 30,842,212 | #DIV/0! | | 1 | | |

Note: JOU - "Jointly owned utility" assets

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 16: SPP Transmission Line Assets

12 Months Ended 12/31/20XX

| Line No. | | Total Transmission Assets | SPP Transmission Assets | Non-SPP Transmission Assets |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| | **Lines** | | | |
| 1 | | $ - | $ - | $ - |
| 2 | | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | | #DIV/0! | #DIV/0! | #DIV/0! |
| | **Substations/Switches** | | | |
| 4 | | $ - | $ - | $ - |
| 5 | | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | | #DIV/0! | #DIV/0! | #DIV/0! |
| | **JOUs** | | | |
| 7 | | $ - | $ - | $ - |
| 8 | | #DIV/0! | $ - | #DIV/0! |
| 9 | | #DIV/0! | $ - | #DIV/0! |
| | **Wisdom II** | | | |
| 10 | | $ - | $ - | $ - |
| 11 | | #DIV/0! | #DIV/0! | #DIV/0! |
| 12 | | #DIV/0! | #DIV/0! | #DIV/0! |
| | **MOS** | | | |
| 13 | | $ - | $ - | $ - |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 16: SPP Transmission Line Assets

12 Months Ended 12/31/20XX

| Line No. | | Total Transmission Assets | SPP Transmission Assets | Non-SPP Transmission Assets |
|---|---|---|---|---|
| | | (a) | (b) | (c) |
| | **Lines** | | | |
| 1 | | $ 30,842,212 | $ 26,128,113 | $ 4,714,099 |
| 2 | | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | | #DIV/0! | #DIV/0! | #DIV/0! |
| | **Substations/Switches** | | | |
| 4 | | $ - | $ - | $ - |
| 5 | | $ - | #DIV/0! | #DIV/0! |
| 6 | | $ - | #DIV/0! | #DIV/0! |
| | **JOUs** | | | |
| 7 | | $ - | $ - | $ - |
| 8 | | #DIV/0! | $ - | #DIV/0! |
| 9 | | #DIV/0! | $ - | #DIV/0! |
| | **Wisdom II** | | | |
| 10 | | $ - | $ - | $ - |
| 11 | | $ - | $ - | $ - |
| 12 | | $ - | $ - | $ - |
| | **MOS** | | | |
| 13 | | $ - | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 14 | #DIV/0! | #DIV/0! | #DIV/0! | 14 | - | #DIV/0! | #DIV/0! |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | $ | $ | | |
| 15 | #DIV/0! | #DIV/0! | #DIV/0! | 15 | - | #DIV/0! | #DIV/0! |
| | | | | $ | | | |
| 16 | #DIV/0! | #DIV/0! | #DIV/0! | 16 | #DIV/0! | #DIV/0! | #DIV/0! |
| 16a | Prior Year Amount | | #DIV/0! | 16a | Prior Year Amount | | |
| 16b | Average of Beginning/Ending Year | | #DIV/0! | 16b | Average of Beginning/Ending Year | | #DIV/0! |

A Summary of assets included/excluded from SPP from the G/L of the Cooperative

B Columns F & L are entered to ensure the totals balance with the general Ledger

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 16a: SPP Transmission Asset List

12 Months Ended 12/31/20XX

W ISDOM 161 161

| SWITCHING STATIONS | | | ACCT 350 | ACCT 352 |
|---|---|---|---|---|
| 2A - D0VER | 69/12.5 | Substation | | |
| 2B - W ILLEMSSEN | 69/12.5 | Substation | | |
| 2C - W ILLIAMS | 69/12.5 | Substation | | |
| 2DT - BUCKNER | 69 | Switching | | |
| 2E - ALDEN JCT | 69 | Switching | | |
| 2F - DRAGER | 161/69 | Switching | | |
| 2G - TOYNE | 69 | Switching | | |
| 2H - AYRSHIRE | 69/12.5 | Substation | | |
| 2J - SHEFFIELD | 161/69 | Switching | | |
| 2K FREDERICKSBURG | 69/12.5 | Substation | | |
| 2M - WHITTEMORE | 69 | Switching | | |
| 2P - PELICAN | 69 | Switching | | |
| 2R - RADCLIFFE | 69 | Switching | | |
| 2U - ARENDS | 69 | Switching | | |
| A - HUMBOLDT | 69 | Switching | | |
| A61 - HENRY HOPE | 161/69 | Substation | | |
| F61 - | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| S<br>wi<br>tc<br>hi<br>ng | | | | | | | | - | smission<br>Assets Only |
| | | | | | | | | - | |
| | **ACCT 353** | **ACCT 354** | **ACCT 355** | **ACCT 356** | **TOT AL** | | | - | |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | T<br>r<br>a<br>n<br>s<br>m<br>i<br>s<br>s<br>i<br>o<br>n | - | Transmission<br>Assets Only |
| | | | | | | | | - | |
| | | | | | | - A s s e t s O n l y | | - | Transmission<br>Assets Only |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | | - | |
| | | | | | | | T<br>r<br>a<br>n<br>s<br>m<br>i<br>s<br>s<br>i<br>o<br>n | - | Transmission<br>Assets Only |
| | | | | | | - A s s e t s O n l y | | | |
| | | | | | | | T<br>r<br>a<br>n | | |

| | | | | |
|---|---|---|---|---|
| B - POCAHONTAS | 69/12.5 | X - SNELL | 69/4.16 | Substation |
| C - DICKENS | 69/12.5 | | | Substation |
| D - BREMER | 161/69 | | | Substation |
| F - W ISDOM | 69 | | | Switching |
| G - GALBRAITH | 69/12.5 | | | Substation |
| H - HAMPTON | 161/69/12.5 | | | Substation |
| I - DINSDALE | 69/12.5 | | | Substation |
| J - STORM LAKE | 69 | | | Switching |
| K - KLEMME | 69/12.5 | | | Substation |
| L - WALLINGFORD | 69 | | | Switching |
| M - GLIDDEN | 69/12.5 | | | Substation |
| N - BURT | 161/69 | | | Substation |
| O- OSGOOD | 161/69 | | | Substation |
| P - PLAINFIELD | 69/12.5 | | | Substation |
| Q - SPRINGFIELD | 69 | | | Switching |
| R - PARKERSBURG | 69 | | | Switching |
| S - SHERWOOD | 69/12.5 | | | Substation |
| T - WEBSTER | 161/69 | | | Substation |
| U - FERNALD | 69 | | | Switching |
| V - CARROLLTON | 69/12.5 | | | Substation |
| W - WELLSBURG | 69 | | | Switc |

| | | |
|---|---|---|
| hing Subs tatio n | Transmission Assets Only | - |
| | | - |
| | Transmission Assets Only | |
| | Transmission Assets Only | |
| | Transmission Assets Only | |
| | Transmission Assets Only | |
| | Transmission Assets Only | |
| | Transmission Assets Only | |
| | Transmission Assets Only | |
| | Transmission Assets Only | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Y - SW EAZY | 69 | Switching | | | | | | | | | - | |
| | | | - | - | - | - | - | - | - | | | |

**Deduct: Non-eligible Circuit Breakers under Attachement Al**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 35301094-F Wisdom 69 | | # | | | | | | | | | | |
| 35301094 - P Plainfield | | | | | | | | | | | | |

**Total Non-eligible Circuit Breakers** -

**Total CB Stations into SPP** -

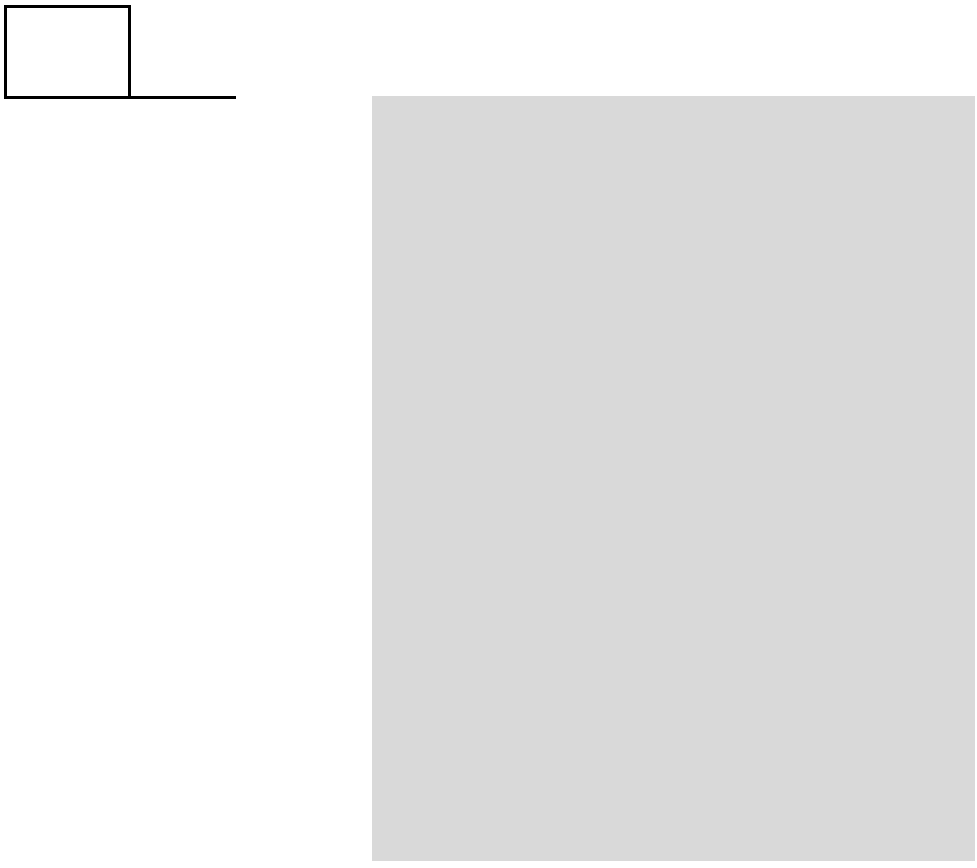
| **LINES** | **Number Miles** | | | | | | | | | | **Line #** | **Number Miles** | **CB Net Value** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L01 LINE 1 | 160.83 | | | | | | | | | - | 1 | 160.8366 | $ - |
| L02 LINE 2 | 66.87 | | | | | | | | | - | 2 | 66.87 | $ - |
| L03 LINE 3 | 51.3 | | | | | | | | | - | 3 | 51.3 | $ - |
| L04 LINE 4 | 101.31 | | | | | | | | | - | 4 | 101.3179 | $ - |
| L05 LINE 5 | 79.14 | | | | | | | | | - | 5 | 79.14 | $ - |
| L06 LINE 6 | 54.95 | | | | | | | | | - | 6 | 54.95 | $ - |
| L07 LINE 7 | 46.77 | | | | | | | | | - | 7 | 46.7744 | $ - |
| L08 LINE 8 | 44.96 | | | | | | | | | - | 8 | 44.96 | $ - |
| L09 LINE 9 | 40.59 | | | | | | | | | - | 9 | 40.59 | $ - |
| L010 LINE 10 | 30.63 | | | | | | | | | - | | 30.6 | $ - |
| | | | | | | | | | | | | L011 LINE 11 | |

126.85 - 10 3 -

12

6. $

11 85 -



| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| L012 LINE 12 | 95.58 | | | | | | | - | 12 | 95.58 | $ - |
| L013 LINE 13 | 32.51 | | | | | | | - | 13 | 32.51 | $ - |
| L014 LINE 14 | 66.83 | | | | | | | - | 14 | 66.83 | $ - |
| L015 LINE 15 | 174.7 | | | | | | | - | 15 | 174.7 | $ - |
| L016 LINE 16 | 13.65 | | | | | | | - | 16 | 13.65 | $ - |
| L017 LINE 17 | 52.46 | | | | | | | - | 17 | 52.46 | $ - |
| L018 LINE 18 | 83.26 | | | | | | | - | 18 | 83.26 | $ - |
| L019 LINE 19 | 94.13 | | | | | | | - | 19 | 94.13 | $ - |
| L020 LINE 20 | 42.44 | | | | | | | - | 20 | 42.44 | $ - |
| L021 LINE 21 | 45.24 | | | | | | | - | 21 | 45.24 | $ - |
| L022 LINE 22 | 39.1 | | | | | | | - | 22 | 39.1 | $ - |
| L023 LINE 23 | 30.36 | | | | | | | - | 23 | 30.36 | $ - |
| L024 LINE 24 | 12.39 | | | | | | | - | 24 | 12.39 | $ - |
| L025 LINE 25 | 34.61 | | | | | | | - | 25 | 34.61 | $ - |
| L026 LINE 26 | 49.78 | | | | | | | - | 26 | 49.78 | $ - |
| L027 LINE 27 | 4.89 | | | | | | | - | 27 | 4.89 | $ - |
| L030 LINE 30 | 40.86 | | | | | | | - | 30 | 40.86 | $ - |
| W/C 50 | 6.3 | | | | | | | - | 50 | 6.3 | $ - |
| W/C 51 | 8.73 | | | | | | | - | 51 | 8.73 | $ - |
| W/C 52 | 3.98 | | | | | | | - | 52 | 3.98 | $ - |
| | 1736.00 | - | - | - | - | - | - | - | | 1736 | $ - |

| **MOTOR OPER SWITCHES (MOS)** | |
|---|---|
| 2AJ31 - FELDMAN | - |
| 2AV70 - REMBRANDT | - |
| 2AV85 - IES ALBERT CITY MOS | - |
| 2AV86 - MARATHON | - |
| 2B2C18 - BLAIRSBURG | - |
| 2B2C82 - BOONDOCKS | - |
| 2DU02-1 - GARDEN CITY | - |
| 2E2L38 - IFE | - |
| 2E2L87 - ALDEN RURAL | - |
| 2MG23 - WHITTEMORE | - |
| 2MG260 - HOBARTON | - |
| A2B28 - TROY | - |
| AB41 - GILMORE CITY | - |
| AG52 - LIVERMORE | - |
| AH43 - WALL LAKE | - |
| AH66 - GALT | - |
| AK69 - BOONE VALLEY | - |
| AK74 - LUVERNE | - |
| AK75 - RENW ICK | - |
| AS40 - EAST | - |
| AS58 - TW IN LAKES | - |
| CF36 - INDUSTRIAL | - |
| CF42 - DICKENS | - |
| CF61 - RIVERTON | - |

DW 801 2
HICKS

-

| | |
|---|---|
| DW 801-2 - HICKS | - |
| GK22 - DENHART | - |
| GK83 - HAW KEYE PRIDE | - |
| HI05 - HAMPTON 161 KV TAP | - |
| HK05 - SHEFFIEL D MPS | - |
| HK59 - ALEXAND ER | - |
| HR03 - GENEVA | - |
| HR76 - DUMONT MPS | - |
| HW 21 - ACKLEY MUNI | - |
| HW 30 - FARMLAN D | - |
| HW 48 - PINE LAKE | - |
| JF45 - CORNELL (N) | - |
| JF46 - CORNELL | - |
| JS04 - LAKE VIEW | - |
| JS14 - ODEBOLT | - |
| JS50 - MAPLE VALLEY | - |
| JS791T2 - ALTA | - |
| KN09 - LIBERTY | - |
| KN13 - HUTCHIN S | - |
| LF08 - MILFORD MUNI | - |
| LF12 - MILFORD | - |
| LF27 - ESTHERVI LLE | - |
| LF291 - IOW A LAKES I | - |
| LF292 - IOW A LAKES II | - |
| LF64 - SUPERIO R | - |
| LF74 - FOSTORIA | - |
| LF77 - | |

GRUVER -

| | |
|---|---|
| LQ55 - MAPLE HILL JST | - |
| LQ78 - VERNON | - |
| LQ81 - RINGSTED | - |
| ME17 - CARROLL TON | - |
| ME53 - TEMPLETON | - |
| OB15 - EMMETSBURG | - |
| OB62 - PLOVER TAP | - |
| OB63 - WHITTEMORE TAP | - |
| OC65 - AYRSHIRE | - |
| OL711-2 - GRAETTINGER | - |
| PR39 - UNVERFERTH | - |
| PR63 - SHELL ROCK ETHANOL | - |
| PV96 - NEW HAMPTON | - |
| PZ16 - PETERSON | - |
| PZ37 - SUMNER | - |
| PZ44 - BRADFORS | - |
| PZ54 - HORTON | - |
| QL06 - EAGLE | - |
| QL19 - GERLED | - |
| QL65 - SW AN LAKE | - |
| RW 24 - APLINGTON JCT | - |
| RW 06 - KELSEY | - |
| RW 57 - FERN | - |
| RZ10 - BRISTOW | - |
| RZ - ROCKFORD | - |
| SM35 - LAKE CITY MPS | - |
| SM47 - | |

BREDA -

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| TX25 - VINCENT | | | | | | | |
| TAP | | | | | | | - |
| WD73-3 - | | | | | | | |
| CRAMER | | | | | | | - |
| WD32 - | | | | | | | |
| DINSDALE | | | | | | | - |
| WD84 - | | | | | | | |
| CONRAD | | | | | | | - |
| XY51 - DUNCOM | | | | | | | |
| BE | | | | | | | - |
| YW 02 - ROLAND | | | | | | | |
| TAP | | | | | | | - |
| YW 11 - WEBSTER | | | | | | | |
| CITY JCT | | | | | | | - |
| YW 33 - | | | | | | | |
| BUCKEYE | | | | | | | - |
| YW 49 - | | | | | | | |
| HORIZON | | | | | | | - |
| YW 67 - PLEASAN | | | | | | | |
| T | | | | | | | - |
| | | | | | | | - |
| | | - | - | - | - | - | - | - |
| **CAPACIT ORS** | | | | | | | |
| BJ56 - | | | | | | | |
| LAURENS | | | | | | | - |
| CF364 - INDUSTRI | | | | | | | |
| AL | | | | | | | - |
| LF07 - ESTHERVI | | | | | | | |
| LLE | | | | | | | - |
| PZ603 FREDERIC | | | | | | | |
| KSBURG | | | | | | | - |
| YW 73 - | | | | | | | |
| ROLAND | | | | | | | - |
| | | | | | | | - |
| | | - | - | - | - | - | - | - |
| | **Total Switches and Capacitors** | - | - | - | - | - | - | - |
| **Deduct Switches not eligible** | | | | | | | |
| 2AJ31 - FELDMA | | | | | | | |
| N | | | | | | | - |
| 2AV70 - REMBRA | | | | | | | |
| NDT | | | | | | | - |
| 2MG260 - HOBART | | | | | | | |
| ON | | | | | | | - |
| A2B28 - | | | | | | | |

TROY -

| | |
|---|---|
| AB41 - GILMORE CITY | - |
| AK69 - BOONE VALLEY | - |
| AS58 - TWIN LAKES | - |
| DW801-2 - HICKS | - |
| GK83 - HAWKEY E PRIDE | - |
| HR76 - DUMONT MPS | - |
| HW21 - ACKLEY MUNI | - |
| HW 78 - ACKLEY MUNI | - |
| JS85 - ALTA MUNI EAST | - |
| LF64 - SUPERIO R | - |
| LF77-2 - GRUVER | - |
| LF84 - MILFORD TAP EAST | - |
| LQ78 - VERNON | - |
| PZ54 - HORTON | - |
| QL19 - GERLED | - |
| QL65 - SWAN LAKE | - |
| RW24 - APLINGT ON JCT | - |
| RZ10 - BRISTOW | - |
| SM47 - BREDA | - |
| SM75 - LAKE CITY MEC | - |
| TX25 - VINCENT TAP | - |
| WD73-3 CRAMER TAP | - |
| XY51-2 - DUNCOM | |

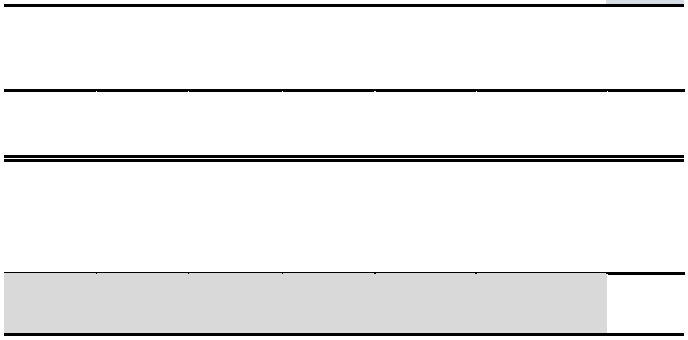
BE -

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| YW11 - WEBSTER CITY JCT HW48 - PINE LAKE | | | | | | | - |
| LF291 - IOWA LAKES I | | | | | | | - |
| LF292 - IOWA LAKES II | | | | | | | - |
| | - | - | - | - | - | - | - |
| **Switches into SPP** | - | - | - | - | - | - | - |
| **Total assets excluding CT and JOU** | - | - | - | - | - | - | - |
| **COMBUSTION TURBINE** | | | | | | | |
| F32 - W ISDOM | | | | | | | - |
| **JOU PLANTS & NIMECA** | | | | | | | |
| WS3 | | | | | | | - |
| WS4 | | | | | | | - |
| NEAL 4 | | | | | | | - |
| NIMECA | | | | | | | - |
| NEAL 4 WC NEAL GRIMES | | | | | | | - |
| LEHIGH | | | | | | | - |
| DAEC | | | | | | | - |
| LW - CB | | | | | | | - |
| LW - WC | | | | | | | - |
| LW - GC | | | | | | | - |
| | - | - | - | - | - | - | - |
| | | | | | | | - |
| **ACCOUNT** | | | | | | | |

**TOTAL**













| | | | | | |
|---|---|---|---|---|---|
| 4,539,630.69 | 244,494.27 | 35,171,984.64 | 1,176,896.01 | 33,472,068.77 | 25,475,767.12 |

## NIMECA

## SPP Area Transmission Line Investment

| Transmission Facility | Tranmission Facility Description/Name | Line # | Voltage Level(s) (kV) | Transmission Line or Substation | Miles of Line | Line Rating (MVA) | Attachment AI Criteria | Bus Number1 | Bus Number2 | Source of Financial Data | Gross Plant | Eligible Customers | Line # AM | Number Miles | Net Value |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | Total NIMECA |
| ALGN | ALGONA SOUTH-ALGONA West | | 69 | Line | 6.71 | 47.00 | Clean | 656340 | 656585 | AMU | | | | | |
| ALGN | ALGONA West-ALGONA East | | 69 | Line | 3.75 | 47.00 | Clean | 656585 | 656387 | AMU | | | | | |
| ALGN | ALGONA DC-Algona North | | 69 | Line | 2.38 | 47.00 | Clean | 656387 | 656339 | AMU | | | | | |
| Coon Rapids | Carrollton-Coon Rapids | | 69 | Line | 6.37 | 41.00 | Radial | 656233 | 656237 | NIMECA | | | | | |
| Laurens | Laurens-Laurens Muni West | | 69 | Line | 1.75 | 58.00 | Clean | 656497 | 656499 | NIMECA | | | | | |
| NH | Fredericksburg-Dairyland | | 69 | Line | 8.70 | 41.00 | Clean | 656025 | 656051 | NIMECA | | | | | |
| Sumner | Tripoli Tap-Meadowbrook Jct | | 69 | Line | 4.65 | 41.00 | Radial | 656027 | 656045 | NIMECA | | | | | |

| | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Webster City | Sweazy - Webster City Jct | 50 | 69 | Line | 6.30 | 41.00 | Clean | 656887 | 656367 | Webster City | | Network |
| Webster City | Sweazy -Wright | 51 | 69 | Line | 8.73 | 48.00 | Clean | 656887 | 636051 | Webster City | | Network |
| Webster City | Bowman Tap-Sweazy | 52 | 69 | Line | 2.84 | 47.00 | Clean | 656909 | 656887 | Webster City | | Network |
| | | | | | | | | | | | $ - | |

## SPP Area Transmission Substation Investment

| Transmission Facility Owner | Tranmission Facility Description/Name | Line # | Voltage Level(s) (kV) | Transmission Switching or Substation | Bus Number1 | Source of Financial Data | Gross Plant | Note: | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| AMU | Algona West | | 69/12.5 | | Siemens | | 67% | Substation | AMU Book | | |
| | | | 69/12.5 | | Hooper | | 67% | | | | |
| AMU | Algona East | | | | | | | Substation | AMU Book | | |
| | | | | | | | | | **Total AMU/ NIMECA** | $ - | |
| W/C | Sweazy | | 69/13.2 | | | | | Substation | WC Books | $ - | |
| W/C - Sweazy | | | | | | | | | | - | |

-

Transmission Assets Only



Transmission Assets Only



Transmission Assets Only

| | | |
|---|---|---|
| Storage Battery | 30% | - |
| Keystone Elec | 30% | - |
| Besler Inc | 30% | - |
| Peterson | 30% | - |
| P&E Engineering | 30% | - |
| WC original $ | 30% | - |
| | | - |

**ATRR REVENUE SPLIT**

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Substations | Lines | WC | MOS | CTS | **Total** | | |
| Corn Belt | #DIV/0! | #DIV/0! | Corn Belt | - | 13,064,056.56 | - | - | #DIV/0! | #DIV/0! | #DIV/0! | |
| NIMECA | - | #DIV/0! | NIMECA | - | - | | | #DIV/0! | #DIV/0! | #DIV/0! | |
| | #DIV/0! | | | | | | | | #DIV/0! | | |
| | #DIV/0! | | | | | | | | | | |

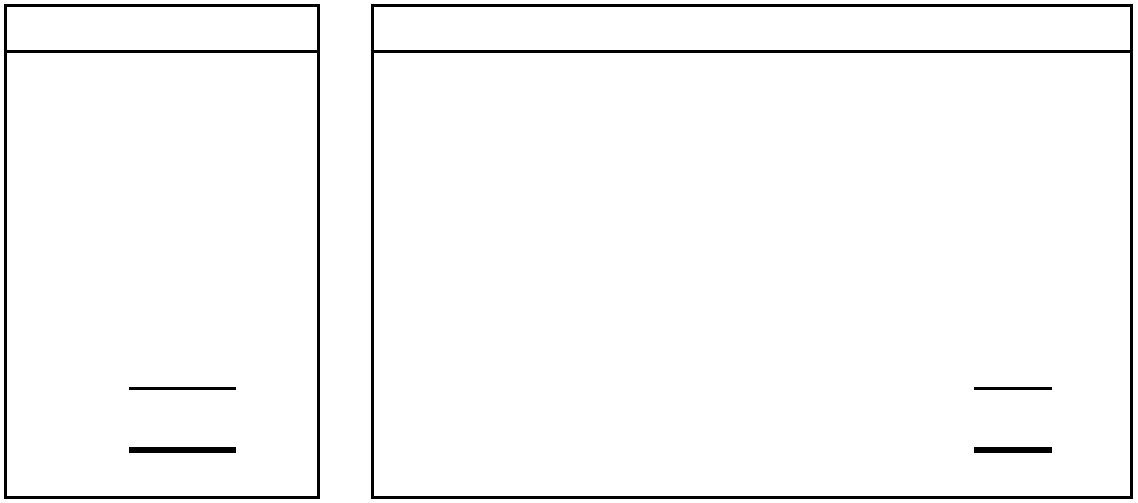
**ELIGIBLE ASSET SPLIT**

| **Acct 350** | Total | CTS |
|---|---|---|
| Lines | - | - |
| Switches | - | - |
| **Acct 353** | | |
| Lines | - | #DIV/0! |
| Switches | - | #DIV/0! |
| MOS | - | #DIV/0! |
| **Acct 355** | | |
| Lines | - | #DIV/0! |

**Acct 356**







| | | | | |
|---|---|---|---|---|
| Lines | - | - | | |
| | | #DIV | | |
| | - | /0! | | |
| **Totals** | | | **In SPP** | **CTS NIME CA** |
| | | #DIV | 13,064,056. | #DIV/ |
| Lines | - | /0! | 56 | 0! |
| | | #DIV | | #DIV/ |
| Switches | - | /0! | - | 0! |
| | | #DIV | | #DIV/ |
| MOS | - | /0! | - | 0! |
| | | #DIV | 13,064,056. | #DIV/ |
| | - | /0! | 56 | 0! |
| | | #DIV | | |
| | - | /0! | | |

Notes:

A The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Corn Belt will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in 's Corn Belt's Implementation Protocols. Corn Belt may not change the columns or the formulas included in these Work Papers during the Annual Update.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 16b: SPP Transmission Asset List BOY

12 Months Ended 12/31/20XX

| | | ACCT 350 | ACCT 352 | ACCT 353 | ACCT 354 | ACCT 355 | ACCT 356 | TOTAL |
|---|---|---|---|---|---|---|---|---|
| **SWITCHING STATIONS** | | | | | | | | |
| | | | | | | | | Transmi |
| | 2M - WHITTEMORE | | | | | | | |
| 2A - D0VER | | | | | | | | |
| 2B - W ILLEMSSEN | | | | | | | | |
| 2C - W ILLIAMS | | | | | | | | |
| 2DT - BUCKNER | | | | | | | | |
| 2E - ALDEN JCT | | | | | | | | |
| 2F - DRAGER | | | | | | | | |
| 2G - TOYNE | | | | | | | | |
| 2H - AYRSHIRE | | | | | | | | |
| 2J - SHEFFIELD | | | | | | | | |
| 2K FREDERICKSBURG | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 69/12.5 | Substation | 69 | Switching | | - | Transmission Assets Only | - | |
| | | 69/12.5 | Substation Switching | | | Transmission Assets Only | - | Transmission Assets Only |
| | | 161/69 | | | | | - | |
| 69/12.5 | Substation | 69/12.5 | Substation Switching | | - | Transmission Assets Only | - | Transmission Assets Only |
| | | 69 | | | | | - | |
| 69/12.5 | Substation | | | | - | Transmission Assets Only | | |
| 69 | Switching | | | | - | | | |
| 69 | Switching | | | | - | | | |
| 161/69 | Switching | | | | - | | | |

Swit

WALLING FORD

2P - PELICAN

2R - RADCLIFF E

2U - ARENDS

A - HUMBOL DT

A61 - HENRY HOPE

F61 - W ISDOM 161

B - POCAHO NTAS

C - DICKENS

D - BREMER

F - W ISDOM

G - GALBRAIT H

H - HAMPTO N

I - DINSDAL E

J - STORM LAKE

K - KLEMME

L -

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | chin | 69/12. | tatio | | | | | Assets |
| 69 | g | 5 | n | | | - | - | Only |
| | S | | Subs | | | | | |
| | w | 69/12. | tatio | | | | | |
| | i | 5 | n | | | | - | |
| | t | | Subs | | | | | |
| | | | tatio | | | | | |
| | c | 161/69 | n | | | | - | |
| | h | | Swit | | | | | |
| | i | | chin | | | | | |
| | n | 69 | g | | | | - | |
| 69 | g | | | | | - | | |
| | S | | | | | | | Transmi |
| | w | | Subs | | | | | ssion |
| | i | 69/12. | tatio | | | | | Assets |
| | t | 5 | n | | | | - | Only |
| | | | Subs | | | | | |
| | c | 161/69 | tatio | | | | | |
| | h | /12.5 | n | | | | - | |
| | i | | | | | | | |
| | n | | | | | | | Transmi |
| 69 | g | | Subs | | | - | | ssion |
| | S | 69/12. | tatio | | | | | Assets |
| | w | 5 | n | | | | - | Only |
| | i | | Swit | | | | | |
| | t | | chin | | | | | |
| | | 69 | g | | | | - | |
| | c | | | | | | | |
| | h | | | | | | | Transmi |
| | i | | Subs | | | | | ssion |
| | n | 69/12. | tatio | | | | | Assets |
| 69 | g | 5 | n | | | - | - | Only |
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| | Swit | | | | | | ssion | |
| | chin | | | | | | Assets | |
| 161 | g | | | | | - | Only | |
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| | Subs | | | | | | ssion | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| M - GLIDDEN | 69/12.5 | Substation | | | | | | | - | | Transmission Assets Only |
| N - BURT | 161/69 | Substation | | | | | | | - | | |
| O-OSGOOD | 161/69 | Substation | | | | | | | - | | |
| P - PLAINFIELD | 69/12.5 | Substation | | | | | | | - | | Transmission Assets Only |
| Q - SPRINGFIELD | 69 | Switching | | | | | | | - | | |
| R - PARKERSBURG | 69 | Switching | | | | | | | - | | |
| S - SHERWOOD | 69/12.5 | Substation | | | | | | | - | | Transmission Assets Only |
| T - WEBSTER | 161/69 | Substation | | | | | | | - | | |
| U - FERNALD | 69 | Switching | | | | | | | - | | |
| V - CARROLLTON | 69/12.5 | Substation | | | | | | | - | | |
| W - WELLSBURG | 69 | Switching | | | | | | | - | | Transmission Assets Only |
| X - SNELL | 69/4.16 | Substation | | | | | | | - | | Transmission Assets Only |
| Y - SW EAZY | 69 | Switching | | | | | | | - | | |
| | | | - | - | - | - | - | - | - | | |
| **Deduct: Non-eligible Circuit Breakers under Attachement Al** | | | # | | | | | | | | |
| 35301094-F Wisdom 69 35301094 | | | | | | | | | | | |

- P
Plainfield

| | | | Total Non-eligible Circuit | |
|---|---|---|---|---|
| | | L012 LINE 12 | 95.58 | |

| LINES | Number Miles | | | |
|---|---|---|---|---|
| L01 LINE 1 | 160.83 | | 252,551.96 | 3,005,244.51 |
| L02 LINE 2 | 66.87 | | 84,560.69 | 810,237.37 |
| L03 LINE 3 | 51.3 | | 92,358.54 | 854,167.67 |
| L04 LINE 4 | 101.31 | | 124,177.65 | 1,533,938.96 |
| L05 LINE 5 | 79.14 | | 65,554.89 | 1,032,807.37 |
| L06 LINE 6 | 54.95 | | 30,076.03 | 488,350.79 |
| L07 LINE 7 | 46.77 | | 29,819.08 | 392,187.73 |
| L08 LINE 8 | 44.96 | | 65,324.98 | 575,931.55 |
| L09 LINE 9 | 40.59 | | 55,893.11 | 918,498.37 |
| L010 LINE 10 | 30.63 | | 29,125.28 | 371,945.63 |
| L011 LINE 11 | 126.85 | | 161,559.07 | 2,071,574.96 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Breakers** | - | | | | | | | | |
| 198,7 | | | | | | | | | | | |
| | 1,7 | **Total CB Stations into SPP** | | | | | | | | | |
| 47, | | | | | | | | | | | |
| 67.90 | | | | | | | | | | | |
| | 826. | | | | | | | | | | |
| 82 | | | | | | | | | | | |

| **Line #** | **Number Net Miles** | **CB Value** |
|---|---|---|
| 3,25 | | $ 3, |
| 257 | | |
| 7,79 | 160 ,796. | |
| 6.47 | 1 .83 | |
| 47 | | |
| 894, | | $ |
| 798. | 66. | |
| 06 | 2 98.06 | 894,7 87 |
| 946, | | $ |
| 526. | 51. | |
| 21 | 3 26.21 | 946,5 3 |
| | | $ |
| 1,65 | | 1, |
| 658 | | |
| 8,11 | 101 ,116. | |
| 6.61 | 4 .31 | |
| 61 | | |
| | | $ |
| 1,09 | | 1, |
| 098 | | |
| 8,36 | 79. ,362. | |
| 2.26 | 5 14 | |
| 26 | | |
| 518, | | $ |
| 426. | 54. | 518,4 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | |
| | | | | | | | | | | | |
| | | | | | | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| L027 LINE 27 | 4.89 | | | | |
| L013 LINE 13 | 32.51 | | 22,949.03 | | 297,717.93 |
| L014 LINE 14 | 66.83 | | 80,810.76 | | 657,937.43 |
| L015 LINE 15 | 174.7 | | 325,977.80 | | 3,449,756.26 |
| L016 LINE 16 | 13.65 | | 41,505.68 | | 116,830.34 |
| L017 LINE 17 | 52.46 | | 39,108.45 | 5,479.52 | 420,955.59 |
| L018 LINE 18 | 83.26 | | 118,274.29 | | 1,447,471.28 |
| L019 LINE 19 | 94.13 | | 541,832.73 | | 1,565,546.10 |
| L020 LINE 20 | 42.44 | | 165,141.08 | | 424,018.59 |
| L021 LINE 21 | 45.24 | | 145,717.21 | | 756,753.19 |
| L022 LINE 22 | 39.1 | | 81,514.81 | | 339,201.82 |
| L023 LINE 23 | 30.36 | | 36,301.19 | | 311,043.27 |
| L024 LINE 24 | 12.39 | | 61,633.03 | | 189,185.37 |
| L025 LINE 25 | 34.61 | | 253,741.46 | | 871,699.41 |
| L026 LINE 26 | 49.78 | | 236,892.80 | | 1,680,984.04 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 156. | 4.8 | 287,1 |
| 26,83 | 260,32 | | | | | | 13 | 27 | 9 56.13 |
| 5.23 | 0.90 | | | | | | | | |
| | | | | | | | | | |
| | | 320, | | | $ | | | | |
| | | 666. | | 32. | 320,6 | | | | |
| | | 96 | 13 | 51 | 66.96 | | | | |
| | | 738, | | | $ | | | | |
| | | 748. | | 66. | 738,7 | | | | |
| | | 19 | 14 | 83 | 48.19 | | | | |
| | | | | | $ | | | | |
| | | 3,77 | | | 3,775 | | | | |
| | | 5,73 | | 174 | ,734. | | | | |
| | | 4.06 | 15 | .7 | 06 | | | | |
| | | 158, | | | $ | | | | |
| | | 336. | | 13. | 158,3 | | | | |
| | | 02 | 16 | 65 | 36.02 | | | | |
| | | 465, | | | $ | | | | |
| | | 543. | | 52. | 465,5 | | | | |
| | | 56 | 17 | 46 | 43.56 | | | | |
| | | | | | $ | | | | |
| | | 1,56 | | | 1,565 | | | | |
| | | 5,74 | | 83. | ,745. | | | | |
| | | 5.57 | 18 | 26 | 57 | | | | |
| | | | | | $ | | | | |
| | | 2,10 | | | 2,107 | | | | |
| | | 7,37 | | 94. | ,378. | | | | |
| | | 8.83 | 19 | 13 | 83 | | | | |
| | | 589, | | | $ | | | | |
| | | 159. | | 42. | 589,1 | | | | |
| | | 67 | 20 | 44 | 59.67 | | | | |
| | | 902, | | | $ | | | | |
| | | 470. | | 45. | 902,4 | | | | |
| | | 40 | 21 | 24 | 70.40 | | | | |
| | | 420, | | | $ | | | | |
| | | 716. | | 39. | 420,7 | | | | |
| | | 63 | 22 | 1 | 16.63 | | | | |
| | | 347, | | | $ | | | | |
| | | 344. | | 30. | 347,3 | | | | |
| | | 46 | 23 | 36 | 44.46 | | | | |
| | | 250, | | | $ | | | | |
| | | 818. | | 12. | 250,8 | | | | |
| | | 40 | 24 | 39 | 18.40 | | | | |
| | | | | | $ | | | | |
| | | 1,12 | | | 1,125 | | | | |
| | | 5,44 | | 34. | ,440. | | | | |
| | | 0.87 | 25 | 61 | 87 | | | | |
| | | | | | $ | | | | |
| | | 1,91 | | | 1,917 | | | | |
| | | 7,87 | | 49. | ,876. | | | | |
| | | 6.84 | 26 | 78 | 84 | | | | |
| | | 287, | | | $ | | | | |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | 653, | | | | $ |
| L030 LINE | | 155,4 | | 498,08 | | | 553. | | | 40. | 653,5 |
| 30 | 40.86 | 66.94 | | 6.92 | | | 86 | 30 | | 86 | 53.86 |
| | | | | | | | 36,2 | | | | $ |
| | | | | 36,231 | | | 31.2 | | | | 36,23 |
| W/C 50 | 6.3 | 0.00 | | .24 | | | 4 | 50 | | 6.3 | 1.24 |
| | | | | | | | | | | 8.7 | $ |
| W/C 51 | 8.73 | 0.00 | | 0.00 | | | - | 51 | | 3 | - |
| | | | | | | | 186, | | | | $ |
| | | 35,24 | 12,38 | 139,17 | | | 809. | 3.9 | | 186,8 | |
| W/C 52 | 3.98 | 6.40 | 8.58 | 4.19 | | | 17 | 52 | | 8 09.17 | |
| | | | | | | | 30,8 | | | | $ |
| | | 3,558, | | 27,265 | | | 42,2 | | | | 30,84 |
| | 1736.0 | 718.0 | 17,86 | ,625.6 | | | 11.7 | | | 173 | 2,211 |
| | 0 | 7 - | 8.10 - | 0 - | | | 7 | | | 6 | .77 |

**MOTOR OPER SWITCHES (MOS)**

| | |
|---|---|
| 2AJ31 - FELDMAN | - |
| 2AV70 - REMBRANDT | - |
| 2AV85 - IES ALBERT CITY MOS | - |
| 2AV86 - MARATHON | - |
| 2B2C18 - BLAIRSBURG | - |
| 2B2C82 - BOONDOCKS | - |
| 2DU02-1 - GARDEN CITY | - |
| 2E2L38 - IFE | - |
| 2E2L87 - ALDEN RURAL | - |
| 2MG23 - WHITTEMORE | - |
| 2MG260 - HOBARTON | - |
| A2B28 - TROY | - |
| AB41 - GILMORE CITY | - |
| AG52 - LIVERMORE | - |
| AH43 - WALL | - |

LAKE -



| | |
|---|---|
| AH66 - GALT | - |
| AK69 - BOONE VALLEY | - |
| AK74 - LUVERNE | - |
| AK75 - RENW ICK | - |
| AS40 - EAST | - |
| AS58 - TW IN LAKES | - |
| CF36 - INDUSTRI AL | - |
| CF42 - DICKENS | - |
| CF61 - RIVERTO N | - |
| DW 801 2 - HICKS | - |
| DW 801-2 - HICKS | - |
| GK22 - DENHART | - |
| GK83 - HAW KEY E PRIDE | - |
| HI05 - HAMPTO N 161 KV TAP | - |
| HK05 - SHEFFIEL D MPS | - |
| HK59 - ALEXAND ER | - |
| HR03 - GENEVA | - |
| HR76 - DUMONT MPS | - |
| HW 21 - ACKLEY MUNI | - |
| HW 30 - FARMLAN D | - |
| HW 48 - PINE LAKE | - |
| JF45 - CORNELL (N) | - |
| JF46 - CORNELL | - |
| JS04 - LAKE VIEW | - |
| JS14 - ODEBOLT | - |
| JS50 - MAPLE VALLEY | - |
| JS791T2 - | |

ALTA -

KN09 -

LIBERTY -

| | |
|---|---|
| KN13 - HUTCHINS | - |
| LF08 - MILFORD MUNI | - |
| LF12 - MILFORD | - |
| LF27 - ESTHERVILLE | - |
| LF291 - IOW A LAKES I | - |
| LF292 - IOW A LAKES II | - |
| LF64 - SUPERIOR | - |
| LF74 - FOSTORIA | - |
| LF77 - GRUVER | - |
| LQ55 - MAPLE HILL JST | - |
| LQ78 - VERNON | - |
| LQ81 - RINGSTED | - |
| ME17 - CARROLLTON | - |
| ME53 - TEMPLETON | - |
| OB15 - EMMETSBURG | - |
| OB62 - PLOVER TAP | - |
| OB63 - WHITTEMORE TAP | - |
| OC65 - AYRSHIRE | - |
| OL711-2 - GRAETTINGER | - |
| PR39 - UNVERFERTH | - |
| PR63 - SHELL ROCK ETHANOL | - |
| PV96 - NEW HAMPTON | - |
| PZ16 - PETERSON | - |
| PZ37 - SUMNER | - |
| PZ44 - BRADFORS | - |
| PZ54 - | |

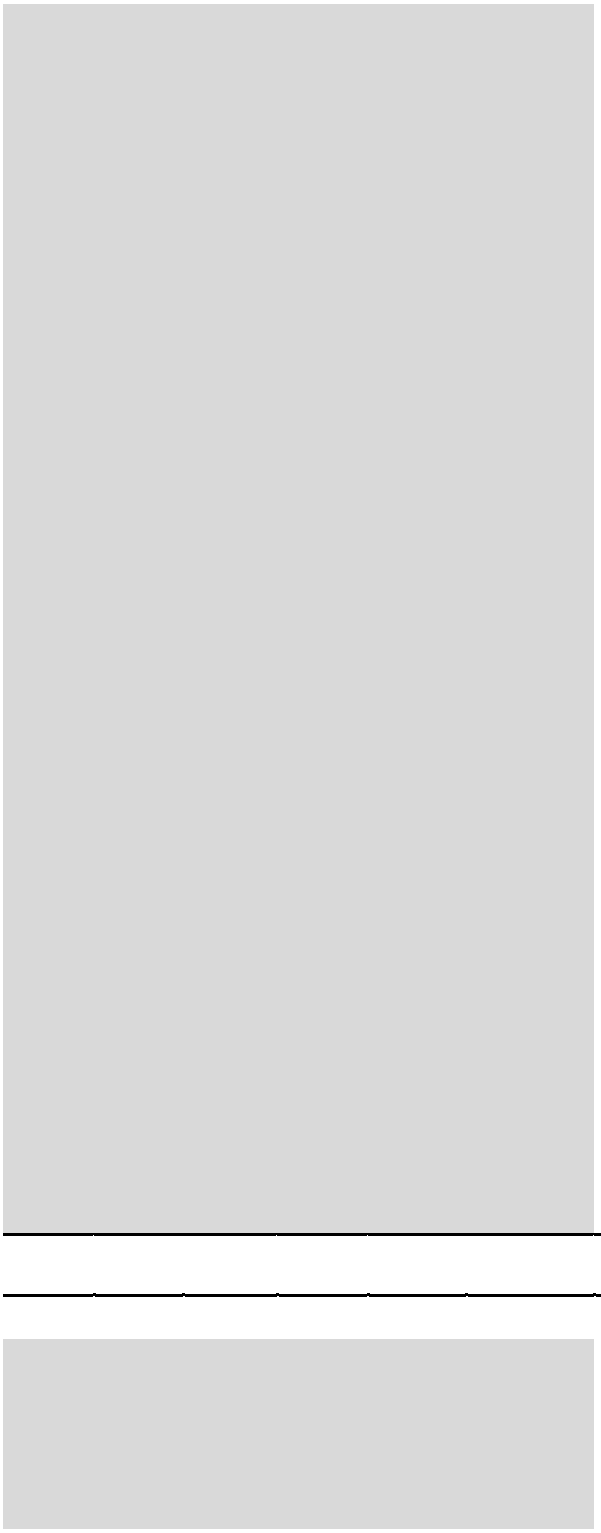
HORTON -

QL06 -

EAGLE -

| | |
|---|---|
| QL19 - GERLED | - |
| QL65 - SW AN LAKE | - |
| RW 24 - APLINGT ON JCT | - |
| RW 06 - KELSEY | - |
| RW 57 - FERN | - |
| RZ10 - BRISTOW | - |
| RZ - ROCKFO RD | - |
| SM35 - LAKE CITY MPS | - |
| SM47 - BREDA | - |
| TX25 - VINCENT TAP | - |
| WD73-3 - CRAMER | - |
| WD32 - DINSDAL E | - |
| WD84 - CONRAD | - |
| XY51 - DUNCOM BE | - |
| YW 02 - ROLAND TAP | - |
| YW 11 - WEBSTER CITY JCT | - |
| YW 33 - BUCKEYE | - |
| YW 49 - HORIZON | - |
| YW 67 - PLEASAN T | - |
| | - |
| | - - - - - - - |
| **CAPACIT ORS** | |
| BJ56 - LAURENS | - |
| CF364 - INDUSTRI AL | - |
| LF07 - ESTHERV ILLE | - |
| PZ603 FREDERI CKSBURG | - |
| YW 73 - ROLAND | - |

-







| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | - | - | - | - | - | - | - |
| | **Total Switches and Capacitors** | - | - | - | - | - | - | - |
| **Deduct Switches not eligible** | | | | | | | | |
| 2AJ31 - FELDMAN | | - | - | - | - | - | - | - |
| 2AV70 - REMBRANDT | | - | - | - | - | - | - | - |
| 2MG260 - HOBART ON | | - | - | - | - | - | - | - |
| A2B28 - TROY | | - | - | - | - | - | - | - |
| AB41 - GILMORE CITY | | - | - | - | - | - | - | - |
| AK69 - BOONE VALLEY | | - | - | - | - | - | - | - |
| AS58 - TWIN LAKES | | - | - | - | - | - | - | - |
| DW801-2 - HICKS | | - | - | - | - | - | - | - |
| GK83 - HAWKEYE PRIDE | | - | - | - | - | - | - | - |
| HR76 - DUMONT MPS | | - | - | - | - | - | - | - |
| HW21 - ACKLEY MUNI | | - | - | - | - | - | - | - |
| HW 78 - ACKLEY MUNI | | - | - | - | - | - | - | - |
| JS85 - ALTA MUNI EAST | | - | - | - | - | - | - | - |
| LF64 - SUPERIOR | | - | - | - | - | - | - | - |
| LF77-2 - GRUVER | | - | - | - | - | - | - | - |
| LF84 - MILFORD TAP EAST | | - | - | - | - | - | - | - |
| LQ78 - VERNON | | - | - | - | - | - | - | - |
| PZ54 - HORTON | | - | - | - | - | - | - | - |
| QL19 - GERLED | | - | - | - | - | - | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| QL65 - SWAN LAKE | - | - | - | - | - | - | - | |
| RW24 - APLINGT ON JCT | - | - | - | - | - | - | - | |
| RZ10 - BRISTOW | - | - | - | - | - | - | - | |
| SM47 - BREDA | - | - | - | - | - | - | - | |
| SM75 - LAKE CITY MEC | - | - | - | - | - | - | - | |
| TX25 - VINCENT TAP | - | - | - | - | - | - | - | |
| WD73-3 CRAMER TAP | - | - | - | - | - | - | - | |
| XY51-2 - DUNCOM BE | - | - | - | - | - | - | - | |
| YW11 - WEBSTE R CITY JCT | - | - | - | - | - | - | - | |
| HW48 - PINE LAKE | - | - | - | - | - | - | - | |
| LF291 - IOWA LAKES I | - | - | - | - | - | - | - | |
| LF292 - IOWA LAKES II | - | - | - | - | - | - | - | |
| | - | - | - | - | - | - | - | |
| **Switches into SPP** | - | - | - | - | - | - | - | |
| **Total assets excluding CT and JOU** | 3,558,718.07 | 17,86 - | 8.10 | - | 27,265,625.60 | 11.7 - | 30,842,27 | |
| **COMBUSTION TURBINE** | | | | | | | | |
| F32 - W ISDOM | - | | | | | | - | |
| **JOU PLANTS & NIMECA** | | | | | | | | |

| | | |
|---|---|---|
| WS3 | | - |
| WS4 | | - |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NEAL 4 | | | | | | | | | | | | | | | - |
| NIMECA | | | | | | | | | | | | | | | - |
| NEAL 4 WC | | | | | | | | | | | | | | | - |
| NEAL 4 GC | | | | | | | | | | | | | | | - |
| NEAL GRIMES | | | | | | | | | | | | | | | |
| LEHIGH | | | | | | | | | | | | | | | - |
| DAEC | | | | | | | | | | | | | | | - |
| LW - CB | | | | | | | | | | | | | | | - |
| LW - WC | | | | | | | | | | | | | | | - |
| LW - GC | | | | | | | | | | | | | | | - |
| | | | | - | - | - | - | - | - | | | | | | - |
| | | | | | | | | | | | | | | | - |
| **ACCOUNT TOTAL** | | | | **3,558,718.07** | **-** | **17,868.10** | **-** | **27,265,625.60** | **-** | | | | | | **30,842,211.77** |
| | | | | 524,944.11 | 174,256.65 | 34,445,917.81 | 1,177,414.01 | -123,978.72 | 20,965,681.90 | | | | | | |

## NIMECA

## SPP Area Transmission Line Investment

| Transmission Facility | Tranmission Facility Description/Name | Line # | Voltage Level(s) (kV) | Transmission Line or Substation | Miles of Line | Line Rating (MVA) | Attachment AI Criteria | Bus Number1 | Bus Number2 | Source of Financial Data | Gross Plant | Eligible Customers | Line # | Number Miles | Net Value |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Owner | | | | | | | | | | | | | | | $ |

| | | |
|---|---|---|
| | | 1,12 |
| AM | | 8,01 |
| U | 12.84 | 3.31 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | $ | | | | | |
| ALGN | ALGONA SOUTH-ALGONA West | **Transmission** | **Tranmission** | **Line** | | 69 | Net Line | 6.71 | 47.00 | Clean | 656340 |
| ALGN | ALGONA West-ALGONA East | | | | | 69 | Line | 3.75 | 47.00 | Clean | 656585 |
| ALGN | ALGONA DC-Algona North | | | | | 69 | Line | 2.38 | 47.00 | Clean | 656387 |
| Coon Rapids | Carrollton-Coon Rapids | | | | | 69 | Line | 6.37 | 41.00 | Radial | 656233 |
| Laurens | Laurens-Laurens Muni West | | | | | 69 | Line | 1.75 | 58.00 | Clean | 656497 |
| NH | Fredericksburg-Dairyland | | | | | 69 | Line | 8.70 | 41.00 | Clean | 656025 |
| Sumner | Tripoli Tap-Meadowbrook Jct | | | | | 69 | Line | 4.65 | 41.00 | Radial | 656027 |
| Webster City | Sweazy-Webster City Jct | 50 | | | | | | | | | |
| Webster City | Sweazy-Wright | 51 | | | | | | | | | |
| Webster City | Bowman Tap-Sweazy | 52 | | | | 69 | Line | 6.30 | 41.00 | Clean | 656887 |
| | | | | | | 69 | Line | 8.73 | 48.00 | Clean | 656887 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 69 | Line Clean City | 2.849 | 47.00 656887 | $ 589,483.59 | Network | ster |
| | | | | $ 329,443.14 | Network | |
| | | | | $ 209,086.58 | Network | |
| | | | | $ 559,614.08 | Coon Rapids, RVEC | |
| | | | | $ 153,740.13 | Network | |
| | | | | $ 764,308.08 | Network | |
| | | | | $ 408,509.49 | Butler Co REC, Sumner Muni | |
| | | | | $ 3,014,185.10 | | |

## SPP Area Transmission Substation Investment

| V | Transmission | Source | | |
|---|---|---|---|---|
| Switching of | | | Network | |
| | | | Network | |
| | | | Network | |
| | | | $ - | |

| Facility Owner | Facility Description/Name | # | tage Level(s) (kV) | or Substation | Bus Number1 | Financial Data | Gross Plant | Note: |
|---|---|---|---|---|---|---|---|---|
| AMU | Algona West | | 69/12.5 | Substation | | AMU Book | | Transmission Assets Only |
| AMU | Algona East | | 69/12.5 | Substation | | AMU Book | | Transmission Assets Only |
| | | | | | | **Total AMU/ NIMECA** | $ - | |
| W/C | Sweazy | | 69/13.2 | Substation | | WC Books | $ - | Transmission Assets Only |
| W/C - Sweazy | | | | | | | | |
| Siemens | | 67% | | - | | | | |
| Hooper | | 67% | | - | | | | |
| Storage Battery | | 30% | | - | | | | |
| Keystone Elec | | 30% | | - | | | | |
| Besler Inc | | 30% | | - | | | | |
| Peterson | | 30% | | - | | | | |
| P&E Engineering | | 30% | | - | | | | |
| WC original $ | | 30% | | - | | | | |
| | | | | - | | | | |

**ATRR REVENUE SPLIT**

**ELIGIBLE ASSET SPLIT**

| | | | | Substations | Lines | WC | MOS | CTS | **Total** | |
|---|---|---|---|---|---|---|---|---|---|---|
| Corn Belt | #DIV/0! | #DIV/0! | Corn Belt | - | 13,064,056.56 | - | - | #DIV/0! | #DIV/0! | #DIV/0! |
| NIMECA | - | #DIV/0! | NIMECA | - | 3,014,185.10 | | | #DIV/0! | #DIV/0! | #DIV/0! |
| | #DIV/0! | | | | | | | | #DIV/0! | |
| | #DIV/0! | | | | | | | | | |

| **Acct 350** | Total | CTS |
|---|---|---|
| Lines | 3,558,718.07 | - |
| Switches | - | - |
| **Acct 353** | | |
| Lines | 17,868.10 | #DIV/0! |
| Switches | - | #DIV/0! |
| MOS | - | #DIV/0! |
| **Acct 355** | | |
| Lines | 27,265,625.60 | #DIV/0! |
| **Acct 356** | | |
| Lines | - | - |
| | 30,842,211.77 | #DIV/0! |

| **Totals** | | | **In SPP** | **CTS NIMECA** |
|---|---|---|---|---|
| Lines | 30,842,211.77 | #DIV/0! | 13,064,056.56 | #DIV/0! |
| Switches | - | #DIV/0! | - | #DIV/0! |
| | | #DIV | | #DIV/ |

MOS - /0! - 0!

| | | | | |
|---|---|---|---|---|
| | 30,842,211.77 | #DIV/0! | 13,064,056.56 | #DIV/0! |
| | - | #DIV/0! | | |
| Form 12 - Utility Plant | 12/31/20XX | 12/31/20XX | Average | |
| Intangible | | | - | |
| Production | | | - | |
| Transmission | | | - | |
| Distribution | | | - | |
| Communication | | | - | |
| General Plant | | | - | |
| | - | - | | |
| Form 12 - Depreciation | 12/31/20XX | 12/31/20XX | Average | |
| Steam | | | - | |
| Nuclear | | | - | |
| Hydaulic | | | | |
| Other | | | - | |
| Transmission | | | - | |
| Distribution | | | - | |
| Communication | | | - | |
| General Plant | | | - | |
| RWIP | | | | |
| | - | - | | |
| Intangible | | | - | |

Notes:

| | | |
|---|---|---|
| A | The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Corn Belt will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in 's Corn Belt's Implementation Protocols. Corn Belt may not change the columns or the formulas included in these Work Papers during the Annual Update. | |

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 17: SPP Transmission Line Assets

13 Months Ended 12/31/XX

| Line No. | Transmission Facility Owner | Tranmisssion Facility Description/Name | Line # | Voltage Level (kV) | Transmission Line or Substation | Miles of Line | Line Rating (MVA) | Attachment AI Criteria | Bus Number1 | Bus Number2 | Source of Financial Data | Gross Plant BOY | Gross Plant EOY | Average Gross Plant | Eligible Customers |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
| 1 | CBPC | Willemssen-Wall Lake MEC | 1 | 69 | Line | 7.511 | 69 | Clean | 656903 | 636236 | CBPC BOOK | 152,124 | - | 76,062 | Network |
| 2 | CBPC | Wall Lake MEC-Williams | 1 | 69 | Line | 5.87 | 58 | Clean | 636236 | 656787 | CBPC BOOK | 321,465 | - | 160,733 | Network |
| 3 | CBPC | Williams-Buckner | 1 | 69 | Line | 4.96 | 47 | Clean | 656787 | 656149 | CBPC BOOK | 100,471 | - | 50,235 | Network |
| 4 | CBPC | Williams-Lyon Tap | 1 | 69 | Line | 3.67 | 58 | Clean | 656787 | 656777 | CBPC BOOK | 74,340 | - | 37,170 | Network |
| 5 | CBPC | Buckner-Alden Jct | 1 | 69 | Line | 6.94 | 47 | Clean | 656149 | 656755 | CBPC BOOK | 140,578 | - | 70,289 | Network |
| 6 | CBPC | Buckner-Radcliffe | 1 | 69 | Line | 5.06 | 69 | Clean | 656149 | 656791 | CBPC BOOK | 102,496 | - | 51,248 | Network |
| 7 | CBPC | Alden Jct-Alden | 1 | 69 | Line | 7.961 | 69 | Clean | 656755 | 656753 | CBPC BOOK | 161,239 | - | 80,619 | Network |
| 8 | CBPC | Alden Jct-Otter Creek | 1 | 69 | Line | 3.261 | 47 | Clean | 656755 | 630839 | CBPC BOOK | 268,597 | - | 134,298 | Network |
| 9 | CBPC | Otter Creek-Wellsburg | 1 | 69 | Line | 0.781 | 47 | Clean | 630839 | 656301 | CBPC BOOK | 218,361 | - | 109,181 | Network |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10 | CBPC | Radcliffe-Fernald | 1 | 69 | Line | 8.03 | 47 | Clean | 656 791 | 630 710 | CBPC BOOK | 365,218 | - | 182,609 | Network |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | CBPC | Humboldt-Webster | 1 | 69 | Line | 12.30 | 47 | Clean | 656355 | 656369 | CBPC BOOK | 249,151 | - | 124,575 | Network |
| 12 | CBPC | Webster-Snell | 1 | 69 | Line | 10.51 | 58 | Clean | 656369 | 656881 | CBPC BOOK | 212,892 | - | 106,446 | Network |
| 13 | CBPC | Snell-Bowman Tap | 1 | 69 | Line | 19.45 | 47 | Clean | 656881 | 656909 | CBPC BOOK | 191,421 | - | 95,710 | Network |
| 14 | CBPC | Webster City Jct-Williams | 1 | 69 | Line | 13.55 | 41 | Clean | 656367 | 656787 | CBPC BOOK | 274,471 | - | 137,235 | Network |
| 15 | CBPC | Wellsburg-Dinsdale | 2 | 69 | Line | 27.05 | 47 | Clean | 656301 | 656281 | CBPC BOOK | 361,960 | - | 180,980 | Network |
| 16 | CBPC | Dinsdale-Hicks Tap | 2 | 69 | Line | 3.507 | 47 | Clean | 656281 | 656307 | CBPC BOOK | 46,834 | - | 23,417 | Network |
| 17 | CBPC | Grundy Center-Wellsburg | 2 | 69 | Line | 7.639 | 47 | Clean | 656289 | 656301 | CBPC BOOK | 102,098 | - | 51,049 | Network |
| 18 | CBPC | Dinsdale-Traer | 2 | 69 | Line | 19.54 | 36 | Clean | 656281 | 656629 | CBPC BOOK | 127,656 | - | 63,828 | Network |
| 19 | CBPC | Parkersburg-Wellsburg | 3 | 69 | Line | 22.33 | 47 | Clean | 656065 | 656301 | CBPC BOOK | 412,006 | - | 206,003 | Network |
| 20 | CBPC | Fern Tap | 3 | 69 | Line | 36.54 | 69 | Radial | 656303 | 656287 | CBPC BOOK | 120,668 | - | 60,334 | Dike Muni, Grundy Co Coop |
| 21 | CBPC | Farmland Tap-Ackley Tap | 3 | 69 | Line | 48.07 | 47 | Radial | 656769 | 656751 | CBPC BOOK | 148,898 | - | 74,449 | MEC, Midland Power Coop |
| 22 | CBPC | Fredericksburg-Dairyland | 4 | 69 | Line | 0.911 | 41 | Clean | 656025 | 656051 | CBPC BOOK | 14,894 | - | 7,447 | Network |
| 23 | CBPC | Bremer County-Fredericksburg | 4 | 69 | Line | 19.28 | 58 | Clean | 656089 | 656025 | CBPC BOOK | 315,551 | - | 157,776 | Network |
| 24 | CBPC | Sumner Jct-Tripoli Tap | 4 | 69 | Line | 5.493 | 41 | Radial | 656077 | 656027 | CBPC BOOK | 89,854 | - | 44,927 | Butler Co REC, Sumner Muni |
| 25 | CBPC | Plainfield-Bremer Co | 4 | 69 | Line | 3.406 | 58 | Clean | 656063 | 656089 | CBPC BOOK | 55,647 | - | 27,823 | Network |
| 26 | CBPC | Plainfield-Waverly Jct | 4 | 69 | Line | 6.382 | 57.4 | Clean | 656063 | 656083 | CBPC BOOK | 104,420 | - | 52,210 | Network |
| | | Parkersburg- | | | | 23.1 | | Clea | 656 | 656 | CBPC | 378,23 | | 189,11 | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27 | CBPC | Rockford Jct | 4 | 69 | Line | 1 | 47 | n | 065 | 067 | BOOK | 6 | - | 8 | Network |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 28 | CBPC | Rockford Jct-Rockford | 4 | 69 | Line | 3.962 | 31 | Radial | 656067 | 656071 | CBPC BOOK | 64,812 | - | 32,406 | Butler Co REC, Rockford Muni |
| 29 | CBPC | Willemssen-Hampton | 5 | 69 | Line | 1.343 | 58 | Clean | 656903 | 656193 | CBPC BOOK | 296,172 | - | 148,086 | Network |
| 30 | CBPC | Humboldt-Willemssen | 5 | 69 | Line | 3.771 | 47 | Clean | 656355 | 656903 | CBPC BOOK | 468,685 | - | 234,342 | Network |
| 31 | CBPC | Hampton-Parkersburg | 5 | 69 | Line | 9.052 | 57.4 | Clean | 656193 | 656065 | CBPC BOOK | 264,390 | - | 132,195 | Network |
| 32 | CBPC | Sheffield-Klemme | 6 | 69 | Line | 4.971 | 41 | Clean | 656205 | 656781 | CBPC BOOK | 235,580 | - | 117,790 | Network |
| 33 | CBPC | Hampton-Sheffield | 6 | 69 | Line | 4.144 | 69 | Clean | 656193 | 656205 | CBPC BOOK | 133,404 | - | 66,702 | Network |
| 34 | CBPC | Sheffield-Sheffield MEC | 6 | 69 | Line | 4.149 | 47 | Clean | 656205 | 656199 | CBPC BOOK | 39,059 | - | 19,529 | Network |
| 35 | CBPC | Klemme-Hancock | 7 | 69 | Line | 9.093 | 41 | Clean | 656781 | 630821 | CBPC BOOK | 82,019 | - | 41,010 | Network |
| 36 | CBPC | Hancock-Algona | 7 | 69 | Line | 3.962 | 41 | Clean | 630821 | 656337 | CBPC BOOK | 306,422 | - | 153,211 | Network |
| 37 | CBPC | Galbraith-Klemme | 8 | 69 | Line | 9.091 | 47 | Clean | 656347 | 656781 | CBPC BOOK | 414,906 | - | 207,453 | Network |
| 38 | CBPC | Boone Valley Jct-Boone Valley | 8 | 69 | Line | 0.072 | 41 | Radial | 656907 | 656000 | CBPC BOOK | 143,627 | - | 71,813 | B.V. Coop, Prairie Energy Coop |
| 39 | CBPC | Humboldt-Galbraith | 9 | 69 | Line | 3.831 | 47 | Clean | 656355 | 656347 | CBPC BOOK | 572,056 | - | 286,028 | Network |
| 40 | CBPC | IPS Luverne-Owl Lake | 9 | 69 | Line | 0.234 | 41 | Radial | 656385 | 656095 | CBPC BOOK | 245,578 | - | 122,789 | B.V. Coop, Midland Power Coop |
| 41 | CBPC | Galbraith-Algona South | 10 | 69 | Line | 4.075 | 47 | Clean | 656347 | 656340 | CBPC BOOK | 53,293 | - | 26,646 | Network |
| 42 | CBPC | Algona North-Burt | 10 | 69 | Line | 5.524 | 47 | Clean | 656339 | 656425 | CBPC BOOK | 72,279 | - | 36,140 | Network |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 43 | CBPC | Algona-Burt | 10 | 69 | Line | 5 1 | 41 | Clea n | 656 337 | 656 425 | CBPC BOOK | 59,054 | - | 29,527 | Network |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 44 | CBPC | Springfield-Burt | 10 | 69 | Line | 12.47 | 47 | Clean | 656557 | 656425 | CBPC BOOK | 163,283 | - | 81,641 | Network |
| 45 | CBPC | Pelican-Okoboji | 11 | 69 | Line | 3.01 | 71.7 | Clean | 656531 | 656523 | CBPC BOOK | 52,990 | - | 26,495 | Network |
| 46 | CBPC | Arends-Milford | 11 | 69 | Line | 17.20 | 71.7 | Clean | 656523 | 656521 | CBPC BOOK | 126,753 | - | 63,376 | Network |
| 47 | CBPC | Dickens-Wisdom | 11 | 69 | Line | 10.95 | 57.4 | Clean | 656437 | 656573 | CBPC BOOK | 192,770 | - | 96,385 | Network |
| 48 | CBPC | Wisdom-Arends | 11 | 69 | Line | 8.51 | 58 | Clean | 656573 | 656523 | CBPC BOOK | 149,815 | - | 74,907 | Network |
| 49 | CBPC | Wallingford-Pelican | 11 | 69 | Line | 18.92 | 71.7 | Clean | 656575 | 656531 | CBPC BOOK | 333,078 | - | 166,539 | Network |
| 50 | CBPC | Estherville Jct-Estherville Tap | 11 | 69 | Line | 2.32 | 41 | Radial | 656591 | 656459 | CBPC BOOK | 40,843 | - | 20,421 | Estherville Muni, ILEC |
| 51 | CBPC | Terril Tap-Terril | 11 | 69 | Line | 0.46 | 41 | Radial | 656589 | 656565 | CBPC BOOK | 8,098 | - | 4,049 | Alliant Energy, ILEC |
| 52 | CBPC | Wallingford-Springfield | 11 | 69 | Line | 27.68 | 41 | Clean | 656575 | 656557 | CBPC BOOK | 487,293 | - | 243,647 | Network |
| 53 | CBPC | Osgood-Emmetsburg MEC | 11 | 69 | Line | 5.90 | 61 | Clean | 656529 | 636100 | CBPC BOOK | 103,867 | - | 51,933 | Network |
| 54 | CBPC | Osgood-Wallingford | 11 | 69 | Line | 10.68 | 57.4 | Clean | 656529 | 656575 | CBPC BOOK | 188,016 | - | 94,008 | Network |
| 55 | CBPC | Springfield-Ledyard | 11 | 69 | Line | 4.58 | 47 | Clean | 656557 | 656501 | CBPC BOOK | 80,629 | - | 40,314 | Network |
| 56 | CBPC | Ayrshire-Dickens | 12 | 69 | Line | 9.75 | 57.4 | Clean | 656419 | 656437 | CBPC BOOK | 198,570 | - | 99,285 | Network |
| 57 | CBPC | Ayrshire-IPS JCT | 12 | 69 | Line | 10.45 | 38 | Clean | 656419 | 656515 | CBPC BOOK | 212,826 | - | 106,413 | Network |
| 58 | CBPC | Whittemore Jct-Algona Muni | 12 | 69 | Line | 21.72 | 58 | Clean | 656377 | 656585 | CBPC BOOK | 442,352 | - | 221,176 | Network |
| 59 | CBPC | Whittemore Jct-Pocahontas | 12 | 69 | Line | 25.13 | 41 | Clean | 656377 | 656537 | CBPC BOOK | 511,801 | - | 255,900 | Network |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 60 | CBPC | Osgood-Ayrshire | 12 | 69 | Line | 5.2 | 69 | Clean | 656 | 656 | CBPC BOOK | 310,991 | - | 155,495 | Network |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 61 | CBPC | Emmetsburg Jct-Whittemore Jct | 12 | 69 | Line | 2.072 | 69 | Clean | 656451 | 656377 | CBPC BOOK | 42,158 | - | 21,079 | Network |
| 62 | CBPC | Humboldt-Pocahontas | 13 | 69 | Line | 6.445 | 47 | Clean | 656355 | 656537 | CBPC BOOK | 260,795 | - | 130,397 | Network |
| 63 | CBPC | Humboldt-Sherwood | 14 | 69 | Line | 3.338 | 41 | Clean | 656355 | 656159 | CBPC BOOK | 589,517 | - | 294,759 | Network |
| 64 | CBPC | East Tap-East Calhoun | 14 | 69 | Radial | 8.402 | 41 | Clean | 656153 | 656151 | CBPC BOOK | 92,855 | - | 46,427 | Calhoun Co REC,MEC |
| 65 | CBPC | Dover-Storm Lake | 15 | 69 | Line | 0.551 | 41 | Clean | 656443 | 656559 | CBPC BOOK | 444,140 | - | 222,070 | Network |
| 66 | CBPC | Dover-Laurens | 15 | 69 | Line | 1.172 | 58 | Clean | 656443 | 656497 | CBPC BOOK | 241,414 | - | 120,707 | Network |
| 67 | CBPC | Laurens Muni West-Fox Run | 15 | 69 | Line | 2.082 | 58 | Clean | 656499 | 656467 | CBPC BOOK | 477,208 | - | 238,604 | Network |
| 68 | CBPC | Marathon Tap-Marathon | 15 | 69 | Line | 2.021 | 47 | Radial | 656513 | 656511 | CBPC BOOK | 43,658 | - | 21,829 | Alliant Energy, ILEC |
| 69 | CBPC | Pocahontas-Dover | 15 | 69 | Line | 1.321 | 41 | Clean | 656537 | 656443 | CBPC BOOK | 244,655 | - | 122,328 | Network |
| 70 | CBPC | Storm Lake-Miles Nelsen | 15 | 69 | Line | 0.142 | 36 | Clean | 656559 | 656519 | CBPC BOOK | 219,153 | - | 109,576 | Network |
| 71 | CBPC | Storm Lake-Buena Vista | 15 | 69 | Line | 2.301 | 57.4 | Clean | 656559 | 635281 | CBPC BOOK | 49,709 | - | 24,855 | Network |
| 72 | CBPC | Buena Vista-Sac Co | 15 | 69 | Line | 0.078 | 41 | Clean | 635281 | 635341 | CBPC BOOK | 232,985 | - | 116,492 | Network |
| 73 | CBPC | Hanover Tap-Hanover | 15 | 69 | Line | 5.432 | 58 | Radial | 656483 | 656481 | CBPC BOOK | 117,357 | - | 58,678 | ILEC, NIPCO |
| 74 | CBPC | Sac Co-Sac City | 15 | 69 | Line | 6.291 | 41 | Clean | 635341 | 656979 | CBPC BOOK | 568,197 | - | 284,099 | Network |
| 75 | CBPC | Sac City-Sherwood | 15 | 69 | Line | 4.371 | 41 | Clean | 656975 | 656159 | CBPC BOOK | 310,574 | - | 155,287 | Network |
| | | | | | | 13. | | | | | | | | | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | 3 | 57 | Radi | 656 | 656 | CBPC | 288,96 | | 144,48 | Calhoun Co |
| 76 | CBPC | Sherwood-Esmay | 15 | 69 | Line | 7 | .4 | al | 159 | 155 | BOOK | 1 | - | 1 | REC, RVEC |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 77 | CBPC | Hampton-ITC IaFalls | 16 | 69 | Line | 13.73 | 69 | Clean | 656193 | 630341 | CBPC BOOK | 159,264 | - | 79,632 | Network |
| 78 | CBPC | Wisdom-WAPA | 17 | 69 | Line | 0.54 | 91.7 | Clean | 656573 | 652581 | CBPC BOOK | 4,792 | - | 2,396 | Network |
| 79 | CBPC | Storm Lake-Fox Run | 17 | 69 | Line | 12.06 | 57.4 | Clean | 656559 | 656467 | CBPC BOOK | 107,024 | - | 53,512 | Network |
| 80 | CBPC | Fox Run-Wisdom | 17 | 69 | Line | 22.87 | 58 | Clean | 656467 | 656573 | CBPC BOOK | 202,954 | - | 101,477 | Network |
| 81 | CBPC | North Spencer - Ind | 17 | 69 | Line | 4.77 | 58 | Clean | 646491 | 656493 | CBPC BOOK | 42,330 | - | 21,165 | Network |
| 82 | CBPC | Ind-Wisdom | 17 | 69 | Line | 3.29 | 58 | Clean | 656493 | 656573 | CBPC BOOK | 29,196 | - | 14,598 | Network |
| 83 | CBPC | Wisdom-Wisdom Jct | 17 | 69 | Line | 7.94 | 58 | Clean | 656573 | 656571 | CBPC BOOK | 70,462 | - | 35,231 | Network |
| 84 | CBPC | Drager-Glidden | 18 | 69 | Line | 2.44 | 57.4 | Clean | 656285 | 656239 | CBPC BOOK | 45,885 | - | 22,943 | Network |
| 85 | CBPC | Toyne-Denison | 18 | 69 | Line | 29.39 | 37.8 | Clean | 656249 | 652583 | CBPC BOOK | 552,694 | - | 276,347 | Network |
| 86 | CBPC | Glidden-Carrollton | 18 | 69 | Line | 9.45 | 57.4 | Clean | 656239 | 656233 | CBPC BOOK | 177,712 | - | 88,856 | Network |
| 87 | CBPC | Carrollton-Toyne | 18 | 69 | Line | 8.95 | 58 | Clean | 656233 | 656249 | CBPC BOOK | 168,309 | - | 84,155 | Network |
| 88 | CBPC | Sherwood-Drager | 18 | 69 | Line | 19.65 | 57.4 | Clean | 656159 | 656285 | CBPC BOOK | 369,528 | - | 184,764 | Network |
| 89 | CBPC | WISDOM 161-OSGOOD 161 | 19 | 161 | Line | 30.64 | 223.1 | Clean | 656570 | 656527 | CBPC BOOK | 685,967 | - | 342,984 | Network |
| 90 | CBPC | BURT 161-HANCOCK 161 | 19 | 161 | Line | 3.71 | 223.1 | Clean | 656423 | 631103 | CBPC BOOK | 754,698 | - | 377,349 | Network |
| 91 | CBPC | OSGOOD 161-BURT 161 | 19 | 161 | Line | 29.78 | 223.1 | Clean | 656527 | 656423 | CBPC BOOK | 666,714 | - | 333,357 | Network |
| 92 | CBPC | BUENA VISTA CO 161-SAC CO 161 | 20 | 161 | Line | 9.663 | 206 | Clean | 635280 | 635340 | CBPC BOOK | 134,102 | - | 67,051 | Network |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | WISDOM 161- | | | | 2. | | | | | | | | | | |
| | | BUENA VISTA CO | | 16 | | 7 | 22 | Clea | 656 | 635 | CBPC | 455,05 | | 227,52 | | |
| 93 | CBPC | 161 | 20 | 1 | Line | 8 | 3 | n | 570 | 280 | BOOK | 8 | - | 9 | Network | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 94 | CBPC | BREMER CO 161-BLACK HAWK CO 161 | 21 | 161 | Line | 23.31 | 25.8 | Clean | 656087 | 636200 | CBPC BOOK | 465,000 | - | 232,500 | Network |
| 95 | CBPC | FLOYD CO 161-BREMER CO DC | 21 | 161 | Line | 21.94 | 25.8 | Clean | 636300 | 656087 | CBPC BOOK | 437,670 | - | 218,835 | Network |
| 96 | CBPC | Fredericksburg-Floyd | 22 | 69 | Line | 24.16 | 58 | Clean | 656025 | 636301 | CBPC BOOK | 259,962 | - | 129,981 | Network |
| 97 | CBPC | Rockford Jct-Floyd MEC | 22 | 69 | Line | 12.47 | 47 | Clean | 656067 | 636301 | CBPC BOOK | 134,177 | - | 67,089 | Network |
| 98 | CBPC | Waverly Jct-Parkersburg | 23 | 69 | Line | 30.22 | 57.4 | Clean | 656083 | 656065 | CBPC BOOK | 345,743 | - | 172,871 | Network |
| 99 | CBPC | HOPE 161-WEBSTER CO 161 | 24 | 161 | Line | 12.40 | 22.3 | Clean | 656353 | 636001 | CBPC BOOK | 251,021 | - | 125,510 | Network |
| 100 | CBPC | BURT DC-HOPE 161 | 25 | 161 | Line | 34.62 | 22.31 | Clean | 656423 | 656353 | CBPC BOOK | 1,125,766 | - | 562,883 | Network |
| 101 | CBPC | Ledyard-Armstrong Grove | 26 | 69 | Line | 22.03 | 47 | Clean | 656501 | 630196 | CBPC BOOK | 848,751 | - | 424,376 | Network |
| 102 | CBPC | Maple Hill-Wallingford | 26 | 69 | Line | 39.51 | 57.4 | Clean | 656505 | 656575 | CBPC BOOK | 366,392 | - | 183,196 | Network |
| 103 | CBPC | SHEFFIELD 161-HAMPTON TAP | 30 | 161 | Line | 12.04 | 21.5 | Clean | 656201 | 656207 | CBPC BOOK | 192,579 | - | 96,290 | Network |
| 104 | CBPC | HAMPTON TAP-HAMPTON 161 | 30 | 161 | Line | 3.04 | 21.5 | Clean | 656207 | 656191 | CBPC BOOK | 48,625 | - | 24,312 | Network |
| 105 | CBPC | HAMPTON TAP-FRANKLIN CO 161 | 30 | 161 | Line | 8.91 | 21.5 | Clean | 656207 | 636230 | CBPC BOOK | 142,515 | - | 71,258 | Network |
| 106 | CBPC | EMERY 161-SHEFFIELD DC | 30 | 161 | Line | 16.88 | 30.8 | Clean | 631048 | 656201 | CBPC BOOK | 269,995 | - | 134,997 | Network |
| 107 | CBPC | Sweazy-Webster City Jct | 50 | 69 | Line | 6.30 | 41 | Clean | 656887 | 656367 | CBPC/WC BOOK | 36,231 | - | 18,116 | Network |
| 108 | CBPC | Sweazy-Wright | 51 | 69 | Line | 8.73 | 48 | Clean | 656887 | 636051 | CBPC/WC BOOK | - | - | - | Network |
| 109 | | Bowman Tap- | | | | 12.8 | | Clean | 656 | 656 | CBPC/WC | 186,80 | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9 | CBPC | Sweazy | 52 | 69 | Line | 4 | 47 | n | 909 | 887 | BOOK | 9 | - | 93,405 | Network |
| ... | | | | | | | | | | | | - | - | - | |

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| ... | | | | | | - | - | - |
| 107 | **Subtotal SPP Transmission Line Investment** | | | | | 26,128,113 | - | 13,064,057 |
| | **Less Non-Eligible Assets under Attachment AI of the SPP Tariff** | | | | | | | |
| ... | | | | | | - | - | - |
| ... | | | | | | - | - | - |
| 108 | **Total Non-Eligible Assets** | | | | | - | - | - |
| 109 | **Total SPP Transmission Substation Investment** | | | | | 26,128,113 | - | 13,064,057 |

| 110 | Property Taxes | Line Type | Pole Miles | Rate per pole mile | Property taxes |
|---|---|---|---|---|---|
| 111 | | 69 | 12<br>21.2 | 55<br>0 | 671,<br>671 |
| 112 | | 161 | 26<br>9.71 | 70<br>0 | 188,<br>797 |
| 113 | | | 14<br>90.9 | | 860,<br>468 |

Notes:

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not change the columns or the formulas included in these Work Papers during the Annual Update.

**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 18: SPP Transmission Substation assets

13 Months Ended 12/31/XX

| Line No. | Transmission Facility Owner | Tranmisssion Facility Description/Name | Line # | Voltage Level(s) (kV) | Transmission Switching or Substation | Bus Number1 | Source of Financial Data | Gross Plant BOY | Gross Plant EOY | Average Gross Plant | Note: |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) |
| 1 | CBPC | Dover Switching Station | 2A | 69/12.5 | Substation | | CBPC BOOK | - | - | - | Transmission Assets Only |
| 2 | CBPC | Willemssen Switching Station | 2B | 69/12.5 | Substation | | CBPC BOOK | - | - | - | Transmission Assets Only |
| 3 | CBPC | Williams Switching Station | 2C | 69/12.5 | Substation | | CBPC BOOK | - | - | - | Transmission Assets Only |
| 4 | CBPC | Buckner Switching Station | 2DT | 69 | Switching | | CBPC BOOK | - | - | - | |
| 5 | CBPC | Alden Jct. Switching Station | 2E | 69 | Switching | | CBPC BOOK | - | - | - | |
| 6 | CBPC | Drager Switching Station | 2F | 161/69 | Switching | | CBPC BOOK | - | - | - | |
| 7 | CBPC | Toyne Switching Station | 2G | 69 | Switching | | CBPC BOOK | - | - | - | |
| 8 | CBPC | Ayrshire Switching Station | 2H | 69/12.5 | Substation | | CBPC BOOK | - | - | - | Transmission Assets Only |
| 9 | CBPC | Sheffield Switching Station | 2J | 161/69 | Switching | | CBPC BOOK | - | - | - | |
| 10 | CBPC | Fredericksburg Switching Station | 2K | 69/12.5 | Substation | | CBPC BOOK | - | - | - | Transmission Assets Only |
| 11 | CBPC | Whittemore Switching Station | 2M | 69 | Switching | | CBPC BOOK | - | - | - | |
| 12 | CBPC | Pelican Switching Station | 2P | 69 | Switching | | CBPC BOOK | - | - | - | |
| 13 | CBPC | Radcliffe Switching Station | 2R | 69 | Switching | | CBPC BOOK | - | - | - | |
| 14 | CBPC | Arends Switching Station | 2U | 69 | Switching | | CBPC BOOK | - | - | - | |
| 15 | CBPC | Humboldt Switching Station | AA | 69 | Switching | | CBPC BOOK | - | - | - | |
| 16 | CBPC | Henry Hope Switching Station | 61 | 161/69 | Substation | | CBPC BOOK | - | - | - | |
| | | Pocahontas Switching | | 69/12. | Substat | | CBPC | | | | Transmission |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 17 | CBPC | Station | B | 5 | ion | BOOK | - | - | - | Assets Only |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 18 | CBPC | Dickens Switching Station | C | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 19 | CBPC | Bremer 161/69 Switching Station | D | 161/69 | Substation | CBPC BOOK | - | - | - | |
| 20 | CBPC | Wisdom Switching Station | F | 69 | Switching | CBPC BOOK | - | - | - | |
| 21 | CBPC | Wisdom 161 Switching Station | F61 | 161 | Switching | CBPC BOOK | - | - | - | |
| 22 | CBPC | Galbraith Switching Station | G | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 23 | CBPC | Hampton Switching Station | H | 161/69/12.5 | Substation | CBPC BOOK | - | - | - | |
| 24 | CBPC | Dinsdale Switching Station | I | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 25 | CBPC | Storm Lake Switching Station | J | 69 | Switching | CBPC BOOK | - | - | - | |
| 26 | CBPC | Klemme Switching Station | K | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 27 | CBPC | Wallingford Switching Station | L | 69 | Switching | CBPC BOOK | - | - | - | |
| 28 | CBPC | Glidden Switching Station | M | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 29 | CBPC | Burt Switching Station | N | 161/69 | Substation | CBPC BOOK | - | - | - | |
| 30 | CBPC | Osgood Switching Station | O | 161/69 | Substation | CBPC BOOK | - | - | - | |
| 31 | CBPC | Plainfield Switching Station | P | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 32 | CBPC | Springfield Switching Station | Q | 69 | Switching | CBPC BOOK | - | - | - | |
| 33 | CBPC | Parkersburg Switching Station | R | 69 | Switching | CBPC BOOK | - | - | - | |
| 34 | CBPC | Sherwood Switching Station | S | 69/12.5 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| 35 | CBPC | Webster Switching Station | T | 161/69 | Substation | CBPC BOOK | - | - | - | |
| 36 | CBPC | Fernald Switching Station | U | 69 | Switching | CBPC BOOK | - | - | - | |
| 37 | CBPC | Carrollton Switching Station | V | 69/12.5 | Substation | CBPC BOOK | - | - | - | |
| 38 | CBPC | Wellsburg Switching Station | W | 69 | Switching | CBPC BOOK | - | - | - | Transmission Assets Only |
| 39 | CBPC | Snell Switching Station | X | 69/4.16 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| ... | CBPC | Sweazy Switching Station | Y | 69/13.2 | Substation | CBPC BOOK | - | - | - | Transmission Assets Only |
| ... | | | | | | | | | - | |
| 40 | **Subtotal SPP Transmission Substation Investment** | | | | | | - | - | - | |
| | **Less Non-Eligible Assets under Attachment AI of the SPP Tariff** | | | | | | | | | |
| 41 | | Wisdom 69 Circuit Breakers - 3 | | | | | - | - | - | |
| ### | | Plainfield Circuit Breaker | | | | | - | - | - | |

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| ... | | | | |
| 45 | **Total Non-Eligible Assets** | - | - | - |
| 46 | **Total SPP Transmission Substation Investment** | - | - | - |

Notes:

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**Corn Belt Power Cooperative**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 19: SPP Transmission MOS assets

13 Months Ended 12/31/2014

| Line No. | CRPID | Location | Gross Plant BOY | Gross Plant EOY | Average Gross Plant | Notes: |
|---|---|---|---|---|---|---|
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | 2AJ31 | Feldman MOS | - | - | - | |
| 2 | 2AV70 | Rembrant MOS | - | - | - | |
| 3 | 2AV85 | IES Albert City MOS | - | - | - | |
| 4 | 2AV86 | Marathon MOS | - | - | - | |
| 5 | 2B2C18 | Blairsburg MOS | - | - | - | |
| 6 | 2B2C82 | Boondocks MOS | - | - | - | |
| 7 | 2DU02-1 | Garden City MOS | - | - | - | |
| 8 | 2E2L38 | IFE MOS | - | - | - | |
| 9 | 2E2L87 | Alden Rural MOS | - | - | - | |
| 10 | 2MG23 | Whittemore MOS | - | - | - | |
| 11 | 2MG60 | Hobarton MOS | - | - | - | |
| 12 | A2B28 | Troy MOS | - | - | - | |
| 13 | AB41 | Gilmore City MOS | - | - | - | |
| 14 | AG52 | Livermore MOS | - | - | - | |
| 15 | AH43 | Wall Lake MOS | - | - | - | |
| 16 | AH66 | Galt MOS | - | - | - | |
| 17 | AK69 | Boone Valley MOS | - | - | - | |
| 18 | AK74 | Luverne MPS MOS | - | - | - | |
| 19 | AK75 | Renwick MOS | - | - | - | |
| 20 | AS40 | East MOS | - | - | - | |
| 21 | AS58 | Twin Lakes MOS | - | - | - | |
| 22 | BJ56 | Laurens Capacitor | - | - | - | |
| 23 | CF36 | Industrial MOS | - | - | - | |
| 24 | CF364 | Industrial Capacitor | - | - | - | |
| 25 | CF42 | Dickens MOS | - | - | - | |
| 26 | CF61 | Riverton MOS (IPL) | - | - | - | |
| 27 | DW80-1 2 | Hicks MOS | - | - | - | |
| 28 | DW801-2 | Hicks MOS | - | - | - | |

| | | | | | |
|---|---|---|---|---|---|
| 29 | GK22 | Denhart MOS | - | - | - |
| 30 | GK83 | Hawkeye Pride MOS | - | - | - |

| | |
|---|---|
| HI05 | Hampton 161 kV Tap MOS |
| HK01 | Sheffield MPS MOS |
| HK59 | Alexander MOS |
| HR03 | Geneva MOS |
| HR76 | Dumont MPS MOS |
| HW21 | Ackley Municipal MOS |
| HW30 | Farmland MOS |
| HW48 | Pine Lake |
| JF45 | Cornell (N) MOS |
| JF46 | Cornell (S) MOS |
| JS04 | Lake View MPS MOS |
| JS14 | Odebolt MOS |
| JS50 | Maple Valley MOS |
| JS791T2 | Alta MOS |
| KN09 | Liberty MOS |
| KN13 | Hutchins MOS |
| LF07 | Estherville Capacitor |
| LF08 | Milford Mun. MOS |
| LF12 | Milford MOS |
| LF27 | Estherville MOS |
| LF291 | Iowa Lakes I |
| LF292 | Iowa Lakes II |
| LF64 | Superior MOS |
| LF74 | Fostoria MOS |
| LF77 | Gruver MOS |
| LQ55 | Maple Hill Jct. MOS |
| LQ78 | Vernon Jct. MOS |
| LQ81 | Ringsted MOS |
| ME17 | Carrollton MOS |
| ME53 | Templeton MOS |
| OB15 | Emmetsburg MOS |
| OB62 | Plover Tap MOS |
| OB63 | Whittemore Tap MOS |
| OC65 | Ayrshire MOS |
| OL711-2 | Greattinger MOS |
| PR39 | Unverferth MOS |
| PR63 | Shell Rock Ethanol MOS |
| PV96 | New Hampton MOS |
| PZ16 | Peterson MOS |
| PZ37 | Sumner Jct. MOS |

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|---|---|---|---|---|---|---|---|---|
| PZ44 | | | | | | - | - | - |
| | - | - | - | | | | | |
| | - | - | - | | | | | |
| Bradford MOS | - | - | - | | | | | |
| | - | - | - | | | | | |
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| PZ54 | - | - | - | | | | | |
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| | - | - | - | | | | | |
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| Horton MOS | - | - | - | | | | | |
| | - | - | - | | | | | |
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| | | MOS | - | - | - |
| | RW57 | Fern MOS | - | - | - |
| | RZ10 | Bristow MOS | - | - | - |
| | RZ34 | Rockford MOS | - | - | - |
| PZ603 | SM35 | Lake City MPS MOS | - | - | - |
| Fredericksburg Capacitor | SM47 | Breda MOS | - | - | - |
| | TX25 | Vincent Tap MOS | - | - | - |
| - | WD26 | Cramer MOS | - | - | - |
| | WD32 | Dinsdale MOS | - | - | - |
| - | WD84 | Conrad MOS | - | - | - |
| - | XY51 | Duncombe MOS | - | - | - |
| QL06 | YW02 | Roland Tap MOS | - | - | - |
| Eagle MOS | YW11 | Webster City Jct. MOS | - | - | - |
| | YW33 | Buckeye MOS | - | - | - |
| - | YW49 | Horizon MOS | - | - | - |
| - | YW67 | Pleasant MOS | - | - | - |
| - | YW73 | Roland Capacitor | - | - | - |
| QL19 | | | - | - | - |
| Gerled MOS | **Subtotal SPP Transmission MOS Investment** | | - | - | - |
| - | | | | | |
| - | **Less Non-Eligible Assets under Attachment AI of the SPP Tariff** | | | | |
| - | TX25-2 | Vincent Tap | - | - | - |
| QL65 | XY51-2 | Duncombe | - | - | - |
| Swan Lake MOS | YW11-1 | Webster City Jct | - | - | - |
| | DW80-2 | Hicks Tap | - | - | - |
| - | WD73-3 | Cramer Tap | - | - | - |
| - | HW21-1 | Ackley Muni | - | - | - |
| - | HW78 | Ackley Muni | - | - | - |
| RW06 | RW24-3 | Applington Jct | - | - | - |
| Kesley MOS | PZ54-3 | Horton Tap | - | - | - |
| - | RZ10-2 | Bristow | - | - | - |
| - | A2B28-3 | Troy | - | - | - |
| - | HR76-3 | Dumont MEC | - | - | - |
| RW24 | GK83-3 | Hawkeye Pride Tap | - | - | - |
| Applington Jct. | AK69-1 | Boone Valley | - | - | - |

| | | | | | |
|---|---|---|---|---|---|
| 110 | LF64-3 | Superior Tap | - | - | - |
| 111 | LF84 | Milford Tap East | - | - | - |
| 112 | LQ78-3 | Vernon Tap | - | - | - |
| 113 | QL19-3 | Gerled Tap | - | - | - |
| 114 | 2MG71 | Hobarton Tap | - | - | - |
| 115 | AB41-3 | Gilmore City Tap | - | - | - |
| 116 | AS58-3 | Twin Lakes Tap | - | - | - |
| 117 | 2AJ31-3 | Feldman Tap | - | - | - |
| 118 | 2AV70-3 | Rembrandt Tap | - | - | - |
| 119 | JS85 | Alta Muni East | - | - | - |
| 120 | SM47-3 | Breda Tap | - | - | - |
| 121 | SM75 | Lake City MEC | - | - | - |
| 122 | LF77-2 | Iowa Lakes Tap | - | - | - |
| 123 | QL65-2 | Swan Lake | - | - | - |
| 124 | HW48 | Pine Lake | - | - | - |
| 125 | LF291 | Iowa Lakes I | - | - | - |
| 126 | LF292 | Iowa Lakes II | - | - | - |
| 127 | | | | | - |
| 128 | | | | | |
| 129 | **Total Non-Eligible Assets** | | - | - | - |
| 130 | **Total SPP Transmission MOS Investment** | | - | - | - |

Notes:

A The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Corn Belt will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in 's Corn Belt's Implementation Protocols. Corn Belt may not change the columns or the formulas included in these Work Papers during the Annual Update.

**Corn Belt Power Cooperative**

**Transmission Formula Rate Implementation Protocols**

## I. Annual Update

1. The transmission formula rate template of the Corn Belt Power Cooperative ("Corn Belt") and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of Corn Belt for transmission service in the Upper Missouri Zone ("UMZ") - Zone 19 of the Southwest Power Pool, Inc. ("SPP"). Corn Belt must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") for Network Integration Transmission Service and the revenue requirements for Scheduling, System Control and Dispatch Service ("Schedule 1 Service"), as well as the SPP Base Plan Zonal and Region-Wide Charge ("Schedule 11 Service") under the SPP Open Access Transmission Tariff ("OATT" or "SPP Tariff"). Corn Belt's ATRR includes the annual transmission revenue requirements associated with the facilities of North Iowa Municipal Electric Cooperative Association ("NIMECA") that are incorporated within the Formula Rate.

2. The ATRR calculated pursuant to the Formula Rate, as well as the SPP-derived rates, shall be applicable to service on and after June 1 of each calendar year through May 31 of the following calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before June 1 of each calendar year, Corn Belt shall:

   (a) recalculate the revenue requirements applicable to Network Integration Transmission Service, Schedule 1 Service, and Schedule 11 Service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

   (b) provide its Annual Update to SPP and request SPP to post such information on SPP's website and Open Access Same-Time Information System ("OASIS"). Within ten (10) days of such posting, Corn Belt shall provide notice of such posting via the SPP e-mail subscription ("Service List").[1] Interested Parties can subscribe to the Service List on the SPP website.

4. If the date for posting the Annual Update falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date." Any delay in the Publication Date will result in an equivalent extension of time for the submission of information requests and for Corn Belt's response to information requests as described in Sections III of these Protocols, and for the submission of Information Challenges and for Corn Belt's response to Informal Challenges as described in Section IV of these Protocols.

5. The Annual Update for the Rate Year shall:

[1] As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP website. As of January 2016, the Exploder List was titled "Formula Rate Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

(a) include a workable populated rate formula template with fully functional spreadsheets showing the calculation of the Annual Update and underlying workpapers in native format with all formulas and links intact;

(b) to the extent specified in the Formula Rate, be based upon Corn Belt's Rural Utilities Service ("RUS") Financial and Operating Report - Power Supply ("Form 12") for the most recent calendar year, and, to the extent specified in the Formula Rate, upon the books and records of Corn Belt consistent with RUS and FERC accounting regulations, policies, and practices.

(c) as and to the extent specified in the Formula Rate, provide sufficiently detailed workpapers and supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the RUS Form 12 or the audited financial statements;

(d) provide sufficient information to enable Interested Parties (as that term is defined in Section II of these Protocols) to replicate the calculation of the formula results from the Formula Rate;

(e) identify any changes in the formula references (page and line numbers) to the RUS Form 12;

(f) identify all material adjustments made to the Formula Rate data in determining formula inputs, including relevant footnotes to the RUS Form 12 or the audited financial statements and any adjustments not shown in the RUS Form 12 or the audited financial statements;

(g) With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

a. The initial implementation of an accounting standard or policy;

b. the initial implementation of accounting practices for unusual or unconventional items where RUS or FERC has not provided specific accounting direction;

c. correction of errors and prior period adjustments that impact the revenue requirement;

d. the implementation of new estimation methods or policies that change prior estimates; and

e. changes to income tax elections if applicable.

ii. Identify items included in the Formula Rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Formula Rate;

iv. Provide, for each item identified pursuant to items I.5.g.i.a - I.5.g.i.c of these Protocols, a

narrative explanation of the individual impact of such changes on charges billed under the Formula Rate.

(h) Identify the equity component of the capital structure used for the calculation of the Weighted Average Cost of Capital ("WACC");

(i) not seek to modify the Formula Rate, as any modification to the Formula Rate will require filing under Section 205 or 206 of the Federal Power Act.

**II. Review of Annual Update**

Corn Belt shall host an open meeting among Interested Parties, no earlier than July 1 and no later than September 1 each year ("Annual Meeting"). No less than seven (7) days prior to such Annual Meeting, Corn Belt shall provide Interested Parties notice on SPP's website and OASIS of the time, date, and location of the Annual Meeting and shall provide notice of such meeting via the Service List. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual Meeting shall (i) permit Corn Belt to explain and clarify its Annual Update and (ii) provide Interested Parties an opportunity to seek information and clarifications from Corn Belt about the Annual Update. The Annual Meeting may be held as solely as a "remote access" meeting (web and voice) to limit travel costs and ease burdens.

If Corn Belt is responsible for the construction of any transmission projects that utilize a regional cost sharing mechanism, Corn Belt shall participate in a joint informational meeting with other transmission owners using formula rates to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. The purpose of the meeting is to enable all interested parties to understand how those Transmission Owners are implementing their formula rates for cost recovery of such projects. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP website and OASIS and distributed to Interested Parties via the Service List no less than seven (7) days prior to such meetings.

**III. Information Exchange Procedures**

1. Interested Parties shall have until September 15 following the Publication Date (unless such period is extended with the written consent of Corn Belt, by FERC order, or by operation of Section I.4) to serve reasonable information and document requests on Corn Belt ("Information Exchange Period"). If September 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(a) the extent or effect of an Accounting Change;

(b) whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

(c) the proper application of the Formula Rate and procedures in these Protocols;

(d) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;

(e) the prudence of actual costs and expenditures;

(f) the effect of any change to the underlying Uniform System of Accounts or the Formula Rate template; or

(g) any other information that may reasonably have substantive effect on the calculation of the Annual

Update pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. Corn Belt shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receiving such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day. Corn Belt shall respond to all information and document requests by no later than October 15 following the Publication Date, unless the Information Exchange Period is extended by Corn Belt or FERC, or by operation of Section I.4.

3. Corn Belt shall request SPP to post on SPP's website and OASIS all information requests from Interested Parties and Corn Belt's response(s) to such requests, and a link to the website will be electronically served upon the Service List; except, however, if responses to information and document requests include material deemed by Corn Belt to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Corn Belt and the requesting party.

4. Corn Belt shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement confidentiality privilege; however, Corn Belt may require that Interested Parties execute a non-disclosure agreement to obtain access to material that Corn Belt deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**IV. Challenge Procedures**

1. Interested Parties shall have until November 15 following the Publication Date (unless such period is extended with the written consent of Corn Belt, by FERC order or by operation of Section I.4) to review the inputs, supporting explanations, allocations, and calculations ("Review Period") and to notify Corn Belt in writing, which may be made electronically, of any specific Informal Challenges. The period of time from the Publication Date until November 15 shall be referred to as the Review Period. If November 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursing a Formal Challenge with respect to any issue for that Annual Update but is not barred from pursing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

2. A party submitting an Informal Challenge to Corn Belt must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Corn Belt shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. Corn Belt, and where applicable, SPP, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If Corn Belt disagrees with such challenge, Corn Belt will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after November 15, and Corn Belt must respond to all Informal Challenges by no later than December 15, unless the Review Period is extended by Corn Belt or FERC or by operation of Section I.4.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

(a) A Formal Challenge shall:

i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or Protocols;

ii. Explain how the action or inaction violates the filed rate formula or Protocols;

iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

a. The extent or effect of an Accounting Change;

b. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

c. The proper application of the Formula Rate and procedures in these Protocols;

d. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying RUS System of Accounts or the Applicable Form; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(b) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on Corn Belt. Service to Corn Belt must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on Corn Belt's Informational Filing required under Section VI of these Protocols.

4. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these Protocols; (3) the proper application of the Formula Rate and procedures in these Protocols; (4) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying RUS System of Accounts or the Applicable Form; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

5. Corn Belt will request SPP to post on SPP's website all Informal Challenges from Interested Parties and Corn Belt's response(s) to such Informal Challenges and a link to the website will be electronically served upon the Service List; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by Corn Belt to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Corn Belt and the requesting party.

6. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by Corn Belt will be reported in the Informational Filing required pursuant to Section VI of these Protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

7. An Interested Party shall have until March 1 following the Review Period (unless such date is extended with the written consent of Corn Belt to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on Corn Belt on the date of such filing as specified in Section IV.3.b above. A Formal Challenge shall be filed in the same docket as Corn Belt's Informational Filing discussed in Section VI of these Protocols. Corn Belt shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

8. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Corn Belt shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

9. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Corn Belt to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

10. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

11. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the RUS System of Accounts or the Applicable Form, shall first raise the matter with Corn Belt in accordance with this Section IV before pursuing a Formal Challenge.

## V. Changes to Annual Update

1. A change to the Formula Rate fixed inputs related to rate of return on equity ("ROE"), depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than Pensions, and ROE incentives for SPP regional projects may not be made absent an appropriate filing with the FERC pursuant

to Federal Power Act Section 205 or Section 206; provided, however, that Corn Belt may make a limited Section 205 filing to change depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than Pensions, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed change(s) are just and reasonable, and not unduly discriminatory. Any filing to change the ROE, or capital structure is not considered a limited filing.

2. If Corn Belt files any corrections to correct a Mistake in its RUS Form 12 or the audited financial statements during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year, with interest computed in accordance with 18 C.F.R. § 35.19a. *See* Worksheet 11 of the Formula Rate template. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as, but not limited to, arithmetic and other inadvertent computational errors, erroneous Form 12 references or the like. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process. Corrections to erroneous Form 12 references in the Formula Rate template may be made in the Annual Update without a Section 205 or 206 filing. There is no deadline for any Interested Party or Corn Belt to notify the other party of any mistake in any RUS Form 12 or the audited financial statements data or specific data applied in the Formula Rate template.

3. Any changes to the data inputs, including but not limited to revisions to Corn Belt's RUS Form 12 or the audited financial statements, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a**.**

## VI. Informational Filings

1. By January 15 of each year, Corn Belt shall submit to FERC an informational filing ("Informational Filing") of its Annual Update. Corn Belt will submit all Informational Filings in the same docket assigned to Corn Belt's first Informational Filing. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that Corn Belt has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, Corn Belt shall provide notice of the Informational Filing to Interested Parties via email and by posting the docket number assigned to Corn Belt's Informational Filing on SPP's website and OASIS and a link to the website will be electronically served upon the Service List.

2. Any challenges to the implementation of Corn Belt's Formula Rate must be made through the Challenge Procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

# ADDENDUM 26 TO ATTACHMENT H – Part 2

## Algona Municipal Utilities

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Algona Municipal Utilities

| Line No. | | Allocated Amount | Line N |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | $ | |

(page 3, line 31) - o .

| | REVENUE CREDITS | (Note T) | Total | Allocator | | | |
|---|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000 00 | 0 | 2a |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000 00 | 0 | 3a |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000 00 | 0 | 4a |

**Allocation of ATRR To SPP UMZ Pricing Zone**

| Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|
| **UMZ (SPP)** | $ - | #DIV/0! | #DIV/0! |
| **Non UMZ *** | $ - | #DIV/0! | #DIV/0! |
| **Total** | $ - | #DIV/0! | #DIV/0! |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5 | Revenues from service provided by the ISO at a discount | 0 | | TP | 0.000000 | 0 | |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 | * Gross transmission plant not included in SPP. |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | | $ - | |
| | DIVISOR | | | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | | (Note A) | 0 | |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | | | (Note B) | | |
| 10 | Plus 12 CP of Network Load not in line 8 | | | | (Note C) | 0 | |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | | | (Note D) | 0 | |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | | | 0 | |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | | | 0 | |

| | | | | | |
|---|---|---|---|---|---|
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | | |
| | | | Peak Rate | | Off-Peak Rate |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.0000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.0000 | Long Term | $0.000 | Long Term |

| | | | Template | | | months ended 12/31/20XX |
|---|---|---|---|---|---|---|
| | | | Algona Municipal Utilities | | | |
| | (1) | (2) | (3) | | (4) | (5) |
| Line No. | | | **Company Total** | **Allocator** | | **Transmission** (Col 3 times Col 4) |
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000 | |
| 2 | Transmission | | 0 | TP | 00 | 0 |
| 3 | Distribution | | 0 | NA | 0.000 | |
| 4 | General & Intangible | | 0 | W/S | 00 | 0 |
| 5 | Common | | 0 | CE | 0.000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 0.0 | |
| | TOTAL GROSS PLANT (sum | | | GP | 00 | |
| 6 | lines 1-5) | | 0 | = | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 0 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 1 | Common | | 0 | CE | 00 | 0 |
| 1 | TOTAL ACCUM. DEPRECIATION (sum | | | | | |
| 2 | lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 1 | | (line 1- | | | | |
| 3 | Production | line 7) | 0 | | | |
| 1 | | (line 2- | | | | |
| 4 | Transmission | line 8) | 0 | | | 0 |
| 1 | | (line 3 | | | | |
| 5 | Distribution | - line 9) | 0 | | | |
| | | (line 4 | | | | |
| 1 | | - line | | | | |
| 6 | General & Intangible | 10) | 0 | | | 0 |
| 1 | Common | (line 5 | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | | - line 11) | | | | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP = | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.0000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.0000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 | 0 |
| 28 | Prepayments | | 0 | GP | 0.000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | | 0 | | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Algona

| Line No. | (1) | (2) | Municipal Utilities (3) Company Total | | (4) Allocator | | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|---|
| | O&M (Note X) | | | | | | |
| 1 | Transmission | | 0 | | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | | 0 | | | 1.000000 | 0 |
| 2 | Less Account 565 | | 0 | | TE | 0.000000 | 0 |
| 3 | A&G | | 0 | | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | | 0 | | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | | 0 | | W/S | 0.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 00 | |
| | | | | 0.0 | |
| 5 | Plus Transmission Related Reg. | | | 00 | |
| a | Comm. Exp. (Note I) | 0 | TE | 00 | 0 |
| | | | | 0.0 | |
| | | | | 00 | |
| 6 | Common | 0 | CE | 00 | 0 |
| | | | | 1.0 | |
| | Transmission Lease | | | 00 | |
| 7 | Payments | 0 | NA | 00 | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| | | | | 0.0 | |
| | | | | 00 | |
| 9 | Transmission | 0 | TP | 00 | 0 |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 0 | General & Intangible | 0 | W/S | 00 | 0 |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 1 | Common | 0 | CE | 00 | 0 |
| 1 | TOTAL DEPRECIATION (Sum lines 9 - | | | | |
| 2 | 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 3 | Payroll | 0 | W/S | 00 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 14 | Highway and vehicle | 0 | W/S | 0.000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | 0.00% | | | |
| | where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.000 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 24 | Amortized Investment Tax Credit (enter negative) | | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | 0 | NA | | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | | 0 | | | 0 |
| 30 | Total Gross Revenue Requirement | | 0 | | | 0 |

| Formula Rate - Non-Levelized | Rate Formula Template<br>Algona Municipal Utilities | For the 12 months ended 12/31/20XX |
|---|---|---|

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |

| | | | | |
|---|---|---|---|---|
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | | 0.0000 |
| | TRANSMISSION EXPENSES | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | 0.0000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | 0.0000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE = | | 0.0000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| $ | TP | All |
|---|---|---|

| | | | | oc ati on | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | |
| 2 | Production | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | | | |
| 3 | Transmission | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | W&S Allocat or ($ / | | |
| 4 | Distribution | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | | | |
| 5 | Other | 0 | 0.00 | 0 | | Allocati on) | | |
| 1 | | | | | | | | W / |
| 6 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | S |

COMMON PLANT ALLOCATOR (CE)
(Note O)

| | | $ | % El ect ric (lin e 17 / lin e 20) | | Labor Ratio | | |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | C |
| 7 | Electric | 0 | | | (line 16) | | E |
| 1 | | | 0.0 | | 0.0000 | | 0. |
| 8 | Gas | 0 | 00 | * | 0 | = | 0 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | 00 | | 0<br>0<br>0<br>0 |
| 19 | Water | | 0 | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | |
| | RETURN (R) | | $ | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | |

| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24 | Long Term Debt | | 31.14% | 4.65 | 0.0145 | =WCLTD |

| | | | | | |
|---|---|---|---|---|---|
| a | | | % | | |
| 24 | | | 10.10 | | |
| b | Proprietary Capital | 68.86% | % | 0.0695 | |
| | | | | 0.0840 | = R |
| 24 | | | | | |
| c | Return Used | | | **0.0000** | |
| 25 | | | Proprietary Capital Cost Rate = | 10.10% | |
| 26 | | | TIER = | 0.00 | |
| | REVENUE CREDITS | | | | |
| | | | | Load | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | | 0 | |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | 0 | |
| 29 | Total of (a)-(b) | | | 0 | |
| | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | | | | |
| 30 | (Note R) | | | $0 | |
| | ACCOUNT 456.1 (OTHER ELECTRIC | | | | |

| | | |
|---|---|---|
| | REVENUES) | |
| 3 | a. Transmission charges for all | |
| 1 | transmission transactions | $0 |
| 3 | b. Transmission charges for all transmission | |
| 2 | transactions included in Divisor on Page 1 | $0 |
| 3 | | |
| 3 | Total of (a)-(b) | $0 |



For the 12 months ended 12/31/20XX

Formula Rate - Non-Levelized Rate Formula Template

Algona Municipal
Utilities

| Note Letter | |
|---|---|
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. |

LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks.

C LF as defined above at time of applicable pricing zone coincident monthly peaks.

D LF as defined above at time of applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

I Prepayments are the electric related prepayments booked to Account No. 165.
Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate

Formula Template,

since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.0 0% | |
| | SIT= | 0.0 0% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.0 0% | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template

| | |
|---|---|
| | (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. |
| U | Include only the amount from Accounts 428, 429 and 430. |
| V | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| W | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| X | Schedule 12-FERC charges should not be included in O&M recovered under this formula rate |
| Y | Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than |

68.86%. If the actual capital structure does not include any long-term debt,
then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update
after the settlement is approved by FERC.

A
A

Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and
which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital
structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that
capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Algona Municipal Uitlities**

**For the Year ended 12/31/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |

Average -

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:
the GFA #, the GFA load, and the GFA transmission revenues.

**No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

## Algona Municipal Uitlities

**For the Year ended 12/31/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Rights | | | | |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reacto | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| r Plant Equipment 32 | | | | |
| 3 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 32 4 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 32 5 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 32 6 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Tot | | | | |

| | | | | |
|---|---|---|---|---|
| al Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 – | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Water Wheels, Turbines, and Generators 33 | $ - | $ - | $ - | $ - |
| 4 - Accessory Electric Equipment 33 | $ - | $ - | $ - | $ - |
| 5 – Misc. Power Plant Equipment 33 | $ - | $ - | $ - | $ - |
| 6 – Roads, Railroads, and Bridges 33 | $ - | $ - | $ - | $ - |
| 7 – Asset Retirement Costs | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| for Hydraulic Production | | | | |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders | $ - | $ - | $ - | $ - |

| , | | | | |
|---|---|---|---|---|
| Products, and Accessories | | | | |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 347 – Asset Retirement Costs | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| for Nuclear Production | | | | |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| Total City-owned Transmission | Algona Transmission System | | | Lehigh Webster | | | Neal 4 | | | Other | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Plant | Accumulated Depreciation | Net Plant | Gross Plant | Accumulated Depreciation | Net Plant | Gross Plant | Accumulated Depreciation | Net Plant | Gross Plant | Accumulated Depreciation | Net Plant |
| | | Depreciation Expense | | | Depreciation Expense | | | Depreciation Expense | | | Depreciation Expense | |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 356 – Overhe | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ad Conductors and Devices | | | | | | | | | | | | | | | | | | | | | | |
| 357 – Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 358 – Underground Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 359 – Roads and Trails | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 359.1 – Asset Retirement Costs for Transm | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ission Plant | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total Transmission Plant** | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 361 – Structures and Improvements | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 362 – Station Equipment | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 363 – Storage Battery | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 368 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Line Transformers | - | - | - | - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Systems 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Intangible Plant | | | | |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |
| 397 – Communication | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total** | $ - | $ - | $ - | $ - |

# Plant In-Service

**Please answer the following questions:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

# Algona Municipal Utilities
# Depreciation Rates

| FERC Account | | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| **Steam Production Plant** | | | |
| 310 – Land and Land Rights | | 0 | #DIV/0! |
| 311 – Structures and Improvements | | 30 | 3.33% |
| 312 – Boiler Plant Equipment | | 30 | 3.33% |
| 314 – Turbogenerator Units | | 10 | 10.00% |
| 315 – Accessory Electric Equipment | | 30 | 3.33% |
| 316 – Misc. Power Plant Equipment | | 30 | 3.33% |
| **Other Production Plant** | | | |
| 340 – Land and Land Rights | | 0 | #DIV/0! |
| 341 – Structures and Improvements | | 17 | 5.88% |
| 344 – Generators | | 22 | 4.55% |
| **Transmission Plant** | | | |
| 350 – Land and Land Rights | | 0 | #DIV/0! |
| 352 – Structures and Improvements | | 22 | 4.55% |
| 353 – Station Equipment | | 25 | 4.00% |
| 354 – Towers and Fixtures | | 25 | 4.00% |
| **Distribution Plant** | | | |
| 360 – Land and Land Rights | | 0 | #DIV/0! |
| 361 – Structures and Improvements | | 20 | 5.00% |

| | | | |
|---|---|---|---|
| 362 – Station Equipment | | 30 | 3.33% |
| 363 – Storage Battery Equipment | | 13 | 7.69% |
| 364 – Poles, Towers, and Fixtures | | 28 | 3.57% |
| 368 – Line Transformers | | 27 | 3.70% |
| 369 – Services | | 25 | 4.00% |
| 370 – Meters | | 24 | 4.17% |
| 371 – Installations on Customer Premises | | 17 | 5.88% |
| 373 – Street lighting and Signal Systems | | 24 | 4.17% |
| **General Plant** | | | |
| 389 – Land and Land Rights | | 0 | #DIV/0! |
| 390 – Structures and Improvements | | 26 | 3.85% |
| 391 – Office Furniture and Equipment | | 10 | 10.00% |
| 392 – Transportation Equipment | | 10 | 10.00% |
| 394 – Tools, Shop and Garage Equipment | | 11 | 9.09% |
| | | | |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Algona Municipal Uitlities
For the Year ended 12/31/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Algona Municipal Uitlities
For the Year ended 12/31/20XX

Materials and Supplies

| | |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | **Amount** |
|---|---|
| Insulators | $ - |
| Relays | $ - |
| Substation Misc Part | $ - |
| Transmission wires | $ - |
| Trans. Line Hardware | $ - |
| Transducers | $ - |

| | | |
|---|---|---|
| | $ | - |
| **Total** | **$** | **-** |

Algona Municipal Uitlities
For the Year ended 12/31/20XX

| **Pre Payment Description** | **Amount** |
|---|---|
| | $ - |
| | - |
| | - |
| | - |
| Total Pre Payments | $ - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

# Algona Municipal Uitlities
# For the Year ended 12/31/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |

| | |
|---|---|
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

# Algona Municipal Uitlities
# For the Year ended 12/31/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| | |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| | |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |

**Administrative and General Expenses**

| | | |
|---|---|---|
| 920 – Administrative and General Salaries | - | |
| 921 – Office Supplies and Expenses | - | |
| 922 – Administrative Expenses Transferred Credit | - | |
| 923 – Outside Services Employed | - | |
| 924 – Property Insurance | - | |
| 925 – Injuries and Damages | - | |
| 926 – Employee Pension and Benefits | - | |
| 927 – Franchise Requirements | - | |
| 928 – Regulatory Commission Expenses | - | |
| 929 – Duplicate Charges Credit | - | |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | - | |
| 933 – Transportation Expenses | - | |
| Total Operations A&G | | - |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | | - |
| **Total Administrative and General Expenses** | | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Algona Municipal Uitlities
For the Year ended 12/31/20XX

| **FERC fees recorded to expense during the year** | **Account Charged** | **Amount** |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Algona Municipal Uitlities
For the Year ended 12/31/20XX

## Taxes Other Than Income Taxes

| | | |
|---|---|---|
| Payroll | $ | - |
| Highway & Vehicle | | - |
| Property | | - |
| Gross | | - |
| Other - Sales and Used Tax | | - |
| Payments in lieu of taxes | | - |
| Fed & State income Tax | | - |
| Total | $ | - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Algona Municipal Uitlities
For the Year ended 12/31/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| xxx | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| xxx | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| Xxxxxxxx | | |
| | - | |

**If a zero is reported for any category above, please provide a brief**

**explanation as to why.**

Algona Municipal Uitlities
For the Year ended 12/31/20XX

**Debt Detail - Electric only**

| | Principal Balance at For the Year ended 12/31/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| Principal & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal

and interest to the appropriate lines of the
audited financial statements.

Algona Municipal Uitlities

**For the Year ended 12/31/20XX**

## Account 454 (Rent from Electric Property)

| **Property Description** | **Amount** |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Rent Income | $ - |

Includes income related only to transmission facilities,
such as pole attachments, rentals and special use.
Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

Algona Municipal Uitlities

**For the Year ended 12/31/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – Part 3

## Alta Municipal Utilities

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Alta Municipal Utilities

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

| | REVENUE CREDITS | (Note T) | Total | Allocator | | | |
|---|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 | 2a |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 | 3a |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 | 4a |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 | |

**Allocation of ATRR To SPP UMZ Pricing Zone**

| | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|
| 2a | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | Total | $ - | #DIV/0! | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | 0 | * Gross transmission plant not included in SPP. |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | $ - | |
| | DIVISOR | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 | |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 | |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 | |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 | |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 | |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 15 | Divisor (sum lines 8-14) | | | | 0 | |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) (line 11/ 12) | | 0.000 | | | |
| | | | Peak Rate | | Off-Peak Rate | |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Shor |

| | | | | | |
|---|---|---|---|---|---|
| 22 | | $0.000 | Long Term | $0.000 | Long Term |

Alta Municipal Utilities

| Line No. | (1) | (2) | (3) Company Total | | (4) Allocator | | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | | |
| 1 | Production | | 0 | | NA | 0.000000 | |
| 2 | Transmission | | 0 | | TP | 0.000000 | 0 |
| 3 | Distribution | | 0 | | NA | 0.000000 | |
| 4 | General & Intangible | | 0 | | W/S | 0.000000 | 0 |
| 5 | Common | | 0 | | CE | 0.000000 | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | 0 | | GP = | 0.000000 % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | Production | | 0 | NA | | |
| | | | | | 0.0000 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.0000 | |
| 10 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0000 | |
| 11 | Common | | 0 | CE | 00 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | |
| 14 | Transmission | (line 2-line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| | | | | | 0.0000 | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP = | % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 19 | Account No. 281 (enter negative) | 0 | | | zero | 0 |
| 20 | Account No. 282 (enter negative) | 0 | | NP | 0.0000 | 0 |
| 21 | Account No. 283 (enter negative) | 0 | | NP | 0.0000 | 0 |
| 22 | Account No. 190 | 0 | | NP | 0.0000 | 0 |
| 23 | Account No. 255 (enter negative) | 0 | | NP | 0.0000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | 0 | | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) 0 | | TP | 0.0000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | 0 | | | | 0 |
| 27 | Materials & Supplies | (Note G) 0 | | TE | 0.0000 | 0 |
| 28 | Prepayments | 0 | | GP | 0.0000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | 0 | | | | 0 |

| | | | |
|---|---|---|---|
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Alta Municipal Utilities

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| Line N | | **Co** | | **Transmission** (Col 3 |

| o. | | mpany Total | Allocator | | times Col 4) |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| 9 | Transmission | 0 | TP | 0.000000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000000 | 0 |
| 11 | Common | 0 | CE | 0.000000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | 0.00% | | | |
| | where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes (line 25 plus line 26) | 0 | | | 0 |

| Li | | | | |
|---|---|---|---|---|
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | 0 | NA | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | | 0 |
| 30 | Total Gross Revenue Requirement | 0 | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

Alta Municipal Utilities

For the 12 months ended 12/31/20XX

| No. | | SUPPORTING CALCULATIONS AND NOTES | | |
|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | | TP = | 0.0000 0 |
| | TRANSMISSION EXPENSES | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |

| | | | | |
|---|---|---|---|---|
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | TP | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | | TE = | 0.00000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | | $ | TP | Allocation | |
|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | |
| 13 | Transmission | 0 | 0.00 | 0 | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) |
| 15 | Other | 0 | 0.00 | 0 | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 16 | Total (sum lines 12-15) | | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE)
(Note O)

| | | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | CE |
|---|---|---|---|---|---|---|---|---|
| 17 | Electric | | 0 | | | | | 0.0000 |
| 18 | Gas | | 0 | 0.000000 | * | 0.0000 | = | 0.0000 |
| 19 | Water | | 0 | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | |

| | | | $ |
|---|---|---|---|
| | RETURN (R) | | |
| 21 | Long Term Interest | Note U | $0 |

| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |
| 24b | Proprietary Capital | | 68.86% | 10.10% | 0.0695 | |
| | | | | | 0.0840 | =R |

| | | |
|---|---|---|
| 24c | Return Used | **0.0000** |

| | | | |
|---|---|---|---|
| 25 | Proprietary Capital Cost Rate = | 10.10% | |
| 26 | | 0.00 | |

| | | | TIER = | |
|---|---|---|---|---|
| | REVENUE CREDITS | | | |
| | | | | Load |
| | ACCOUNT 447 (SALES FOR RESALE) | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | | 0 |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | 0 |
| 29 | Total of (a)-(b) | | | 0 |
| | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) | | | |
| 30 | (Note R) | | | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | | |
| 31 | a. Transmission charges for all transmission transactions | | | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | | | $0 |
| 33 | Total of (a)-(b) | | | $0 |

Formula Rate - Non-Levelized

Rate Formula Template

Alta Municipal Utilities

For the 12 months ended 12/31/20XX

Note L

| Letter | |
|---|---|
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by |

any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

Cash Working Capital assigned to transmission is one-eighth of

H O&M allocated to transmission at page 3, line 8, column 5.

Prepayments are the electric related prepayments booked to Account No. 165.

Line 5 - EPRI Annual Membership Dues, all Regulatory

I Commission Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

Includes only FICA, unemployment, highway, property, gross

J receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

The currently effective income tax rate, where FIT is the Federal

K income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce

rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00 % | (State Income Tax Rate or |
| | SIT= | 0.00 % | Composite SIT) |
| | p = | 0.00 % | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and

no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

| | |
|---|---|
| X | Schedule 12-FERC charges should not be included in O&M recovered under this formula rate |
| Y | Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by FERC. |
| AA | Per the settlement terms of Docket ER15-2028, any NIMECA |

Member participating in an SPP project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Alta Municpal Utilities**

**For the Year ended 12/31/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:
the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

## Alta Municpal Utilities
**For the Year ended 12/31/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| and Land Rights | | | | |
| 3 11 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 3 12 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |
| 3 13 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 3 | $ | $ | | $ |

| | | | | |
|---|---|---|---|---|
| 14 – Turbogenerator Units 3 | - | - | $ - | - |
| 15 – Accessory Electric Equipment 3 | $ - | $ - | $ - | $ - |
| 16 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |

| | | | | | |
|---|---|---|---|---|---|
| **Nuclear Production Plant** | | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - | |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - | |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - | |
| 323 – Turbogen | $ - | $ - | $ - | $ - | |

| | | | | |
|---|---|---|---|---|
| erator Units | | | | |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset Retirement Costs for Nuclear Productio | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| n | | | | |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 | $ | $ | | $ |

| | | | | |
|---|---|---|---|---|
| 32 – Reservoirs, Dams, and Waterways | 3 | - | - | $ - |
| 33 – Water Wheels, Turbines, and Generators | 3 | $ - | $ - | $ - | $ - |
| 34 - Accessory Electric Equipment | 3 | $ - | $ - | $ - | $ - |
| 35 – | | $ - | $ - | $ | $ - |

| | | | | |
|---|---|---|---|---|
| Misc. Power Plant Equipment | | | - | |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Production Plant | | | | |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, | $ - | $ - | $ - | $ - |

| | | | | | |
|---|---|---|---|---|---|
| and Accessories | | | | | |
| 343 – Prime Movers | $ - | $ - | $ - | $ - | |
| 344 – Generators | $ - | $ - | $ - | $ - | |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - | |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - | |

| | | | | |
|---|---|---|---|---|
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| Total City-owned Transmiission | Combined Transmiission System | | | Lehigh Webster | | | Walter Scott 4 | | | Other Trasmission | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Acc | N | Dep | Acc | N | Dep | Acc | N | Dep | Acc | N | Dep |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Gross Plant | umulated Depreciation | et Plant | reciation Expense | | Gross Plant | umulated Depreciation | et Plant | reciation Expense | | Gross Plant | umulated Depreciation | et Plant | reciation Expense | | Gross Plant | umulated Depreciation | et Plant | reciation Expense |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Equipment | | | | | | | | | | | | | | | | | | | | | | |
| 354 – Towers and Fixtures | $ - | | $ - | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |
| 355 – Poles and Fixtures | $ - | | $ - | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |
| 356 – Overhead Conductors and Devices | $ - | | $ - | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |
| 357 – Underground Conduit | $ - | | $ - | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |
| 35 | $ | | $ | $ | | $ | $ | | $ | | $ | $ | | $ | | $ | $ | | $ | | $ | $ | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 358 – Underground Conductors and Devices | - | | - | $ - | | - | | - | $ - | | - | | - | $ - | | - | | - | $ - | | - | | - | $ - | | - | | - | $ - | |
| 359 – Roads and Trails | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |
| **Total Transmission Plant** | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | | $ - | | $ - | $ - | |

| | | | | |
|---|---|---|---|---|
| **Distribution Plant** | | | | |
| 360 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Conductors and Devices | | | | |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Prop | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| erty on Customers Premises | | | | |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total | $ | $ | $ | |

| | | | | |
|---|---|---|---|---|
| Distribution Plant | - | - | $ - | - |

**Intangible Plant**

| | | | | |
|---|---|---|---|---|
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Total Intangible | $ - | $ - | $ - | $ - |

| Plant | | | |
|---|---|---|---|
| **General Plant** | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Tran | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| sportation Equipment | | | | |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – | $ - | $ - | $ | $ - |

| | | | | |
|---|---|---|---|---|
| Power Operated Equipment | | | - | |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – | $ - | $ - | $ | $ - |

| | | | | |
|---|---|---|---|---|
| Asset Retirement Costs for General Plant | | | - | |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Service** | $ - | $ - | $ - | $ - |

**Please answer the following questions:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet?

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet?

Does the Total Depreciation expense tie to the

depreciation expense reflected in the audited income statement?

## Alta Municipal Utilities
## Depreciation Rates

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 351 | Energy Storage Equipment - Transmission | 40 | 2.50% |
| 352 | Structures & Improvements | 40 | 2.50% |
| 353 | Station Equipment | 40 | 2.50% |
| 354 | Towers & Fixtures | 40 | 2.50% |
| 355 | Poles & Fixtures | 40 | 2.50% |
| 356 | Overhead Conductors and Devices | 40 | 2.50% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 40 | 2.50% |
| 391 | Office Furniture & Equipment | 10 | 10.00% |
| 392 | Transportation Equipment | 10 | 10.00% |
| | | | |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Alta Municpal Utilities
For the Year ended 12/31/20XX

| | Land Held For Future Use |
|---|---|
| | $ |
| Production | - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Alta Municpal Utilities
For the Year ended 12/31/20XX

Materials and Supplies

| | |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | **Amount** |
|---|---|
| Insulators | $ - |
| Relays | $ - |
| Substation Misc Part | $ - |
| Transmission wires | $ - |
| Trans. Line Hardware | $ - |
| Transducers | $ - |
| | $ - |
| **Total** | **$ -** |

Alta Municpal Utilities
For the Year ended 12/31/20XX

| Pre Payment Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Pre Payments | $ - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

# Alta Municpal Utilities
## For the Year ended 12/31/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |

| | |
|---|---|
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

# Alta Municpal Utilities
# For the Year ended 12/31/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| | |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| | |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |

| | | |
|---|---|---|
| **Administrative and General Expenses** | | |
| 920 – Administrative and General Salaries | | - |
| 921 – Office Supplies and Expenses | | - |
| 922 – Administrative Expenses Transferred Credit | | - |
| 923 – Outside Services Employed | | - |
| 924 – Property Insurance | | - |
| 925 – Injuries and Damages | | - |
| 926 – Employee Pension and Benefits | | - |
| 927 – Franchise Requirements | | - |
| 928 – Regulatory Commission Expenses | | - |
| 929 – Duplicate Charges Credit | | - |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | | |
| Total Operations A&G | | - |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | | - |
| **Total Administrative and General Expenses** | | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Alta Municpal Utilities
For the Year ended 12/31/20XX

| FERC fees recorded to expense during the year | Account Charged | Amount |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Alta Municpal Utilities
For the Year ended 12/31/20XX

## Taxes Other Than Income Taxes

| | | |
|---|---|---|
| Payroll | $ | - |
| Highway & Vehicle | | - |
| Property | | - |
| Gross | | - |
| Other - please explain | | - |
| Payments in lieu of taxes | | - |
| Fed & State income Tax | | - |
| Total | $ | - |

Should tie to a line item on the audited financial statements - provide explanation and

reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

Alta Municpal Utilities
For the Year ended 12/31/20XX

| | $ | |
|---|---|---|
| EPRI Costs | - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | $ | |
|---|---|---|
| xxx | - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| xxx | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| | $ | recorded in USofA account _____ , reflected in I/S |
| Admin & General Advertising | - | in _____exp |
| Xxxxxxxx | | |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

Alta Municpal Utilities
For the Year ended 12/31/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 12/31/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ | $ |

| | | |
|---|---|---|
| | - | - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| Principal & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

Alta Municpal Utilities

**For the Year ended 12/31/20XX**

## Account 454 (Rent from Electric Property)

| Property Description | Amount | |
|---|---|---|
| XXXXX | $ | - |
| XXXXX | | - |
| XXXXX | | - |
| XXXXX | - | |
| Total Rent Income | $ - | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation |

Alta Municpal Utilities

**For the Year ended 12/31/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – Part 4

## Bancroft Municipal Utilities

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Bancroft Municipal Utilities

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of ATRR To SPP UMZ Pricing**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |
| 7 | NET REVENUE REQUIREMENT | (line 1 | | | | $ |

| | Zone | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|---|
| 2a | | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | | Total | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | |
|---|---|---|---|---|
| | | minus line 6) | | - |
| | DIVISOR | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | |
| 17 | Network & P-to-P Rate ($/kW/Mo) (line 11/ 12) | | 0.000 | |

| Peak Rate | Off-Peak Rate |
|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | e | | | |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized — Rate Formula Template — For the 12 months ended 12/31/20XX

Bancroft Municipal Utilities

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000 | |
| 2 | Transmission | | 0 | TP | 0.000 | 0 |
| 3 | Distribution | | 0 | NA | 0.000 | |
| 4 | General & Intangible | | 0 | W/S | 0.000 | 0 |
| 5 | Common | | 0 | CE | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 00 | |
| | | | | | 0.00 | |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | 0 | GP= | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.00 | |
| 10 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.00 | |
| 11 | Common | | 0 | CE | 00 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | |
| 14 | Transmission | (line 2-line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| | | | | | 0.00 | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | % | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | 0 | | NP | zero | 0 |
| 20 | Account No. 282 (enter negative) | 0 | | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | 0 | | NP | 0.000 | 0 |
| 22 | Account No. 190 | 0 | | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | 0 | | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | 0 | | | | 0 |
| 25 | LAND HELD FOR FUTURE USE (Note G) | 0 | | TP | 0.000 | 0 |
| | WORKING CAPITAL (Note H) | | | | | |
| 26 | CWC | 0 | | | | 0 |
| 27 | Materials & Supplies (Note G) | 0 | | TE | 0.000 | 0 |
| 28 | Prepayments | 0 | | GP | 0.000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | 0 | | | | 0 |

| | | | |
|---|---|---|---|
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

Bancroft Municipal Utilities

For the 12 months ended 12/31/20XX

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | **Company Tot** | **Allocator** | **Transmission** (Col 3 times Col 4) |

**al**

| | | | | | |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000 | 0 |
| 3 | A&G | 0 | W/S | 0.000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000 | 0 |
| 6 | Common | 0 | CE | 0.000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000 | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 9 | Transmission | 0 | TP | 0.000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000 | 0 |
| 11 | Common | 0 | CE | 0.000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | INCOME TAXES (Note K) | | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | 0.00% | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | 0.00 | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.00 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | 0 | NA | | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | | 0 | | | 0 |
| 30 | Total Gross Revenue Requirement | | 0 | | | 0 |

Formula Rate - Non-Levelized

Rate Formula Template

Bancroft Municipal Utilities

For the 12 months ended 12/31/20XX

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded | | 0 |

| | | | | |
|---|---|---|---|---|
| | from ISO rates (Note M) | | | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP | = | 0.00000 |
| | TRANSMISSION EXPENSES | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE | = | 0.00000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | $ | TP | All oca |
|---|---|---|---|

| | | | | tion | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) | | | |
| 15 | Other | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | CE |
|---|---|---|---|---|---|---|---|
| 17 | Electric | 0 | | | (line 16) | | 0.0000 |
| 18 | Gas | 0 | 0.00000 | * | 0.00000 | = | 0 |
| 19 | Water | 0 | | | | | |
| 20 | Total (sum lines 17-19) | 0 | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | RETURN (R) | | $ | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | |

| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |
| 24b | Proprietary Capital | | 68.86% | 10.10% | 0.0695 | |
| | | | | | 0.0840 | =R |

| | | |
|---|---|---|
| 24c | Return Used | **0.0000** |

| | | | |
|---|---|---|---|
| 25 | | Proprietary Capital Cost Rate = | 10.10% |
| 26 | | TIER = | 0.00 |

REVENUE CREDITS

| | | | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | 0 |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | 0 |
| 29 | Total of (a)-(b) | | 0 |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | |
| 31 | a. Transmission charges for all transmission transactions | | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | | $0 |
| 33 | Total of (a)-(b) | | $0 |

Formula Rate - Non-Levelized

Rate Formula Template

Bancroft Municipal Utilities

For the 12 months ended 12/31/20XX

Note Letter

A

The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks.

| | |
|---|---|
| | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic |
| B | reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. |
| G | Transmission related only. |
| H | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165. |

Line 5 - EPRI Annual Membership Dues, all Regulatory Commission
I Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission
Expenses directly related to
transmission service, ISO filings or
transmission siting.
Includes only FICA, unemployment, highway, property, gross receipts, and
J other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not
included in transmission revenue requirement in the Rate Formula
Template,
since they are recovered elsewhere.
The currently effective income tax rate, where FIT is the Federal income
K tax rate; SIT is the State income tax rate, and p =
"the percentage of federal income tax deductible for state income taxes".
If the utility is taxed in more than one state it must attach a
work paper showing the name of each state and how the blended or composite
SIT was developed. Furthermore, a utility that
elected to utilize amortization of tax credits against taxable income, rather than
book tax credits to Account No. 255 and reduce
rate base, must reduce its income tax expense by the
amount of the Amortized Investment Tax Credit.
multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| | | 0.0 | |
| Inputs Required: | FIT = | 0% | |
| | | | (State Income Tax Rate or |
| | | 0.0 | Composite |
| | SIT= | 0% | SIT) |
| | | | (percent of federal income tax deductible for |
| | | 0.0 | state |
| | p = | 0% | purposes) |

Removes dollar amount of transmission expenses included in the OATT
L ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and

561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts

| | |
|---|---|
| | 428, 429 and 430. |
| V | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| W | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| X | Schedule 12-FERC charges should not be included in O&M recovered under this formula rate |
| Y | Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by |

FERC.

A
A

Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and
which has regional cost sharing (“Project Costs”), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital
structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act (“FPA”) Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Bancroft Municipal Utilities**

**For the Year ended 12/31/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## Bancroft Municipal Utilities

**For the Year ended 12/31/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | | | | |
| 310 – Land and Land Rights | - | - | - | - |
| 311 – Structures and Improvements | - | - | - | - |
| 312 – Boiler Plant | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 313 – Engines and Engine-Driven Generators | - | - | - | - |
| 314 – Turbogenerator Units | - | - | - | - |
| 315 – Accessory Electric Equipment | - | - | - | - |
| 316 – Misc. Power Plant Equipment | - | - | - | - |
| Total Steam Production Plant | - | - | - | - |
| **Nuclear Production Plant** | | | | |

| | | | | |
|---|---|---|---|---|
| 320 – Land and Land Rights | - | - | - | - |
| 321 – Structures and Improvements | - | - | - | - |
| 322 – Reactor Plant Equipment | - | - | - | - |
| 323 – Turbogenerator Units | - | - | - | - |
| 324 – Accessory Electric Equipment | - | - | - | - |
| 325 – Misc. Power Plant Equipment | - | - | - | - |
| 326 – Asset Retirement Costs | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| for Nuclear Production | | | | |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | - | - | - | - |
| 331 – Structures and Improvements | - | - | - | - |
| 332 – Reservoirs, Dams, and Waterways | - | - | - | - |
| 333 – Water Wheels, Turbines, and Generato | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| rs | | | | |
| 334 - Accessory Electric Equipment | - | - | - | - |
| 335 – Misc. Power Plant Equipment | - | - | - | - |
| 336 – Roads, Railroads, and Bridges | - | - | - | - |
| 337 – Asset Retirement Costs for Hydraulic Production | - | - | - | - |
| Total Hydraulic Production Plant | - | - | - | - |
| **Other Production Plant** | | | | |
| 340 – Land | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| and Land Rights | | | | |
| 341 – Structures and Improvements | - | - | - | - |
| 342 – Fuel Holders, Products, and Accessories | - | - | - | - |
| 343 – Prime Movers | - | - | - | - |
| 344 – Generators | - | - | - | - |
| 345 – Accessory Electric Equipment | - | - | - | - |
| 346 – Misc. Power Plant Equipment | - | - | - | - |
| 347 – Asset | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Retirement Costs for Nuclear Production | | | | |
| Total Other Production Plant | - | - | - | - |
| **Total Production Plant** | - | - | - | - |

| | Total City-owned Transmiission | | | | Combined Transmiission System | | | | Lehigh Webster | | | | Neal 4 | | | | Other Trasmission | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | - | - | - | - | $ - | $ - | $ - | $ - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 352 – Structures and Improvements | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 353 – Station Equipment | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 354 – Towers and Fixtures | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 355 – Poles and Fixtures | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 356 – Overhead Conductors and Devices | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 357 – Underground Conduit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 358 – Underground Conductors and Devices | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 359 – Roads and Trails | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 359.1 – Asset Retirement Costs for Transmission Plant | - | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Total Transmission Plant** | - | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | - | | - | - | - | | | | | | | | | | | | | | | |
| 361 – Structures and Improvements | - | | - | - | - | | | | | | | | | | | | | | | |
| 362 – Station Equipment | - | | - | - | - | | | | | | | | | | | | | | | |
| 363 – Storage Battery Equipment | - | | - | - | - | | | | | | | | | | | | | | | |
| 364 – | | | | | | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| Poles, Towers, and Fixtures | - | - | - | - |
| 365 – Overhead Conductors and Devices | - | - | - | - |
| 366 – Underground Conduit | - | - | - | - |
| 367 – Underground Conductors and Devices | - | - | - | - |
| 368 – Line Transformers | - | - | - | - |
| 369 – Services | - | - | - | - |
| 370 – Meters | - | - | - | - |
| 371 – Installations on Customer Premises | - | - | - | - |
| 372 – Leased Property on | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Customers Premises | | | | |
| 373 – Street lighting and Signal Systems | - | - | - | - |
| 374 – Asset Retirement Costs for Distribution Plant | - | - | - | - |
| Total Distribution Plant | - | - | - | - |
| **Intangible Plant** | | | | |
| 301 Organization | - | - | - | - |
| 302 Franchises and Consents | - | - | - | - |
| 303 Miscellaneous Intangible | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Plant | | | | |
| Total Intangible Plant | - | - | - | - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | - | - | - | - |
| 390 – Structures and Improvements | - | - | - | - |
| 391 – Office Furniture and Equipment | - | - | - | - |
| 392 – Transportation Equipment | - | - | - | - |
| 393 – Stores Equipment | - | - | - | - |
| 394 – Tools, | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Shop and Garage Equipment | | | | |
| 395 – Laboratory Equipment | - | - | - | - |
| 396 – Power Operated Equipment | - | - | - | - |
| 397 – Communication Equipment | - | - | - | - |
| 398 – Miscellaneous Equipment | - | - | - | - |
| 399 – Other Tangible Property | - | - | - | - |
| 399.1 – Asset Retirement Costs for General Plant | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| **Total General Plant** | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| **Grand Total Plant In-Service** | - | - | - | - |

**Please answer the following questions:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet?

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet?

Does the Total

Depreciation expense tie to the depreciation expense reflected in the audited income statement?

## Bancroft Municipal Utilities
## Depreciation Rates

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 352 | Structures & Improvements | 35 | 2.86% |
| 353 | Station Equipment | 35 | 2.86% |
| 354 | Towers & Fixtures | 35 | 2.86% |
| 355 | Poles & Fixtures | 35 | 2.86% |
| 356 | Overhead Conductors and Devices | 35 | 2.86% |
| 357 | Underground Conduit | 35 | 2.86% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 20 | 5.00% |
| 391 | Office Furniture and Equipment | 3 | 33.33% |
| 392 | Transportation Equipment | 10 | 10.00% |
| 394 | Tools, Shop and Garage Equipment | 20 | 5.00% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

Materials and Supplies

| | | |
|---|---|---|
| Production | $ | - |
| Transmission | | - |
| Distribution | | - |
| Other | | - |
| | $ | - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

| **Pre Payment Description** | | **Amount** |
|---|---|---|
| XXXXX | $ | - |
| XXXXX | | - |
| XXXXX | | - |
| XXXXX | | - |
| Total Pre Payments | $ | - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

# Bancroft Municipal Utilities
# For the Year ended 12/31/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |

| | |
|---|---|
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

## Bancroft Municipal Utilities
## For the Year ended 12/31/20XX

| **Customer Accts & Admin and General Expenses** | **Amount** |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| | |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |

| | | |
|---|---|---|
| **Sales Expenses** | | |
| 911 – Supervision | | - |
| 912 – Demonstrating and Selling Expenses | | - |
| 913 – Advertising Expenses | | - |
| 916 – Miscellaneous Sales Expenses | | - |
| **Sales Expenses** | | - |
| | | |
| **Administrative and General Expenses** | | |
| 920 – Administrative and General Salaries | | - |
| 921 – Office Supplies and Expenses | | - |
| 922 – Administrative Expenses Transferred Credit | | - |
| 923 – Outside Services Employed | | - |
| 924 – Property Insurance | | - |
| 925 – Injuries and Damages | | - |
| 926 – Employee Pension and Benefits | | - |
| 927 – Franchise Requirements | | - |
| 928 – Regulatory Commission Expenses | | - |
| 929 – Duplicate Charges Credit | | - |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | | - |
| Total Operations A&G | | - |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | | - |
| **Total Administrative and General Expenses** | | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

## Taxes Other Than Income Taxes

| | | |
|---|---|---|
| Payroll | $ | - |
| Highway & Vehicle | | - |
| Property | | - |
| Gross | | - |
| Other - please explain | | - |
| Payments in lieu of taxes | | - |
| Fed & State income Tax | | - |
| Total | $ | - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

| **FERC fees recorded to expense during the year** | **Account Charged** | **Amount** |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| Fuel adjustment clause docket XX | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

Bancroft Municipal Utilities
For the Year ended 12/31/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 12/31/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |

| | | | |
|---|---|---|---|
| | - | $ | - |
| Total | $ - | $ | - |
| Principal & Interest Grand Total | $ - | $ | - |

Total Principal and Total Interest should tie to lines on the audited financial statements. If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

Bancroft Municipal Utilities

**For the Year ended 12/31/20XX**

## Account 454 (Rent from Electric Property)

| **Property Description** | **Amount** |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Rent Income | $ - |

Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

Bancroft Municipal Utilities

**For the Year ended 12/31/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – Part 5

## Coon Rapids Municipal Utilities (CRMU)

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/2014

Coon Rapids Municipal Utilities

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of ATRR To SPP**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |

**UMZ Pricing Zone**

| | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|
| 2a | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | Total | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | | |
|---|---|---|---|---|---|
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | $ - |

DIVISOR

| | | | | |
|---|---|---|---|---|
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | 0 |

| | | | | |
|---|---|---|---|---|
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | |

| Peak | Off-Peak |
|---|---|

| | | | Rate | | Rate | |
|---|---|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/2014

Coon Rapids Municipal Utilities

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000 | |
| 2 | Transmission | | 0 | TP | 00 | 0 |
| 3 | Distribution | | 0 | NA | 0.000 | |
| 4 | General & Intangible | | 0 | W/S | 00 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5 | Common | 0 | | CE | 0.000000% | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | 0 | | GP= | 0.000000% | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | 0 | | NA | | |
| 8 | Transmission | 0 | | TP | 0.000000% | 0 |
| 9 | Distribution | 0 | | NA | | |
| 10 | General & Intangible | 0 | | W/S | 0.000000% | 0 |
| 11 | Common | 0 | | CE | 0.000000% | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | 0 | | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | |
| 14 | Transmission | (line 2-line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | | NP= | 0.000000% 0 |

| | | | | | % | |
|---|---|---|---|---|---|---|
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000% | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000% | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000% | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000% | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000% | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000% | 0 |
| 28 | Prepayments | | 0 | GP | 0.000% | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - | | 0 | | | 0 |

| | | | |
|---|---|---|---|
| 29 | 28) | | |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/2014

Coon Rapids Municipal Utilities

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | **Company** | **Allocator** | **Transmission** (Col 3 times Col 4) |

| | | Total | r | | |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | EXPENSE (Note W) | | | | |
| 9 | Transmission | 0 | TP | 0.000000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000000 | 0 |
| 11 | Common | 0 | CE | 0.000000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.000000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | | 0 | | | 0 |
| | INCOME TAXES | (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.0000% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | 0.0000% | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.0000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | 0 | NA | | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | | 0 | | | 0 |

| | | | |
|---|---|---|---|
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/2014

Coon Rapids Municipal Utilities

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |

| | | | | |
|---|---|---|---|---|
| 2 | Less transmission plant excluded from ISO rates (Note M) | | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | 0.00000 | |

TRANSMISSION EXPENSES

| | | | | |
|---|---|---|---|---|
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | 0.00000 | |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | 0.00000 | |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE = | 0.00000 | |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | $ | TP | All oca |
|---|---|---|---|

| | | | | tion | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | |
| 2 | Production | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | | | |
| 3 | Transmission | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | W&S Allocator ($ / Allocation) | | |
| 4 | Distribution | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | | | |
| 5 | Other | 0 | 0.00 | 0 | | | | |
| 1 | | | | | | | | W |
| 6 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | /S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | CE |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 7 | Electric | 0 | | | (line 16) | | 0.0000 |
| 1 | | | 0.00000 | | | | |
| 8 | Gas | 0 | | * | 0.00000 | = | 0 |
| 1 | | | | | | | |
| 9 | Water | 0 | | | | | |
| 2 | Total (sum lines 17-19) | 0 | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 0 | | | | | | | |
| | RETURN (R) | | $ | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | |
| | **Actual Capital Structure** | | $ | % | Cost (Note P) | Weighted | |
| 22 | Long Term Debt | | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | | 0 | 0% | | 0.0000 | =R |
| | **Fixed Capital Structure** | Note Z | | % | Cost | Weighted | |
| 24a | Long Term Debt | | | 31.14% | 4.65% | 0.0145 | =WCLTD |
| 24b | Proprietary Capital | | | 68.86% | 10.10% | 0.0695 | |
| | | | | | | 0.0840 | =R |
| 24c | Return Used | | | | | **0.0000** | |

| | | | |
|---|---|---|---|
| 25 | | Proprietary Capital Cost Rate = | 10.10% |
| 26 | | TIER = | 0.00 |

REVENUE CREDITS

| | | | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | 0 |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | 0 |
| 29 | Total of (a)-(b) | | 0 |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | |
| 31 | a. Transmission charges for all transmission transactions | | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | | $0 |
| 33 | Total of (a)-(b) | | $0 |

Formula Rate - Non-Levelized

Rate Formula Template

Coon Rapids Municipal Utilities

For the 12 months ended 6/30/2014

| Note | Letter | |
|---|---|---|
| | A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of |

applicable pricing zone coincident monthly peaks.

B RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks.

C LF as defined above at time of applicable pricing zone coincident monthly peaks.

D LF as defined above at time of applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165.

Line 5 - EPRI Annual Membership Dues, all Regulatory Commission
I Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission
Expenses directly related to
transmission service, ISO filings or
transmission siting.
Includes only FICA, unemployment, highway, property, gross receipts, and
J other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not
included in transmission revenue requirement in the Rate Formula
Template,
since they are recovered elsewhere.
The currently effective income tax rate, where FIT is the Federal income
K tax rate; SIT is the State income tax rate, and p =
"the percentage of federal income tax deductible for state income taxes".
If the utility is taxed in more than one state it must attach a
work paper showing the name of each state and how the blended or composite
SIT was developed. Furthermore, a utility that
elected to utilize amortization of tax credits against taxable income, rather than
book tax credits to Account No. 255 and reduce
rate base, must reduce its income tax expense by the
amount of the Amortized Investment Tax Credit.
multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| | | 0.0 | |
| Inputs Required: | FIT = | 0% | |
| | | | (State Income Tax Rate or |
| | | 0.0 | Composite |
| | SIT= | 0% | SIT) |
| | | | (percent of federal income tax deductible for |
| | | 0.0 | state |
| | p = | 0% | purposes) |

Removes dollar amount of transmission expenses included in the OATT
L ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and

561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts

| | |
|---|---|
| | 428, 429 and 430. |
| V | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| W | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| X | Schedule 12-FERC charges should not be included in O&M recovered under this formula rate |
| Y | Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by |

FERC.

A Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.
A

**Coon Rapids Municipal Electric Utility**

**For the Year ended 6/30/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jul 13 | - |
| Aug 13 | - |
| Sep 13 | - |
| Oct 13 | - |
| Nov 13 | - |
| Dec 13 | - |
| Jan 14 | - |

| | |
|---|---|
| Feb 14 | - |
| Mar 14 | - |
| Apr 14 | - |
| May 14 | - |
| Jun 14 | - |
| Sub total | - |
| | |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

## Coon Rapids Municipal Electric Utility

**For the Year ended 6/30/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Boiler Plant Equipment | - | - | - | - |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear** | | | | |

| | | | | |
|---|---|---|---|---|
| **Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Retirement Costs for Nuclear Production | | | | |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 – Water Wheels, Turbines, | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| and Generators | | | | |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |

| | | | | |
|---|---|---|---|---|
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| | Total City-owned Transmiission | | | | Combined Transmission System | | | | Other Transmission | | | | Neal 4 | | | | Lehigh Webster | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 358 – Underground Conductors and | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Devices | | | | | | | | | | | | | | | | | | | | | | |
| 359 – Roads and Trails | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Total Transmission Plant** | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | |
| 361 – Structures and Improvements | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | |
| 362 – Station Equipment | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installatio | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| ns on Customer Premises | | | | |
| 372 – Leased Property on Customers | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 | | | | |

| | | | | |
|---|---|---|---|---|
| Franchises and Consents | - | - | - | - |
| 303 Miscellaneous Intangible Plant | - | - | - | - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | - | - | - | - |
| 390 – Structures and Improvements | - | - | - | - |
| 391 – Office Furniture and Equipment | - | - | - | - |
| 392 – Transportation Equipme | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| nt | | | | |
| 393 – Stores Equipment | - | - | - | - |
| 394 – Tools, Shop and Garage Equipment | - | - | - | - |
| 395 – Laboratory Equipment | - | - | - | - |
| 396 – Power Operated Equipment | - | - | - | - |
| 397 – Communication Equipment | - | - | - | - |
| 398 – Miscellaneous Equipment | - | - | - | - |
| 399 – Other Tangible Property | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| 399.1 – Asset Retirement Costs for General Plant | - | - | - | - |
| **Total General Plant** | - | - | - | - |

## Grand Total Plant In-Service

| | | | | |
|---|---|---|---|---|
| | - | - | - | - |

**Please answer the following questions:**

Does the Grand total Gross Plant In-Service tie to the

Gross Plant In-Service reflected on the audited balance sheet?

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet?

Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement?

# Coon Rapids Municipal Utilities
# Depreciation Rates

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 352 | Structures & Improvements | 40 | 2.50% |
| 353 | Station Equipment | 40 | 2.50% |
| 354 | Towers & Fixtures | 25 | 4.00% |
| 355 | Poles & Fixtures | 25 | 4.00% |
| 356 | Overhead Conductors and Devices | 25 | 4.00% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 25 | 4.00% |
| 391 | Office Furniture and Equipment | 10 | 10.00% |
| 392 | Transportation Equipment | 10 | 10.00% |
| 394 | Tools, Shop and Garage Equipment | 10 | 10.00% |
| 395 | Laboratory Equipment | 5 | 20.00% |
| 396 | Power Operated Equipment | 10 | 10.00% |
| 397 | Communication Equipment | 7.5 | 13.33% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

Materials and Supplies

| | | |
|---|---|---|
| Production | $ | - |
| Transmission | | - |
| Distribution | | - |
| Other | | - |
| | $ | - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

| Pre Payment Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Pre Payments | $ - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

## Coon Rapids Municipal Electric Utility
## For the Year ended 6/30/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |

| | |
|---|---|
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

# Coon Rapids Municipal Electric Utility
# For the Year ended 6/30/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| **Administrative and General Expenses** | |

| | | |
|---|---|---|
| 920 – Administrative and General Salaries | | - |
| 921 – Office Supplies and Expenses | | - |
| 922 – Administrative Expenses Transferred Credit | | - |
| 923 – Outside Services Employed | | - |
| 924 – Property Insurance | | - |
| 925 – Injuries and Damages | | - |
| 926 – Employee Pension and Benefits | | - |
| 927 – Franchise Requirements | | - |
| 928 – Regulatory Commission Expenses | | - |
| 929 – Duplicate Charges Credit | | - |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | | - |
| Total Operations A&G | | - |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | | - |
| **Total Administrative and General Expenses** | | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

| FERC fees recorded to expense during the year | Account Charged | Amount |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

## Taxes Other Than Income Taxes

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other - please explain | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| Fuel adjustment clause docket XX | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

Coon Rapids Municipal Electric Utility
For the Year ended 6/30/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 6/30/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | $ | - | $ | - |
| | $ | - | $ | - |
| | $ | - | $ | - |
| Total | $ | - | $ | - |

| | | | | |
|---|---|---|---|---|
| Principal Balance & Interest Grand Total | $ | - | $ | - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

Coon Rapids Municipal Electric Utility

**For the Year ended 6/30/20XX**

## Account 454 (Rent from Electric Property)

| **Property Description** | **Amount** | |
|---|---|---|
| XXXXX | $ - | |
| XXXXX | - | |
| XXXXX | - | |
| XXXXX | - | |
| Total Rent Income | $ - | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation |

Coon Rapids Municipal Electric Utility

**For the Year ended 6/30/20XX**

## Account 456.1 (Other Electric Revenues)

| | **Account 456.1** |
|---|---|
| | **Revenue** |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |

| | | |
|---|---|---|
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| Total Revenue | $ | - |

# ADDENDUM 26 TO ATTACHMENT H – Part 6

## Graettinger Municipal Light Plant

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Graettinger Municipal Light Plant

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of ATRR To SPP UMZ Pricing**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |

| | Zone | | | |
|---|---|---|---|---|
| | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
| 2a | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | Total | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | |
|---|---|---|---|---|
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | $ - |
| | DIVISOR | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | |

Pe Off-

| | | | ak Rate | | Peak Rate | |
|---|---|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Graettinger Municipal Light Plant

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000 | |
| 2 | Transmission | | 0 | TP | 00 | 0 |
| 3 | Distribution | | 0 | NA | | |
| 4 | General & Intangible | | 0 | W/S | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 00 | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 5 | Common | | 0 | CE | 00 | 0 |
| | | | | | 0.0 | |
| | TOTAL GROSS PLANT (sum lines | | | | 00 | |
| 6 | 1-5) | | 0 | GP= | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 0 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 1 | Common | | 0 | CE | 00 | 0 |
| 1 | TOTAL ACCUM. DEPRECIATION (sum lines 7- | | | | | |
| 2 | 11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 1 | | (line 1- | | | | |
| 3 | Production | line 7) | 0 | | | |
| 1 | | (line 2- | | | | |
| 4 | Transmission | line 8) | 0 | | | 0 |
| 1 | | (line 3 - | | | | |
| 5 | Distribution | line 9) | 0 | | | |
| 1 | | (line 4 - | | | | |
| 6 | General & Intangible | line 10) | 0 | | | 0 |
| 1 | Common | (line 5 - | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | | line 11) | | | | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 28 | Prepayments | 0 | GP | 0.000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Graettinger Municipal Light Plant

| Lin | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | | | **Transmission** |

e

| No. | | Company Total | Allocator | | (Col 3 times Col 4) |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 00 | |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| 9 | Transmission | 0 | TP | 0.000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000 | 0 |
| 11 | Common | 0 | CE | 0.000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 18 | Other | 0 | GP | 0.000000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.000% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | 0.000% | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | 0 | NP | 0.000000 | 0 |
| 27 | Total Income Taxes (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN | 0 | NA | | 0 |

| | | | |
|---|---|---|---|
| | [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | 0 |
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Graettinger Municipal Light Plant

Line No.

**SUPPORTING CALCULATIONS AND**

## NOTES

TRANSMISSION PLANT
INCLUDED IN ISO RATES

| | | | |
|---|---|---|---|
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | 0.00000 |

TRANSMISSION EXPENSES

| | | | |
|---|---|---|---|
| 6 | Total transmission expenses (page 3, line 1, column 3) | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | 0.00000 |
| 11 | Percentage of transmission | T | 0.00000 |

| | | | |
|---|---|---|---|
| 1 | expenses included in ISO Rates (line 9 times line 10) | E = | |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | | $ | TP | Allocation | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) | | | |
| 15 | Other | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | Labor Ratio | |
|---|---|---|---|---|---|
| 17 | Electric | 0 | | (line 16) | CE |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 18 | Gas | | 0 | | 0.00000 | * | 0.00000 | = | 0.0000 |
| 19 | Water | | 0 | | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | | |
| | RETURN (R) | | $ | | | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | | | |

| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |

| | | | | | |
|---|---|---|---|---|---|
| 24b | Proprietary Capital | 68.86% | 10.10% | 0.0695 | |
| | | | | 0.0840 | = R |
| 24c | Return Used | | | **0.0000** | |
| 25 | | | Proprietary Capital Cost Rate = | 10.10% | |
| 26 | | | TIER = | 0.00 | |
| | REVENUE CREDITS | | | | |
| | | | | Load | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | | 0 | |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | 0 | |
| 29 | Total of (a)-(b) | | | 0 | |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | | $0 | |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | | | |
| 31 | a. Transmission charges for all transmission transactions | | | $0 | |

| | | |
|---|---|---|
| 3 | b. Transmission charges for all transmission | |
| 2 | transactions included in Divisor on Page 1 | $0 |
| 3 | | |
| 3 | Total of (a)-(b) | $0 |



For the 12 months ended 6/30/20XX

Formula Rate - Non-Levelized

Rate Formula Template

Graettinger
Municipal Light Plant

| Note Letter | |
|---|---|
| | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. |
| A | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory |

assets

or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

Prepayments are the electric related prepayments booked to Account No. 165.

I Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit.

multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| | | 0.0 | |
| Inputs Required: | FIT = | 0% | |
| | | | (State Income Tax Rate or |
| | | 0.0 | Composite |
| | SIT= | 0% | SIT) |
| | | | (percent of federal income tax deductible for |
| | | 0.0 | state |
| | p = | 0% | purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

X Schedule 12-FERC charges should not be included in O&M recovered under this formula rate

Y Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA.

When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC.

| | |
|---|---|
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by FERC. |
| A<br>A | Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate. |

**Graettinger Municipal Light Plant**

**For the Year ended 6/30/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |
| | |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

| | | |
|---|---|---|
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| | | |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## Graettinger Municipal Light Plant

**For the Year ended 6/30/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Producti** | | | | |

**on Plant**

| | | | | |
|---|---|---|---|---|
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Asset Retirement Costs for Nuclear Production | - | - | - | - |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Water Wheels, Turbines, and Generators | - | - | - | - |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Misc. Power Plant Equipment | - | - | - | - |
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| Total City-owned Transmiission | Combined Transmiission System | | | | Lehigh Webster | | | | Neal 4 | | | | Other Trasmission | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Accumulated Depreciation | Net Plant | Depreciation Expenns | Gross | Accumulated Depreciation | Net Plant | Depreciation Expenns | Gross | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciat | Net Plant | Depreciation Expense |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Plant** | **tion** | | **e** | **Plant** | **tion** | | **e** | **Plant** | **tion** | | | | **nt** | **ion** | | |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – Undergro | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| und Conduit | | | | | | | | | | | | | | | | | | | | | | |
| 358 – Underground Conductors and Devices | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| 359 – Roads and Trails | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| **Total Transmission Plant** | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structure | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| s and Improvements | | | | |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Servic** | $ - | $ - | $ - | $ - |

**e**

**Please answer the following questions:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement? If no, please provide an explanation & reconciliation.

**Graettinger Municipal Light & Plant**
**Depreciation Rates**

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 352 | Structures & Improvements | 30 | 3.33% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 25 | 4.00% |
| 391 | Office Furniture and Equipment | 7 | 14.29% |
| 392 | Transportation Equipment | 15 | 6.67% |
| 393 | Stores Equipment | 25 | 4.00% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

Materials and Supplies

| | | |
|---|---|---|
| Production | $ | - |
| Transmission | | - |
| Distribution | | - |
| Other | | - |
| | $ | - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

| Pre Payment Description | | Amount |
|---|---|---|
| XXXXX | $ | - |
| XXXXX | | - |
| XXXXX | | - |
| XXXXX | | - |
| Total Pre Payments | $ | - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

## Graettinger Municipal Light Plant
## For the Year ended 6/30/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |

| | |
|---|---|
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

# Graettinger Municipal Light Plant
# For the Year ended 6/30/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |

| | |
|---|---|
| 921 – Office Supplies and Expenses | - |
| 922 – Administrative Expenses Transferred Credit | - |
| 923 – Outside Services Employed | - |
| 924 – Property Insurance | - |
| 925 – Injuries and Damages | - |
| 926 – Employee Pension and Benefits | - |
| 927 – Franchise Requirements | - |
| 928 – Regulatory Commission Expenses | - |
| 929 – Duplicate Charges Credit | - |
| 930.1 – General Advertising Expenses | - |
| 930.2 – Miscellaneous General Expenses | - |
| 931 – Rents | - |
| Total Operations A&G | - |
| 935 – Maintenance of General Plant | - |
| Total Maintenance A&G | - |
| **Total Administrative and General Expenses** | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

| FERC fees recorded to expense during the year | Account Charged | Amount |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

## Taxes Other Than Income Taxes

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other - please explain | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| Fuel adjustment clause docket XX | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

Graettinger Municipal Light Plant
For the Year ended 6/30/20XX

| **Debt Detail - Electric only** | **Principal Balance at For the Year ended 6/30/20XX** | **Interest Expense** |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| | | - | $ | - |
| | | - | $ | - |
| Total | $ | - | $ | - |
| Principal & Interest Grand Total | $ | - | $ | - |

Total Principal and Total Interest should tie to lines on the audited financial statements. If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

Graettinger Municipal Light Plant

**For the Year ended 6/30/20XX**

## Account 454 (Rent from Electric Property)

| **Property Description** | **Amount** |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Rent Income | $ - |

Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

Graettinger Municipal Light Plant

**For the Year ended 6/30/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – Part 7

## Laurens Municipal Power

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Laurens Municipal Power

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of ATRR To SPP UMZ Pricing**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |
| 7 | NET REVENUE REQUIREMENT | (line 1 | | | | $ |

| | Zone | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|---|
| 2a | | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | | Total | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | |
|---|---|---|---|---|
| | | minus line 6) | | - |
| | DIVISOR | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | |
| 17 | Network & P-to-P Rate ($/kW/Mo) (line 11/ 12) | | 0.000 | |

| Peak Rate | Off-Peak Rate |
|---|---|

| | | | e | | | |
|---|---|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized — Rate Formula Template — For the 12 months ended 12/31/20XX

Laurens Municipal Power

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000 | |
| 2 | Transmission | | 0 | TP | 0.000 | 0 |
| 3 | Distribution | | 0 | NA | 0.000 | |
| 4 | General & Intangible | | 0 | W/S | 0.000 | 0 |
| 5 | Common | | 0 | CE | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 00 | |
| | | | | | 0.00 | |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | 0 | GP= | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.00 | |
| 10 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.00 | |
| 11 | Common | | 0 | CE | 00 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | |
| 14 | Transmission | (line 2-line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| | | | | | 0.00 | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | % | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 | 0 |
| 28 | Prepayments | | 0 | GP | 0.000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |

| | | | |
|---|---|---|---|
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

Laurens Municipal Power

For the 12 months ended 12/31/20XX

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | **Company Tot** | **Allocator** | **Transmission** (Col 3 times Col 4) |

**al**

| | | | | | |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 9 | Transmission | 0 | TP | 0.000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000 | 0 |
| 11 | Common | 0 | CE | 0.000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | INCOME TAXES (Note K) | | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | 0.00% | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.0000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | 0 | NA | | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | | 0 | | | 0 |
| 30 | Total Gross Revenue Requirement | | 0 | | | 0 |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Laurens Municipal Power

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded | | 0 |

| | | | | |
|---|---|---|---|---|
| | from ISO rates (Note M) | | | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP | = | 0.00000 |
| | TRANSMISSION EXPENSES | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE | = | 0.00000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | $ | TP | All oca |
|---|---|---|---|

| | | | | tion | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) | | | |
| 15 | Other | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | CE |
|---|---|---|---|---|---|---|---|
| 17 | Electric | 0 | | | (line 16) | | 0.0000 |
| 18 | Gas | 0 | 0.00000 | * | 0.00000 | = | 0 |
| 19 | Water | 0 | | | | | |
| 20 | Total (sum lines 17-19) | 0 | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | RETURN (R) | | $ | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | |

| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |
| 24b | Proprietary Capital | | 68.86% | 10.10% | 0.0695 | |
| | | | | | 0.0840 | =R |

| | | |
|---|---|---|
| 24c | Return Used | **0.0000** |

| | | | |
|---|---|---|---|
| 25 | | Proprietary Capital Cost Rate = | 10.10% |
| 26 | | TIER = | 0.00 |

REVENUE CREDITS

| | | | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | 0 |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | 0 |
| 29 | Total of (a)-(b) | | 0 |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | |
| 31 | a. Transmission charges for all transmission transactions | | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | | $0 |
| 33 | Total of (a)-(b) | | $0 |

Formula Rate - Non-Levelized

Rate Formula Template

Laurens Municipal Power

For the 12 months ended 12/31/20XX

Note Letter

A

The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks.

| | |
|---|---|
| | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic |
| B | reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. |
| G | Transmission related only. |
| H | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. Prepayments are the electric related prepayments booked to Account No. 165. |

| | | | | |
|---|---|---|---|---|
| I | Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. | | | |
| | Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting. | | | |
| J | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. | | | |
| K | The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26). | | | |
| | | | 0.0 | |
| | Inputs Required: | FIT = | 0% | |
| | | | | (State Income Tax Rate or |
| | | | 0.0 | Composite |
| | | SIT= | 0% | SIT) |
| | | | | (percent of federal income tax deductible for |
| | | | 0.0 | state |
| | | p = | 0% | purposes) |
| L | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and | | | |

561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts

| | |
|---|---|
| | 428, 429 and 430. |
| V | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| W | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| X | Schedule 12-FERC charges should not be included in O&M recovered under this formula rate |
| Y | Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by |

FERC.

A
A

Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and
which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital
structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**City of Laurens Municipal Power**

**For the Year ended 12/31/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## City of Laurens Municipal Power

**For the Year ended 12/31/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land Rights | | $ - | $ - | $ - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipme | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| nt | | | | |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Production Plant** | | | | |

| | | | | |
|---|---|---|---|---|
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset Retireme | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| nt Costs for Nuclear Production | | | | |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 – Water Wheels, Turbines, | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| and Generators | | | | |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |

| | | | | |
|---|---|---|---|---|
| 340 – Land and Land Rights | | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| Total City-owned Transmiission | Combined Transmiission System | | | | Lehigh Webster | | | | Neal 4 | | | | Other Trasmission | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
| **Transmission Plant** | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 358 – Underground Conductors and | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Devices | | | | | | | | | | | | | | | | | | | | | | |
| 359 – Roads and Trails | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Total Transmission Plant** | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | |
| 361 – Structures and Improvements | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | |
| 362 – Station Equipme | $ - | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| nt | | | | |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| Organization | - | - | - | - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structures and Improvements | $ - | $ - | $ - | - |
| 391 – Office Furniture and Equipment | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| 392 – Transportation Equipment | - | - | - | - |
| 393 – Stores Equipment | - | - | - | - |
| 394 – Tools, Shop and Garage Equipment | - | - | - | - |
| 395 – Laboratory Equipment | - | - | - | - |
| 396 – Power Operated Equipment | - | - | - | - |
| 397 – Communication Equipment | - | - | - | - |
| 398 – Miscellaneous Equipment | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| 399 – Other Tangible Property | - | - | - | - |
| 399.1 – Asset Retirement Costs for General Plant | - | - | - | - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Service** | $ - | $ - | $ - | $ - |

**Please answer the following**

**questions:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.
Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement? If no, please provide an explanation & reconciliation.

## Laurens
## Depreciation Rates

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 351 | Energy Storage Equipment - Transmission | **36** | 2.78% |
| 352 | Structures & Improvements | **36** | 2.78% |
| 353 | Station Equipment | **38** | 2.63% |
| 354 | Towers & Fixtures | **36** | 2.78% |
| 355 | Poles & Fixtures | **36** | 2.78% |
| 356 | Overhead Conductors and Devices | **36** | 2.78% |
| | **General Plant** | | |

| | | | |
|---|---|---|---|
| 390 | Land and Land Rights* | 0 | #DIV/0! |
| 390 | Structures & Improvements | **30** | 3.33% |
| | | | |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

City of Laurens Municipal Power
For the Year ended 12/31/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

City of Laurens Municipal Power
For the Year ended 12/31/20XX

Materials and Supplies

| | | |
|---|---|---|
| Production | $ | - |
| Transmission | | - |
| Distribution | | - |
| Other | | - |
| | $ | - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

**We do not keep any materials or supplies for the transmission line. Corn Belt does all maintenance.**

City of Laurens Municipal Power
For the Year ended 12/31/20XX

| Pre Payment Description | | Amount |
|---|---|---|
| XXXXX | $ | - |
| XXXXX | $ | - |
| XXXXX | $ | - |
| XXXXX | $ | - |
| Total Pre Payments | $ | - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

## City of Laurens Municipal Power
## For the Year ended 12/31/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |

| | |
|---|---|
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

# City of Laurens Municipal Power
# For the Year ended 12/31/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |

| | | |
|---|---|---|
| 921 – Office Supplies and Expenses | | - |
| 922 – Administrative Expenses Transferred Credit | | - |
| 923 – Outside Services Employed | | - |
| 924 – Property Insurance | | - |
| 925 – Injuries and Damages | | - |
| 926 – Employee Pension and Benefits | | - |
| 927 – Franchise Requirements | | - |
| 928 – Regulatory Commission Expenses | | - |
| 929 – Duplicate Charges Credit | | - |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | | - |
| Total Operations A&G | | - |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | | - |
| **Total Administrative and General Expenses** | | - |

City of Laurens Municipal Power
For the Year ended 12/31/20XX

| **FERC fees recorded to expense during the year** | **Account Charged** | **Amount** |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

City of Laurens Municipal Power
For the Year ended 12/31/20XX

## Taxes Other Than Income Taxes

| | | |
|---|---|---|
| Payroll | $ | - |
| Highway & Vehicle | | - |
| Property | | - |
| Gross | | - |
| Other - please explain | | - |
| Payments in lieu of taxes | | - |
| Fed & State income Tax | | - |
| Total | $ | - |

financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the
audited financials includes the above amounts.

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

City of Laurens Municipal Power
For the Year ended 12/31/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| Fuel adjustment clause docket XX | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

City of Laurens Municipal Power
For the Year ended 12/31/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 12/31/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |

| | | |
|---|---|---|
| | - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| Principal Balance & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

City of Laurens Municipal Power

**For the Year ended 12/31/20XX**

## Account 454 (Rent from Electric Property)

| **Property Description** | **Amount** | |
|---|---|---|
| XXXXX | $ - | |
| XXXXX | - | |
| XXXXX | - | |
| XXXXX | - | |
| Total Rent Income | $ - | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation |

City of Laurens Municipal Power

**For the Year ended 12/31/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – Part 8

## Milford Municipal Utilities

For the 12 months ended 6/30/20XX

Formula Rate - Non-Levelized

Rate Formula Template

Milford Municipal Utilities

| Line No | | Allocated Amount | Li |
|---|---|---|---|

| . | | | | | | | ne No. |
|---|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | | | | | $ - | |
| | REVENUE CREDITS | (Note T) | Total | Allocator | | | |
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 | 2a |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 | 3a |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 | 4a |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 | |

**Allocation of ATRR To SPP UMZ Pricing Zone**

| Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|
| **UMZ (SPP)** | $ - | #DIV/0! | #DIV/0! |
| **Non UMZ *** | $ - | #DIV/0! | #DIV/0! |
| **Total** | $ - | #DIV/0! | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | 0 | * Gross transmission plant not included in SPP. |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | $ - | |
| | DIVISOR | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 | |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 | |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 | |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 | |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 | |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 | |
| 15 | Divisor (sum lines 8-14) | | | 0 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | | | |
| | | | Peak Rate | | Off-Peak Rate | |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Milford Municipal Utilities

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | | |
| 2 | Transmission | | 0 | TP | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 00 | |
| 3 | Distribution | | 0 | NA | | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 4 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 5 | Common | | 0 | CE | 00 | 0 |
| | | | | | 0.0 | |
| | TOTAL GROSS PLANT (sum lines | | | | 00 | |
| 6 | 1-5) | | 0 | GP= | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 0 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 1 | Common | | 0 | CE | 00 | 0 |
| 1 | TOTAL ACCUM. DEPRECIATION (sum lines 7- | | | | | |
| 2 | 11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 1 | | (line 1- | | | | |
| 3 | Production | line 7) | 0 | | | |
| 1 | | (line 2- | | | | |
| 4 | Transmission | line 8) | 0 | | | 0 |
| 1 | | (line 3 - | | | | |
| 5 | Distribution | line 9) | 0 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note | 0 | TE | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | | G) | | | 00<br>00<br>0.0 | |
| 28 | Prepayments | | 0 | GP | 00 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | | 0 | | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Milford Municipal Utilities

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| L | | | | **Transm** |

| Line No. | | Company Total | Allocator | | ission (Col 3 times Col 4) |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 00 | |
| | | | | 00 | |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| | | | | 0.0 | |
| | | | | 00 | |
| 9 | Transmission | 0 | TP | 00 | 0 |
| 1 | | | | 0.0 | |
| 0 | General & Intangible | 0 | W/S | 00 | 0 |
| 1 | | | | 0.0 | |
| 1 | Common | 0 | CE | 00 | 0 |
| 1 | | | | | |
| 2 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 3 | Payroll | 0 | W/S | 00 | 0 |
| 1 | | | | 0.0 | |
| 1 | | | | 00 | |
| 4 | Highway and vehicle | 0 | W/S | 00 | 0 |
| 1 | | | | | |
| 5 | PLANT RELATED | | | | |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 6 | Property | 0 | GP | 00 | 0 |
| 1 | | | | zer | |
| 7 | Gross Receipts | 0 | NA | o | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | 0.00% | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate | 0 | NA | | 0 |

| | | | |
|---|---|---|---|
| | of Return (page 4, line 24)] | | |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | 0 |
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

Milford Municipal Utilities

For the 12 months ended 6/30/20XX

| Line No. | SUPPORTING CALCULATIONS AND NOTES |
|---|---|

TRANSMISSION PLANT
INCLUDED IN ISO RATES

| | | | |
|---|---|---|---|
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | 0.00000 |

TRANSMISSION EXPENSES

| | | | |
|---|---|---|---|
| 6 | Total transmission expenses (page 3, line 1, column 3) | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE = | 0.00000 |

WAGES & SALARY ALLOCATOR (W&S)
(Note Y)

| | | $ | TP | Allocation | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) | | | |
| 15 | Other | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | | |
|---|---|---|---|---|---|---|---|---|
| 17 | Electric | 0 | | | (line 16) | | | CE |
| 18 | Gas | 0 | 0.00000 | * | 0.00000 | = | | 0.0000 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | 0 |
| | | | | | | | | 0 |
| 19 | Water | | 0 | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | |
| | RETURN (R) | | $ | | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | | |
| | **Actual Capital Structure** | | $ | % | | Cost (Note P) | Weighted | |
| 22 | Long Term Debt | | 0 | 0% | | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | | 0 | 0% | | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | | 0 | 0% | | | 0.0000 | = R |
| | **Fixed Capital Structure** | Note Z | | % | | Cost | Weighted | |
| 24a | Long Term Debt | | | 31.14% | | 4.65% | 0.0145 | =WCLTD |
| 24b | Proprietary Capital | | | 68.86% | | 10.10% | 0.0695 | |
| | | | | | | | 0.0840 | = R |

| | | | | |
|---|---|---|---|---|
| 24c | Return Used | | | **0.0000** |
| 25 | | Proprietary Capital Cost Rate = | | 10.10% |
| 26 | | | TIER = | 0.00 |
| | REVENUE CREDITS | | | |
| | | | | Load |
| | ACCOUNT 447 (SALES FOR RESALE) | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | | 0 |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | 0 |
| 29 | Total of (a)-(b) | | | 0 |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | | |
| 31 | a. Transmission charges for all transmission transactions | | | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | | | $0 |
| 33 | Total of (a)-(b) | | | $0 |

Formula Rate - Non-Levelized

Rate Formula Template

Milford Municipal Utilities

For the 12 months ended 6/30/20XX

Note Le

| tt e r | |
|---|---|
| | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. |
| A | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic |
| B | reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. |

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

I Prepayments are the electric related prepayments booked to Account No. 165.
Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,
since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit.
multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.0 0% | |
| | SIT= | 0.0 0% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.0 0% | (percent of federal income tax |

deductible for state purposes)

Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and
L 561.BA.

Removes transmission plant determined to be state-jurisdictional by
M Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

Removes dollar amount of transmission plant included in the development
N of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

Debt cost rate = long-term interest (line 21) / long term debt (line 22). The
P Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Line 29 must equal zero since all short-term power sales must be
Q unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

Includes income related only to transmission facilities, such
R as pole attachments, rentals and special use.

Grandfathered agreements whose rates have been changed to eliminate or
S mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

The revenues credited on page 1 lines 2-5 shall include only the amounts received
T directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include

| | |
|---|---|
| U | revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. Include only the amount from Accounts 428, 429 and 430. |
| V | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| W | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| X | Schedule 12-FERC charges should not be included in O&M recovered under this formula rate |
| Y | Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a |

debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by FERC.

A
A

Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Milford Municipal Utilities**

**For the Year ended 06/30/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jul 13 | - |
| Aug 13 | - |
| Sep 13 | - |
| Oct 13 | - |
| Nov 13 | - |
| Dec 13 | - |
| Jan 14 | - |
| Feb 14 | - |
| Mar 14 | - |
| Apr 14 | - |
| May 14 | - |
| Jun 14 | - |
| Sub total | - |
| | |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## Milford Municipal Utilities

**For the Year ended 06/30/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Land and Land Rights | - | - | - | - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipme | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| nt | | | | |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Reservoirs, Dams, and Waterways | - | - | - | - |
| 333 – Water Wheels, Turbines, and Generators | $ - | $ - | $ - | $ - |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Hydraulic Production | | | | |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| Total City-owned Transmission | Combined Transmission System | | | Neal 4 | | | Lehigh Webster | | | Other Transmission | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ac | Net | De | Ac | Net | De | Ac | Net | De | Ac | Net | De |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Gross Plant | cumulated Depreciation | Plant | preciation Expense | Gross Plant | cumulated Depreciation | Plant | preciation Expense | Gross Plant | cumulated Depreciation | Plant | preciation Expense | Gross Plant | cumulated Depreciation | Plant | preciation Expense |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | * $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhea | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| d Conductors and Devices | | | | | | | | | | | | | | | | | | | | | | |
| 357 – Underground Conduit | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 358 – Underground Conductors and Devices | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 359 – Roads and Trails | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Total Transmission Plant** | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| **Distribution** | | | | | | | | | | | | | | | | | | | | | | |

| **Plant** | | | | |
|---|---|---|---|---|
| 360 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Undergro | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| und Conductors and Devices | | | | |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Distribution Plant | | | | |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Rights | | | | |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-** | $ - | $ - | $ - | $ - |

# Servic
# e

**Please answer the followin g question s:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement? If no, please provide an explanation & reconciliation.

**Milford**

**Depreciation Rates**

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 351 | Energy Storage Equipment - Transmission | 20 | 5.00% |
| 352 | Structures & Improvements | 20 | 5.00% |
| 353 | Station Equipment | 20 | 5.00% |
| 354 | Towers & Fixtures | 20 | 5.00% |
| 355 | Poles & Fixtures | 20 | 5.00% |
| 356 | Overhead Conductors and Devices | 20 | 5.00% |
| 357 | Underground Conduit | 20 | 5.00% |
| 358 | Underground Conductors and Devices | 20 | 5.00% |
| 359 | Roads and Trails | 20 | 5.00% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 50 | 2.00% |
| 391 | Office Furniture and Equipment | 7 | 14.29% |
| 392 | Transportation Equipment | 7 | 14.29% |
| 394 | Tools, Shop and Garage Equipment | 10 | 10.00% |
| 397 | Communication Equipment | 7 | 14.29% |
| | **Intangible Plant** | | |
| 302 | Franchises and consents | 0 | #DIV/0! |
| | | | |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Milford Municipal Utilities
For the Year ended 06/30/20XX

| | Land Held For Future Use |
|---|---|
| | $ |
| Production | - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Milford Municipal Utilities
For the Year ended 06/30/20XX

| | Materials and Supplies |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |

| | |
|---|---|
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects M&S
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies
and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ - | |
| Relays | $ - | |
| Substation Misc Part | $ - | |
| Transmission wires | $ - | |
| Trans. Line Hardware | $ - | |
| Transducers | $ - | |
| | $ - | |
| **Total** | **$ -** | |

Milford Municipal Utilities
For the Year ended 06/30/20XX

| **Pre Payment Description** | | **Amount** |
|---|---|---|
| XXXXX | $ | - |
| XXXXX | | - |
| XXXXX | | - |

| | |
|---|---|
| XXXXX | - |
| Total Pre Payments | $ - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

## Milford Municipal Utilities
## For the Year ended 06/30/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |

| | |
|---|---|
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

If you have account 565 expenses - provide brief but descriptive detail of the 565 expenses.

# Milford Municipal Utilities
# For the Year ended 06/30/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |

| | | |
|---|---|---|
| 921 – Office Supplies and Expenses | | - |
| 922 – Administrative Expenses Transferred Credit | | - |
| 923 – Outside Services Employed | | - |
| 924 – Property Insurance | | - |
| 925 – Injuries and Damages | | - |
| 926 – Employee Pension and Benefits | | - |
| 927 – Franchise Requirements | | - |
| 928 – Regulatory Commission Expenses | | - |
| 929 – Duplicate Charges Credit | | - |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | | - |
| Total Operations A&G | | - |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | | - |
| **Total Administrative and General Expenses** | | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Milford Municipal Utilities
For the Year ended 06/30/20XX

| FERC fees recorded to expense during the year | Account Charged | Amount |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Milford Municipal Utilities
For the Year ended 06/30/20XX

## Taxes Other Than Income Taxes

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other - please explain | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

Milford Municipal Utilities
For the Year ended 06/30/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| xxx | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| xxx | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

Milford Municipal Utilities
For the Year ended 06/30/20XX

| Debt Detail - Electric only | Principal Balance at For the Year ended 06/30/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| Total | $ - | $ - |
| Principal & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements. If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

Milford Municipal Utilities

**For the Year ended 06/30/20XX**

## Account 454 (Rent from Electric Property)

| **Property Description** | **Amount** |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Rent Income | $ - |

Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

Milford Municipal Utilities

**For the Year ended 06/30/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| | $ - |
| | $ - |
| | $ - |
| | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – Part 9

## New Hampton Municipal Light Plant

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

New Hampton Municipal Light Plant

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of ATRR To SPP UMZ Pricing**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |

| | Zone | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|---|
| 2a | | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | | Total | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | | |
|---|---|---|---|---|---|
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | $ - |
| | DIVISOR | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | | |

Pe Off-

| | | | ak Rate | | Peak Rate | |
|---|---|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

New Hampton Municipal Light Plant

| Line No. | (1) | (2) | (3) Company Total | | (4) Allocator | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | | NA | |
| | | | | | 0.0 00 | |
| 2 | Transmission | | 0 | | TP 00 | 0 |
| 3 | Distribution | | 0 | | NA | |
| 4 | General & Intangible | | 0 | | W/S 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 00 | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 5 | Common | | 0 | CE | 00 | 0 |
| | | | | | 0.0 | |
| | TOTAL GROSS PLANT (sum lines | | | | 00 | |
| 6 | 1-5) | | 0 | GP= | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 0 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 1 | Common | | 0 | CE | 00 | 0 |
| 1 | TOTAL ACCUM. DEPRECIATION (sum lines 7- | | | | | |
| 2 | 11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 1 | | (line 1- | | | | |
| 3 | Production | line 7) | 0 | | | |
| 1 | | (line 2- | | | | |
| 4 | Transmission | line 8) | 0 | | | 0 |
| 1 | | (line 3 - | | | | |
| 5 | Distribution | line 9) | 0 | | | |
| 1 | | (line 4 - | | | | |
| 6 | General & Intangible | line 10) | 0 | | | 0 |
| 1 | Common | (line 5 - | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | | line 11) | | | | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 28 | Prepayments | 0 | GP | 0.000 00 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

New Hampton Municipal Light Plant

| Lin | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | | | **Transmission** |

e

| No. | | Company Total | Allocator | | (Col 3 times Col 4) |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 00 | |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| | | | | 0.0 | |
| | | | | 00 | |
| 9 | Transmission | 0 | TP | 00 | 0 |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 0 | General & Intangible | 0 | W/S | 00 | 0 |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 1 | Common | 0 | CE | 00 | 0 |
| 1 | | | | | |
| 2 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 3 | Payroll | 0 | W/S | 00 | 0 |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 4 | Highway and vehicle | 0 | W/S | 00 | 0 |
| 1 | | | | | |
| 5 | PLANT RELATED | | | | |
| | | | | 0.0 | |
| 1 | | | | 00 | |
| 6 | Property | 0 | GP | 00 | 0 |
| 1 | | | | zer | |
| 7 | Gross Receipts | 0 | NA | o | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | 0.00% | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN | 0 | NA | | 0 |

| | | | |
|---|---|---|---|
| | [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | 0 |
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

New Hampton Municipal Light Plant

For the 12 months ended 6/30/20XX

| Line No. | **SUPPORTING CALCULATIONS AND** |
|---|---|

## NOTES

TRANSMISSION PLANT
INCLUDED IN ISO RATES

| | | | |
|---|---|---|---|
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | 0.00000 |

TRANSMISSION EXPENSES

| | | | |
|---|---|---|---|
| 6 | Total transmission expenses (page 3, line 1, column 3) | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | 0.00000 |
| 11 | Percentage of transmission | T | 0.00000 |

| | | | |
|---|---|---|---|
| 1 | expenses included in ISO Rates (line 9 times line 10) | = | E |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | | $ | TP | Allocation | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) | | | |
| 15 | Other | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | Labor Ratio | |
|---|---|---|---|---|---|
| 17 | Electric | 0 | | (line 16) | CE |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 18 | Gas | | 0 | | 0.00000 | * | 0.00000 | = | 0.0000 |
| 19 | Water | | 0 | | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | | |
| | RETURN (R) | | $ | | | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | | | |

| | **Actual Capital Structure** | | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|---|
| 22 | Long Term Debt | | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |

| | | | | | |
|---|---|---|---|---|---|
| 24b | Proprietary Capital | 68.86% | 10.10% | 0.0695 | |
| | | | | 0.0840 | = R |
| 24c | Return Used | | | **0.0000** | |
| 25 | | | Proprietary Capital Cost Rate = | 10.10% | |
| 26 | | | TIER = | 0.00 | |
| | REVENUE CREDITS | | | | |
| | | | | Load | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | | 0 | |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | 0 | |
| 29 | Total of (a)-(b) | | | 0 | |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | | $0 | |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | | | |
| 31 | a. Transmission charges for all transmission transactions | | | $0 | |

| | | |
|---|---|---|
| 3 | b. Transmission charges for all transmission | |
| 2 | transactions included in Divisor on Page 1 | $0 |
| 3 | | |
| 3 | Total of (a)-(b) | $0 |



For the 12 months ended 6/30/20XX

Formula Rate - Non-Levelized

Rate Formula Template

New Hampton Municipal Light Plant

| Note Letter | |
|---|---|
| | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. |
| A | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory |

assets

or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

Prepayments are the electric related prepayments booked to Account No. 165.

I Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit.

multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.0 0% | |
| | SIT= | 0.0 0% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.0 0% | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

X Schedule 12-FERC charges should not be included in O&M recovered under this formula rate

Y Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA.

When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA

Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC.

| | |
|---|---|
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by FERC. |
| A<br>A | Per the settlement terms of Docket ER15-2028, any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate. |

**New Hampton Municipal Light Plant**

**For the Year ended 6/30/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jul 13 | - |
| Aug 13 | - |
| Sep 13 | - |
| Oct 13 | - |
| Nov 13 | - |
| Dec 13 | - |
| Jan 14 | - |
| Feb 14 | - |
| Mar 14 | - |
| Apr 14 | - |
| May 14 | - |
| Jun 14 | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

| | | |
|---|---|---|
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## New Hampton Municipal Light Plant

### For the Year ended 6/30/20XX

## Plant Summary

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Rights | | | | |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Production Plant | | | | |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 326 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 – Water Wheels, Turbines, | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| and Generators | | | | |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |
| 340 – | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| Land and Land Rights | - | - | - | - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 347 – Asset Retiremen | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| t Costs for Nuclear Productio n | | | | |
| Total Other Productio n Plant | $ - | $ - | $ - | $ - |
| **Total Productio n Plant** | $ - | $ - | $ - | $ - |

| | Total City-owned Transmiission | | | | Common Transmiission System | | | | Lehigh Webster | | | | Walter Scott 4 | | | | Other Trasmission | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
| **Transmis sion Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| and Improvements | | | | | | | | | | | | | | | | | | | | |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 358 – Underground Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 359 – Roads and Trails | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retiremen | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| t Costs for Transmission Plant | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total Transmission Plant** | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | | | |
| 361 – Structures and Improvements | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | | | |
| 362 – Station Equipment | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | | | |
| 363 – Storage Battery Equipment | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | | | |
| 364 – Poles, Towers, and | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| Fixtures | | | | |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Premises | | | | |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property (CTS) | | | $ - | |
| Generation and Transmission System (WS4) | | | | |
| 399.1 – Asset | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Retirement Costs for General Plant | | | | |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Service** | $ - | $ - | $ - | $ - |

# New Hampton Municipal Light Plant
# Depreciation Rates

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 351 | Energy Storage Equipment - Transmission | 40 | 2.50% |
| 352 | Structures & Improvements | 40 | 2.50% |
| 353 | Station Equipment | 40 | 2.50% |
| 354 | Towers & Fixtures | 40 | 2.50% |
| 355 | Poles & Fixtures | 40 | 2.50% |
| 356 | Overhead Conductors and Devices | 40 | 2.50% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 25 | 4.00% |
| 391 | Office Furniture and Equipment | 25 | 4.00% |
| 392 | Transportation Equipment | 25 | 4.00% |
| 393 | Stores Equipment | 25 | 4.00% |
| 394 | Tools, Shop and Garage Equipment | 25 | 4.00% |
| 395 | Laboratory Equipment | 25 | 4.00% |
| 396 | Power Operated Equipment | 25 | 4.00% |
| 397 | Communication Equipment | 25 | 4.00% |
| 398 | Miscellaneous Equipment | 25 | 4.00% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

Land Held For Future Use

| | |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

Materials and Supplies

| | |
|---|---|
| Production | |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S

and indicate what other items are included
in that financial statement line item
by providing a brief but descriptive
explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies
and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

| | **Pre Payment Description** | | **Amount** |
|---|---|---|---|
| XXXXX | | $ | - |
| XXXXX | | | - |
| XXXXX | | | - |

| | |
|---|---|
| XXXXX | - |
| Total Pre Payments | $ - |

# New Hampton Municipal Light Plant
## For the Year ended 6/30/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |

| | |
|---|---|
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

## New Hampton Municipal Light Plant
## For the Year ended 6/30/20XX

| **Customer Accts & Admin and General Expenses** | **Amount** |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| | |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |

| | |
|---|---|
| **Total Customer Service and Informational Expenses** | - |
| | |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| | |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |
| 921 – Office Supplies and Expenses | - |
| 922 – Administrative Expenses Transferred Credit | - |
| 923 – Outside Services Employed | - |
| 924 – Property Insurance | - |
| 925 – Injuries and Damages | - |
| 926 – Employee Pension and Benefits | - |
| 927 – Franchise Requirements | - |
| 928 – Regulatory Commission Expenses | - |
| 929 – Duplicate Charges Credit | - |
| 930.1 – General Advertising Expenses | - |
| 930.2 – Miscellaneous General Expenses | - |
| 931 – Rents | - |
| Total Operations A&G | - |
| 935 – Maintenance of General Plant | - |
| Total Maintenance A&G | - |
| **Total Administrative and General Expenses** | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

| FERC fees recorded to expense during the year | Account Charged | Amount |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

## Taxes Other Than Income Taxes

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other - please explain | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| xxx | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| xxx | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

New Hampton Municipal Light Plant
For the Year ended 6/30/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 6/30/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| Principal Balance & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

New Hampton Municipal Light Plant

**For the Year ended 6/30/20XX**

## Account 454 (Rent from Electric Property)

| Property Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Rent Income | $ - |

Includes income related only to transmission facilities,
such as pole attachments, rentals and special use.
Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |

| | | |
|---|---|---|
| xxxxx | $ | - |
| xxxxx | $ | - |
| Total Revenue | $ | - |

# ADDENDUM 26 TO ATTACHMENT H – Part 10

## Spencer Municipal Utilities

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Spencer Municipal Utilities

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of ATRR To SPP UMZ Pricing**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |

| | Zone | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|---|
| 2a | | UMZ (SPP) | $ - | #DIV/0! | #DIV/0! |
| 3a | | Non UMZ * | $ - | #DIV/0! | #DIV/0! |
| 4a | | Total | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | |
|---|---|---|---|---|
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | $ - |
| | DIVISOR | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | |

Pe Off-Peak

| | | | ak Rate | | Rate | |
|---|---|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized — Rate Formula Template — For the 12 months ended 12/31/20XX

Spencer Municipal Utilities

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000 | |
| 2 | Transmission | | 0 | TP | 00 | 0 |
| 3 | Distribution | | 0 | NA | | |
| 4 | General & Intangible | | 0 | W/S | 0.0 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | 00 | |
| | | | | | 00 | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 5 | Common | | 0 | CE | 00 | 0 |
| | | | | | 0.0 | |
| | TOTAL GROSS PLANT (sum lines | | | | 00 | |
| 6 | 1-5) | | 0 | GP= | % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| | | | | | 0.0 | |
| | | | | | 00 | |
| 8 | Transmission | | 0 | TP | 00 | 0 |
| 9 | Distribution | | 0 | NA | | |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 0 | General & Intangible | | 0 | W/S | 00 | 0 |
| | | | | | 0.0 | |
| 1 | | | | | 00 | |
| 1 | Common | | 0 | CE | 00 | 0 |
| 1 | TOTAL ACCUM. DEPRECIATION (sum lines 7- | | | | | |
| 2 | 11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 1 | | (line 1- | | | | |
| 3 | Production | line 7) | 0 | | | |
| 1 | | (line 2- | | | | |
| 4 | Transmission | line 8) | 0 | | | 0 |
| 1 | | (line 3 - | | | | |
| 5 | Distribution | line 9) | 0 | | | |
| 1 | | (line 4 - | | | | |
| 6 | General & Intangible | line 10) | 0 | | | 0 |
| 1 | Common | (line 5 - | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 7 | | line 11) | | | | |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 28 | Prepayments | 0 | GP | 0.000 00 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Spencer Municipal Utilities

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| Lin | | | | **Transmission** |

e

| No. | | Company Total | Allocator | | (Col 3 times Col 4) |
|---|---|---|---|---|---|
| | O&M (Note X) | | | | |
| 1 | Transmission | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | 0 | TE | 0.000000 | 0 |
| 3 | A&G | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.000000 | 0 |
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 00 | |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| 9 | Transmission | 0 | TP | 0.000000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000000 | 0 |
| 11 | Common | 0 | CE | 0.000000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.000000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 18 | Other | 0 | GP | 0.000% | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000% | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.0000% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | 0.0000% | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | 0 | NP | 0.000% | 0 |
| 27 | Total Income Taxes (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN | 0 | NA | | 0 |

| | | | |
|---|---|---|---|
| | [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | 0 |
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

Spencer Municipal Utilities

For the 12 months ended 12/31/20XX

| Line No. | **SUPPORTING CALCULATIONS AND** |
|---|---|

## NOTES

TRANSMISSION PLANT
INCLUDED IN ISO RATES

| | | | |
|---|---|---|---|
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | 0.00000 |

TRANSMISSION EXPENSES

| | | | |
|---|---|---|---|
| 6 | Total transmission expenses (page 3, line 1, column 3) | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | 0.00000 |
| 11 | Percentage of transmission | T | 0.00000 |

| | | | | |
|---|---|---|---|---|
| 1 | expenses included in ISO Rates (line 9 times line 10) | | E = | |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | | $ | TP | Allocation | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | | W&S Allocator ($ / Allocation) | | |
| 15 | Other | 0 | 0.00 | 0 | | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | |
|---|---|---|---|---|---|---|---|
| 17 | Electric | 0 | | | (line 16) | | CE |
| 18 | Gas | 0 | 0.0 | * | 0.00000 | = | 0. |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 18 | | | | | 00 | | 0 |
| | | | | | 00 | | 0 |
| | | | | | | | 0 |
| | | | | | | | 0 |
| | | | | | | | 0 |
| 19 | Water | | 0 | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | |
| | RETURN (R) | | $ | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | | | | | | |
|---|---|---|---|---|---|---|
| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |
| 25 | Proprietary Capital | | 68.86% | 10. | 0.0695 | |

| | | | | |
|---|---|---|---|---|
| 4b | | 10 % | 0.0840 | = R |
| 24c | Return Used | | **0.0000** | |
| 25 | | Proprietary Capital Cost Rate = | 10.10% | |
| 26 | | TIER = | 0.00 | |
| | REVENUE CREDITS | | Load | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | 0 | |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | 0 | |
| 29 | Total of (a)-(b) | | 0 | |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | | $0 | |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | | | |
| 31 | a. Transmission charges for all transmission transactions | | $0 | |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | | $0 | |

| | | |
|---|---|---|
| 3 | | |
| 3 | Total of (a)-(b) | $0 |



Formula Rate - Non-Levelized

Rate Formula Template

Spencer Municipal Utilities

For the 12 months ended 12/31/20XX

| Note Letter | |
|---|---|
| | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. |
| A | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic |
| B | reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or |

109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

Cash Working Capital assigned to transmission is one-eighth of O&M

H allocated to transmission at page 3, line 8, column 5.

Prepayments are the electric related prepayments booked to Account No. 165.

Line 5 - EPRI Annual Membership Dues, all Regulatory Commission

I Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

Includes only FICA, unemployment, highway, property, gross receipts, and

J other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

The currently effective income tax rate, where FIT is the Federal income

K tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit.

multiplied by (1/1-T) (page 3, line 26).

| | | |
|---|---|---|
| Inputs Required: | FIT = | 0.0<br>0% |

| | | | |
|---|---|---|---|
| | | | (State Income Tax Rate or |
| | | 0.0 | Composite |
| | SIT= | 0% | SIT) |
| | | | (percent of federal income tax deductible for |
| | | 0.0 | state |
| | p = | 0% | purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1

and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

X Schedule 12-FERC charges should not be included in O&M recovered under this formula rate

Y Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA.
When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA
Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC.

Z Per the settlement terms of Docket ER15-2028, the return used is

calculated with the fixed capital structure capped at 68.86% equity or the actual capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update after the settlement is approved by FERC.

A Per the settlement terms of Docket ER15-2028, any NIMECA Member
A participating in an SPP project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Spencer Municipal Utilities**

**For the Year ended 12/31/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## Spencer Municipal Utilities
## For the Year ended 12/31/20XX

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | | | | |
| 310 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Producti** | | | | |

**on Plant**

| | | | | |
|---|---|---|---|---|
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Asset Retirement Costs for Nuclear Production | - | - | - | - |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Water Wheels, Turbines, and Generators | - | - | - | - |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | | | $ - | |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| – Misc. Power Plant Equipment | - | - | - | - |
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| **Total City-owned Transmiission** | **Combined Transmiission System** | | | | **Walter Scott 4** | | | | **Lehigh Webster** | | | | **Neal 4** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Gross** | **Accumulated Depreciation** | **Net Plant** | **Depreciation Expenns** | **Gross** | **Accumulated Depreciation** | **Net Plant** | **Depreciation Expenns** | **Gross** | **Accumulated Depreciation** | **Net Plant** | **Depreciation Expense** | **Gross Plant** | **Accumulated Depreciat** | **Net Plant** | **Depreciation Expense** |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Plant** | **tion** | | **e** | **Plant** | **tion** | | **e** | **Plant** | **tion** | | | | **nt** | **ion** | | |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – Undergro | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| und Conduit | | | | | | | | | | | | | | | | | | | | | | |
| 358 – Underground Conductors and Devices | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| 359 – Roads and Trails | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| **Total Transmission Plant** | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | | $ - | |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | $ - | | $ - | | $ - | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structure | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| s and Improvements | | | | |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Servic** | $ - | $ - | $ - | $ - |

**e**

**Please answer the following questions:**

Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet? If no, please provide an explanation & reconciliation.

Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement? If no, please provide an explanation & reconciliation.

**Spencer Municipal Utilities**
**Depreciation Rates**

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 351 | Energy Storage Equipment - Transmission | 33 | 3.03% |
| 352 | Structures & Improvements | 33 | 3.03% |
| 353 | Station Equipment | 33 | 3.03% |
| 354 | Towers & Fixtures | 33 | 3.03% |
| 355 | Poles & Fixtures | 33 | 3.03% |
| 356 | Overhead Conductors and Devices | 33 | 3.03% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 33 | 3.03% |
| 391 | Office Furniture and Equipment | 7 | 14.29% |
| 392 | Transportation Equipment | 5 | 20.00% |
| | **Intangible Plant** | | |
| 303 | Miscellaneous intangible plant | 33 | 3.03% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Spencer Municipal Utilities
For the Year ended 12/31/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

Spencer Municipal Utilities
For the Year ended 12/31/20XX

Materials and Supplies

| | | |
|---|---|---|
| Production | $ | - |
| Transmission | | - |
| Distribution | | - |
| Other | | - |
| | $ | - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects M&S
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies
and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

Spencer Municipal Utilities
For the Year ended 12/31/20XX

| Pre Payment Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Pre Payments | $ - |

Should tie to a financial statement line item - if not please
indicate what line of the audited financials reflects Pre Payments
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

## Spencer Municipal Utilities
## For the Year ended 12/31/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |

| | |
|---|---|
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

## Spencer Municipal Utilities
## For the Year ended 12/31/20XX

| **Customer Accts & Admin and General Expenses** | **Amount** |
|---|---|
| **Customer Accounts Expenses** | |

| | |
|---|---|
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| | |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| | |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| | |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |
| 921 – Office Supplies and Expenses | - |
| 922 – Administrative Expenses Transferred Credit | - |
| 923 – Outside Services Employed | - |
| 924 – Property Insurance | - |
| 925 – Injuries and Damages | - |
| 926 – Employee Pension and Benefits | - |
| 927 – Franchise Requirements | - |
| 928 – Regulatory Commission Expenses | - |

| | |
|---|---|
| 929 – Duplicate Charges Credit | - |
| 930.1 – General Advertising Expenses | - |
| 930.2 – Miscellaneous General Expenses | - |
| 931 – Rents | - |
| Total Operations A&G | - |
| 935 – Maintenance of General Plant | - |
| Total Maintenance A&G | - |
| **Total Administrative and General Expenses** | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Customer Operations

Spencer Municipal Utilities
For the Year ended 12/31/20XX

| **FERC fees recorded to expense during the year** | **Account Charged** | | **Amount** |
|---|---|---|---|
| FERC fees payable to FERC | - | $ | - |
| FERC fees paid to an RTO | - | | - |

| | | |
|---|---|---|
| Other FERC fees paid | - | - |
| Total | | $ - |

Spencer Municipal Utilities
For the Year ended 12/31/20XX

## Taxes Other Than Income Taxes

| | | |
|---|---|---|
| Payroll | $ | - |
| Highway & Vehicle | | - |
| Property | | - |
| Gross | | - |
| Other - please explain | | - |
| Payments in lieu of taxes | | - |
| Fed & State income Tax | | - |
| Total | $ | - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

Spencer Municipal Utilities
For the Year ended 12/31/20XX

EPRI Costs $ - recorded in Usof A account _____, reflected in I/S in

_____ exp

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| Fuel adjustment clause docket XX | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

Spencer Municipal Utilities
For the Year ended 12/31/20XX

| **Debt Detail - Electric only** | **Principal Balance at For the Year ended 12/31/20XX** | **Interest Expense** |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |

| | | |
|---|---|---|
| | $ | $ |
| Total | - | - |

| | | |
|---|---|---|
| | $ | $ |
| | - | - |
| | | $ |
| | - | - |
| | | $ |
| | - | - |
| | $ | $ |
| Total | - | - |

| | | |
|---|---|---|
| | $ | $ |
| | - | - |
| | | $ |
| | - | - |
| | | $ |
| | - | - |
| | $ | $ |
| Total | - | - |

| | | |
|---|---|---|
| | $ | $ |
| | - | - |
| | | $ |
| | - | - |
| | | $ |
| | - | - |
| | $ | $ |
| Total | - | - |

| | | |
|---|---|---|
| | $ | $ |
| | - | - |
| | | $ |
| | - | - |
| | | $ |
| | - | - |
| Total | $ | $ |

| | | |
|---|---|---|
| | - | - |
| | $ - | $ - |
| | - | - |
| | - | $ - |
| Total | $ - | $ - |
| Principal Balance & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements. If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

Spencer Municipal Utilities

**For the Year ended 12/31/20XX**

## Account 454 (Rent from Electric Property)

| Property Description | Amount | |
|---|---|---|
| XXXXX | $ - | |
| XXXXX | - | |
| XXXXX | - | |
| XXXXX | - | |
| Total Rent Income | $ - | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item |
| none related to transmission lines | | by providing a brief but descriptive explanation |

Spencer Municipal Utilities

**For the Year ended 12/31/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |

| | | |
|---|---|---|
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| Total Revenue | $ | - |

# ADDENDUM 26 TO ATTACHMENT H – Part 11

## West Bend Municipal Utilities

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

West Bend

| Line No. | | Allocated Amount | Line No. |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | |

**Allocation of**

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.000000 | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.000000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |

**ATRR To SPP UMZ Pricing Zone**

| | Pricing Zone (1) | Gross Plant (2) | Allocation (3) | ATRR (4) |
|---|---|---|---|---|
| 2a | **UMZ (SPP)** | $ - | #DIV/0! | #DIV/0! |
| 3a | **Non UMZ *** | $ - | #DIV/0! | #DIV/0! |
| 4a | **Total** | $ - | #DIV/0! | #DIV/0! |

* Gross transmission plant not included in SPP.

| | | | | | |
|---|---|---|---|---|---|
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | $ - |
| | DIVISOR | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | | (Note B) | |
| 10 | Plus 12 CP of Network Load not in line 8 | | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | | |

| | | | Peak Rate | | Off-Peak Rate | |
|---|---|---|---|---|---|---|
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 22 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

| Line No. | (1) | (2) | (3) West Bend **Company Total** | **Allocator** | (4) | (5) **Transmission** (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | | |
| 2 | Transmission | | 0 | TP | 0.000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 3 | Distribution | 0 | NA | 0.000% | | |
| 4 | General & Intangible | 0 | W/S | 0.000% | 0 | |
| 5 | Common | 0 | CE | 0.000% | 0 | |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | 0 | GP= | 0.000% | 0 | |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | 0 | NA | | | |
| 8 | Transmission | 0 | TP | 0.000% | 0 | |
| 9 | Distribution | 0 | NA | | | |
| 10 | General & Intangible | 0 | W/S | 0.000% | 0 | |
| 11 | Common | 0 | CE | 0.000% | 0 | |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | 0 | | | 0 | |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) 0 | | | | |
| 14 | Transmission | (line 2-line 8) 0 | | | 0 | |
| 15 | Distribution | (line 3 - line 9) 0 | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.000 | 0 |
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 | 0 |
| 28 | Prepayments | | 0 | GP | 0.000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | | 0 | | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

West Bend

For the 12 months ended 6/30/20XX

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | O&M (Note X) | | | | | |
| 1 | Transmission | | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | | 0 | | 1.000000 | 0 |
| 2 | Less Account 565 | | 0 | TE | 0.000000 | 0 |
| 3 | A&G | | 0 | W/S | 0.000000 | 0 |
| 4 | Less FERC Annual Fees | | 0 | W/S | 0.000000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | | 0 | W/S | 0.000000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | | 0 | TE | 0.000000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 6 | Common | 0 | CE | 0.000000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.000000 | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7, 7a less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| 9 | Transmission | 0 | TP | 0.000000 | 0 |
| 10 | General & Intangible | 0 | W/S | 0.000000 | 0 |
| 11 | Common | 0 | CE | 0.000000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.000000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.000000 | 0 |
| 15 | PLANT RELATED | | | | |

| | | | | | |
|---|---|---|---|---|---|
| 16 | Property | 0 | GP | 0.000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |
| | INCOME TAXES (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | 0.00% | | | |
| 23 | 1 / (1 - T) = (from line 21) | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes (line 25 | 0 | | | 0 |

| | | | | |
|---|---|---|---|---|
| 7 | | plus line 26) | | |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | 0 | NA | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | | 0 |
| 30 | Total Gross Revenue Requirement | 0 | | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

West Bend

For the 12 months ended 6/30/20XX

L

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | | |
|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | | TP = | 0.00000 |
| | TRANSMISSION EXPENSES | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | TP | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | | | TE = | 0.00000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Y)

| | | $ | TP | Allocation | | | |
|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator ($ / Allocation) | | |
| 15 | Other | 0 | 0.00 | 0 | | | |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = 0.0000 | = | W/S |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | $ | % Ele | Labor Ratio |
|---|---|---|---|---|

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 17 | Electric | | 0 | | | Electric (line 17 / line 20) | | (line 16) | | CE |
| 18 | Gas | | 0 | | | 0.000000 | * | 0.00000 | = | 0.000000 |
| 19 | Water | | 0 | | | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | | | |
| | RETURN (R) | | $ | | | | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | | | | |

| | **Actual Capital Structure** | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.0000 | =WCLTD |
| 23 | Proprietary Capital | 0 | 0% | 10.10% | 0.0000 | |
| 24 | Total (sum lines 22, 23) | 0 | 0% | | 0.0000 | =R |

| | **Fixed Capital Structure** | Note Z | % | Cost | Weighted | |
|---|---|---|---|---|---|---|
| 24a | Long Term Debt | | 31.14% | 4.65% | 0.0145 | =WCLTD |
| 24b | Proprietary Capital | | 68.86% | 10.10% | 0.0695 | |
| | | | | | 0.0840 | = R |
| 24c | Return Used | | | | **0.0000** | |
| 25 | | | Proprietary Capital Cost Rate = | | 10.10% | |
| 26 | | | | TIER = | 0.00 | |

REVENUE CREDITS

| | | | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) | | |
| 27 | a. Bundled Non-RQ Sales for Resale | (Note Q) | 0 |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | 0 |
| 29 | Total of (a)-(b) | | 0 |

| | | |
|---|---|---|
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | |
| 31 | a. Transmission charges for all transmission transactions | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | $0 |
| 33 | Total of (a)-(b) | $0 |

| Note Letter | | ended 6/30/20XX |
|---|---|---|
| | | West Bend |
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. | |
| B | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. | |

Measured at time of applicable pricing zone coincident monthly peaks.

C LF as defined above at time of applicable pricing zone coincident monthly peaks.

D LF as defined above at time of applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

I Prepayments are the electric related prepayments booked to Account No. 165.
Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,
since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income

tax rate; SIT is the State income tax rate, and p =

"the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit.

multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| | | 0.0 | |
| Inputs Required: | FIT = | 0% | |
| | | | (State Income Tax Rate or |
| | | 0.0 | Composite |
| | SIT= | 0% | SIT) |
| | | | (percent of federal income tax deductible for |
| | | 0.0 | state |
| | p = | 0% | purposes) |

Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and
L 561.BA.

Removes transmission plant determined to be state-jurisdictional by
M Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test).

Removes dollar amount of transmission plant included in the development
N of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

X Schedule 12-FERC charges should not be included in O&M recovered under this formula rate

Y Per the settlement terms of Docket ER15-2028, the Gross Plant Allocator

| | |
|---|---|
| | may be used in lieu of the Wages & Salary Allocator by setting the WSA = GPA. |
| | When this is done, The Net SPP ATRR using the GPA and the Net SPP ATRR using 5.1% for the WSA are entered in NIMECA |
| | Workpaper Z to calculate the annual payment to MRES. This payment is in effect the first rate update after the settlement is approved by FERC. |
| Z | Per the settlement terms of Docket ER15-2028, the return used is calculated with the fixed capital structure capped at 68.86% equity or the actual |
| | capital structure if the equity percentage in the actual capital structure is equal to or lower than 68.86%. If the actual capital structure does not include any long-term debt, |
| | then the fixed capital structure will use a debt cost of 4.65% to calculate the fixed capital structure return. This is in effect the first rate update |
| | after the settlement is approved by FERC. |
| A | Per the settlement terms of Docket ER15-2028, any NIMECA Member |
| A | participating in an SPP project the total cost of which is $10,000,000 or more and |
| | which has regional cost sharing (“Project Costs”), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital |
| | structure equity component higher than |

50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**West Bend**

**For the Year ended 06/30/20XX**

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jul 13 | - |
| Aug 13 | - |
| Sep 13 | - |
| Oct 13 | - |
| Nov 13 | - |
| Dec 13 | - |
| Jan 14 | - |
| Feb 14 | - |
| Mar 14 | - |
| Apr 14 | - |
| May 14 | - |
| Jun 14 | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

## West Bend

## For the Year ended 06/30/20XX

### Plant Summary

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| Structures and Improvements | - | - | - | - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Nuclear Production Plant | | | | |

| | | | | |
|---|---|---|---|---|
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | | | | |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 – Water Wheels, Turbines, and Generators | $ - | $ - | $ - | $ - |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Plant Equipment | | | | |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Products, and Accessories | | | | |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| | Total City-owned Transmiission | | | | Combined Transmiission System | | | | Lehigh Webster | | | | Walter Scott 4 Total | | | | Other Trasmission | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – Underground Conduit | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 358 – Underground Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 359 – Roads and Trails | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total Transmission Plant** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Distribution Plant** | | | | |
| 360 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| Underground Conductors and Devices | - | - | - | - |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Distribution Plant | | | | |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipmen | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| t | | | | |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Servic** | $ - | $ - | $ - | $ - |

**e**

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 352 | Structures & Improvements | 30 | 3.33% |
| 354 | Towers & Fixtures | 30 | 3.33% |
| 355 | Poles & Fixtures | 30 | 3.33% |
| 356 | Overhead Conductors and Devices | 30 | 3.33% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 25 | 4.00% |
| 391 | Office Furniture and Equipment | 10 | 10.00% |
| 392 | Transportation Equipment | 15 | 6.67% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

West Bend
For the Year ended 06/30/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Land Held For Future Use
and indicate what other items are included in that financial statement line item
by providing a brief but descriptive explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use
and the amounts related to each item of Transmission land held for future use

West Bend
For the Year ended 06/30/20XX

Materials and Supplies

| | | |
|---|---|---|
| Production | $ | - |
| Transmission | | - |
| Distribution | | - |
| Other | | - |
| | $ | - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects M&S and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | | **Amount** |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

West Bend
For the Year ended 06/30/20XX

| Pre Payment Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Pre Payments | $ - |

Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation

## West Bend
## For the Year ended 06/30/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |

| | |
|---|---|
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

# West Bend
# For the Year ended 06/30/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |

| | |
|---|---|
| 921 – Office Supplies and Expenses | - |
| 922 – Administrative Expenses Transferred Credit | - |
| 923 – Outside Services Employed | - |
| 924 – Property Insurance | - |
| 925 – Injuries and Damages | - |
| 926 – Employee Pension and Benefits | - |
| 927 – Franchise Requirements | - |
| 928 – Regulatory Commission Expenses | - |
| 929 – Duplicate Charges Credit | - |
| 930.1 – General Advertising Expenses | - |
| 930.2 – Miscellaneous General Expenses | - |
| 931 – Rents | - |
| Total Operations A&G | - |
| 935 – Maintenance of General Plant | - |
| Total Maintenance A&G | - |
| **Total Administrative and General Expenses** | - |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

West Bend
For the Year ended 06/30/20XX

| FERC fees recorded to expense during the year | Account Charged | Amount |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

West Bend
For the Year ended 06/30/20XX

## Taxes Other Than Income Taxes

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts.

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

West Bend
For the Year ended 06/30/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| xxx | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| xxxx | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising<br>Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**If a zero is reported for any category above, please provide a brief explanation as to why.**

West Bend
For the Year ended 06/30/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 06/30/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | $ - | $ - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| Principal Balance & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

West Bend

**For the Year ended 06/30/20XX**

## Account 454 (Rent from Electric Property)

| Property Description | Amount | |
|---|---|---|
| XXXXX | $ - | |
| XXXXX | - | |
| XXXXX | - | |
| XXXXX | - | |
| Total Rent Income | $ - | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. Should tie to a financial statement line item - if not please indicate what line of the audited financials reflects Pre Payments and indicate what other items are included in that financial statement line item by providing a brief but descriptive explanation |

West Bend

**For the Year ended 06/30/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |

| | | |
|---|---|---|
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| xxxxx | $ | - |
| Total Revenue | $ | - |

# ADDENDUM 26 TO ATTACHMENT H – Part 12

## Grundy Center Municipal Utilities



| | | |
|---|---|---|
| Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 6/30/20XX |
| | Grundy Center Municipal Utilities | |

| Lin | | Allocated |
|---|---|---|

| No. | | | | | Amount | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | | | | $ - | | | | | **ATRR** |
| | | | | | | | **Pricing Zone** | **Gross Plant** | **Allocation** | **ATRR** |
| | | | | | | | **UMZ (SPP)** | $ - | #DIV/0! | **#DIV/0!** |
| | REVENUE CREDITS | (Note T) | Total | Allocator | | | **Non UMZ *** | $ - | #DIV/0! | #DIV/0! |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.0000 | 0 | **Total** | $ - | #DIV/0! | #DIV/0! | |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.0000 | 0 | | | | | |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.0000 | 0 | * Gross tranmission plant not included in SPP. | | | | |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.0000 | 0 | | | | | |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 | | | | | |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | | $ - | | | | | |

DIVISOR

| | | | |
|---|---|---|---|
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | (Note B) | 0 |
| 10 | Plus 12 CP of Network Load not in line 8 | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | 0 |
| 15 | Divisor (sum lines 8-14) | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) | (line 11/ 12) | 0.000 | | | |
| | | | Peak Rate | | Off-Peak Rate | |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual Charge($/MWh) | (Note | $0. | Short Term | $0.000 | Short |

| | | | | | |
|---|---|---|---|---|---|
| 1 | E) | 000 | | | t Te r m |
| 2 2 | | $0. 000 | Long Term | $0.000 | Lo ng Te r m |

Grundy Center Municipal Utilities

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | | |
| 2 | Transmission | | 0 | TP | 0.00000 | 0 |
| 3 | Distribution | | 0 | NA | | |

| | | | | | |
|---|---|---|---|---|---|
| 4 | General & Intangible | 0 | W/S | 0.16499 | 0 |
| 5 | Common | 0 | CE | 0.00000 | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | 0 | GP= | 0.000% | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | |
| 7 | Production | 0 | NA | | |
| 8 | Transmission | 0 | TP | 0.00000 | 0 |
| 9 | Distribution | 0 | NA | | |
| 10 | General & Intangible | 0 | W/S | 0.16499 | 0 |
| 11 | Common | 0 | CE | 0.00000 | 0 |
| 1 | TOTAL ACCUM. DEPRECIATION (sum lines 7- | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | 11) | | | | | |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | |
| 14 | Transmission | (line 2-line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 2 | Account No. 282 (enter | | 0 | NP | 0.0000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 0 | negative) | | | 0 | |
| 21 | Account No. 283 (enter negative) | 0 | NP | 0.0000 | 0 |
| 22 | Account No. 190 | 0 | NP | 0.0000 | 0 |
| 23 | Account No. 255 (enter negative) | 0 | NP | 0.0000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE (Note G) | 0 | TP | 0.0000 | 0 |
| | WORKING CAPITAL (Note H) | | | | |
| 26 | CWC | 0 | | | 0 |
| 27 | Materials & Supplies (Note G) | 0 | TE | 0.0000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 28 | Prepayments | 0 | GP | 0.0000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | 0 | | | 0 |

Grundy Center Municipal Utilities

| Line No. | (1) | (2) | (3) | | (4) | (5) |
|---|---|---|---|---|---|---|
| | | | **Company Total** | **Allocator** | | **Transmission** |
| | O&M (Note X) | | | | | |
| 1 | Transmission | | 0 | TE | 0.00000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note V) | | 0 | | 1.00000 | 0 |
| 2 | Less Account 565 | | 0 | TE | 0.00000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 3 | A&G | 0 | W/S | 0.16499 | 0 |
| 4 | Less FERC Annual Fees | 0 | W/S | 0.16499 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note I) | 0 | W/S | 0.16499 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note I) | 0 | TE | 0.00000 | 0 |
| 6 | Common | 0 | CE | 0.00000 | 0 |
| 7 | Transmission Lease Payments | 0 | NA | 1.00000 | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| 9 | Transmission | 0 | TP | 0.0000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 0 | |
| 10 | General & Intangible | 0 | W/S | 0.1649 | 0 |
| 11 | Common | 0 | CE | 0.0000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.1649 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.1649 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.0000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | 0 | |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.0000 0 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.0000 0 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |

| | | | |
|---|---|---|---|
| | INCOME TAXES (Note K) | | NA |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | 0.00% | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | 0.00% | |
| | where WCLTD=(page 4, line 22) and R= (page 4, line 24) | | |
| | and FIT, SIT & p are as given in footnote K. | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | 1 / (1 - T) = (from line 21) | | 0.0000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.00000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | 0 | NA | | 0 |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | | 0 | | | 0 |

| | | | |
|---|---|---|---|
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Grundy Center Municipal Utilities

| Line No. | | SUPPORTING CALCULATIONS |
|---|---|---|

**AND NOTES**

| | | | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | -0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | 0.00000 |
| | TRANSMISSION EXPENSES | | |
| 6 | Total transmission expenses (page 3, line | | 0 |

| | | | |
|---|---|---|---|
| | 1, column 3) | | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE = | 0.00000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Z)

| | | $ | TP | Allocation |
|---|---|---|---|---|
| 1 | Production | 0 | 0.00 | 0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 12 | | | | | | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | | W&S Allocator | | | |
| 15 | Other | 0 | 0.00 | 0 | | ($ / Allocation) | | | Cell to solve for W/S by setting this to zero by changing J222 |
| 16 | Total (sum lines 12-15) | 0 | | 0 | = | 0.16499 | = | W/S | -16.50% |

| | | | |
|---|---|---|---|
| COMMON PLANT ALLOCATOR (CE) (Note O) | | | |
| | **$** | % Electric | Labor Ratio |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 17 | Electric | | 0 | | (line 17 / line 20) | | (line 16) | | CE |
| 18 | Gas | | 0 | | 0.00000 | * | 0.16499 | = | 0.00000 |
| 19 | Water | | 0 | | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | | |
| | RETURN (R) | | $ | | | | | | |
| 21 | Long Term Interest | Note U | $0 | | | | | | |
| | | | $ | % | Cost (Note | | Weighted | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | P) | | |
| 22 | Long Term Debt | 0 | 0% | 0.00% | 0.00% | =WCLTD |
| 23 | Proprietary Capital | 0 | 100% | 10.10% | 10.10% | |
| 24 | Total (sum lines 22, 23) | 0 | 100% | | 10.10% | =R |
| 25 | | | | | 10.1000% | |
| 26 | | | | TIER = | 0.00 | |
| | REVENUE CREDITS | | | | | |
| | | | | | Load | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | | (Note Q) | | 0 | |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | | 0 | |
| | Total of (a)-(b) | | | | 0 | |

| | | |
|---|---|---|
| 29 | | |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R) | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | |
| 31 | a. Transmission charges for all transmission transactions | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 | $0 |
| 33 | Total of (a)-(b) | $0 |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 6/30/20XX

Grundy Center Municipal Utilities

Note

Let

t

e

r

A The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service

which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).

B Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable

even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service"

for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years.

LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks.

C LF as defined above at time of applicable pricing zone coincident monthly peaks.

D LF as defined above at time of applicable pricing zone coincident monthly peaks.

E The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any

F The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets

or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility

chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.

G Transmission related only.

H Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

Prepayments are the electric related

prepayments booked to Account No. 165.

I Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

J Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

K The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p =

"the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a

work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that

elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce

rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit.

multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.00% | |
| | SIT= | 0.00% | (State Income Tax Rate or Composite SIT) |
| | p = | 0.00% | (percent of federal income tax deductible for state purposes) |

L Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

M Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account

balances are adjusted to reflect

application of seven-factor test).

N Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation

step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up

facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

O Enter dollar amounts

P Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation

after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and

the FERC, if the entity is under FERC's jurisdiction.

Q Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account

No. 456.1 and all other uses are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1

and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate

pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements)

or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include

revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct

assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner

revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.

X Schedule 12-FERC charges should not be included in O&M recovered under this formula rate

Z If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S

allocator at page 4 line 16 equal to the gross plant allocator (GP) at page 2, line 6.

A Any NIMECA Member participating in an SPP
A project the total cost of which is $10,000,000 or more and

which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital

structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that

capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Grundy Center Municipal Utilities**

**For the Year ended 06/30/20XX**

**Attachment H divisor**

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |

| | |
|---|---|
| Dec | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:

the GFA #, the GFA load, and the GFA transmission revenues. **No GFA.**

| | Jan | Feb | Mar | Apr | May | June | July | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| GFA Trans Rev | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |

| | | |
|---|---|---|
| GFA Trans Rev | - | - |
| GFA # | | |
| GFA Load | - | - |
| GFA Trans Rev | - | - |

**Grundy Center Municipal Utilities**

**For the Year ended 06/30/20XX**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |

310 –

| | | | | |
|---|---|---|---|---|
| Land and Land Rights | - | - | - | - |
| 311 – Structures and Improvements | - | - | - | - |
| 312 – Boiler Plant Equipment | - | - | - | - |
| 313 – Engines and Engine-Driven Generators | - | - | - | - |
| 314 – Turbogenerator Units | - | - | - | - |
| 315 – Accessory Electric | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 316 – Misc. Power Plant Equipment | - | - | - | - |
| Total Steam Production Plant | - | - | - | - |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | - | - | - | - |
| 322 – | | | | |

| | | | | |
|---|---|---|---|---|
| Reactor Plant Equipment | - | - | - | - |
| 323 – Turbogenerator Units | - | - | - | - |
| 324 – Accessory Electric Equipment | - | - | - | - |
| 325 – Misc. Power Plant Equipment | - | - | - | - |
| 326 – Asset Retirement Costs for Nuclear Production | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | - | - | - | - |
| 332 – Reservoirs, Dams, and Waterways | - | - | - | - |
| 333 – Water Wheels, Turbines, | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| and Generators | | | | |
| 334 - Accessory Electric Equipment | - | - | - | - |
| 335 – Misc. Power Plant Equipment | - | - | - | - |
| 336 – Roads, Railroads, and Bridges | - | - | - | - |
| 337 – Asset Retirement Costs for Hydraulic Production | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Total Hydraulic Production Plant | - | - | - | - |
| | | | | |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | - | - | - | - |
| 342 – Fuel Holders, Products, and Accessories | - | - | - | - |
| 343 – Prime | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| Movers | | | | |
| 344 – Generators | - | - | - | - |
| 345 – Accessory Electric Equipment | - | - | - | - |
| 346 – Misc. Power Plant Equipment | - | - | - | - |
| 347 – Asset Retirement Costs for Nuclear Production | - | - | - | - |
| Total Other Productio | - | - | - | - |

n Plant

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total Productio n Plant** | - | - | - | - | | | | | | | | | | | | | | | | |

| | **Total City-owned Transmission** | **Combined Transmission System** | | | | **Walter Scott 4** | | | | **Neal 4** | | | | **Other Transmission** | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **Ac cu mu lat ed** | **Ne t** | **De pr eci ati on** | | **Ac cu mu lat ed** | **Ne t** | **De pr eci ati on** | | **Ac cu mu lat ed** | **Ne t** | **De pre cia tio n** | | **Acc um ula ted** | **Ne t** | **De pre cia tio n** | |
| | | **Gr oss Pla nt** | **De pr eci ati on** | **Pla nt** | **Ex pe ns e** | **Gr oss Pla nt** | **De pr eci ati on** | **Pla nt** | **Ex pe ns e** | **Gr oss Pla nt** | **De pr eci ati on** | **Pla nt** | **Ex pe nse** | **Gr oss Pla nt** | **De pre cia tio n** | **Pla nt** | **Ex pe nse** |
| **Transmis sion Plant** | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 350 – Land and Land Rights | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | | $ - | $ - | $ - | | | $ - | $ - | | | $ - | | | | $ - | $ - | $ - | | | $ - | | | |
| 353 – Station Equipment | $ - | | $ - | $ - | $ - | | | $ - | | | | $ - | | | | $ - | | $ - | | | $ - | | | |
| 354 – Towers and Fixtures | $ - | | $ - | $ - | $ - | | | $ - | | | | $ - | | | | $ - | | $ - | | | $ - | | | |
| 355 – Poles and Fixtures | $ - | | $ - | $ - | $ - | | | $ - | | | | $ - | | | | $ - | | $ - | | | $ - | | | |
| 356 – Overhead Conductors and Devices | $ - | | $ - | $ - | $ - | | | $ - | | | | $ - | | | | $ - | | $ - | | | $ - | | | |
| 357 – | $ | | $ | $ | $ | | | $ | | | | $ | | | | $ | | | | | $ | | | |

| | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Underground Conduit | - | | - | - | - | | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 358 – Underground Conductors and Devices | $ - | | $ - | $ - | $ - | | $ - | - | - | - | $ - | - | - | - | $ - | - | - | - | $ - | - | - | - |
| 359 – Roads and Trails | $ - | | $ - | $ - | $ - | | $ - | - | - | - | $ - | - | - | - | $ - | - | - | - | $ - | - | - | - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | $ - | $ - | $ - | | $ - | - | - | - | $ - | - | - | - | $ - | - | - | - | $ - | - | - | - |
| **Total Transmission Plant** | $ - | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Distribution Plant** | | | | |
| 360 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| Overhead Conductors and Devices | - | - | - | - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Premises | | | | |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Rights | | | | |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipme | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| nt | | | | |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| Asset Retirement Costs for General Plant | - | - | - | - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Service** | $ - | $ - | $ - | $ - |

**Please answer the following questions:**

Does the Grand total Gross Plant

In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet?

Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet?

Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement?

**Grundy Center Municipal Utilities**

**Depreciation Rates**

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 352 | Structures & Improvements | 40 | 2.50% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 25 | 4.00% |
| 392 | Transportation Equipment | 25 | 4.00% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

Grundy Center Municipal Utilities

For the Year ended 06/30/20XX

| | Land Held For Future Use | |
|---|---|---|
| Production | $ - | |
| Transmission | - | |
| Distribution | - | |
| Other | - | |
| | $ - | Should tie to a financial statement line item - if not please<br><br>indicate what line of the audited financials reflects Land Held For Future Use<br><br>and indicate what other items are included in that financial statement line item<br><br>by providing a brief but descriptive |

explanation

**Below -** Provide a brief but descriptive list of the Transmission land held for future use

and the amounts related to each item of Transmission land held for future use

Grundy Center Municipal Utilities

For the Year ended 06/30/20XX

| | Materials and Supplies | |
|---|---|---|
| Production | $ - | |
| Transmission | - | |
| Distribution | - | |
| Other | - | |
| | $ - | Should tie to a financial statement line item - if not please |

indicate what line of the audited financials reflects M&S

and indicate what other items are included in that financial statement line item

by providing a brief but descriptive explanation

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies

and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | **Amount** | |
|---|---|---|
| Insulators | $ | - |
| Relays | $ | - |
| Substation Misc Part | $ | - |
| Transmission wires | $ | - |
| Trans. Line Hardware | $ | - |
| Transducers | $ | - |
| | $ | - |
| **Total** | **$** | **-** |

Grundy Center Municipal Utilities

For the Year ended 06/30/20XX

| **Pre Payment Description** | **Amount** | |
|---|---|---|
| Property Insurance | $ | - |
| XXXXX | | - |
| XXXXX | | - |
| XXXXX | | - |
| Total Pre Payments | $ | - |

Should tie to a financial statement line item - if not please

indicate what line of the audited financials reflects Pre Payments

and indicate what other items are included in that financial statement line item

by providing a brief but descriptive explanation

**Grundy Center Municipal Utilities**

**For the Year ended 06/30/20XX**

| **Transmission O&M Expenses** | **Amount** |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | - |
| 561.6 – Transmission Service Studies | - |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |

| | |
|---|---|
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Please provide the following information:**

What line of the audited financial statements includes the Transmission O&M Expense?

Provide a brief but descriptive list of the items and associated amounts reflected in that line of the financial statements

**Grundy Center Municipal Utilities**

**For the Year ended 06/30/20XX**

| **Customer Accts & Admin and General Expenses** | **Amount** |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |

| | |
|---|---|
| **Total Customer Service and Informational Expenses** | - |
| | |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| | |
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | - |
| 921 – Office Supplies and Expenses | - |
| 922 – Administrative Expenses Transferred Credit | - |
| 923 – Outside Services Employed | - |
| 924 – Property Insurance | - |
| 925 – Injuries and Damages | - |
| 926 – Employee Pension and Benefits | - |
| 927 – Franchise Requirements | - |
| 928 – Regulatory Commission Expenses | - |

| | | |
|---|---|---|
| 929 – Duplicate Charges Credit | - | |
| 930.1 – General Advertising Expenses | | - |
| 930.2 – Miscellaneous General Expenses | | - |
| 931 – Rents | - | |
| Total Operations A&G | - | |
| 935 – Maintenance of General Plant | | - |
| Total Maintenance A&G | - | |
| **Total Administrative and General Expenses** | - | |

**Please provide the following information:**

What line of the audited financial statements includes the A&G Expense?

What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense?

Grundy Center Municipal Utilities

For the Year ended 06/30/20XX

| **FERC fees recorded to expense during the year** | **Account Charged** | **Amount** |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

Grundy Center Municipal Utilities

For the Year ended 06/30/20XX

**Taxes Other Than Income Taxes**

| | | |
|---|---|---|
| Payroll | $ | - |
| Highway & Vehicle | | - |
| Property | | - |
| Gross | | - |
| Other - please explain | | - |
| Payments in lieu of taxes | | - |
| Fed & State income Tax | | |
| Total | $ | - |

Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city.

| | | |
|---|---|---|
| Grundy Center Municipal Utilities | | |
| For the Year ended 06/30/20XX | | |
| | | |
| | | |
| | | |
| | | |
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |
| | | |
| | | |
| | | |
| | | |
| Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related** | | |
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |
| | | |
| | | |
| Non Safety Advertising (provide a brief but descriptive list of charges) | | |
| Admin & General Advertising | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| Xxxxxxxx | | |
| | - | |
| | | |
| | | |
| **If a zero is reported for any category above, please provide a brief explanation as to why.** | | |

Grundy Center Municipal Utilities
For the Year ended 06/30/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 06/30/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| | $ | $ |
| Total | - | - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| | $ | $ |
| Total | - | - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| | $ | $ |
| Total | - | - |
| | $ | $ |

| | | |
|---|---|---|
| | - | - |
| | - | - |
| | - | - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | - | - |
| | - | - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| | $ - | $ - |
| | - | - |
| | - | - |
| Total | $ - | $ - |

| | | |
|---|---|---|
| Principal & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements.

If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

| | | | |
|---|---|---|---|
| Grundy Center Municipal Utilities | | | |
| **For the Year ended 06/30/20XX** | | | |
| | | | |
| | | | |
| **Account 454 (Rent from Electric Property)** | | | |
| | | | |
| | | | |
| **Property Description** | **Amount** | | |
| | | | |
| XXXXX | $ - | | |
| XXXXX | - | | |
| XXXXX | - | | |
| XXXXX | - | | |
| Total Rent Income | $ - | | Includes income related only to transmission facilities, |
| | | | such as pole attachments, rentals and special use. |
| | | | Should tie to a financial statement line item - if not please |
| | | | indicate what line of the audited financials reflects Pre Payments |
| | | | and indicate what other items are included in that financial statement line item |
| | | | by providing a brief but descriptive explanation |

| Grundy Center Municipal Utilities | | |
|---|---|---|
| **For the Year ended 06/30/20XX** | | |
| | | |
| | | |
| **Account 456.1 (Other Electric Revenues)** | **Account 456.1** | |
| | | **Revenue** |
| | | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| Total Revenue | $ - | |

# ADDENDUM 26 TO ATTACHMENT H – Part 13

## Sumner Municipal Light Plant



For the 12 months ended 12/31/20XX

Formula Rate - Non-Levelized

Rate Formula Template

Sumner Municipal Light Plant

| Line No. | | Allocated Amount | |
|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | $ - | **ATR** |

| | REVENUE CREDITS | (Note T) | Total | Allocator | | |
|---|---|---|---|---|---|---|
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.000000 | 0 |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.000000 | 0 |
| 4 | Revenues from Grandfathered Interzonal | | 0 | TP | 0.000000 | 0 |

| Pricing Zone | Gross Plant | R Allocation | ATRR |
|---|---|---|---|
| **UMZ (SPP)** | $ - | #DIV/0! | **#DIV/0!** |
| **Non UMZ *** | $ - | #DIV/0! | #DIV/0! |
| **Total** | $ - | #DIV/0! | #DIV/0! |

* Gross tranmission

| | | | | | | |
|---|---|---|---|---|---|---|
| | Transactions | | | 00 | | plant not included in SPP. |
| 5 | Revenues from service provided by the ISO at a discount | 0 | TP | 0.000 | 0 | |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | 0 | |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | $ - | |
| | DIVISOR | | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | (Note A) | 0 | |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | | (Note B) | 0 | |
| 10 | Plus 12 CP of Network Load not in line 8 | | | (Note C) | 0 | |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | | (Note D) | 0 | |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | | 0 | |
| 13 | Less Contract Demand from Grandfathered Interzonal | | | | 0 | |

| | | | | | |
|---|---|---|---|---|---|
| 13 | transactions over one year (enter negative) (Note S) | | | | |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | 0 |
| 15 | Divisor (sum lines 8-14) | | | | 0 |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) (line 11/ 12) | | 0.000 | | |
| | | | Peak Rate | | Off-Peak Rate |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 |
| 20 | Point-To-Point Rate | (line | 0.0 | Capped at weekly | $0.000 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 0 | ($/MWh) | 16/ 4,160 ; line 16/ 8,760<br><br>times 1,000 ) | 00 | | | |
| | | | | and daily rates | | |
| 2 1 | FERC Annual Charge($/MWh) | (Note E) | $0.000 | Short Term | $0.000 | Short Term |
| 2 2 | | | $0.000 | Long Term | $0.000 | Long Term |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Sumner Municipal Light Plant

| Line No. | (1) | (2) | (3) Company Total | (4) Allocator | | (5) Transmission |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | | 0 | NA | 0.000000 | |
| 2 | Transmission | | 0 | TP | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 3 | Distribution | | 0 | NA | | |
| 4 | General & Intangible | | 0 | W/S | 0.000000 | 0 |
| 5 | Common | | 0 | CE | 0.000000 | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | 0 | GP = | 0.000000 % | 0 |
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | | 0 | NA | | |
| 8 | Transmission | | 0 | TP | 0.000000 | 0 |
| 9 | Distribution | | 0 | NA | | |
| 10 | General & Intangible | | 0 | W/S | 0.000000 | 0 |
| 11 | Common | | 0 | CE | 0.000000 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 14 | Transmission | (line 2- line 8) | 0 | | | 0 |
| 15 | Distribution | (line 3 - line 9) | 0 | | | |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP = | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 21 | Account No. 283 (enter negative) | | 0 | NP | 0.0000 | 0 |
| 22 | Account No. 190 | | 0 | NP | 0.0000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | Account No. 255 (enter negative) | | 0 | NP | 0.000 00 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | (Note G) | 0 | TP | 0.000 00 | 0 |
| | WORKING CAPITAL | (Note H) | | | | |
| 26 | CWC | | 0 | | | 0 |
| 27 | Materials & Supplies | (Note G) | 0 | TE | 0.000 00 | 0 |
| 28 | Prepayments | | 0 | GP | 0.000 00 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | | 0 | | | 0 |

Formula Rate - Non-Levelized — Rate Formula Template — For the 12 months ended 12/31/20XX

Sumner Municipal Light Plant

| Line No. | (1) | (2) | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | O&M (Note X) | | | | | |
| 1 | Transmission | | 0 | TE | 0.000000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note | | 0 | | 1.000 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| | V) | | | 00 | |
| | | | | 0.0 | |
| | | | | 00 | |
| 2 | Less Account 565 | 0 | TE | 00 | 0 |
| | | | | 0.0 | |
| | | | | 00 | |
| 3 | A&G | 0 | W/S | 00 | 0 |
| | | | | 0.0 | |
| | | | | 00 | |
| 4 | Less FERC Annual Fees | 0 | W/S | 00 | 0 |
| | Less EPRI & Reg. | | | 0.0 | |
| | Comm. Exp. & Non-safety | | | 00 | |
| 5 | Ad(Note I) | 0 | W/S | 00 | 0 |
| | Plus Transmission | | | 0.0 | |
| 5 | Related Reg. Comm. Exp. | | | 00 | |
| a | (Note I) | 0 | TE | 00 | 0 |
| | | | | 0.0 | |
| | | | | 00 | |
| 6 | Common | 0 | CE | 00 | 0 |
| | | | | 1.0 | |
| | Transmission Lease | | | 00 | |
| 7 | Payments | 0 | NA | 00 | 0 |
| | TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, | | | | |
| 8 | 5) | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note W) | | | | |
| | | | | 0.0 | |
| | | | | 00 | |
| 9 | Transmission | 0 | TP | 00 | 0 |
| 1 | General & Intangible | 0 | W/S | 0.0 | 0 |

| | | | | | |
|---|---|---|---|---|---|
| 10 | | | | 0000 | |
| 11 | Common | 0 | CE | 0.0000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note J) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | 0 | W/S | 0.0000 | 0 |
| 14 | Highway and vehicle | 0 | W/S | 0.0000 | 0 |
| 15 | PLANT RELATED | | | | |
| 16 | Property | 0 | GP | 0.0000 | 0 |
| 17 | Gross Receipts | 0 | NA | zero | 0 |
| 18 | Other | 0 | GP | 0.0000 | 0 |
| 19 | Payments in lieu of taxes | 0 | GP | 0.0000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | INCOME TAXES | (Note K) | | NA | | |
| 21 | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | 0.00% | | | |
| 22 | CIT=(T/1-T) * (1-(WCLTD/R)) = | | 0.00% | | | |
| | where WCLTD=(page 4, line 22) and R= (page 4, line 24) and FIT, SIT & p are as given in footnote K. | | | | | |
| 23 | 1 / (1 - T) = (from line 21) | | 0.000 | | | |
| 24 | Amortized Investment Tax Credit (enter negative) | | 0 | | | |
| 25 | Income Tax Calculation = line 22 * line 28 | | 0 | NA | | 0 |
| 26 | ITC adjustment (line 23 * line 24) | | 0 | NP | 0.000 | 0 |
| 27 | Total Income Taxes | (line 25 plus line 26) | 0 | | | 0 |
| 28 | RETURN [ Rate Base (page 2, line | | 0 | NA | | 0 |

| | | | |
|---|---|---|---|
| | 30) * Rate of Return (page 4, line 24)] | | |
| 29 | REV. REQUIREMENT (sum lines 8, 12,20,27,28) | 0 | 0 |
| 30 | Total Gross Revenue Requirement | 0 | 0 |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

Sumner Municipal Light Plant

Line No.

**SUPPORTING CALCULATIONS AND NOTES**

| | | | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note M) | | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note N ) | | 0 |
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | T P = | 0.0000 0 |
| | TRANSMISSION EXPENSES | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note L) | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | 0 |
| 9 | Percentage of transmission expenses after adjustment | | 0.0000 0 |

| | | | | | |
|---|---|---|---|---|---|
| | (line 8 divided by line 6) | | | | |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | | | TP = | 0.0000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | | | TE = | 0.0000 |

WAGES & SALARY ALLOCATOR (W&S) (Note Z)

| | | $ | TP | Allocation | | | | |
|---|---|---|---|---|---|---|---|---|
| 12 | Production | 0 | 0.00 | 0 | | | | |
| 13 | Transmission | 0 | 0.00 | 0 | | | | |
| 14 | Distribution | 0 | 0.00 | 0 | W&S Allocator | | | |
| 15 | Other | 0 | 0.00 | 0 | ($ / Allocation) | | | Cell to solve for W/S by setting this to zero by changing J222 |
| 16 | Total (sum lines 12-15) | 0 | | 0 | 0.0000 = 0 | = | W/S | 0.00% |

COMMON PLANT ALLOCATOR (CE) (Note O)

| | | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | CE |
|---|---|---|---|---|---|---|---|---|
| 17 | Electric | | 0 | | | | | |
| 18 | Gas | | 0 | 0.000000 | * | 0.00000 | = | ##### |
| 19 | Water | | 0 | | | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | | | |

RETURN (R)

| | | | $ |
|---|---|---|---|
| 21 | Long Term Interest | Note U | $0 |

| | $ | % | Cost (Note | Weighted |
|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | P) | | |
| 22 | | | | 0.00 | | =WCLTD |
| 23 | Long Term Debt | 0 | 0% | % | 0.00% | |
| 24 | Proprietary Capital | 0 | 0% | 10.10 % | 0.00% | |
| 25 | Total (sum lines 22, 23) | 0 | 0% | | 0.00% | = R |
| 25 | | | | | 10.100 | |
| 25 | | | | | 0% | |
| 26 | | | | TIER = | 0.00 | |
| | REVENUE CREDITS | | | | | |
| | | | | | Load | |
| | ACCOUNT 447 (SALES FOR RESALE) | | | | | |
| 27 | a. Bundled Non-RQ Sales for Resale | | (Note Q) | | 0 | |
| 28 | b. Bundled Sales for Resale included in Divisor on page 1 | | | | 0 | |
| 29 | Total of (a)-(b) | | | | 0 | |
| | ACCOUNT 454 (RENT FROM ELECTRIC | | | | | |
| 30 | PROPERTY) (Note R) | | | | $0 | |

| | | |
|---|---|---|
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | |
| | a. Transmission charges | |
| 3 | for all transmission | |
| 1 | transactions | $0 |
| | b. Transmission charges for all | |
| 3 | transmission transactions included in | |
| 2 | Divisor on Page 1 | $0 |
| 3 | | |
| 3 | Total of (a)-(b) | $0 |

12/31/20XX

Sumner Municipal Light Plant

| Note Letter | |
|---|---|
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. |
| B | RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" |

| | |
|---|---|
| | for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any |
| F | The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated. |
| G | Transmission related only. |
| H | Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5. |
| | Prepayments are the electric related prepayments booked to Account No. 165. |

Line 5 - EPRI Annual Membership Dues, all Regulatory

I Commission Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

Includes only FICA, unemployment, highway, property, gross

J receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate,

K and p =

"the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit. multiplied by (1/1-T) (page 3, line 26).

| | | | |
|---|---|---|---|
| Inputs Required: | FIT = | 0.0 0% | |
| | | | (State Income Tax Rate or |
| | SIT= | 0.0 0% | Composite SIT) |

| | | | |
|---|---|---|---|
| | p = | 0.0<br>0% | (percent of federal income tax deductible for state purposes) |

| | |
|---|---|
| L | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA. |
| M | Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test). |
| N | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| O | Enter dollar amounts |
| P | Debt cost rate = long-term interest (line 21) / long term debt (line 22). The Proprietary Capital Cost rate is implicit, a residual calculation after TIER is determined. TIER will be supported in the filing and no change in TIER may be made absent a filing with the ISO and the FERC, if the entity is under FERC's jurisdiction. |
| Q | Line 29 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses |

are to be included in the divisor.

R Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

S Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1 and the loads are included in line 13, page 1. Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

T The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

U Include only the amount from Accounts 428, 429 and 430.

V Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

W Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation

amounts unless authorized by FERC.

X Schedule 12-FERC charges should not be included in O&M recovered under this formula rate

Z If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 4 line 16 equal to the gross plant allocator (GP) at page 2, line 6.

A Any NIMECA Member participating in an SPP
A project the total cost of which is $10,000,000 or more and which has regional cost sharing ("Project Costs"), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act ("FPA") Section 205 filing proposing that capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Sumner Municipal Light Plant** | | | | | | | | | | | | | | | |
| **For the Year ended 12/31/20XX** | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| **Attachment H divisor** | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| **Report the CP of your load in the Pricing Zone for Each Month in KWs** | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| Jan | - | | | | | | | | | | | | | | |
| Feb | - | | | | | | | | | | | | | | |
| Mar | - | | | | | | | | | | | | | | |
| Apr | - | | | | | | | | | | | | | | |
| May | - | | | | | | | | | | | | | | |
| Jun | - | | | | | | | | | | | | | | |
| Jul | - | | | | | | | | | | | | | | |
| Aug | - | | | | | | | | | | | | | | |
| Sep | - | | | | | | | | | | | | | | |
| Oct | - | | | | | | | | | | | | | | |
| Nov | - | | | | | | | | | | | | | | |
| Dec | - | | | | | | | | | | | | | | |
| Sub total | - | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| Average | - | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | |
| Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA: | | | | | | | | | | | | | | | |
| the GFA #, the GFA load, and the GFA transmission revenues. | **No GFA.** | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Jan** | **Feb** | **Mar** | **Apr** | **May** | **June** | **Jul** | **Aug** | **Sep** | **Oct** | **Nov** | **Dec** | **Total** | **Average** |
| | | | | | | | | | | | | | | |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| | | | | | | | | | | | | | | |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Sumner Municipal Light Plant** | | | | | | |
| **For the Year ended 12/31/20XX** | | | | | | |
| | | | | | | |
| **Plant Summary** | | | | | | |
| | | | | | | |
| | | | **Accumulated** | **Net** | **Depreciation** | |
| | **Gross Plant** | | **Depreciation** | **Plant** | **Expense** | |
| **Production Plant** | | | | | | |
| | | | | | | |
| **Steam Production Plant** | $ - | | $ - | $ - | $ - | |
| 310 – Land and Land Rights | $ - | | $ - | $ - | $ - | |
| 311 – Structures and Improvements | $ - | | $ - | $ - | $ - | |
| 312 – Boiler | $ - | | $ - | $ - | $ - | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant Equipment | | | | | | | | | | | | | | | | | | | | | | | | | |
| 313 – Engines and Engine-Driven Generators | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 314 – Turbogenerator Units | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 315 – Accessory Electric Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 316 – Misc. Power Plant Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| Total Steam Production Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Nuclear Production Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
| 320 – | $ | | | $ | $ | $ | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Land and Land Rights | - | | | - | - | - | | | | | | | | | | | | | | | | | | | |
| 321 – Structures and Improvements | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 322 – Reactor Plant Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 323 – Turbogenerator Units | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 324 – Accessory Electric Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 325 – Misc. Power Plant Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 326 – Asset Retirement Costs for Nuclear | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Production | | | | | | | | | | | | | | | | | | | | | | | | | |
| Total Nuclear Production Plant | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Hydraulic Production Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
| 330 – Land and Land Rights | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 331 – Structures and Improvements | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 332 – Reservoirs, Dams, and Waterways | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 333 – Water Wheels, Turbines, and Generators | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 334 - | $ | | | $ | $ | $ | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Accessory Electric Equipment | - | | | - | - | - | | | | | | | | | | | | | | | | | | | |
| 335 – Misc. Power Plant Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 336 – Roads, Railroads, and Bridges | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| Total Hydraulic Production Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Other Production Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
| 340 – | $ | | | $ | $ | $ | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Land and Land Rights | - | | | - | - | - | | | | | | | | | | | | | | | | | | | |
| 341 – Structures and Improvements | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 342 – Fuel Holders, Products, and Accessories | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 343 – Prime Movers | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 344 – Generators | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 345 – Accessory Electric Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 346 – Misc. Power Plant Equipment (WS4 assets) | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 347 – | $ | | | $ | $ | $ | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Asset Retirement Costs for Nuclear Production | - | | | - | - | - | | | | | | | | | | | | | | | | | | | |
| Total Other Production Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total Production Plant** | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| | **Total City-owned Transmiission** | | | | | | | **Combined Transmiission System** | | | | | **Neal 3 and Lehigh Webster** | | | | | **WS4 161 and 345 kV** | | | | | **Other Trasmission** | | | |
| | | | | | | | | | **Accumulated** | **Net** | **Depreciation** | | | **Accumulated** | **Net** | **Depreciation** | | | **Accumulated** | **Net** | **Depreciation** | | | **Accumulated** | **Net** | **Depreciation** |
| | | | | | | | | **Gross Plant** | **Depreciation** | **Plant** | **Expense** | | **Gross Plant** | **Depreciation** | **Plant** | **Expense** | | **Gross Plant** | **Depreciation** | **Plant** | **Expense** | | **Gross Plant** | **Depreciation** | **Plant** | **Expense** |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 357 – Underground | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Conduit | | | | | | | | | | | | | | | | | | | | | | | | | |
| 358 – Underground Conductors and Devices | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 359 – Roads and Trails | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total Transmission Plant** | $ - | | | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - | | $ - | $ - | $ - | $ - |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | | | | | | |
| 360 – Land and Land Rights | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 361 – | $ | | | $ | $ | $ | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Structures and Improvements | - | | | - | - | - | | | | | | | | | | | | | | | | | | | |
| 362 – Station Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 363 – Storage Battery Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 364 – Poles, Towers, and Fixtures | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 365 – Overhead Conductors and Devices | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 366 – Underground Conduit | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 367 – Underground Conductors and Devices | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 368 – Line Transformers | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 369 – Services | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 370 – Meters | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 371 – Installations on Customer Premises | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 372 – Leased Property on Customers Premises | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 373 – Street lighting and Signal Systems | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Total Distribution Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Intangible Plant** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 301 Organization | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |
| 302 Franchises and Consents | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |
| 303 Miscellaneous Intangible Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Total Intangible Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | | |
| **General Plant** | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 389 – Land and Land Rights | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 390 – Structures and Improvements | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 391 – Office Furniture and Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 392 – Transportation Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 393 – Stores Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 394 – Tools, Shop and Garage Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 395 – Laboratory Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 396 – Power Operate | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| d Equipment | | | | | | | | | | | | | | | | | | | | | | | | | |
| 397 – Communication Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 398 – Miscellaneous Equipment | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 399 – Other Tangible Property | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| 399.1 – Asset Retirement Costs for General Plant | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Total General Plant** | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Grand Total Plant In-** | $ - | | | $ - | $ - | $ - | | | | | | | | | | | | | | | | | | | |

| **Service** | | | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | | | | | | | | | | | | | | | | |
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| | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Please answer the following questions:** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Does the Grand total Gross Plant In-Service tie to the Gross Plant In-Service reflected on the audited balance sheet? | | | | | | | | | | | | | | | | | | | | | | | | | |
| Does Total Accum Depre tie to Accum Depre reflected on the audited balance sheet? | | | | | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| Does the Total Depreciation expense tie to the depreciation expense reflected in the audited income statement? If no, please provide an explanation & reconciliation. | | | | | | | | | | | | | | | | | | | | | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |
| | | **Sumner Municipal Light Plant** | | | |
| | | **Depreciation Rates** | | | |
| | | | | | |
| | | | | | |
| | | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| | | 350 | Land and Land Rights* | N/A | 0.00% |
| | | 351 | Energy Storage Equipment - Transmission | 40 | 2.50% |
| | | 352 | Structures & Improvements | 45 | 2.22% |
| | | 353 | Station Equipment | 45 | 2.22% |
| | | 354 | Towers & Fixtures | 45 | 2.22% |
| | | 355 | Poles & Fixtures | 58 | 1.72% |
| | | 356 | Overhead Conductors and Devices | 53 | 1.89% |
| | | | **General Plant** | | |
| | | 390 | Structures & Improvements | 40 | 2.50% |
| | | 392 | Transportation Equipment | 10 | 10.00% |
| | | | | | |
| | | *** Land is not depreciable.** | | | |
| | | **Note: These depreciation rates will not be changed absent a FERC order.** | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Sumner Municipal Light Plant | | | | | | | | | | |
| For the Year ended 12/31/20XX | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | Land Held For Future Use | | | | | | | | | |
| | | | | | | | | | | |
| Production | $ - | | | | | | | | | |
| Transmission | - | | | | | | | | | |
| Distribution | - | | | | | | | | | |
| Other | - | | | | | | | | | |
| | $ - | | Should tie to a financial statement line item - if not please | | | | | | | |
| | | | indicate what line of the audited financials reflects Land Held For Future Use | | | | | | | |
| | | | and indicate what other items are included in that financial statement line item | | | | | | | |
| | | | by providing a brief but descriptive explanation | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Below -** Provide a brief but descriptive list of the Transmission land held for future use | | | | | | | | | | |
| and the amounts related to each item of Transmission land held for future use | | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Sumner Municipal Light Plant | | | | | | | | | | |
| For the Year ended 12/31/20XX | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | Materials and Supplies | | | | | | | | | |
| | | | | | | | | | | |
| Production | $ - | | | | | | | | | |
| Transmission | - | | | | | | | | | |
| Distribution | - | | | | | | | | | |
| Other | - | | | | | | | | | |
| | $ - | | Should tie to a financial statement line item - if not please | | | | | | | |
| | | | indicate what line of the audited financials reflectes M&S | | | | | | | |
| | | | and indicate what other items are included in that financial statement line item | | | | | | | |
| | | | by providing a brief but descriptive explanation | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies | | | | | | | | | | |
| and the amounts related to each item of Transmission related Materials and Supplies | | | | | | | | | | |
| | | | | | | | | | | |
| **Transmission Materials & Supplies** | | | | | | | | | | |
| | | | | | | | | | | |
| **Material Group** | **Amount** | | | | | | | | | |
| Insulators | $ - | | | | | | | | | |
| Relays | $ - | | | | | | | | | |
| Substation Misc Part | $ - | | | | | | | | | |
| Transmission wires | $ - | | | | | | | | | |
| Trans. Line Hardware | $ - | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Transducers | $ - | | | | | | | | | |
| | $ - | | | | | | | | | |
| **Total** | **$ -** | | | | | | | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Sumner Municipal Light Plant | | | | | | | | | | |
| For the Year ended 12/31/20XX | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| | | | | | | | | | | |
| **Pre Payment Description** | **Amount** | | | | | | | | | |
| | | | | | | | | | | |
| Prepaid Insurance | $ - | | | | | | | | | |
| XXXXX | - | | | | | | | | | |
| XXXXX | - | | | | | | | | | |
| XXXXX | - | | | | | | | | | |
| Total Pre Payments | $ - | | | | | | | | | |
| | | | Should tie to a financial statement line item - if not please | | | | | | | |
| | | | indicate what line of the audited financials reflectes Pre Payments | | | | | | | |
| | | | and indicate what other items are included in that financial statement line item | | | | | | | |
| | | | by providing a brief but descriptive explanation | | | | | | | |

| **Sumner Municipal Light Plant** | | |
|---|---|---|
| **For the Year ended 12/31/20XX** | | |
| | | |
| **Transmission O&M Expenses** | | **Amount** |
| Operation | | |
| 560 – Operation Supervision and Engineering | | - |
| 561 – Load Dispatching | | - |
| 561.1 – Load Dispatch – Reliability | | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | | - |
| 561.4 – Scheduling, System Control and Dispatch Services | | - |
| 561.5 – Reliability, Planning and Standards Development | | - |
| 561.6 – Transmission Service Studies | | - |
| 561.7 – Generation Interconnection Studies | | - |
| 561.8 – Reliability, Planning and Standards Development Service | | - |
| 562 – Station Expenses | | - |
| 563 – Overhead Lines Expenses | | - |
| 564 – Underground Lines Expenses | | - |
| 565 – Transmission of Electricity by Others | | - |
| 566 – Miscellaneous Transmission Expenses | | - |
| 567 – Rents | | - |
| Total Operations | | - |
| Maintenance | | |
| 568 – Maintenance Supervision and Engineering | | - |
| 569 – Maintenance of Structures | | - |
| 569.1 – Maintenance of Computer Hardware | | - |
| 569.2 – Maintenance of Computer Software | | - |
| 569.3 – Maintenance of Communication Equipment | | - |

| | | | |
|---|---|---|---|
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | | - | |
| 570 – Maintenance of Station Equipment | | - | |
| 571 – Maintenance of Overhead Lines | | - | |
| 572 – Maintenance of Underground Lines | | - | |
| 573 – Maintenance of Miscellaneous Transmission Plant | | - | |
| Total Maintenance | | - | |
| Total Transmission O&M Expense | | - | |
| | | | |
| | | | |
| **Please provide the following information:** | | | |
| What line of the audited financial statements includes the Transmission O&M Expense? | | | |

| | | | | |
|---|---|---|---|---|
| **Sumner Municipal Light Plant** | | | | |
| **For the Year ended 12/31/20XX** | | | | |
| | | | | |
| | | | | |
| **Customer Accts & Admin and General Expenses** | | **Amount** | | |
| | | | | |
| **Customer Accounts Expenses** | | | | |
| 901 – Supervision | | - | | |
| 902 – Meter Reading Expenses | | - | | |
| 903 – Customer Records and Collection Expenses | | - | | |
| 904 – Uncollectible Accounts | | - | | |
| 905 – Miscellaneous Customer Accounts Expenses | | - | | |
| **Total Customer Accounts Expense** | | - | | |
| | | | | |
| **Customer Service and Informational Expenses** | | | | |
| 907 – Supervision | | - | | |
| 908 – Customer Assistance Expenses | | - | | |
| 909 – Informational and Instructional Expenses | | - | | |
| 910 – Miscellaneous Customer Service and Informational Expenses | | - | | |
| **Total Customer Service and Informational Expenses** | | - | | |
| | | | | |
| **Sales Expenses** | | | | |
| 911 – Supervision | | - | | |
| 912 – Demonstrating and Selling Expenses | | - | | |
| 913 – Advertising Expenses | | - | | |

| | | | | |
|---|---|---|---|---|
| 916 – Miscellaneous Sales Expenses | | - | | |
| **Sales Expenses** | | - | | |
| | | | | |
| **Administrative and General Expenses** | | | | |
| 920 – Administrative and General Salaries | | - | | |
| 921 – Office Supplies and Expenses | | - | | |
| 922 – Administrative Expenses Transferred Credit | | - | | |
| 923 – Outside Services Employed | | - | | |
| 924 – Property Insurance | | - | | |
| 925 – Injuries and Damages | | - | | |
| 926 – Employee Pension and Benefits | | - | | |
| 927 – Franchise Requirements | | - | | |
| 928 – Regulatory Commission Expenses | | - | | |
| 929 – Duplicate Charges Credit | | - | | |
| 930.1 – General Advertising Expenses | | - | | |
| 930.2 – Miscellaneous General Expenses | | - | | |
| 931 – Rents | | - | | |
| Total Operations A&G | | - | | |
| 935 – Maintenance of General Plant | | - | | |
| Total Maintenance A&G | | - | | |
| **Total Administrative and General Expenses** | | - | | |
| | | | | |
| | | | | |
| | | | | |
| **Please provide the following information:** | | | | |
| What line of the audited financial statements includes the A&G Expense? | | | | |
| | | | | |
| | | | | |

| | |
|---|---|
| What line of the audited financial statements includes the Customer Account, Customer Service, and Sales Expense? | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Sumner Municipal Light Plant | | | | | | |
| For the Year ended 12/31/20XX | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | **Account** | | | | | |
| **FERC fees recorded to expense during the year** | **Charged** | **Amount** | | | | |
| | | | | | | |
| FERC fees payable to FERC | - | $ - | | | | |
| FERC fees paid to an RTO | - | - | | | | |
| Other FERC fees paid | - | - | | | | |
| | | | | | | |
| Total | | $ - | | | | |

| | | |
|---|---|---|
| Sumner Municipal Light Plant | | |
| For the Year ended 12/31/20XX | | |
| | | |
| **Taxes Other Than Income Taxes** | | |
| | | |
| Payroll | $ - | |
| Highway & Vehicle | - | |
| Property | - | |
| Gross | - | |
| Other - please explain | - | |
| Payments in lieu of taxes | - | |
| Fed & State income Tax | - | |
| Total | $ - | Should tie to a line item on the audited financial statements - provide explanation and reconciliation if it doesn't. Also indicate what line of the audited financials includes the above amounts. |
| | | |
| | | |
| Please provide brief description of any payments in lieu of taxes or transfers from the utility to the city. | | |

| | | |
|---|---|---|
| Sumner Municipal Light Plant | | |
| For the Year ended 12/31/20XX | | |
| | | |
| | | |
| | | |
| | | |
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |
| | | |
| | | |
| | | |
| | | |
| Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related** | | |
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |
| | | |
| | | |
| Non Safety Advertising (provide a brief but descriptive list of charges) | | |
| Admin & General Advertising | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| Xxxxxxxx | | |
| | - | |
| | | |
| | | |
| **If a zero is reported for any category above, please provide a brief explanation as to why.** | | |

Sumner Municipal Light Plant
For the Year ended 12/31/20XX

## Debt Detail - Electric only

| | Principal Balance at For the Year ended 12/31/20XX | Interest Expense |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ | $ |

| | | |
|---|---|---|
| | - | - |
| | - | - |
| | - | - |
| | $ - | $ - |
| Total | - | - |

| | | |
|---|---|---|
| | $ - | $ - |
| | - | - |
| | - | - |
| | $ - | $ - |
| Total | - | - |

| | | |
|---|---|---|
| | $ - | $ - |
| | - | - |
| | - | - |
| | $ - | $ - |
| Total | - | - |

| | | |
|---|---|---|
| Principal & Interest Grand Total | $ - | $ - |

Total Principal and Total Interest should tie to lines on the audited financial statements. If they don't, provide an explanation and a work paper reconciling the debt principal and interest to the appropriate lines of the audited financial statements.

| | | | |
|---|---|---|---|
| Sumner Municipal Light Plant | | | |
| **For the Year ended 12/31/20XX** | | | |
| | | | |
| | | | |
| **Account 454 (Rent from Electric Property)** | | | |
| | | | |
| | | | |
| **Property Description** | **Amount** | | |
| | | | |
| XXXXX | $ - | | |
| XXXXX | - | | |
| XXXXX | - | | |
| XXXXX | - | | |
| Total Rent Income | $ - | | Includes income related only to transmission facilities, |
| | | | such as pole attachments, rentals and special use. |
| | | | Should tie to a financial statement line item - if not please |
| | | | indicate what line of the audited financials reflectes Pre Payments |
| | | | and indicate what other items are included in that financial statement line item |
| | | | by providing a brief but descriptive explanation |

| Sumner Municipal Light Plant | | |
|---|---|---|
| **For the Year ended 12/31/20XX** | | |
| | | |
| | | |
| **Account 456.1 (Other Electric Revenues)** | **Account 456.1** | |
| | | **Revenue** |
| | | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| xxxxx | $ - | |
| Total Revenue | $ - | |
| | | |
| | | |

**ADDENDUM 27 TO ATTACHMENT H**

**NorthWestern Corporation (South Dakota)**

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(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)


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**Formula Rate Template Inputs**

**(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)**

**Data Entered Directly From FERC Form No. 1 ("FF1"):**

| Line No | Account/Description/Classification | Inputs From 20XX FERC Form 1 | FF1 Page Location | Template Sheet of the Link |
|---|---|---|---|---|
| 1 | Prepayments (165) End of Year | | 110.57c footnote | ATT 5 - Cost Support, Ln. 37 |
| 1a | Prepayments (165 Beginning of Year) | | 110.57d footnote | ATT 5 –Cost Support, Ln. 37 |
| 2 | Preferred Stock Issued (204) - End of Year | | 112.3c | ATT 8 - Pref Stock, Ln. 2, Col. A |
| 3 | Preferred Stock Issued (204) - Beg of Year | | 112.3d | ATT 8 - Pref Stock, Ln. 1, Col. A |
| 4 | Unappropriated Undistrib Subsid Earnings (216.1) - End of Yr | | 112.12c | ATT 7 - Com Stock, Ln. 2, Col. G |
| 5 | Unappropriated Undistrib Subsid Earnings (216.1) - Beg of Yr | | 112.12d | ATT 7 - Com Stock, Ln. 1, Col. G |
| 6 | Accum Other Comp Income (219) - End of Year | | 112.15c | ATT 7 - Com Stock, Ln. 2, Col. F |
| 7 | Accum Other Comp Income (219) - Beginning of Year | | 112.15d | ATT 7 - Com Stock, Ln. 1, Col. F |
| 8 | Total Proprietary Capital - End of Year (Total Company) | | 112.16c | ATT 7 - Com Stock, Ln. 2, Col. A |
| 9 | Total Proprietary Capital - Beginning of Year (Total Company) | | 112.16d | ATT 7 - Com Stock, Ln. 1, Col. A |
| 10 | Bonds (221) - End of Year (Total Company) | | 112.18c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. B |
| 11 | Bonds (221) - Beginning of Year (Total Company) | | 112.18d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. B |
| 12 | (Less) Reacquired Bonds (222) - End of Year | | 112.19c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. C |
| 13 | (Less) Reacquired Bonds (222) - Beginning of Year | | 112.19d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. C |
| 14 | Advances from Assoc Companies (223) - End of Year | | 112.20c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. A |
| 15 | Advances from Assoc Companies (223) - Beginning of Year | | 112.20d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. A |
| 16 | Other Long Term Debt (224) - End of Year | | 112.21c | ATT 9 - LTD, Pg. 1, Ln. 2, Col. D |
| 17 | Other Long Term Debt (224) - Beginning of Year | | 112.21d | ATT 9 - LTD, Pg. 1, Ln. 1, Col. D |
| 18 | Unamortized Premium on Long Term Debt - End of Year | | 112.22c | ATT 9 - LTD, Pg. 1, Ln. 5 |
| 19 | Unamortized Premium on Long Term Debt - Beginning of Year | | 112.22d | ATT 9 - LTD, Pg. 1, Ln. 4 |
| 20 | (Less) Unamortized Disc. on Long-Term Debt (Debit) - End of Yr | | 112.23c | ATT 9 - LTD, Pg. 1, Ln. 8 |
| 21 | (Less) Unamortized Disc. on Long-Term | | 112.23d | ATT 9 - LTD, Pg. 1, |

| | | | | |
|---|---|---|---|---|
| | Debt (Debit) - Beg of Yr | | | Ln. 7 |
| 22 | Accumulated Provision for Injuries and Damages (228.2) | | 112.28c | ATT 4 - Non-Escrowed Funds, Ln. 4 |
| 23 | Elec - Taxes Other than Income Taxes (408.1) | | 115.14g | ATT 2 - Other Taxes, Ln. 22 |
| 24 | Interest on LTD (427) | | 117.62c | ATT 9 - LTD, Pg. 2, Ln. 1 |
| 25 | Amort of Debt Disc & Expenses (428) | | 117.63c | ATT 9 - LTD, Pg. 2, Ln. 2 |
| 26 | Amort of Loss on Reacquired Debt (428.1) | | 117.64c | ATT 9 - LTD, Pg. 2, Ln. 3 |
| 27 | (less) Amort of Premium on Debt-Credit (429) | | 117.65c | ATT 9 - LTD, Pg. 2, Ln. 4 |
| 28 | (less) Amort of Gain on Reacquired Debt-Credit (429.1) | | 117.66c | ATT 9 - LTD, Pg. 2, Ln. 5 |
| 29 | Total Dividends Declared Pref Stock (437) | | 118.29c | ATT 8 - Preferred Stock, Ln. 4, Col. F |
| 30 | Electric - Amortization of Other Utility Plant | | 200.21c | Appendix A - Ln. 8 |
| 31 | Total Intangible Plant | | 205.5g | Appendix A - Ln. 22 |
| 32 | Total Electric Plant in Service | | 207.104g | Appendix A - Ln. 6 |
| 33 | Trn - Total Transmission Plant | | 207.58g | ATT 5 - Cost Support, Ln. 1a |
| 34 | Transmission Materials & Supplies End of Year | | 227.8.c footnote | Appendix A - Ln. 41 |
| 34 a | Transmission Materials & Supplies Beginning of Year | | 227.8.c footnote | ATT 5 Cost Support, Ln. 41 |
| 35 | Stores Expense Undistributed (Account 163) | | 227.16.c | Appendix A - Ln. 38 |
| 36 | Total (Acct 190) | | 234.18c | ATT 1 - ADIT, Pg. 1, Ln. 9 |
| 37 | Total (Acct 281) | | 273.17k | Line not used |
| 38 | Total (Acct 282) | | 275.9k | ATT 1 - ADIT, Pg. 1, Ln. 18 |
| 39 | Total (Acct 283) | | 277.19k | ATT 1 - ADIT, Pg. 1, Ln. 28 |
| 40 | Interest on Debt to Assoc. Companies | | 117.67c | ATT-9 - LTD, Pg. 2, Ln. 5a |
| 41 | Gen - Total General Plant | | 207.99g | Appendix A - Ln. 21 |
| 42 | Transmission Accum. Depreciation | | 219.25c | Line not used |
| 43 | General Accum. Depreciation | | 219.28c | Appendix A - Ln. 29 |
| 44 | Total Accum Depr Utility Plant | | 219.29.c | Appendix A - Ln. 7 |
| 45 | Amortized Investment Tax Credit | | 266.8f | ATT 5 - Cost Support, Ln. 103 |
| 46 | Trn Oper Transmission of Elec by Others | | 321.96b | ATT 5 - Cost Support, Ln. 50 |
| 47 | Total Transmission Expenses | | 321.112b | ATT 5 - Cost Support, Ln. 49 |
| 48 | A&G Oper Regulatory Commission Expenses | | 323.189b | Appendix A - Ln. 58 & ATT - 5, Ln. 63 |

| | | | | |
|---|---|---|---|---|
| 49 | A&G Oper General Advertising Expenses | | 323.191b | Appendix A - Ln. 59 |
| 50 | Total Admin & General Expenses | | 323.197b | Appendix A - Ln. 54 |
| 51 | Depreciation Exp (403) - Intangible Plant | | 336.1b | Appendix A - Ln.69 |
| 52 | Depr Exp Asset Retire (403.1) - Intangible Plant | | 336.1c | Appendix A - Ln. 69 |
| 53 | Amort Lim Term (404) - Intangible Plant | | 336.1d | Appendix A - Ln. 69 |
| 54 | Amort of Other Intangible Electric Plant (405) | | 336.1e | Appendix A - Ln. 69 |
| 55 | Depreciation Exp (403) - Transmission Plant | | 336.7b | Line not used |
| 56 | Depr Exp Asset Retire (403.1) - Transmission Plant | | 336.7c | Not used |
| 57 | Amort Lim Term (404) - Transmission Plant | | 336.7d | Not used |
| 58 | Depreciation Exp (403) - General Plant | | 336.10b | Appendix A - Ln. 68 |
| 59 | Depr Exp Asset Retire (403.1) - General Plant | | 336.10c | Appendix A - Ln. 68 |
| 60 | Amort Lim Term (404)- General Plant | | 336.10d | Appendix A - Ln. 68 |
| 61 | Tot Elec O & M Transmission Direct Payroll | | 354.21b | Appendix A - Ln. 1 |
| 62 | Tot Elec O & M Admin & General Direct Payroll | | 354.27b | Appendix A - Ln. 3 |
| 63 | Total Elec O & M Direct Payroll | | 354.28b | Appendix A - Ln. 2 |
| 64 | Transmission Towers and Fixtures | | 206.51.b | Appendix A - Ln. 16 |
| 65 | Transmission Poles And Fixtures | | 206.52.b | Appendix A - Ln. 16 |
| 66 | Distribution Poles, Towers, and Fixtures | | 206.64.b | Appendix A - Ln. 15 |
| 67 | Rent from Electric Property | | 300.19.b | ATT 3 - Revenue Credits, Ln. 1 |
| 68 | SD Property Taxes | | 263.23i | ATT 2 - Other Taxes, Ln. 1 |
| 69 | ND Property Taxes | | 263.37i | ATT 2 - Other Taxes, Ln. 1 |
| 70 | IA Property Taxes | | 263.1.12i | ATT 2 - Other Taxes, Ln. 1 |
| 71 | Coal Conversion | | 263.1.18i | ATT 2 - Other Taxes, Ln. 16 |
| 72 | Gross Revenue | | 263.1.24i | ATT 2 - Other Taxes, Ln. 17 |
| 73 | Delaware Franchise | | 263.1.31i | ATT 2 - Other Taxes, Ln. 15 |
| 74 | Vehicle Tax | | 263.5i | ATT 2 - Other Taxes, Ln. 3 |
| 75 | Payroll Tax - FICA | | 263.7i | ATT 2 - Other Taxes, Ln. 8 |
| 76 | Payroll Tax - Medicare | | 263.14i | ATT 2 - Other Taxes, Ln. 8 |
| 77 | Payroll Tax - FUT | | 263.25i | ATT 2 - Other Taxes, Ln. 9 |
| 78 | Payroll Tax - FUT-SD | | 263.32i | ATT 2 - Other Taxes, |

| | | | | |
|---|---|---|---|---|
| | | | | Ln. 10 |

Inputs



**Formula Rate Template Inputs**

**(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)**

**Data Input from Company Records and/or Verification Required (Manual Input)**

| Line No | Account/Description/Classification | Inputs From End of Year | Source of Data | Template Sheet of the Link |
|---|---|---|---|---|
| 1 | Federal Income Tax Rate | | From Tax Department | Appendix A - Ln. 98 |
| 2 | State Income Tax Rate | | From Tax Department | Appendix A - Ln. 99 |
| 3 | Percent of Federal Tax Eligible for Deduction by South Dakota | | From Tax Department | Appendix A - Ln. 100 |
| 4 | State Income Tax Rate | | From Tax Department | Line not used |
| 5 | State Income Tax Rate | | From Tax Department | Line not used |
| 6 | State Income Tax Rate | | From Tax Department | Line not used |
| 7 | Specific FERC 909 Ad costs | | Company Records | ATT 5 - Cost Support, Ln. 64 |
| 8 | EPRI Annual Membership Dues | | Company Records | Line not used |
| 9 | Plant Held for Future Use (Account 105) - Total | | FF1, 214.47.d | Appendix A - Ln. 26 |
| 10 | Plant Held for Future Use (Account 105) - Non-Transmission | | FF1, 214.47.d | Appendix A - Ln. 26 |
| 11 | Transmission Related Regulatory Expenses | | FF1, 350.41-44.d | ATT - 5, Ln. 63 |
| 12 | Plant Held for Future Use (Non-Land) - Transmission Only | | Company Records | Appendix A - Ln. 26 |
| 13 | Transmission Gross Plant under SPP tariff | | Company Records from Mgr of Property Acctg From ATT 11, Col f L33 | Appendix A - Ln. 20 |
| 14 | Transmission Accumulated Depreciation on assets under SPP tariff | | Company Records from Mgr of Property Acctg From ATT 11, Col | Appendix A - Ln. 28 |

| | | | | |
|---|---|---|---|---|
| | | | g L33 | |
| 15 | Revenues from Directly Assigned Transmission Facilities (ATT 3, Note 2) | | ATT 5 - Cost Support, Ln. 117 | |
| 16 | Charges billed to Transmission Owner for system integration and transmission costs paid to others that benefit transmission customers and are recorded in Account 565. | | Verify amount annually | |
| 17 | Other Electric Revenues – Transmission for Others (Schedule 11) | | 330.18 Row 7 Col. n (Acct 456.1). To: ATT-12 | |
| 18 | Other Electric Revenues - Transmission for Others (Schedules 7 & 8) | | 330.18 Row 5 Col. n From (Acct 456.1). To: ATT-3, Line 4. Also see ATT 3, Notes 1 & 4 | |
| 19 | Net revenues associated with Transmission Service Requests, Sponsored Upgrades, and Generation Interconnections for which the load is not included in the divisor. | | Need to verify during each annual update if there are any such TSR revenues (including TSR revenue from SPP customers not in zone) for load that is NOT included in the UMZ divisor. | |
| 20 | Pre-OATT grandfathered Non-Firm Point to Point Service bundled demand revenues for which the load is not included in the divisor received by Transmission Owner and for which the revenues are divided between production and transmission functions. | | This represents "Point-To-Point" demand revenue margins derived from any "grandfathered" agreements. The non-RQ "Demand Revenues" found in FF1, Pg. 311, Col. h (and page 311 extensions) for these customers should be reduced by the sum of the Demand Charges (costs) found in FF1, Pg. 327, col. j (and page 327 extensions) for these customers. | |
| 21 | Annual Depreciation Expense for Transmission Assets under SPP tariff | | Company Records from Mgr of Property Acctg From ATT 11, Col i L33 | Appendix A - Ln. 67 |
| 22 | Transmission Pole/Structure Investment (Accts 354+355) under SPP tariff | | Company Records from Mgr of Property Acctg From ATT 11, Col f L40 | Appendix A - Ln. 17 |
| 23 | Unamortized Debt Expense (Acct 181) - Beginning of Year | | 111.69d | ATT-9 - LTD, Pg. 1, Ln. 10 |
| 24 | Unamortized Debt Expense (Acct 181) - End of Year | | 111.69c | ATT-9 - LTD, Pg. 1, Ln. 11 |
| 25 | Unamortized Loss on Reacquired Debt - Beginning of Year (Acct 189) | | 111.81d | ATT-9 - LTD, Pg. 1, Ln. 13 |
| 26 | Unamortized Loss on Reacquired Debt - End of Year (Acct 189) | | 111.81c | ATT-9 - LTD, Pg. 1, Ln. 14 |
| 27 | Unamortized Gain on Reacquired Debt - Beginning of Yr (Acct 257) | | 113.61d | ATT-9 - LTD, Pg. 1, Ln. 16 |

| | | | | |
|---|---|---|---|---|
| 28 | Unamortized Gain on Reacquired Debt - End of Yr (Acct 257) | | 113.61c | ATT-9 - LTD, Pg. 1, Ln. 17 |

**The Worksheets listed below require Input of Data directly into the Worksheets themselves:**

| Line | Sheet | Description/Source |
|---|---|---|
| 29 | ATT 1 - ADIT | Accumulated Def Inc Taxes - Verify with Tax Department. |
| 30 | ATT 5 - Cost Support | From company records |
| | | |

**APPENDIX A**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| | | | Notes | FF1 Page # or Instruction | |
|---|---|---|---|---|---|
| **Shaded cells are input cells** | | | | | |
| **Allocators** | | | | | |
| | **Wages & Salary Allocation Factor** | | | | |
| 1 | Transmission Wages Expense | | | p354.21.b [From Inputs, Pg. 1, Ln. 61] | - |
| 1a | Transmission under SPP Tariff Factor | | | [From ATT-5, Ln. 1a] | #DIV/0! |
| 2 | Total Wages Expense | | | p354.28.b [From Inputs, Pg. 1, Ln. 63] | 0 |
| 3 | Less A&G Wages Expense | | | p354.27.b [From Inputs, Pg. 1, Ln. 62] | 0 |
| 4 | Total Wages Less A&G Wages Expense | | | (Line 2 - Line 3) | 0 |
| 5 | **Wages & Salary Allocator** | | | (Line 1 * Line 1a) / Line 4 | **#DIV/0!** |
| | **Plant Allocation Factors** | | | | |
| 6 | Electric Plant in Service | | | p207.104.g [From Inputs, Pg. 1, Ln. 32] | 0 |
| 7 | Accumulated Depreciation (Total Electric Plant) | | | p219.29.c [From Inputs, Pg. 1, Ln. 44] | 0 |
| 8 | Accumulated Intangible Amortization (Other Utility Plant) | | (Note A) | p200.21.c [From Inputs, Pg. 1, Ln. 30] | 0 |
| 9 | Total Accumulated Depreciation | | | (Line 7 + 8) | 0 |
| 10 | Net Plant | | | (Line 6 - Line 9) | 0 |
| 11 | Transmission Gross Plant under SPP tariff (excluding Land Held for Future Use) | | | (Line 27 - Line 26) | #DIV/0! |
| 12 | **Gross Plant Allocator** | | | (Line 11 / Line 6) | **#DIV/0!** |
| 13 | Transmission Net Plant under SPP tariff (excluding Land Held for Future Use) | | | (Line 35 - Line 26) | #DIV/0! |
| 1 | **Net Plant Allocator** | | | (Line 13 / Line 10) | **#DIV/** |

| | | | | |
|---|---|---|---|---|
| 4 | | | | **0!** |

**T/D Pole Allocation Factor**

| | | | | |
|---|---|---|---|---|
| 15 | Gross Distribution Pole/Structure Investment (Acct 364) | | p206.64.b [From Inputs, Pg. 1, Ln. 66] | - |
| 16 | Gross Transmission Pole/Structure Investment (Accts 354 + 355) | | p206.51.b + p206.52.b [From Inputs, Pg. 1, Lns. 64 & 65] | - |
| 17 | Transmission Pole/Structure Investment (Accts 354 + 355) under SPP tariff | | From Inputs, Pg. 2, Line 22 | - |
| 18 | Total Pole/Tower Gross Plant | | (Line 15 + Line 16) | - |
| 19 | **T/D Revenue Allocation Factor (For Pole Attachment Revenue)** | | (Line 17 / Line 18) | **#DIV/0!** |

## Plant Calculations

**Plant In Service**

| | | | | |
|---|---|---|---|---|
| 20 | **Transmission Plant In Service under SPP tariff** | | [From Inputs, Pg. 2, Ln. 13] | **0** |
| 21 | General | | p207.99.g [From Inputs, Pg. 1, Ln. 41] | 0 |
| 22 | Intangible | | p205.5.g [From Inputs, Pg. 1, Ln. 31] | 0 |
| 23 | Total General and Intangible Plant | | (Line 21 + Line 22) | 0 |
| 24 | Wage & Salary Allocator | | (Line 5) | #DIV/0! |
| 25 | **Total General and Intangible Functionalized to Transmission** | | (Line 23 * Line 24) | **#DIV/0!** |
| 26 | **Land Held for Future Use** | (Note C) | [From Inputs, Pg. 2, Lns. 9, 10, & 12] | **0** |
| 27 | **Total Plant In Rate Base** | | **(Line 20 + Line 25 + Line 26)** | **#DIV/0!** |

**Accumulated Depreciation**

| | | | | |
|---|---|---|---|---|
| 28 | Transmission Accumulated Depreciation for assets under SPP tariff | (Note B) | [From Inputs, Pg. 2, Ln. 14] | **0** |
| 29 | General Plant Accumulated Depreciation | | p219.28.c [From Inputs, Pg. 1, Ln. 43] | 0 |
| 30 | Accumulated Intangible Amortization (Other Utility Plant) | | (Line 8) | 0 |

| | | | | |
|---|---|---|---|---|
| 31 | Total Accumulated Depreciation | | (Line 29 + 30) | 0 |
| 32 | Wage & Salary Allocator | | (Line 5) | #DIV/0! |
| 33 | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission | | (Line 31 * Line 32) | #DIV/0! |
| 34 | **Total Accumulated Depreciation** | | **(Sum Lines 28 + 33)** | **#DIV/0!** |
| 35 | **Total Net Property, Plant & Equipment** | | **(Line 27 - Line 34)** | **#DIV/0!** |

**Adjustment To Rate Base**

| | | | | |
|---|---|---|---|---|
| | **Accumulated Deferred Income Taxes** | | | |
| 36 | **ADIT** | | [From ATT 1, Pg. 1, Ln. 32] | **#DIV/0!** |
| | **Prepayments** | | | |
| 37 | Prepayments | (Note A) | [From ATT-5, Ln. 37] | **#DIV/0!** |
| | **Materials and Supplies** | | | |
| 38 | Undistributed Stores Expense | (Note A) | p227.16.c [From Inputs, Pg. 1, Ln. 35] | 0 |
| 39 | Wage & Salary Allocator | | (Line 5) | #DIV/0! |
| 40 | Total Undistributed Stores Expense Allocated to Transmission | | (Line 38 * Line 39) | #DIV/0! |
| 41 | Transmission Materials & Supplies | | [From ATT-5, Ln. 41] | #DIV/0! |
| 42 | **Total Materials & Supplies Allocated to Transmission** | | (Line 40 + Line 41) | **#DIV/0!** |
| | **Cash Working Capital** | | | |
| 43 | Operation & Maintenance Expense | | (Line 66) | #DIV/0! |
| 44 | 1/8th Rule | | 1/8 | 12.5% |
| 45 | **Total Cash Working Capital Allocated to Transmission** | | (Line 43 * Line 44) | **#DIV/0!** |
| 46 | **Non-Escrowed Funds** | | [From ATT-4, Line 3, Col. C] | **#DIV/0!** |
| 47 | **Total Adjustment to Rate Base** | | (Lines 36 + 37 + 42 + 45 | **#DIV/** |

| | | | | |
|---|---|---|---|---|
| 7 | | | + 46) | **0!** |
| 48 | **Rate Base** | | (Line 35 + Line 47) | **#DIV/0!** |

Appendix A

Page 1 of 3

**APPENDIX A**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

**Operations & Maintenance Expense**

**Transmission O&M**

| | | | | |
|---|---|---|---|---|
| 49 | Transmission O&M | | [From ATT-5, Ln. 49] | #DIV/0! |
| 50 | Less Account 565 | | [From ATT-5, Ln. 50] | #DIV/0! |
| 51 | Line left intentionally blank | | | |
| 52 | Plus Charges billed to Transmission Owner and booked to Account 565 | | [From ATT-5, Ln. 52] | 0 |
| 53 | **Transmission O&M** | | (Lines 49 - 50) | **#DIV/0!** |

**Allocated Administrative & General Expenses**

| | | | | |
|---|---|---|---|---|
| 54 | Total A&G | | 323.197b [From Inputs, Pg. 1, Ln. 50] | 0 |
| 55 | Line left intentionally blank | | | |
| 56 | Line left intentionally blank | | | |
| 57 | Line left intentionally blank | | | |
| 58 | Less Regulatory Commission Exp Account 928 | (Note D) | p323.189.b [From Inputs, Pg. 1, Ln. 48] | 0 |
| 59 | Less General Advertising Exp Account 930.1 | | p323.191.b [From Inputs, Pg. 1, Ln. 49] | 0 |
| 60 | Administrative & General Expenses | | Sum (Lines 54 to 55) - Sum (Lines 56 to 59) | 0 |
| 61 | Wage & Salary Allocator | | (Line 5) | #DIV/0! |
| 62 | **Administrative & General Expenses Allocated to Transmission** | | (Line 60 * Line 61) | **#DIV/0!** |

**Directly Assigned A&G**

| | | | | |
|---|---|---|---|---|
| 63 | Regulatory Commission Exp Account 928 | (Note F) | [From ATT-5, Ln. 63] | 0 |
| 64 | Safety/Peak Alert Advertising Exp (Acct 909) | (Note E) | [From ATT-5, Ln. 64] | #DIV/0! |
| 65 | **Subtotal - Accounts 909 and 928 - Transmission Related** | | (Line 63 + Line 64) | **#DIV/0!** |
| 66 | **Total Transmission O&M** | | **(Lines 53 + 62 + 65)** | **#DIV/0!** |

**Depreciation & Amortization Expense**

**Depreciation Expense**

| | | | | |
|---|---|---|---|---|
| 67 | Transmission Depreciation Expense for Assets under SPP tariff | (Note B) | p336.7.b&c&d [From Inputs, Pg. 2, Ln. 21] | **0** |
| 68 | General Depreciation Expense Including Amortization of Limited Term Plant | | p336.10.b&c&d [From Inputs, Pg. 1, Lns. 58, 59, & 60] | 0 |
| 69 | Intangible Amortization | (Note A) | p336.1.b&c&d&e [From Inputs, Lns. 51, 52, 53, & 54] | 0 |
| 70 | Total | | (Line 68 + Line 69) | 0 |
| 71 | Wage & Salary Allocator | | (Line 5) | #DIV/0! |
| 72 | **General Depreciation & Intangible Amortization Allocated to Transmission** | | (Line 70 * Line 71) | **#DIV/0!** |
| 73 | **Total Transmission Depreciation & Amortization** | | **(Lines 67 + 72)** | **#DIV/0!** |

**Taxes Other than Income Taxes**

| | | | | |
|---|---|---|---|---|
| 74 | **Taxes Other than Income Taxes** | | [From ATT-2, Pg. 1, Ln. 14] | **#DIV/0!** |
| 75 | **Total Taxes Other than Income Taxes** | | **(Line 74)** | **#DIV/0!** |

**Return \ Capitalization Calculations**

**Long Term Interest**

| | | | | |
|---|---|---|---|---|
| 76 | **Long Term Interest & Hedging Costs** | | [From ATT-9, Pg. 2, Ln. 6] | **-** |

| | | | | |
|---|---|---|---|---|
| 77 | **Preferred Dividends** | | [From ATT-8, Pg. 1, Ln. 4] | **0** |
| | **Common Stock** | | | |
| 78 | Proprietary Capital | | [From ATT-7, Pg. 1, Ln. 3, Col. A] | 0 |
| 79 | Less Accumulated Other Comprehensive Income Account 219 | | [From ATT-7, Pg. 1, Ln. 3, Col. F] | 0 |
| 80 | Less Preferred Stock | | [From ATT-8, Pg. 1, Ln. 3, Col. F] | 0 |
| 81 | Less Account 216.1 | | [From ATT-7, Pg. 1, Ln. 3, Col. G] | 0 |
| 82 | **Common Stock** | | (Line 78 - 79 - 80 - 81) | **0** |
| | **Capitalization** | | | |
| 83 | Total Long Term Debt (Average) | | [From ATT-6, Pg. 1, Ln. 1, Col A] | 0 |
| 84 | Preferred Stock | | [From ATT-6, Pg. 1, Ln. 2, Col A] | 0 |
| 85 | Common Stock | | [From ATT-6, Pg. 1, Ln. 3, Col A] | 0 |
| 86 | **Total Capitalization** | | (Sum Lines 83 to 85) | **0** |
| 87 | Debt % | Total Long Term Debt | [From ATT-6, Pg. 1, Ln. 1, Col B] | #DIV/0! |
| 88 | Preferred % | Preferred Stock | [From ATT-6, Pg. 1, Ln. 2, Col B] | #DIV/0! |
| 89 | Common % | Common Stock | [From ATT-6, Pg. 1, Ln. 3, Col B] | #DIV/0! |
| 90 | Debt Cost | Total Long Term Debt | [From ATT-6, Pg. 1, Ln. 1, Col C] | #DIV/0! |
| 91 | Preferred Cost | Preferred Stock | [From ATT-6, Pg. 1, Ln. 2, Col C] | 0.00% |
| 92 | Common Cost | Common Stock | [From ATT-6, Pg. 1, Ln. 3, Col C] | 0.00% |
| 93 | Weighted Cost of Debt | Total Long Term Debt (WCLTD) | (Line 87 * Line 90) | #DIV/0! |
| 94 | Weighted Cost of Preferred | Preferred Stock | (Line 88 * Line 91) | #DIV/0! |
| 95 | Weighted Cost of Common | Common Stock | (Line 89 * Line 92) | #DIV/0! |
| 96 | **Rate of Return on Rate Base ( ROR )** | | (Sum Lines 93 to 95) | **#DIV/0!** |
| 97 | **Investment Return = Rate Base * Rate of Return** | | **(Line 48 * Line 96)** | **#DIV/0!** |

**APPENDIX A**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

## Composite Income Taxes

### Income Tax Rates

| | | | | | |
|---|---|---|---|---|---|
| 98 | FIT=Federal Income Tax Rate | | (Note G) | [From Inputs, Pg. 2, Ln. 1] | 0.00% |
| 99 | SIT=State Income Tax Rate or Composite | | (Note G) | [From Inputs, Pg. 2, Ln. 2] | 0.00% |
| 100 | p | (% of fed inc tax deductible for state purposes) | (Note G) | [From Inputs, Pg. 2, Ln. 3] | 0.00% |
| 101 | T | T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = | | | 0.00% |
| 102 | T / (1-T) | Tax Gross-Up | | | 0.00% |

### ITC Adjustment

| | | | | |
|---|---|---|---|---|
| 103 | Amortized Investment Tax Credit - Transmission Related | | [From ATT-5, Ln. 103] | #DIV/0! |
| 104 | **ITC Adjust. Allocated to Trans. - Grossed Up** | ITC Adjustment x 1 / (1-T) | (Line 103 * (1 / (1-Line 101)) | **#DIV/0!** |
| 105 | **Income Tax Component =** | (T/1-T) * Investment Return * (1-(WCLTD/ROR)) = | [Line 102 * Line 97 * (1-(Line 93 / Line 96))] | **#DIV/0!** |
| 106 | **Total Income Taxes** | | **(Line 105 - Line 104 – Line 103e)** | **#DIV/0!** |

## Revenue Requirement

### Summary

| | | | |
|---|---|---|---|
| 107 | Net Property, Plant & Equipment | (Line 35) | #DIV/0! |
| 108 | Total Adjustment to Rate Base | (Line 47) | #DIV/0! |
| 1 | Rate Base | (Line 48) | #DIV/ |

| | | | |
|---|---|---|---|
| 109 | | | 0! |
| 110 | Total Transmission O&M | (Line 66) | #DIV/0! |
| 111 | Total Transmission Depreciation & Amortization | (Line 73) | #DIV/0! |
| 112 | Taxes Other than Income | (Line 75) | #DIV/0! |
| 113 | Investment Return | (Line 97) | #DIV/0! |
| 114 | Income Taxes | (Line 106) | #DIV/0! |
| **115** | **Gross Revenue Requirement** | **(Sum Lines 110 to 114)** | **#DIV/0!** |

**Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities**

| | | | |
|---|---|---|---|
| 116 | Transmission Plant In Service under SPP tariff | (Line 20) | 0 |
| 117 | Revenues from Direct Assigned Transmission Facilities | (Note H) [From ATT-5, Ln. 117] | 0 |
| 118 | Included Transmission Facilities | (Line 116 - Line 117) | 0 |
| 119 | Inclusion Ratio | (Line 118 / Line 116) | #DIV/0! |
| 120 | Gross Revenue Requirement | (Line 115) | #DIV/0! |
| **121** | **Adjusted Gross Revenue Requirement** | (Line 119 * Line 120) | **#DIV/0!** |

**Revenue Credits & Adjustments**

| | | | |
|---|---|---|---|
| 122 | Revenue Credits (Includes Schedule 11) | [From ATT-3, Ln. 10] | #DIV/0! |
| 122a | Refunds and Surcharges (Adjustments to Gross ATRR) | | |
| 1 | **Total Revenue Credits and** | (Line 122 + Line 122a) | **#DIV/** |

| | | | |
|---|---|---|---|
| 2 | **Adjustments** | | **0!** |
| 2 | | | |
| b | | | |

| | | | |
|---|---|---|---|
| **1** | | | |
| **2** | | | **#DIV/** |
| **3** | **Annual Total Net Revenue Requirement** | **(Line 121 - Line 122b)** | **0!** |

| | | | |
|---|---|---|---|
| 12 | | | |
| 4 | Line Intentionally Left Blank | | |
| 12 | Adjustments to prior Rate | | |
| 5 | Year Revenue Requirement | | |
| **1** | **Annual Total Net Revenue** | | |
| **2** | **Requirement from** | | **#DIV/** |
| **6** | **Schedule 9** | **(sum Line 123 to 125)** | **0!** |

**Notes:**

A Electric portion only.

B Includes only transmission assets under the SPP tariff.

C Includes Transmission portion only.

D Includes all Regulatory Commission Expenses for all Electric jurisdictions.

E Includes safety-related and load/grid congestion management advertising expense included in Account 909 (Product codes ADAS, ADCS, ADPA).

F Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting; as itemized on ATT-5, Ln. 63.

G The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the South Dakota income tax rate, and p = the percentage of federal income tax deductible for South Dakota state income taxes.

H There are no direct assigned transmission facilities on our system as of 12/31/2014. Annual verification/updates will be documented on ATT 5.

Appendix A

Page 3 of 3

**Attachment 1 - ACCUMULATED DEFERRED INCOME TAXES ACCOUNT 190**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| Line | Account | Identification | *(A)* *YE Balance* | *(B)* *100% Non-Transmission Related* | *(C)* *100% Transmission Related* | *(D)* *Plant Related* | *(E)* *Labor Related* | *(F)* *Total Added to Rate base* | *(G)* *Description* |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 190.0 | Deferred FIT - Unbilled Revenue | | | | - | | | |
| 2 | 190.0 | Deferred FIT - Officers & Directors Deferred Comp. | | | | | - | | Deferred compensation, tax deductible when paid |
| 3 | 190.0 | Deferred FIT - Reserves & Accruals | | | | - | | | |
| 4 | 190.0 | Deferred FIT - Post Retirement Benefits - Pension | | | | | - | | Relates to pensions - tax funding vs book accrual |
| 5 | 190.0 | Environmental Liability | | - | | | | | All natural gas related |
| 6 | 190.0 | Deferred FIT - Non-jurisdictional (SD Gas, NE Gas) | | - | | | | | Not South Dakota Electric related |
| 7 | | | | | | | | | |
| 8 | | **Total** | - | - | 0 | - | - | | |
| 9 | | **Conform - [FF1, pg. 234, ln. 18, col. c] (From Inputs Pg. 1, Line 36)** | - | | | | | | |
| 10 | | **Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]** | | 0.00% | 100.00% | #DIV/0! | #DIV/0! | | |
| 11 | | **Total Transmission** | | 0 | 0 | #DIV/0! | #DIV/0! | #DIV/0! | |
| 12 | | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | 282.0 | Accum Def FIT - Accel Depr & Amort. | | | | - | | | Accelerated Depreciation & Amortization of non-flow thru |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 15 | 282.0 | Accum Def FIT - Non-jurisdictional (SD Gas, NE Gas) | | - | | | | items<br><br>Not South Dakota Electric related |
| 16 | | | | | | | | |
| 17 | | **Total** | - | - | 0 | - | 0 | |
| 18 | | **Conform - [FF1, pg. 275, ln. 9, col. k] (Inputs Pg. 1, Line 38)** | - | | | | | |
| 19 | | **Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]** | | 0.00% | 100.00% | #DIV/0! | #DIV/0! | |
| 20 | | **Total Transmission** | | - | 0 | #DIV/0! | #DIV/0! | |
| 21 | | | | | | | | |
| 22 | | | | | | | | |
| 23 | 283.0 | Regulatory Assets | | - | | | | MGP |
| 24 | 283.0 | FAS109 Flow through deferred taxes | | - | | | | tax gross up on FAS109 flow through deferred taxes |
| 25 | 283.0 | Non-jurisdictional (SD Gas, NE Gas) | | - | | | | Not South Dakota Electric related |
| 26 | | | | | | | | |
| 27 | | **Total** | - | - | 0 | 0 | 0 | |
| 28 | | **Conform - [FF1, pg. 277, ln. 19, col. k] (Inputs Pg. 1, Line 39)** | - | | | | | |
| 29 | | **Allocator [EX-col. B, DIR-col. C, GP-col. D, SW-col. E]** | | 0.00% | 100.00% | #DIV/0! | #DIV/0! | |
| 30 | | **Total Transmission** | | 0 | 0 | #DIV/0! | #DIV/0! | |
| 31 | | | | | | | | |
| 32 | | **Total ADIT (Ln. 11 + Ln. 20 + Ln 30)** | | | | | #DIV/0! | To Appendix A, Line 36 |

**Attachment 2 - Taxes Other Than Income**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| | | Column A | Column B | Column C |
|---|---|---|---|---|
| | | **Pg. 263 & 263.1** | | **Allocated Amount** |
| | **OTHER TAXES:** | **Col (i)** | **Allocator** | |
| | **Currently Included on Appendix A** | | | |
| | **Plant Related:** | | **Gross Plant Allocator** | |
| 1 | Real and Personal Property (State, Municipal or Local) -Current FF1 Year [FF1, Pg. 263, Lns. 23i & 37i; Pg. 263.1, Lns. 12i, 18i, 24i & 31i][From Inputs, Pg. 1, Lns. 68-70] | 0 | | |
| 2 | | | | |
| 3 | Vehicle Taxes [From Inputs, Pg. 1, Ln. 74] | 0 | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | **Total Plant Related [GP Allocator from Appendix A, Ln. 12]** | 0 | #DIV/0! | #DIV/0! |
| | **Labor Related:** | | **Wages & Salary Allocator** | |
| 8 | Social Security (FICA/OAB) [FF1, Pg. 263, Ln.5i] [From Inputs, Pg. 1, Ln. 75-76] | 0 | | |
| 9 | Federal Unemployment Comp. [FF1, Pg. 263, Ln. 7i] [From Inputs, Pg. 1, Ln. 77] | 0 | | |
| 10 | State Unemployment Comp. [From Inputs, Pg. 1, Lines 78] | 0 | | |
| 11 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | **Total Labor Related [Wages & Sal. Alloc. from Appendix A, Ln.5]** | 0 | #DIV/0! | #DIV/0! |

| | | |
|---|---|---|
| 14 | **Total Included (Column C, Lines 7 + 13)** [To Appendix A, Line 74] | #DIV/0! |

**Currently Excluded from Appendix A**

| | | |
|---|---|---|
| 15 | Corporate Franchise-Retail [Current Year] [From Inputs, Pg. 1, Ln. 73] [FF1, Pg. 263, Col. i, Lns. 16, 21, & 35; Pg. 263.1, Col. i, Lns. 6, 14, 20, 26, & 33] | 0 |
| 16 | Coal Conversion [From Inputs Pg. 1, Ln. 71] | 0 |
| 17 | SD Gross Receipts Tax [From Inputs, Pg. 2, Ln. 72] | 0 |
| 18 | | |
| 19 | | |
| 20 | **Subtotal of Excluded Taxes, [Ln. 15 + Ln. 16 + Ln.17]** | 0 |
| 21 | **Total, Included and Excluded (Column A, Lines 7 + 13 + 20)** | 0 |
| 22 | **Total Other Taxes [FF1, pg. 115.14.g] [From Inputs, Pg. 1, Ln. 23]** | - |
| 23 | Difference (Line 21 - Line 22) | - |

Criteria for Allocation:

| | |
|---|---|
| A | Other Taxes that are incurred through ownership of plant, including transmission plant, will be allocated based on the Gross Plant Allocator. |
| B | Other Taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. |
| C | Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator. |

## Attachment 3 - Revenue Credits

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| | | |
|---|---|---|
| | **Account 454 - Rent from Electric Property** | |
| 1 | Rent from Electric Property [FF1, Pg. 300, Ln. 19, Col. b] [From Inputs, Pg. 1, Ln. 67] | - |
| 2 | T/D Revenue Allocation Factor [From Appendix A, Ln. 19] | #DIV/0! |
| 3 | Rent from Electric Transmission Property [Line 1 x Line 2] | #DIV/0! |
| | **Other Electric Revenues (Note 1)** | |
| 4 | SPP Schedule 7 & 8 Transmission Revenues (Note 1 & Note 3) [From Inputs, Pg. 2, Ln. 18] | 0 |
| 5 | Non-Firm Point-to-Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 3) [From Inputs, Pg. 2, Ln. 20] | 0 |
| 6 | Direct Assigned Facilities Revenues (Note 2) [From Inputs, Pg. 2, Ln. 15] | 0 |
| 7 | Other Revenues Associated with Loads Outside of NorthWestern's Zone [From Inputs, Pg. 2, Ln. 19] | 0 |
| 8 | Rev. Rqmt. (w/o incentives) from SPP Base Plan Funded Upgrades (Schedule 11 Revenue) [From ATT-12, Page 2, Ln. 39, ATRR w/o Incentives] | #DIV/0! |
| 9 | Line Intentionally Left Blank | |
| 10 | Gross Revenue Credits (sum Lines 3 thru 8) [To Appendix A, Line 122] | #DIV/0! |

**Note 1**: All Schedule 7 & 8 revenues derived as a Transmission Owner from SPP for loads not included in the system peak and for which the cost of the service is recovered under this formula will be included in this revenue credit. These revenues are booked in Account 456.1 (Firm Point-to-Point and Non-Firm Point-to-Point). All NorthWestern point-to-point transmission customers are included in the UMZ Load Divisor.

**Note 2**: If the costs associated with Directly Assigned Transmission Facility Charges are included in this TFR, the associated revenues will be included in this TFR. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in this TFR, the associated revenues will not be included in this TFR.

**Note 3**: The portion of Point-to-Point revenues collected by SPP and assigned to NorthWestern are included on ATT 3, Ln. 4. Any demand revenue margins collected directly by NorthWestern for "grandfathered" bundled contracts will be included on ATT 3, Ln. 6. See note on "Inputs" worksheet, Pg. 2, Ln. 20 regarding remaining pre-OATT contracts.

Attachment 3
Page 1 of 1

## Attachment 4, NON-ESCROWED FUNDS

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

The purpose of this worksheet is to individually document the value(s) of the non-escrowed reserve funds that will be credited against working capital. All inputs are derived from the Company's Books and Records, as described.

| Line | Description of Reserve: | FERC Reserve Acct | FERC Expense Acct [1] | Balance 12/31/20xx COL. A | Allocator NP COL. B | Working Capital Adjustment (Col. C = Col. A x Col. B) COL. C |
|---|---|---|---|---|---|---|
| 1. | Accum Prov for Inj/Damgs | 228.2 | 925 | $ - | #DIV/0! | #DIV/0! |
| 2. | Other adjustments | | | | #DIV/0! | #DIV/0! |
| 3. | **Total** (Ln. 1 + Ln. 2) [Appendix A, Pg. 1, Ln. 46] | | | $ - | | #DIV/0! |
| 4. | Conformation [FF1, Pg. 112, Ln. 28, Col. c] [From Inputs, Pg. 1, Ln. 22] | | | - | | |

[1] Account 925 is the FERC expense account which includes the cost of insurance, the cost of claims not covered by insurance, the re-imbursement from insurance companies, and amounts credited to account 228.2 as Accumulated Provision for Injuries and Damages.

## Attachment 5 - Cost Support

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| | Prepayments | | FF1 Amount | | Gross Plant Allocator | Functionalized to Transmission | Details |
|---|---|---|---|---|---|---|---|
| | Prepayments – Beginning of Year | FF1 Pg. 110.57.c [From Inputs, Pg. 1, Ln. 1a] | 0 | | | | |
| | Prepayments – End of Year | FF1 Pg. 110.57.c [From Inputs, Pg. 1, Ln. 1] | 0 | | | | |
| 37 | Prepayments | Average BOY/EOY Prepayments | 0 | | #DIV/0! | #DIV/0! | |

| | Materials and Supplies | | FF1 Amount | Transmission under SPP % | Functionalized to Transmission | Details |
|---|---|---|---|---|---|---|
| | Materials and Supplies – End of | FF1 Pg. 228.8.c [From Inputs, | 0 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Year | Pg. 1, Ln. 34] | | | |
| | Materials and Supplies – Beginning of Year | FF1 Pg. 228.8.d [From Inputs, Pg. 1, Ln. 34a] | 0 | | |
| 41 | Materials and Supplies – Average | Average BOY/EOY Materials and Supplies | 0 | #DIV/0! | #DIV/0! |

| Regulatory Expense Related to Transmission Cost Support: | | FF1 Amount | | Allocated to transmission | Functionalized to Transmission | Details |
|---|---|---|---|---|---|---|
| 63 | Regulatory Commission Exp Account 928 | FF1 323.189.b [From Inputs, Pg. 1, Ln. 48] & 350.41.d thru 350.44.d [From Inputs, Pg. 2, Ln. 11] | 0 | 0.00% | 0 | |

| Advertisements: | | FF1 Amou | | T/D Allocator | Functionalized to Transmissio | Details |
|---|---|---|---|---|---|---|

| | | | nt | | | n | |
|---|---|---|---|---|---|---|---|
| 6<br>4 | Advertisements<br>FERC<br>909 | FF1 111.57.c [From Inputs, Pg. 2, Ln. 7] | 0 | | #DIV/0! | #DIV/0! | NorthWestern uses Account 909 for its Safety and Informational Advertising. The account includes expenses incurred while conveying information to customers about safety and providing information to customers about utilizing their electric service. Costs during the test year included listing our phone number in telephone directories, safety campaigns around Call Before You Dig and Louie the Lightning Bug, tree safety and awareness, customer education on easy billing plans, and monthly bill inserts to customers. |

| ITC Adjustment: | | | FF1 Amount | | GP Allocator | Functionalized to Transmission | Details |
|---|---|---|---|---|---|---|---|
| 1<br>0<br>3 | Amortized<br>Investment<br>Tax Credit | FF1 266.8.f [From Inputs, Pg.1, Ln. 45] | 0 | | #DIV/0! | #DIV/0! | |

| | | **Adjustment to Remove Revenue Requirements Associated w/ Excluded Transmission Facilities** | **Revenues from Direct Assigned Transmission Facilities** | **General Description of the Direct Assigned Transmission Facilities** |
|---|---|---|---|---|
| 1<br>1<br>7 | Revenues from Direct Assigned Transmission Facilities | [From Inputs, Pg. 2, Ln. 15] | 0 | Direct Assignment Facilities: Facilities or portions of facilities that are constructed by any Transmission Owner(s) for the sole use/benefit of a particular Transmission Customer or a particular group of customers or a particular Generation Interconnection Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreements that govern service to the Transmission Customer(s) and Generation Interconnection Customer(s) and shall be subject to Commission approval. |

| | Adjustments to Transmission O&M: | | Total | | Transmission under SPP Factor | Functionalized to Transmission | Details |
|---|---|---|---|---|---|---|---|
| 49 | Transmission O&M | FF1 321.112.b [From Inputs, Pg. 1, Ln. 47] | 0 | | #DIV/0! | #DIV/0! | |
| 50 | Less Account 565 | FF1 321.96.b [From Inputs, Pg. 1, Ln. 46] | 0 | | #DIV/0! | #DIV/0! | |
| 52 | Plus Charges billed to Transmission Owner and booked to Account 565 | [From Inputs, P | 0 | | #DIV/0! | #DIV/0! | |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | g.2,Ln.16] | | | | |

| | Adjustments to Transmission Plant for only assets under SPP tariff: | | Total Transmission | | Transmission under SPP | Details |
|---|---|---|---|---|---|---|
| 20 | Transmission Assets | FF1 207.58g [From Inputs, Pg. 1, Ln. 33] | 0 | | - | |
| 1a | Transmission under SPP Factor (Transmission under SS divided by Total Transimssion) | | #DIV/0! | | | |

**Attachment 6, WEIGHTED AVERAGE COST OF CAPITAL**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| Line | Type of Capital | Total Company Average Capitalization ($) Balance | Source | Weighted Cost Ratios (%) | Cost of Capital (%) | Source | Weighted Cost of Capital (%) |
|---|---|---|---|---|---|---|---|
| | | Col A | | Col B = Col A/Col A Total | Col C | | Col D = Col B x Col C |
| **1.** | Long Term Debt | - | [Note (1)] | #DIV/0! | #DIV/0! | [Note (4)] | #DIV/0! |
| **2.** | Preferred Stock | 0 | [Note (2)] | #DIV/0! | 0.00% | [Note (5)] | #DIV/0! |
| **3.** | Common Stock | - | [Note (3)] | #DIV/0! | | | #DIV/0! |
| **4.** | Totals | - | | #DIV/0! | | | |
| **5.** | **Weighted Average Cost of Capital ("R")** | | | | | | #DIV/0! |

Note(1): From ATT 9, Pg. 1, Ln. 3.

Note (2): From ATT 8, Pg. 1, Ln. 3.

Note (3): From ATT 7, Pg. 1, Ln. 4.

Note(4): From ATT 9, Page 2, Ln. 8

Note (5): From ATT 8, Pg. 1, Ln. 5.

**Attachment 7, COMMON STOCK**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| Line | Date | **Total Proprietary Capital*** Balance | Source | **Preferred Stock** Outstanding Balance Acct 204 | Source | Premium (Discount) Acct 207, 213-Pfd | Source | Gains/(Losses) on Reacq'd Preferred Stock Acct 210 | Source | Other Paid-In Capital (Preferred Stock) Accts 208 - 211 | Source | **Acc Other Comp Income** Acct 219 | Source | **Unappropriated Undistributed Subsidiary Earnings** Acct 216.1 | Source | **Common Equity Balance** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Col A | | Col B | | Col C | | Col D | | Col E | | Col F | | Col G | | Col H (H=A-B-C-D-E-F-G) |
| **1.** | 12/31/20xx | - | [Note (1)] | 0 | [Note (3)] | 0 | [Note (5)] | 0 | [Note (7)] | 0 | [Note (9)] | 0 | [Note (11)] | 0 | [Note (13)] | - |
| **2.** | 12/31/20xx | - | [Note (2)] | 0 | [Note(4)] | 0 | [Note (6)] | 0 | [Note (8)] | 0 | [Note (10)] | 0 | [Note (12)] | 0 | [Note (14)] | - |
| **3.** | | - | | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | |

**4.** **Common Equity Balance** [Average of Beg of Yr & End of Yr CE Balance]: -
[To ATT-6, Page 1, Line 3, Col A]

* Includes both Common and Preferred Stock accounts.

| | |
|---|---|
| [Note (1)]: | FF1, Pg. 112, Ln. 16, Col. d. [From Inputs, Pg. 1, Ln. 9] |
| [Note (2)]: | FF1, Pg. 112, Ln. 16, Col. c. [From Inputs, Pg. 1, Ln. 8] |
| [Note (3)]: | From ATT 8, Ln. 1, Col. A. |
| [Note (4)]: | From ATT 8, Ln. 2, Col. A. |
| [Note (5)]: | From ATT 8, Ln. 1; Col. B + Col. C. |
| [Note (6)]: | From ATT 8, Ln. 2; Col. B + Col. C. |
| [Note (7)]: | From ATT 8, Ln. 1, Col. D. |
| [Note (8)]: | From ATT 8, Ln. 2, Col. D. |
| [Note (9)]: | From ATT 8, Ln. 1, Col. E. |
| [Note (10)]: | From ATT 8, Ln. 2, Col. E. |
| [Note (11)]: | FF1, Pg. 112, Ln. 15, Col. d. [From Inputs, Pg. 1, Ln. 7] |
| [Note (12)]: | FF1, Pg. 112, Ln. 15, Col. c. [From Inputs, Pg. 1, Ln. 6] |
| [Note (13)]: | FF1, Pg. 112, Ln. 12, Col. D [From Inputs, Pg. 1, Ln. 5] |
| [Note (14)]: | FF1, Pg. 112, Ln. 12, Col. C [From Inputs, Pg. 1, Ln. 4] |

Attachment 7
Page 1 of 1

**Attachment 8, PREFERRED STOCK**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

| | | Preferred Stock | | Premium on Preferred Stock | | Discount on Preferred Stock | | Gain/(Loss) On Reaq'd Pref Stock | | Other Paid-In Capital - Preferred | | Total Outstanding |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Acct 204 | Data Source | Acct 207 | Data Source | Acct 213 | Data Source | Acct 210 | Data Source | Accts 208, 209, 211 | Data Source | Col G = Cols A+B-C+D+E+F |
| Line | Date | Col A | | Col B | | Col C | | Col D | | Col E | | COL F |
| **1.** | 12/31/20xx | 0 | [Note (1)] | 0 | [Note (3)] | 0 | [Note (5)] | 0 | [Note (7)] | 0 | [Note (9)] | 0 |
| **2.** | 12/31/20xx | 0 | [Note (2)] | 0 | [Note (4)] | 0 | [Note (6)] | 0 | [Note (8)] | 0 | [Note (10)] | 0 |
| **3.** | | | | | | | | | | | | **Avg of B of Yr and E of Yr Pref Stock** [To ATT 6, Pg. 1, Col. A, Ln. 2]: 0 |
| **4.** | | | | | | | | | | | | **Preferred Dividends** [Note 11]: 0 |
| **5.** | | | | | | | | | | | | **Average Cost Rate** [Ln 4 / Ln 3] [To ATT 6, Pg. 1, Col. C, Ln. 2]: 0.00 % |

Note (1): FF1, Pg. 112, Ln. 3, Col d. [From Inputs, Pg. 1, Ln. 3]

Note (2): FF1, Pg. 112, Ln. 3, Col c. [From Inputs, Pg. 1, Ln. 2]

Note (3): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. d that are associated with Premium on Preferred

Stock; as derived from the Company's Books and Records.

Note (4): The Acct 207 dollars included in FF1, Pg. 112, Ln. 6, Col. c that are associated with Premium on Preferred Stock; as derived from the Company's Books and Records.

Note (5): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. d that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (6): The Acct 213 dollars included in FF1, Pg. 112, Ln. 9, Col. c that are associated with Discount on Preferred Stock; as derived from the Company's Books and Records.

Note (7): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (8): The Acct 210 dollars included in FF1, Pg. 253, Col. b that are associated with the Gains/(Losses) on Reacquired Preferred Stock; as derived from the Company's Books and Records.

Note (9): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. d that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (10): The Acct 208-211 dollars included in FF1, Pg. 112, Ln. 7, Col. c that are associated with the Other Paid-In Capital on Preferred Stock; as derived from the Company's Books and Records.

Note (11): The Acct 214-217 dollars included in FF1, Pg. 112, Ln. 10,13, Col. c that are associated with the capital stock expense; as derived from the Company's Books and Records.

Note (12) The Acct 214-217 dollars included in FF1, Pg. 112, Ln. 10,13, Col. c that are associated with thecapital stock expense; as derived from the Company's Books and Records.

Attachment 8
Page 1 of 1

**Attachment 9, LONG-TERM DEBT**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

**GROSS PROCEEDS - LTD OUTSTANDING**

| | | Advances from Associated Company LTD | | Bonds | | Reacquired Bonds | | Other Long Term Debt | | Total Long Term Debt Outstanding |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Acct 223 | Source | Acct 221 | Source | Acct 222 | Source | Acct 224 | Source | Col E= Cols A+B+C+D |
| Line | Date | Col A | | Col B | | Col C | | Col D | | Col E |
| 1. | 12/31/20xx | 0 | [Note (1)] | - | [Note (3)] | 0 | [Note (5)] | - | [Note (7)] | - |
| 2. | 12/31/20xx | 0 | [Note (2)] | - | [Note (4)] | 0 | [Note (6)] | - | [Note (8)] | - |
| 3. | | **GROSS PROCEEDS** (Avg of Beg of Yr and End of Yr LTD Gross Outstanding Balances in Col E) [To ATT 6, Pg.1, Ln. 1, Col. A]: | | | | | | | | - |

| | | | |
|---|---|---|---|
| Note (1): | FF1, Pg. 112, Line 20, Col d. [From Inputs, Pg. 1, Ln. 15] | Note (5): | FF1, Pg. 112, Ln 19, Col. d. [From Inputs, Pg. 1, Ln. 13] |
| Note (2): | FF1, Pg. 112, Line 20, Col c. [From Inputs, Pg. 1, Ln. 14] | Note (6): | FF1, Pg. 112, Ln 19, Col. c. [From Inputs, Pg. 1, Ln. 12] |
| Note (3): | FF1, Pg. 112, Ln 18, Col. D [From Inputs, Pg. 1, Ln. 11] | Note (7): | FF1, Pg. 112, Ln 21, Col. d. [From Inputs, Pg. 1, Ln. 17] |
| Note (4): | FF1, Pg. 112, Ln 18, Col. C [From Inputs, Pg.1, Ln. 10] | Note (8): | FF1, Pg. 112, Ln 21, Col. c. [From Inputs, Pg. 1, Ln. 16] |

**NET PROCEEDS**

| Line | Date | | |
|---|---|---|---|
| **4.** | 12/31/20xx | Unamortized balance Premiums (Beg of Yr) (Acct 225) [Form 1, Pg. 112, Ln. 22, Col. d] [From Inputs, Pg. 1, Ln. 19] | 0 |
| **5.** | 12/31/20xx | Unamortized balance Premiums (End of Yr) (Acct 225) [Form 1, Pg. 112, Ln. 22, Col. c] [From Inputs, Pg. 1, Ln. 18] | 0 |
| **6.** | | **Avg of Beg & End of Yr Premiums** | 0 |
| **7.** | 12/31/20xx | Unamortized balance Discounts (Beg of Yr) (Acct 226) [Form 1, Pg. 112, Ln. 23, Col. d] [From Inputs, Pg. 1, Ln. 21] | - |
| **8.** | 12/31/20xx | Unamortized balance Discounts (End of Yr) (Acct 226) [Form 1, Pg. 112, Ln. 23, Col. c] [From Inputs, Pg. 1, Ln. 20] | - |
| **9.** | | **Avg of Beg & End of Yr Discounts** | - |
| 10 | 12/31/20xx | Unamortized Debt Expense (Acct 181) Beg of Year [Form 1, Pg. 111, Ln. 69, Col. d] [From Inputs, Pg. 2, Ln. 23] | - |
| 11 | 12/31/20xx | Unamortized Debt Expense (Acct 181) End of Year [Form 1, Pg. 111, Ln. 69, Col. c] [From Inputs, Pg. 2, Ln. 24] | - |
| 12 | | **Avg of Beg & End of Yr** | - |
| 13 | 12/31/20xx | Unamortized Loss on Reacquired Debt - Beginning of Year (Acct 189)[Form 1, Pg. 111, Ln. 81, Col. d] [From Inputs, Pg. 1, Ln. 25] | - |
| 14 | 12/31/20xx | Unamortized Loss on Reacquired Debt - End of Year (Acct 189) [Form 1, Pg. 111, Ln. 81, Col. c] [From Inputs, Pg. 1, Ln. 26] | - |
| 15 | | **Avg of Beg & End of Yr** | - |

| | | | |
|---|---|---|---|
| | 12/31/20xx | Unamortized Gain on Reacquired Debt - Beginning of Yr (Acct 257)[Form 1, Pg. 113, Ln. 81, Col. d] [From Inputs, Pg. 1, Ln. 27] | |
| 16 | | | - |
| | 12/31/20xx | Unamortized Gain on Reacquired Debt -End of Yr (Acct 257)[Form 1, Pg. 113, Ln. 81, Col. d] [From Inputs, Pg. 1, Ln. 28] | |
| 17 | | | - |
| | | **Avg of Beg & End of Yr** | |
| 18 | | | |
| **19.** | | Gross Proceeds [From Line 3, above] | - |
| **20.** | | Plus: Unamortized balance Premiums [From Line 6, above] | 0 |
| **21.** | | Less: Unamortized balance Discounts [From Line 9, above] | - |
| **22.** | | **NET PROCEEDS** (Avg of Beg of Yr and End of Yr LTD): | - |

General Note: Net long-term average debt balance is used as the divisor to determine LTD debt cost rate. Gross long-term average debt balance is used in the capital structure.



**Attachment 9, LONG-TERM DEBT**

(For Rate Year Beginning April 1, 20XX, Based on December 31, 20XX Data)

**LTD COSTS AND EXPENSES (Actual)**

| Line | | |
|---|---|---|
| **1.** | LTD Interest Expense [FF1, Pg. 117, Ln. 62, Col. C] [From Inputs Pg.1, Ln. 24] | 0 |
| **2.** | Amortization Debt Discount and Expense (Acct 428) [FF1, Pg. 117, Ln. 63, Col. c] [From Inputs, Pg. 1, Ln. 25] | 0 |
| **3.** | Amortization of Loss on Reacquired Debt (Acct 428.1) [FF1, Pg. 117, Ln. 64, Col. c] [From Inputs, Pg. 1, Ln. 26] | 0 |
| **4.** | Less: Amort Premium on Debt Credit (Acct 429) [FF1, Pg. 117, Ln. 65, Col. c] [From Inputs, Pg.1, Ln. 27] | 0 |
| **5.** | Less: Amort Gain on Debt Credit (Acct 429.1) [FF1, Pg. 117, Ln. 66, Col. c] [From Inputs, Pg. 1, Ln. 28] | 0 |

| | | |
|---|---|---|
| **5a.** | Plus: Interest on Debt to Associated Companies (Acct 430) [FF1, Pg. 117, Ln. 67, Col. c] [From Inputs, Pg. 1, Ln. 40] | 0 |
| **6.** | **TOTAL LTD Interest Amount** | - |
| **7.** | Total Long Term Debt Balance (Net Proceeds) [From Pg. 1, Ln. 13, above] | - |
| **8.** | **Embedded Cost of Long Term Debt [Line 6/Line 7]** [To ATT 6, Pg. 1, Ln. 1, Col. C] | **#DIV/0!** |

| Attachment 10, DEPRECIATION RATES | | | | | |
|---|---|---|---|---|---|
| (For Rate Year Beginning April 1, 2xxx, Based on December 31, 2xxx Data) | | | | | |
| Line | FERC | | Description | | 20xx Rates (%)[1] |
| 1 | | | STEAM GENERATION - Big Stone | | |
| 2 | 310 | | 310.0-BSP-Land | | 0.00% |
| 3 | 311 | | 311.0-BSP-Structures & Improvement | | 0.63% |
| 4 | 312 | | 312.0-BSP-Boiler Plant Equipment | | 1.28% |
| 5 | 314 | | 314.0-BSP-Turbo-Generator | | 1.40% |
| 6 | 315 | | 315.0-BSP-Accessory Electric | | 0.94% |
| 7 | 316 | | 316.0-BSP-Misc Power Plant | | 1.11% |
| 8 | | | STEAM GENERATION - Coyote | | |
| 9 | 310 | | 310.0-CYP-Land | | 0.00% |
| 10 | 311 | | 311.0-CYP-Structures & Improvements | | 0.92% |
| 11 | 312 | | 312.0-CYP-Boiler Plant Equipment | | 1.05% |
| 12 | 314 | | 314.0-CYP-Turbo-Generator | | 1.61% |
| 13 | 315 | | 315.0-CYP-Accessory Electric | | 1.29% |
| 14 | 316 | | 316.0-CYP-Misc Power Plant | | 1.71% |
| 15 | | | STEAM GENERATION - Neal 4 | | |
| 16 | 311 | | 311.0-NLP-Structures & Improvement | | 0.63% |
| 17 | 312 | | 312.0-NLP-Boiler Plant Equipment | | 2.63% |
| 18 | 314 | | 314.0-NLP-Turbo-Generator | | 1.72% |
| 19 | 315 | | 315.0-NLP-Accessory Electric | | 1.23% |
| 20 | 316 | | 316.0-NLP-Misc Power Plant | | 1.43% |
| 21 | | | OTHER GENERATION | | |
| 22 | 340 | | 340.0-Other Production-Diesel-Land | | 0.00% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 23 | 341 | | 341.0-Other Production-Diesel-Struc | | | 2.07% | | | |
| 24 | 342 | | 342.0-Other Production-Diesel-Fuel | | | 2.24% | | | |
| 25 | 342 | | 342.1-GT Pipelines | | | 2.24% | | | |
| 26 | 342 | | 342.2-GT Compressors | | | 2.24% | | | |
| 27 | 343 | | 343.0-Prime Movers & Generators | | | 2.41% | | | |
| 28 | 344 | | 344.0-Movers and Generators | | | 2.66% | | | |
| 29 | 345 | | 345.0-Accessory Electric Equipment | | | 2.60% | | | |
| 30 | 346 | | 346.0-Misc. Power Plant Equipment | | | 3.46% | | | |
| 31 | | | TRANSMISSION | | | | | | |
| 32 | 350 | | 350.1-Transmission Land | | | 0.00% | | | |
| 33 | 350 | | 350.2-Transmission Land Rights | | | 0.00% | | | |
| 34 | 352 | | 352.0-Trans Elec Structures & Impro | | | 2.03% | | | |
| 35 | 353 | | 353.0-Trans Elec Station Equipment | | | 2.53% | | | |
| 36 | 355 | | 355.0-Tran Elec Poles & Fixtures | | | 4.65% | | | |
| 37 | 356 | | 356.0-Tran Elec Overhead Conductors | | | 2.81% | | | |
| 38 | 357 | | 357.0-Transmission-Underground Cond | | | 2.08% | | | |
| 39 | 358 | | 358.0-Transmission-UG Conductor & D | | | 3.26% | | | |
| 40 | | | DISTRIBUTION | | | | | | |
| 41 | 360 | | 360.1-Distribution Land | | | 0.00% | | | |
| 42 | 360 | | 360.2-Distribution Land Rights | | | 0.00% | | | |
| 43 | 361 | | 361.0-Distribution Structures & Imp | | | 2.39% | | | |
| 44 | 362 | | 362.0-Distribution Elec Station Equ | | | 2.60% | | | |
| 45 | 364 | | 364.0-Distribution Poles & Fixtures | | | 5.39% | | | |
| 46 | 365 | | 365.0-Distribution Overhead Conduct | | | 3.86% | | | |
| 47 | 366 | | 366.0-Distribution UG Conduit | | | 2.79% | | | |
| 48 | 367 | | 367.0-Distribution UG Conductor & D | | | 3.35% | | | |
| 49 | 368 | | 368.0-Distribution Line Transformer | | | 2.20% | | | |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 50 | 369 | | 369.1-Distribution Service Overhead | | | 4.72% | | | |
| 51 | 369 | | 369.2-Distribution Service Undergro | | | 4.72% | | | |
| 52 | 370 | | 370.0-Distribution Meters Electric | | | 4.97% | | | |
| 53 | 371 | | 371.0-Distribution-Install on Cust | | | 7.46% | | | |
| 54 | 373 | | 373.1-Dist Street Lighting & Signal | | | 5.41% | | | |
| 55 | | | INTANGIBLE | | | | | | |
| 56 | 303 | | 303.1-Intan Plant 10 Year Software | | | 10.00% | | | |
| 57 | 303 | | 303.5-Intan Plant 5 Year Software | | | 20.00% | | | |
| 58 | | | GENERAL | | | | | | |
| 59 | 389 | | 389.0-General Plant-Land | | | 0.00% | | | |
| 60 | 390 | | 390.1-Gen Plt Structures & Impv Dis | | | 2.04% | | | |
| 61 | 392 | | 392.20-Gen Plt Util Trans-Trailers | | | 5.94% | | | |
| 62 | 392 | | 392.40-Gen Plt Util Trans-Heavy Tru | | | 5.61% | | | |
| 63 | 392 | | 392.50-Gen Plt Util Trans-Light Tru | | | 10.03% | | | |
| 64 | 393 | | 393.0-Gen Plt Util Stores Equipment | | | 3.12% | | | |
| 65 | 394 | | 394.0-Gen Plt Util Tools,Shop, & Ga | | | 6.67% | | | |
| 66 | 396 | | 396.0-Gen Plt Util Power Operated E | | | 4.59% | | | |
| 67 | 397 | | 397.0-Gen Plt Util Comm Equip Compu | | | 10.00% | | | |
| 68 | 397 | | 397.2-Gen Plt Util Comm Equip Other | | | 7.29% | | | |
| | | | | | | | | | |
| | [1] These depreciation and amortization rates shall not change absent a Section 205 or 206 filing before the Commission. | | | | | | | | |
| Attachment 10 | | | | | | | | | |
| Page 1 of 1 | | | | | | | | | |

| Line | Asset Location | EOY Original Cost | EOY Depreciation Reserve | EOY Net Book Value | BOY Original Cost | BOY Depreciation Reserve | BOY Net Book Value | Average Original Cost 20XX-20XX | Average Depreciation Reserve 20XX-20XX | Average Net Book Value 20XX-20XX | Original Cost in SPP | Depreciation Reserve in SPP | Net Book Value in SPP | Annual Depreciation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
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| 36 | **Grand Total** | | | | | | | | | | | | | |
| 37 | | | | | | | | | | | | | | |
| 38 | | | | | | | | | *Breakout by FERC account:* | | | | | |
| 39 | | | | | | | | | 350.1-Transmission Land | | | | | |
| 40 | | | | | | | | | 350.2-Trans Land Rights | | | | | |
| 41 | | | | | | | | | 352.0-Transmission-Structu | | | | | |
| 42 | | | | | | | | | 353.0-Transmission-Stat Eq | | | | | |
| 43 | | | | | | | | | 355.0-Tran Elec Poles & Fixtures | | | | | |
| 4 | | | | | | | | | 356.0-Tran Elec OH Conductors & | | | | | |

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| 45 | | | | | | | | | 357.0-Trans-UG Conduit | | | | | |
| | | | | | | | | | 358.0-Transmission-UG Conductor & D | | | | | |
| | | | | | | | | | 397.0-Electric 10yr Comm Equip | | | | | |

## Attachment 12, Base Plan Funded Projects

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED**
**UPGRADE SUMMARY LISTS:**

| Ln | BASE PLAN and "PARTIAL" BASE PLAN FUNDED (RELIABILITY) UPGRADES | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | BOY/EOY Average Net Book Value | ATRR w/o Incentives | Incentive ATRR | Gross ATRR w/ Incentives | Sch. 11 Point to Point Revenue Credit | Net ATRR w/ Incentives |
| 1 | 0 | 3 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 2 | 0 | 4 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 3 | 0 | 5 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | 0 | 6 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 5 | 0 | 7 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 6 | 0 | 8 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 7 | 0 | 9 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 8 | 0 | 10 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 9 | 0 | 11 | 0 | 1/0/1900 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 10 | 0 | 12 | 0 | 1/0/190 | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0 |

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| 5 | **Reliability and "Partial" Base Plan Funded Upgrade Totals** | | | | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |
| 4 | | | | | | | | | | |

**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE SUMMARY LISTS (Continued):**

| Ln | ECONOMIC UPGRADES | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | BOY/EOY Average Net Book Value | ATRR w/o Incentives | Incentive ATRR | Gross ATRR w/ Incentives | Sch. 11 Point to Point Revenue Credit | Net ATRR w/ Incentives |
| 1 | | | | | | | | | | |
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| 9 | | | | | | | | | | |
| 10 | **Economic Upgrade Totals** | | | | $ - | $ - | $ - | $ - | $ - | $ - |

| BALANCED PORTFOLIO UPGRADES |
|---|

| | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | BOY/EOY Average Net Book Value | ATRR w/o Incentives | Incentive ATRR | Gross ATRR w/ Incentives | Sch. 11 Point to Point Revenue Credit | Net ATRR w/ Incentives |
|---|---|---|---|---|---|---|---|---|---|---|
| 11 | | | | | | | | | | |
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| 19 | | | | | | | | | | |
| 20 | **Balanced Portfolio Upgrade Totals** | | | | $ - | $ - | $ - | $ - | $ - | $ - |

| | **INTEGRATED TRANSMISSION PLANNING UPGRADES** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | SPP UID # | "Detail" Page, From Below | Upgrade Description | In-Service Date | BOY/EOY Average Net Book Value | ATRR w/o Incentives | Incentive ATRR | Gross ATRR w/ Incentives | Sch. 11 Point to Point Revenue Credit | Net ATRR w/ Incentives |
| 21 | | | | | | | | | | |
| 22 | | | | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 23 | | | | | | | | | |
| 24 | | | | | | | | | |
| 25 | | | | | | | | | |
| 26 | | | | | | | | | |
| 27 | | | | | | | | | |
| 28 | | | | | | | | | |
| 29 | | | | | | | | | |
| 30 | | | | | | | | | |
| 31 | | | | | | | | | |
| 32 | | | | | | | | | |
| 33 | | | | | | | | | |
| 34 | | | | | | | | | |
| 35 | | | | | | | | | |
| 36 | | | | | | | | | |
| 37 | | | | | | | | | |
| 38 | **Integrated Transmission Planning Upgrade Totals** | | | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 39 | **TOTAL** (Net Plant, ATRR w/o Incentives, Incentive ATRR) for SPP Base Plan Funded Upgrades<br><br>[Sum Line 54 (Page 1) , Line 10 (Page 2), Line 20 (Page 2), & Line 38 (Page 2)] | $ - | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! | #DIV/0! |



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED**
**UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |

| | | |
|---|---|---|
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | #DIV/0! |
| | **Investment Return on Upgrade w/o Incentive** | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | #DIV/0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | #DIV/0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV/0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV/0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV/0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV/0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV/0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV/0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV/0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV/0! |
| | **Depreciation Expense** | |

| | | |
|---|---|---|
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV/0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV/0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property | | | |

| | | |
|---|---|---|
| | Acctg From ATT 11] | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | #DIV /0! |
| | **Investment Return on Upgrade w/o Incentive** | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | #DIV /0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | #DIV /0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV /0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV /0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV /0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV /0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV /0! |
| | **Transmission O&M** | |

| | | |
|---|---|---|
| | **Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV /0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV /0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV /0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV /0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV /0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV /0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV /0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV /0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV /0! |

| | | |
|---|---|---|
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

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Line

| | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |

| | | | | |
|---|---|---|---|---|
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV /0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | | | #DIV /0! |
| | **Investment Return on Upgrade w/o Incentive** | | | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | | | #DIV /0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | | | #DIV /0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | | | #DIV /0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | | | #DIV /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | | | #DIV /0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | | | |
| 17. | Total General and Intangible | | | #DIV |

| | | |
|---|---|---|
| | Functionalized to Transmission [From Appendix A, Ln. 25] | /0! |
| | Subtotal General and Intangible Accum. | #DIV |
| 18. | Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | /0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV /0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV /0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV /0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV /0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV /0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV /0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV /0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV /0! |

| | | |
|---|---|---|
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV /0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV /0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV /0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV /0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational

purposes).

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | | | #DIV/0! |
| | **Investment Return on Upgrade w/o Incentive** | | | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | | | #DIV/0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | | | #DIV/0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | | | #DIV/0! |
| 14. | Rate of Return on Rate | | | #DIV |

| | | |
|---|---|---|
| | Base (ROR) [From Appendix A, Ln. 96] | /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV /0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV /0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV /0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV /0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV /0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV /0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV /0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV /0! |
| | **Income Taxes Attributable to Upgrade** | |

| | | |
|---|---|---|
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment 12
Pg. 6 of 14

**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

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years may change as this Attachment 12 of this Transmission Formula Rate is
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years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation,
to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

Line

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV /0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | | | #DIV /0! |
| | **Investment Return on Upgrade w/o Incentive** | | | |

| | | |
|---|---|---|
| | Total Adjustments to Rate | #DIV/0! |
| 11. | Base [From Appendix A, Ln. 47] | |
| | Portion of Adjustments to Rate | #DIV/0! |
| 12. | Base Attributable to Upgrade [Line 11 x Line 10] | |
| | Upgrade adjusted | #DIV/0! |
| 13. | BOY/EOY Net Book Value [Line 6 - Line 12] | |
| | Rate of Return on Rate | #DIV/0! |
| 14. | Base (ROR) [From Appendix A, Ln. 96] | |
| | Investment Return w/o | #DIV/0! |
| 15. | Incentive on Upgrade [Line 13 x Line 14] | |
| | | |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| | Total General and Intangible | #DIV/0! |
| 17. | Functionalized to Transmission [From Appendix A, Ln. 25] | |
| | Subtotal General and Intangible Accum. | #DIV/0! |
| 18. | Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | |
| | General and Intangible Functionalized to | #DIV/0! |
| 19. | Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | |
| | | |
| | **Transmission O&M Attributable to Upgrade** | |
| | Total Transmission O&M | #DIV/0! |
| 20. | [From Appendix A, Ln. 66] | |
| | Transmission O&M | #DIV/0! |
| 21. | Attributable to Upgrade [Line 10 x Line 20] | |
| | | |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |

| | | |
|---|---|---|
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV/0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV/0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

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**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

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Line

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From | | | $ - |

| | | |
|---|---|---|
| | Inputs, Pg. 2, Ln. 14] | |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | #DIV/0! |
| | **Investment Return on Upgrade w/o Incentive** | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | #DIV/0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | #DIV/0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV/0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV/0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV/0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV/0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV/0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV/0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV/0! |
| 21. | Transmission O&M Attributable to Upgrade | #DIV/0! |

| | | |
|---|---|---|
| | [Line 10 x Line 20] | |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV/0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV/0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 +** | #DIV/0! |

| |
|---|
| **Line 31]** |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

Line

| | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |

| | | |
|---|---|---|
| 5. | Upgrade In-Service Date: | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | #DIV /0! |
| | **Investment Return on Upgrade w/o Incentive** | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | #DIV /0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | #DIV /0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV /0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV /0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV /0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV /0! |
| 19. | General and Intangible Functionalized to | #DIV |

| | | |
|---|---|---|
| | Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | /0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV /0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV /0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV /0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV /0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV /0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV /0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV /0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT | #DIV /0! |

| | | |
|---|---|---|
| | 6, Ln. 3, Col. B] | |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV /0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV /0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV /0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment 12
Pg. 9 of 14

**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

| Line | | |
|---|---|---|
| 1. | Upgrade Description: | |

| | | Column A | | Column B |
|---|---|---|---|---|
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | | | #DIV/0! |
| | **Investment Return on Upgrade w/o Incentive** | | | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | | | #DIV/0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | | | #DIV/0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | | | #DIV/0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | | | #DIV/0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | | | #DIV/0! |

| | | |
|---|---|---|
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV/0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV/0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV/0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV/0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV/0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV/0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV/0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |

| | | |
|---|---|---|
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

Attachment 12
Pg. 10 of 14

**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior

years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation,
to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

Line

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | | | #DIV/0! |
| | **Investment Return on Upgrade w/o Incentive** | | | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | | | #DIV/0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade | | | #DIV/0! |

| | | |
|---|---|---|
| | [Line 11 x Line 10] | |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV /0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV /0! |
| | | |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV /0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV /0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV /0! |
| | | |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV /0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV /0! |
| | | |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV /0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x | #DIV /0! |

| | | |
|---|---|---|
| | Line 23] | |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00% |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED**
**UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |

| | | |
|---|---|---|
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | #DIV/0! |
| | **Investment Return on Upgrade w/o Incentive** | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | #DIV/0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | #DIV/0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV/0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV/0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV/0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV/0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV/0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV/0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV/0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV/0! |
| | **Depreciation Expense** | |

| | | |
|---|---|---|
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV/0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV/0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV/0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV/0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV/0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

| Line | | | | |
|---|---|---|---|---|
| 1. | Upgrade Description: | | | |
| | | Column A | | Column B |
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV/0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value | | | |

| | | |
|---|---|---|
| | [Company Records from Mgr of Property Acctg From ATT 11] | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | #DIV /0! |
| | **Investment Return on Upgrade w/o Incentive** | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | #DIV /0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | #DIV /0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | #DIV /0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | #DIV /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | #DIV /0! |
| 16. | **Total General and Intangible Functionalized to Transmission Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV /0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV /0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV /0! |

| | | |
|---|---|---|
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV /0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV /0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV /0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV /0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV /0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV /0! |
| 27. | **Upgrade ATRR w/o Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | #DIV /0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV /0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x | #DIV /0! |

| | | |
|---|---|---|
| | Line 29 x 100] | |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV/0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV/0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.



**Attachment 12, SPP Base Plan Funded Projects**

(For Rate Year Beginning April 1, 20xx, Based on December 31, 20xx Data)

**SPP BASE PLAN FUNDED UPGRADE DETAILS:**

The calculated revenue requirements displayed below for prior years may change as this Attachment 12 of this Transmission Formula Rate is updated in subsequent years. The values displayed for the current year are valid only during the current year. Any changes to the prior years' calculations will not result in a refund or additional charge for prior years. NorthWestern reserves the option, but not the obligation, to "lock in" such prior years revenue requirements during each successive Annual Update (to retain data for informational purposes).

Line

| | | | |
|---|---|---|---|
| 1. | Upgrade Description: | | |
| | | Column | Column B |

| | | A | | |
|---|---|---|---|---|
| 2. | SPP UID # : | | | |
| 3. | SPP NTC Approval Letter Date: | | Incentive ROE (See Note 1, below): | 0.00 % |
| 4. | Upgrade Status: | | ROE Incentive Adder to ROR [Line 3 X Line 30, Col. B]: | #DIV /0! |
| 5. | Upgrade In-Service Date: | | | |
| 6. | Average BOY/EOY Net Book Value [Company Records from Mgr of Property Acctg From ATT 11] | | | |
| 7. | Average BOY/EOY Transmission Gross Plant under SPP tariff [From Inputs, Pg. 2, Ln. 13] | | | $ - |
| 8. | Average BOY/EOY Transmission Accum Depreciation on assets under SPP tariff [From Inputs, Pg. 2, Ln. 14] | | | $ - |
| 9. | Average BOY/EOY Net Transmission Under SPP tariff [Line 7 - Line 8] | | | $ - |
| 10. | Upgrade Percentage of Net Transmission Under SPP tariff [Line 6 / Line 9] | | | #DIV /0! |
| | **Investment Return on Upgrade w/o Incentive** | | | |
| 11. | Total Adjustments to Rate Base [From Appendix A, Ln. 47] | | | #DIV /0! |
| 12. | Portion of Adjustments to Rate Base Attributable to Upgrade [Line 11 x Line 10] | | | #DIV /0! |
| 13. | Upgrade adjusted BOY/EOY Net Book Value [Line 6 - Line 12] | | | #DIV /0! |
| 14. | Rate of Return on Rate Base (ROR) [From Appendix A, Ln. 96] | | | #DIV /0! |
| 15. | Investment Return w/o Incentive on Upgrade [Line 13 x Line 14] | | | #DIV /0! |
| 16. | **Total General and Intangible Functionalized to Transmission** | | | |

| | | |
|---|---|---|
| | **Attributable to Upgrade** | |
| 17. | Total General and Intangible Functionalized to Transmission [From Appendix A, Ln. 25] | #DIV/0! |
| 18. | Subtotal General and Intangible Accum. Depreciation Allocated to Transmission [From Appendix A, Ln. 33] | #DIV/0! |
| 19. | General and Intangible Functionalized to Transmission Attributable to Upgrade [(Line 17 - Line 18) x Line 10] | #DIV/0! |
| | **Transmission O&M Attributable to Upgrade** | |
| 20. | Total Transmission O&M [From Appendix A, Ln. 66] | #DIV/0! |
| 21. | Transmission O&M Attributable to Upgrade [Line 10 x Line 20] | #DIV/0! |
| | **Depreciation Expense** | |
| 22. | Annual Depreciation [Company Records from Mgr of Property Acctg From ATT 11] | |
| | **Taxes Other than Income Taxes Attributable to Upgrade** | |
| 23. | Total Taxes Other than Income Taxes [From Appendix A, Ln. 75] | #DIV/0! |
| 24. | Taxes Other than Income Taxes Attributable to Upgrade [Line 10 x Line 23] | #DIV/0! |
| | **Income Taxes Attributable to Upgrade** | |
| 25. | Total Income Taxes [From Appendix A, Ln. 106] | #DIV/0! |
| 26. | Income Taxes Attributable to Upgrade [Line 10 x Line 25] | #DIV/0! |
| 27. | **Upgrade ATRR w/o** | #DIV |

| | | |
|---|---|---|
| | **Incentive [Lines 15 + 19 + 21 + 22 + 24 + 26]** | /0! |
| 28. | Tax Gross-Up Factor [From Appendix A, Ln. 102] | 0.00 % |
| 29. | Weighted Cost Ratio of Common Stock [From ATT 6, Ln. 3, Col. B] | #DIV /0! |
| 30. | Percentage Point increase in ROR for each 1.00% of "Incentive ROE" [(0.0100/Line 28) x Line 29 x 100] | #DIV /0! |
| 31. | Incentive Investment Return on Upgrade [Line 4 x Line 13] | #DIV /0! |
| 32. | **Upgrade ATRR w Incentives [Line 27 + Line 31]** | #DIV /0! |

Note 1: The Incentive ROE percentage shall remain at zero, except as authorized by FERC through a separate Section 205 filing for specific SPP projects.

# NorthWestern Corporation (South Dakota)
# Formula Rate Protocols

NorthWestern Corporation d/b/a NorthWestern Energy's Formula Rate Template and these Formula Rate Protocols together compose NorthWestern Energy's filed rate ("**Formula Rate**") for transmission service in the Upper Missouri Zone ("**UMZ**") of Southwest Power Pool, Inc. ("**SPP**"). NorthWestern Energy must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirement ("**ATRR**").

The Formula Rate applies to service on and after April 1 of each calendar year through March 31 of the following calendar year ("**Rate Year**"). On or before March 1 of each year, NorthWestern Energy will recalculate the ATRR for the upcoming Rate Year in accordance with the Formula Rate ("**Annual Update**"). These Protocols outline the procedures for notice and review of, and challenges to, NorthWestern Energy's Annual Update.

If the deadline for any requirement in these Protocols falls on a Saturday, Sunday, or legal holiday, the requirement will be due the next business day.

## I. Annual Update – Publication, Meetings, and Notice Requirements

A. Publication

1. On or before March 1, NorthWestern Energy will provide its Annual Update to SPP, and SPP will post the Annual Update on its OASIS. The date on which such posting occurs is that year's "**Publication Date**."

2. Within 10 days of the Publication Date, NorthWestern Energy will provide electronic notice of the Annual Update to all Interested Parties through the Formula Rate Posting Information Notification List discussed in Paragraph I.C.

3. Any delay in the Publication Date will result in an equivalent extension of time for subsequent deadlines.

B. Annual Meeting

1. Each year, NorthWestern Energy will host an open meeting no sooner than 30 days after the Publication Date and no later than June 1 ("**Annual Meeting**"). NorthWestern Energy will provide remote access for participation in the Annual Meeting.

2. The Annual Meeting will permit NorthWestern Energy to explain and clarify its Annual Update and provide Interested Parties (as defined in Paragraph I.C) an

opportunity to seek information and clarifications from NorthWestern Energy about the Annual Update.

3. At least 7 days before the Annual Meeting, NorthWestern Energy will provide notice of the time, date, location, and remote access instructions for the Annual Meeting through a posting on SPP's OASIS and via the Formula Rate Posting Information Notification List.

C. As used in these Protocols "Formula Rate Posting Information Notification List" means the email exploder maintained by SPP of Interested Parties , provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification List through the "Exploder List" link on the SPP website. As of January 2016, the Exploder List was titled "Formula Rate Posting Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. "**Interested Parties**" include but are not limited to customers under the SPP tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

D. Joint Informational Meeting

1. NorthWestern Energy will endeavor to coordinate with other transmission owners using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

2. Notice of any Joint Informational Meeting will be provided at least 7 days before the meeting through a posting on SPP's OASIS and via the Formula Rate Posting Information Notification List. The notice will include the time, date, location, and remote access instructions for the meeting.

3. Any Joint Informational Meetings will be held on or before August 1 of each year.

## II. Annual Update - Contents

A. The Annual Update for the Rate Year will include a workable data-populated Formula Rate Template and underlying workpapers in native format with all formulas and links intact.

B. To the extent specified in the Formula Rate, the Annual Update will be based upon NorthWestern Energy's FERC Form No. 1 for the most recent calendar year and, to the extent specified in the Formula Rate, upon the books and records of NorthWestern Energy consistent with FERC accounting regulations, policies, and practices.

C. The Annual Update will provide sufficiently detailed workpapers and supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to

develop the Formula Rate and are not otherwise available directly from the FERC Form No. 1.

D. The Annual Update will provide sufficient information to enable Interested Parties to replicate the calculation.

E. The Annual Update will identify any changes in the formula references (page and line numbers) to the FERC Form No. 1.

F. The Annual Update will identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1, and any adjustments not shown in the FERC Form No. 1.

G. With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("**Accounting Change**"), the Annual Update will:

1. Identify any Accounting Changes, including:

    a. The initial implementation of an accounting standard or policy;

    b. The initial implementation of accounting practices for unusual or unconventional items where the Federal Energy Regulatory Commission ("FERC") has not provided specific accounting direction;

    c. Correction of errors and prior period adjustments that impact the revenue requirement;

    d. The implementation of new estimation methods or policies that change prior estimates; and

    e. Changes to income tax elections.

2. Identify items included in the Formula Rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

3. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction on inputs to the Formula Rate; and

4. For each Accounting Change identified pursuant to this section, provide a narrative explanation of the individual impact of such change on charges billed under the Formula Rate.

H. The Annual Update will not seek to modify the Formula Rate.

I. The following inputs will be stated values to be used in the Formula Rate until changed pursuant to a Federal Power Act Section 205 or 206 proceeding:

1. Rate of return on common equity ("ROE"); and

2. The depreciation and/or amortization rates.

## III. Information Exchange Procedures

Each Annual Update will be subject to the following Information Exchange Procedures.

A. Interested Parties will have until September 1 following the Publication Date (unless such period is extended with the written consent of NorthWestern Energy or by FERC order) to serve reasonable information and document requests on NorthWestern Energy ("**Information Exchange Period**"). The scope of such information and document requests will be limited to what is necessary to determine:

1. The extent, effect, or impact of an Accounting Change;

2. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

3. The proper application of the Formula Rate and procedures in these Protocols;

4. The accuracy of data and consistency with the Formula Rate of the changes shown in the Annual Update;

5. The prudence of actual costs and expenditures;

6. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests may not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

B. NorthWestern Energy must make a good-faith effort to respond to information and document requests pertaining to the Annual Update within 15 business days of receiving such requests. Information and document requests received after 4:00 P.M. Central Prevailing Time will be considered received the next business day. NorthWestern Energy will respond to all information and document requests by no later than October 1 following the Publication Date, unless the Information Exchange Period is extended by NorthWestern Energy or by FERC.

C. NorthWestern Energy will cause to be posted on SPP's OASIS all information and document requests from Interested Parties and NorthWestern Energy's response to such requests, unless the responses include material deemed by NorthWestern Energy to be confidential information. Any confidential information will not be publicly posted but will be made

available to a requesting party pursuant to a confidentiality agreement to be executed by NorthWestern Energy and the requesting party.

D. NorthWestern Energy may not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement privilege in any subsequent FERC proceeding addressing NorthWestern Energy's Annual Update.

## IV. Challenge Procedures

A. A challenge must be limited to issues that may be necessary to determine (1) the extent, effect, or impact of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these Protocols; (3) the proper application of the Formula Rate and procedures in these Protocols; (4) the accuracy of data and consistency with the Formula Rate of the changes shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

B. Informal Challenge

1. Interested Parties will have until October 31 after the Publication Date (unless such period is extended with the written consent of NorthWestern Energy or by FERC order) to review the inputs, supporting explanations, allocations, and calculations and to notify NorthWestern Energy in writing, which notice may be made electronically, of any specific Informal Challenge. The period of time from the Publication Date until October 31 is the "**Review Period**."

2. Failure to pursue an issue through an Informal Challenge will not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update, as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursing a Formal Challenge with respect to any issue for that Annual Update, but is not barred from pursuing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

3. A party submitting an Informal Challenge to NorthWestern Energy must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects and must provide an appropriate explanation and documents to support its challenge.

4. NorthWestern Energy must make a good-faith effort to respond to any Informal Challenge within 20 business days of notice of such challenge. NorthWestern Energy will appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If NorthWestern Energy disagrees with such challenge, NorthWestern Energy will

provide the Interested Party with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.

5. No Informal Challenge may be submitted after October 31, and NorthWestern Energy must respond to all Informal Challenges by no later than November 30, unless the Review Period is extended by NorthWestern Energy or by FERC.

6. Informal Challenges are subject to the resolution procedures and limitations in this Section IV.

7. NorthWestern Energy will cause to be posted on SPP's OASIS all Informal Challenges from Interested Parties and NorthWestern Energy's response to such Informal Challenges, unless a challenge or the response includes material deemed by NorthWestern Energy to be confidential information. Any confidential information will not be publicly posted but will be made available to the challenging party pursuant to a confidentiality agreement to be executed by NorthWestern Energy and the challenging party.

8. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by NorthWestern Energy will be reported in the Informational Filing required pursuant to Section VI of these Protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

C. Formal Challenge

1. A Formal Challenge must satisfy all of the following requirements:

a. A Formal Challenge must clearly identify the action or inaction which is alleged to violate the Formula Rate.

b. A Formal Challenge must explain how the action or inaction violates the Formula Rate.

c. A Formal Challenge must set forth the business, commercial, economic, or other issues presented by the action or inaction as such relates to or affects the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

iii. The proper application of the Formula Rate;

iv. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;

v. The prudence of actual costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or the FERC Form No. 1; or

vii. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

d. A Formal Challenge must make a good-faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction.

e. A Formal Challenge must state whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party and, if so, provide an explanation why timely resolution cannot be achieved in that forum.

f. A Formal Challenge must state the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief.

g. A Formal Challenge must include all documents that support the facts in the Formal Challenge in possession of or otherwise attainable by the filing party, including but not limited to contracts and affidavits.

h. A Formal Challenge must state whether the filing party utilized the Informal Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and if not, describe why not.

2. An Interested Party will have until January 15 following the Review Period (unless such date is extended with the written consent of NorthWestern Energy to continue efforts to resolve an Informal Challenge) to file a Formal Challenge with FERC. A Formal Challenge must be filed in the same docket as NorthWestern Energy's Informational Filing discussed in Section VI, below.

3. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on NorthWestern Energy. Service to NorthWestern Energy must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge must serve the individual listed as the contact person on NorthWestern Energy's Informational Filing discussed in Section VI, below.

4. NorthWestern Energy must respond to the Formal Challenge by the deadline established by FERC, unless an extension is granted by FERC.

5. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

6. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or the FERC Form No. 1 must first raise the matter with NorthWestern Energy before pursuing a Formal Challenge.

7. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, NorthWestern Energy bears the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate in that year's Annual Update. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Except as specifically provided herein, nothing in these Protocols limits NorthWestern Energy's right to file unilaterally, pursuant to Federal Power Act Section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to Section 206 of the Federal Power Act and the regulations thereunder.

E. No party may seek to modify the Formula Rate under these Challenge Procedures, and the Annual Update is not subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, a filing under Section 205 or 206of the Federal Power Act.

## V. Changes to Annual Update

A. If NorthWestern Energy files any corrections to correct a Mistake in its FERC Form No. 1 during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges will be reflected in the Annual Update for the next effective Rate Year, with interest computed in accordance with 18 C.F.R. § 35.19a ("**FERC's Interest Rate**"). For purposes of these Protocols, "**Mistake**" means errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or other inadvertent computational errors, erroneous Form No. 1 references, or the like. Mistakes do not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process. Corrections to erroneous FERC Form No. 1 references in the Formula Rate Template may be made in the Annual Update without a Section 205 or 206 filing. There is no deadline for any Interested Party or NorthWestern Energy to notify the other party of any mistake in any FERC Form No. 1 data or specific data applied in the Formula Rate Template.

B. Any changes to the data inputs, including but not limited to revisions to NorthWestern Energy's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, will be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism will apply in lieu of mid-Rate Year

adjustments. Interest on any refund will be calculated in accordance with FERC's Interest Rate, and interest on any surcharge will be calculated using the lower of FERC's Interest Rate or NorthWestern Energy's short-term borrowing rate, if applicable.

## VI. Informational Filing

A. By December 15 of each year, NorthWestern Energy will submit to FERC an informational filing of its Annual Update ("**Informational Filing**"), which will be filed in a new docket each year. This Informational Filing will include the information that is reasonably necessary to determine (1) that input data under the Formula Rate is properly recorded in any underlying workpapers; (2) that NorthWestern Energy has properly applied the Formula Rate; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of Accounting Changes that affect Formula Rate inputs. The Informational Filing will also describe any corrections or adjustments made during the Review Period, and will note any aspects of the Formula Rate or its inputs that are subject to an ongoing dispute under the Challenge Procedures.

B. Within 5 days of such Informational Filing, NorthWestern Energy will provide notice of the Informational Filing via the Formula Rate Posting Information Notification List and by posting the docket number assigned to NorthWestern Energy's Informational Filing on SPP's OASIS.

C. Any challenges to the implementation of NorthWestern Energy's Formula Rate must be made through the Challenge Procedures described in Section IV, above, or in a separate complaint proceeding, and not in response to the Informational Filing.

# ADDENDUM 26 TO ATTACHMENT H – Part 14

North Iowa Municipal Electric Cooperative Association (NIMECA)



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20 XX

NIMEC A Agency

| Line No. | | Allocated Amount |
|---|---|---|

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT (page 3, line 31) | | | | | $ - | |
| | REVENUE CREDITS | (Note O) | Total | Allocator | | | |
| 2 | Account No. 454 | (page 4, line 30) | 0 | TP | 0.0000 | 0 | |
| 3 | Account No. 456.1 | (page 4, line 33) | 0 | TP | 0.0000 | 0 | |
| 4 | Revenues from Grandfathered Interzonal Transactions | NIMECA Financial Statements | 0 | TP | 0.0000 | 0 | |

| Pricing Zone | Gross Plant | ATRR Allocation | ATRR |
|---|---|---|---|
| **UMZ (SPP)** | $ - | #DIV/0! | **#DIV/0!** |
| **Non UMZ *** | $ - | #DIV/0! | #DIV/0! |
| **Total** | $ - | #DIV/0! | #DIV/0! |

* Gross tranmission plant not included in SPP.

| | | | | | | |
|---|---|---|---|---|---|---|
| 5 | Revenues from service provided by the ISO at a discount | NIMECA Financial Statements | 0 | TP | 0.0000 | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |
| 7 | NET REVENUE REQUIREMENT | (line 1 minus line 6) | | | | $ - |
| | DIVISOR | | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8. | | | | (Note B) | 0 |
| 10 | Plus 12 CP of Network Load not in line 8 | | | | (Note C) | 0 |
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | | | | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | | | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note S) | | | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | | | 0 | |
| 15 | Divisor (sum lines 8-14) | | | | 0 | |
| 16 | Annual Cost ($/kW/Yr) | (line 7/ line 15) | 0.000 | | | |
| 17 | Network & P-to-P Rate ($/kW/Mo) (line 11/ 12) | | 0.000 | | | |
| | | | Peak Rate | | Off-Peak Rate | |
| 18 | Point-To-Point Rate ($/kW/Wk) | (line 16 / 52; line 16/ 52) | 0.000 | | $0.000 | |
| 19 | Point-To-Point Rate ($/kW/Day) | (line 16/ 260; line 16/ 365) | 0.000 | Capped at weekly rate | $0.000 | |
| 20 | Point-To-Point Rate ($/MWh) | (line 16/ 4,160; line 16/ 8,760 times 1,000) | 0.000 | Capped at weekly and daily rates | $0.000 | |
| 21 | FERC Annual | | $0.0 | Short | $0.000 | Sh |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Charge($/MWh) | (Note E) | 00 | Term | | ort Te rm Lo ng |
| 2 | | | $0.0 | Long | | Te |
| 2 | | | 00 | Term | $0.000 | rm |



Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

NIMECA Agency

| (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|
| | | | | **Transmis** |

| Line No. | | | Company Total | Allocator | | sion (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | **RATE BASE:** | | | | | |
| | GROSS PLANT IN SERVICE (Note W) | | | | | |
| 1 | Production | Worksheet 2 | 0 | NA | 0.0000 0 | 0 |
| 2 | Transmission | Worksheet 2 | 0 | TP | 0.0000 0 | 0 |
| 3 | Distribution | Worksheet 2 | 0 | NA | 0.0000 0 | 0 |
| 4 | General & Intangible | Worksheet 2 | 0 | W/S | 0.0000 0 | 0 |
| 5 | Common | NIMECA Financial Statements | 0 | CE | 0.0000 0 | 0 |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | 0 | GP= | 0.000 | 0 |

| | | | | | % | |
|---|---|---|---|---|---|---|
| | ACCUMULATED DEPRECIATION (Note W) | | | | | |
| 7 | Production | Worksheet 2 | 0 | NA | 0.000000 | 0 |
| 8 | Transmission | Worksheet 2 | 0 | TP | 0.000000 | 0 |
| 9 | Distribution | Worksheet 2 | 0 | NA | 0.000000 | 0 |
| 10 | General & Intangible | Worksheet 2 | 0 | W/S | 0.000000 | 0 |
| 11 | Common | NIMECA Financial Statements | 0 | CE | 0.000000 | 0 |
| 12 | TOTAL ACCUM. DEPRECIATION (sum lines 7-11) | | 0 | | | 0 |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1-line 7) | 0 | | | 0 |
| 14 | Transmission | (line 2-line 8) | 0 | | | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 15 | Distribution | (line 3 - line 9) | 0 | | | 0 |
| 16 | General & Intangible | (line 4 - line 10) | 0 | | | 0 |
| 17 | Common | (line 5 - line 11) | 0 | | | 0 |
| 18 | TOTAL NET PLANT (sum lines 13-17) | | 0 | NP= | 0.000 % | 0 |
| | ADJUSTMENTS TO RATE BASE (Note F) | | | | | |
| 19 | Account No. 281 (enter negative) | NIMECA Financial Statements | 0 | | zero | 0 |
| 20 | Account No. 282 (enter negative) | NIMECA Financial Statements | 0 | NP | 0.0000 | 0 |
| 21 | Account No. 283 (enter negative) | NIMECA Financial Statements | 0 | NP | 0.0000 | 0 |
| 22 | Account No. 190 | NIMECA Financi | 0 | NP | 0.0000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| 23 | Account No. 255 (enter negative) | al Statements NIMECA Financial Statements | 0 | NP | 0.0000 | 0 |
| 24 | TOTAL ADJUSTMENTS (sum lines 19 - 23) | | 0 | | | 0 |
| 25 | LAND HELD FOR FUTURE USE | Worksheet 5 (Note F) | 0 | TP | 0.0000 | 0 |
| 26 | WORKING CAPITAL<br>CWC | (Note G) (Page 3, line 8 / 8) | 0 | | | 0 |
| 27 | Materials & Supplies | Worksheet 6 (Note F) | 0 | TE | 0.0000 | 0 |
| 28 | Prepayments | Worksheet 7 | 0 | GP | 0.0000 | 0 |
| 29 | TOTAL WORKING CAPITAL (sum lines 26 - 28) | | 0 | | | 0 |
| 30 | RATE BASE (sum lines 18, 24, 25, and 29) | | 0 | | | 0 |

Formula Rate - Non-Levelized

Rate Formula Template

For the 12 months ended 12/31/20XX

NIMECA Agency

| Line No. | (1) | (2) | (3) | (4) | (5) |
|---|---|---|---|---|---|
| | | | **Company Total** | **Allocator** | **Transmission** (Col 3 times Col 4) |

| | O&M | | | | | |
|---|---|---|---|---|---|---|
| 1 | Transmission | Worksheet 8 | 0 | TE | 0.0000 | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note P) | Worksheet 8 | 0 | | 1.0000 | 0 |
| 2 | Less Account 565 | Worksheet 8 | 0 | TE | 0.0000 | 0 |
| 3 | A&G | Worksheet 9 | 0 | W/S | 0.0000 | 0 |
| 4 | Less FERC Annual Fees | Worksheet 10 | 0 | W/S | 0.0000 | 0 |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad(Note H) | Worksheet 12 | 0 | W/S | 0.0000 | 0 |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note H) | Worksheet 12 | 0 | TE | 0.0000 | 0 |
| 6 | Common | NIMECA Financial Statements | 0 | CE | 0.0000 | 0 |
| 7 | Transmission Lease Payments | NIMECA Financial Stateme | 0 | NA | 1.0000 | 0 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | nts | | | | |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | | 0 | | | 0 |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note Q) | | | | | |
| 9 | Transmission | Worksheet 2 | 0 | TP | 0.00000 | 0 |
| 10 | General & Intangible | Worksheet 2 | 0 | W/S | 0.00000 | 0 |
| 11 | Common | NIMECA Financial Statements | 0 | CE | 0.00000 | 0 |
| 12 | TOTAL DEPRECIATION (Sum lines 9 - 11) | | 0 | | | 0 |
| | TAXES OTHER THAN INCOME TAXES (Note I) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | Worksheet 11 | 0 | W/S | 0.00000 | 0 |
| 14 | Highway and vehicle | Worksheet 11 | 0 | W/S | 0.00000 | 0 |
| 15 | PLANT RELATED | | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5 | | | | | | |
| 16 | Property | Worksheet 11 | 0 | GP | 0.0000 | 0 |
| 17 | Gross Receipts | Worksheet 11 | 0 | NA | zero | 0 |
| 18 | Other | Worksheet 11 | 0 | GP | 0.0000 | 0 |
| 19 | Payments in lieu of taxes | Worksheet 11 | 0 | GP | 0.0000 | 0 |
| 20 | TOTAL OTHER TAXES (sum lines 13 - 19) | | 0 | | | 0 |
| 21 | RETURN [ Rate Base (page 2, line 30) * Rate of Return (page 4, line 24)] | | 0 | NA | | 0 |
| 22 | REV. REQUIREMENT (sum lines 8, 12,20 and 21) | | 0 | | | 0 |
| 23 | Total Gross Revenue Requirement (line 22) | | 0 | | | 0 |

Formula Rate - Non-Levelized

Rate Formula Template

NIMECA Agency

For the 12 months ended 12/31/20XX

| Line No. | | SUPPORTING CALCULATIONS AND NOTES | |
|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | |
| 1 | Total transmission plant (page 2, line 2, column 3) | Worksheet 3 | 0 |
| 2 | Less transmission plant excluded from ISO rates (Note K) | Worksheet 3 | 0 |
| 3 | Less transmission plant included in OATT Ancillary Services (Note L ) | | 0 |

| | | | | |
|---|---|---|---|---|
| 4 | Transmission plant included in ISO rates (line 1 less lines 2 & 3) | | | 0 |
| 5 | Percentage of transmission plant included in ISO Rates (line 4 divided by line 1) | TP = | | 0.00000 |
| | TRANSMISSION EXPENSES | | | |
| 6 | Total transmission expenses (page 3, line 1, column 3) | | | 0 |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note J) | Worksheet 8 | | 0 |
| 8 | Included transmission expenses (line 6 less line 7) | | | 0 |
| 9 | Percentage of transmission expenses after adjustment (line 8 divided by line 6) | | | 0.00000 |
| 10 | Percentage of transmission plant included in ISO Rates (line 5) | TP = | | 0.00000 |
| 11 | Percentage of transmission expenses included in ISO Rates (line 9 times line 10) | TE = | | 0.00000 |
| | WAGES & SALARY ALLOCATOR (W&S) (Note R) | | | |

| | | | $ | TP | Allocation | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 12 | Production | Worksheet 14 | 0 | 0.000 | 0 | | | | |
| 13 | Transmission | Worksheet 14 | 0 | 0.000 | 0 | | | | |
| 14 | Distribution | Worksheet 14 | 0 | 0.000 | 0 | W&S Allocator | | | |
| 15 | Other | Worksheet 14 | 0 | 0.000 | 0 | ($ / Allocation) | | | |
| 16 | Total (sum lines 12-15) | | 0 | | 0 | = | 0.00000 | = | W/S |

COMMON PLANT ALLOCATOR (CE)

| | | | $ | % Electric (line 17 / line 20) | | Labor Ratio | | |
|---|---|---|---|---|---|---|---|---|
| 17 | Electric | Page 2, Line 6 | 0 | | | (line 16) | | CE |
| 1 | Gas | NIMEC | 0 | 0.0 | * | 0.00000 | = | 0. |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | A Financial Statements NIMECA Financial Statements | | 000 0 | | 0 0 0 0 0 |
| 19 | Water | | 0 | | | |
| 20 | Total (sum lines 17-19) | | 0 | | | |
| | RETURN (R) | | $ | | | |
| 21 | Long Term Interest | Worksheet 3 | $0 | | | |

| | | | $ | % | Cost (Note P) | Weighted | |
|---|---|---|---|---|---|---|---|
| 22 | Long Term Debt | Worksheet 3 NIMECA Financial Statements | 0 | 0 % | 0.00% | 0.00% | =WCLTD |
| 23 | Proprietary Capital | | 0 | 0 % | 10.10% | 0.00% | |
| 24 | Total (sum lines 22, 23) | | 0 | 0 % | | 0.00% | =R |

| | | |
|---|---|---|
| 25 | Return On Equity | 10.1000% |
| 26 | | |
| | REVENUE CREDITS | |
| | | Load |
| 30 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note M) | $0 |
| | ACCOUNT 456.1 (OTHER ELECTRIC REVENUES) | |
| 31 | a. Transmission charges for all transmission transactions Worksheet 16 | $0 |
| 32 | b. Transmission charges for all transmission transactions included in Divisor on Page 1 Worksheet 16 | $0 |
| 33 | | |
| 33 | Total of (a)-(b) | $0 |

| | | |
|---|---|---|
| Formula Rate - Non-Levelized | Rate Formula Template<br><br>NIMECA<br>Agency | For the 12 months ended 12/31/20XX |

Note Letter

A

The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning).

12 coincident peak monthly loads are reported in Worksheet 1.

B Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable

even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service"

for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years.

LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks.

C LF as defined above at time of applicable pricing zone coincident monthly peaks.

D LF as defined above at time of applicable pricing zone coincident monthly peaks.

E The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets

or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility

chose to utilize amortization of tax credits against taxable income as discussed in Note J. Account 281 is not allocated.

F Transmission related only.

G Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

H Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

I Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate

Formula Template,

since they are recovered elsewhere.

J Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

K Removes transmission plant determined to be ineligible for recovery under the SPP tariff and Attachment AI. See Worksheet 3 for details.

L Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation

step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up

facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

M Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

N Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4, page 1

and the loads are included in line 13, page 1. Grandfathered agreements whose rates have <u>not</u> been changed to eliminate or mitigate

pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1.

O The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements)

or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include

revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct

assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission
P Owner

revenue requirements.

Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts
Q unless authorized by FERC.

R If the agency has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S

allocator at page 4 line 16 equal to the gross plant allocator (GP) at page 2, line 6.

S Any NIMECA Member participating in an SPP project the total cost of which is $10,000,000 or more and

which has regional cost sharing (“Project Costs”), may not recover a return on its share of those Project Costs through a transmission formula rate using a capital

structure equity component higher than 50% unless the NIMECA Member makes a single-issue Federal Power Act (“FPA”) Section 205 filing proposing that

capital structure. This provision is effective until a NIMECA Member makes a general FPA Section 205 filing to change its formula rate.

**Workpaper 1 Divisor Load**

**NIMECA Agency**

**For the Year ended 12/31/20XX**

***Loads are reported in the NIMECA Members' Attachment Hs***

# Attachment H divisor

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month

for each GFA:
the GFA #, the GFA load, and the GFA transmission revenues.

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | - |

# Workpaper 2_Plant and Depreciation

## NIMECA Agency
## For the Year ended 12/31/20XX

## Plant Summary

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Land Rights 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipm | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| ent | | | | |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Reactor Plant Equipment | | | | |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 33 | $ | $ | $ | $ |

| | | | | |
|---|---|---|---|---|
| 3 – Water Wheels, Turbines, and Generators 33 | - | - | - | - |
| 4 - Accessory Electric Equipment 33 | $ - | $ - | $ - | $ - |
| 5 – Misc. Power Plant Equipment 33 | $ - | $ - | $ - | $ - |
| 6 – Roads, Railroads, and Bridges 33 | $ - | $ - | $ - | $ - |
| 7 – Asset Retirement Costs | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| for Hydraulic Production | | | | |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| , Products, and Accessories 34 | | | | |
| 3 – Prime Movers 34 | $ - | $ - | $ - | $ - |
| 4 – Generators 34 | $ - | $ - | $ - | $ - |
| 5 – Accessory Electric Equipment 34 | $ - | $ - | $ - | $ - |
| 6 – Misc. Power Plant Equipment (WS4 assets) 34 | $ - | $ - | $ - | $ - |
| 7 – Asset Retirem | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| ent Costs for Nuclear Production | | | | |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |

| Total City-owned Transmiission | Combined Transmiission System | | | | Other Transmission | | | | Other Trasmission | | | | Other Trasmission | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Transmission Plant** | | | | | | | | | | | | | | | | | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 357 – | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ | $ |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Underground Conduit | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 358 – Underground Conductors and Devices | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 359 – Roads and Trails | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Total Transmission Plant** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Distribution Plant** | | | | | | | | | | | | | | | | | | | | |

| | | | | |
|---|---|---|---|---|
| 360 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Undergr | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| ound Conduit | | | | |
| 367 – Undergr ound Conduc tors and Devices | $ - | $ - | $ - | $ - |
| 368 – Line Transfo rmers | $ - | $ - | $ - | $ - |
| 369 – Service s | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installat ions on Custom er Premis es | $ - | $ - | $ - | $ - |
| 372 – Leased Propert y on Custom ers Premis es | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consen | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| ts | | | | |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Equipment | | | | |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipm | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| ent | | | | |
| 399 – Other Tangible Property | $ - | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Service** | $ - | $ - | $ - | $ - |

Total Plant balances are listed on page
of the audited financial statements.



# Workpaper 3_Ineligible Transmission Plant
# NIMECA Agency

For the Year ended 12/31/20XX

| | | 20XX CTS Additions | 20XX CTS Additions | 20XX CTS Additions | Total CTS Additions |
|---|---|---|---|---|---|
| 1 | Total CTS additions (Note A) | $ - | $ - | $ - | $ - |
| 2 | NIMECA Share of CTS additions | 0.00% | 0.00% | 0.00% | |
| 3 | NIMECA share of total CTS additions (line 1 x line 2) | $ - | $ - | $ - | $ - |
| 4 | Total CTS additions (line 1) | $ - | $ - | $ - | $ - |
| 5 | CTS retirements gross plant | $ - | $ - | $ - | $ - |
| 6 | Net CTS additions (line 4 + line 5) | $ - | $ - | $ - | $ - |
| 7 | CTS SPP Attachment AI net eligible additions (Note B) | $ - | $ - | $ - | $ - |
| 8 | CTS SPP Attachment AI ineligible additions (line 6 - line 7) (Note C) | $ - | $ - | $ - | $ - |
| 9 | NIMECA share of SPP Attachment AI ineligible additions | 0.00% | 0.00% | 0.00% | |
| 1 | NIMECA share of SPP Attachment AI ineligible additions | $ | $ | $ | $ |

| | | | | | |
|---|---|---|---|---|---|
| 0 | (line 8 x line 9) | - | - | - | - |
| 1 | Transmission plant included in OATT Ancillary Services | $ | $ | $ | $ |
| 1 | (Note D) | - | - | - | - |

A Total CTS additions includes all transmission improvements completed during the year.

This can be found on Corn Belt FRT Worksheet 1. This workpaper includes Corn Belt and NIMECA additions.

B CTS SPP additions includes all improvements eligible under Attachment AI of the SPP tariff.

C CTS additions are the additions ineligible under SPP Attachment AI.

D Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation

step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up

facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

# Workpaper 4_Depreciation Rates
# NIMECA Agency
# Depreciation Rates

| FERC Account | Transmission Plant | Average Service Life In Years | Calculated Annual Depreciation Rate |
|---|---|---|---|
| 350 | Land and Land Rights* | N/A | 0.00% |
| 351 | Energy Storage Equipment - Transmission | 30 | 3.33% |
| 352 | Structures & Improvements | 30 | 3.33% |
| 353 | Station Equipment | 30 | 3.33% |
| 354 | Towers & Fixtures | 30 | 3.33% |
| 355 | Poles & Fixtures | 30 | 3.33% |
| 356 | Overhead Conductors and Devices | 30 | 3.33% |
| | **General Plant** | | |
| 390 | Structures & Improvements | 20 | 5.00% |
| 391 | Office Furniture & Equipment | 5 | 20.00% |
| 392 | Transportation Equipment | 5 | 20.00% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

# Workpaper 5_Land Held For Future Use

NIMECA Agency

For the Year ended 12/31/20XX

| | Land Held For Future Use |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Land Held for Future Use is listed on Page of the audited financial Statements

**Workpaper 6_Materials Supplies**

NIMECA Agency

For the Year ended 12/31/20XX

| | Materials and Supplies |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

Materials & Supplies are listed on page of the audited financial statements.

**Workpaper 7_Prepayments**

NIMECA Agency

For the Year ended 12/31/20XX

| Pre Payment Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Pre Payments | $ - |

Prepayments are listed on page
of the audited financial statements.

# Workpaper 8_Transmission O&M
## NIMECA Agency
## For the Year ended 12/31/20XX

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | $ - |
| 561 – Load Dispatching | $ - |
| 561.1 – Load Dispatch – Reliability | $ - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | $ - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | $ - |
| 561.4 – Scheduling, System Control and Dispatch Services | $ - |
| 561.5 – Reliability, Planning and Standards Development | $ - |
| 561.6 – Transmission Service Studies | $ - |
| 561.7 – Generation Interconnection Studies | $ - |
| 561.8 – Reliability, Planning and Standards Development Service | $ - |
| 562 – Station Expenses | $ - |
| 563 – Overhead Lines Expenses | $ - |
| 564 – Underground Lines Expenses | $ - |
| 565 – Transmission of Electricity by Others | $ - |
| 566 – Miscellaneous Transmission Expenses | $ - |
| 567 – Rents | $ - |
| Total Operations | $ - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | $ - |
| 569 – Maintenance of Structures | $ - |
| 569.1 – Maintenance of Computer Hardware | $ - |
| 569.2 – Maintenance of Computer Software | $ - |
| 569.3 – Maintenance of Communication Equipment | $ - |

| | | |
|---|---|---|
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | $ | - |
| 570 – Maintenance of Station Equipment | $ | - |
| 571 – Maintenance of Overhead Lines | $ | - |
| 572 – Maintenance of Underground Lines | $ | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | $ | - |
| Total Maintenance | $ | - |
| Total Transmission O&M Expense | $ | - |

Transmission O&M Expenses are listed on page
of the audited financial statements.

# Workpaper 9_Customer Accounts, Admin & General Expenses
## NIMECA Agency
## For the Year ended 12/31/20XX

| Customer Accts & Admin and General Expenses | Amount |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | $ - |
| 902 – Meter Reading Expenses | $ - |
| 903 – Customer Records and Collection Expenses | $ - |
| 904 – Uncollectible Accounts | $ - |
| 905 – Miscellaneous Customer Accounts Expenses | $ - |
| **Total Customer Accounts Expense** | $ - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | $ - |
| 908 – Customer Assistance Expenses | $ - |
| 909 – Informational and Instructional Expenses | $ - |
| 910 – Miscellaneous Customer Service and Informational Expenses | $ - |
| **Total Customer Service and Informational Expenses** | $ - |
| **Sales Expenses** | |
| 911 – Supervision | $ - |
| 912 – Demonstrating and Selling Expenses | $ - |
| 913 – Advertising Expenses | $ - |
| 916 – Miscellaneous Sales Expenses | $ - |
| **Sales Expenses** | $ - |

| | |
|---|---|
| **Administrative and General Expenses** | |
| 920 – Administrative and General Salaries | $ - |
| 921 – Office Supplies and Expenses | $ - |
| 922 – Administrative Expenses Transferred Credit | $ - |
| 923 – Outside Services Employed | $ - |
| 924 – Property Insurance | $ - |
| 925 – Injuries and Damages | $ - |
| 926 – Employee Pension and Benefits | $ - |
| 927 – Franchise Requirements | $ - |
| 928 – Regulatory Commission Expenses | $ - |
| 929 – Duplicate Charges Credit | $ - |
| 930.1 – General Advertising Expenses | $ - |
| 930.2 – Miscellaneous General Expenses | $ - |
| 931 – Rents | $ - |
| Total Operations A&G | $ - |
| 935 – Maintenance of General Plant | $ - |
| Total Maintenance A&G | $ - |
| **Total Administrative and General Expenses** | $ - |

Customer Account, Admin & General Expenses are listed on page of the audited financial statements.

**Workpaper 10_FERC Fees**

NIMECA Agency

For the Year ended 12/31/20XX

| **FERC fees recorded to expense during the year** | **Account Charged** | **Amount** |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | | $ - |

**Workpaper 11_Taxes Other Than Income Taxes**

NIMECA Agency

For the Year ended 12/31/20XX

# Taxes Other Than Income Taxes

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other - please explain | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

Payroll Tax Expenses are listed on page(s) _____ of the audited financial statements.

**Workpaper 12_EPRI Reg Comm and Non Safety Expenses**

NIMECA Agency

For the Year ended 12/31/20XX

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| | | recorded in UsofA account 928, reflected in I/S in Regulatory commission exp |
| | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising Xxxxxxxx | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| | - | |

**Workpaper 13_Debt Detail**

NIMECA Agency

For the Year ended 12/31/20XX

| **Debt Detail - Electric only** | **Principal Balance at For the Year ended 12/31/20XX** | **Interest Expense** |
|---|---|---|
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |
| | $ - | $ - |
| | - | $ - |
| | - | $ - |
| Total | $ - | $ - |

| | | | |
|---|---|---|---|
| | $ | - | $ - |
| | | - | $ - |
| | | - | $ - |
| Total | $ | - | $ - |
| | $ | - | $ - |
| | | - | $ - |
| | | - | $ - |
| Total | $ | - | $ - |
| | $ | - | $ - |
| | | - | $ - |
| | | - | $ - |
| Total | $ | - | $ - |
| Principal & Interest Grand Total | $ | - | $ - |

Total Principal and Total Interest ties to page(s)

of the audited financial statements.

**Workpaper 14_Wages & Salary**

NIMECA Agency

For the Year ended 12/31/20XX

## Wages & Salary

| | | |
|---|---|---|
| Production | $ | - |
| Transmisisson | $ | - |
| Distribution | $ | - |
| Other | $ | - |
| Total | $ | - |
| A&G | $ | - |
| Total Wages | $ | - |

**Workpaper 15_Account 454 Revenues**

NIMECA Agency

**For the Year ended 12/31/20XX**

## Account 454 (Rent from Electric Property)

| Property Description | Amount |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |
| Total Rent Income | $ - |

Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

**Workpaper 16_Account 456.1 Revenues**

NIMECA Agency

**For the Year ended 12/31/20XX**

## Account 456.1 (Other Electric Revenues)

| | Account 456.1 Revenue |
|---|---|
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Revenue | $ - |

# ADDENDUM 26 TO ATTACHMENT H – PART 15

Transmission Formula Rate Implementation Protocols

for

North Iowa Municipal Electric Cooperative Association (NIMECA) and the NIMECA Members

## I. Annual Update

1. The transmission formula rate templates of North Iowa Municipal Electric Cooperative Association ("NIMECA") and the NIMECA Members and these Formula Rate Implementation Protocols ("Protocols") together comprise the filed rate ("Formula Rate") of NIMECA and the NIMECA Members for transmission service in the Upper Missouri Zone ("UMZ") - Zone 19 of the Southwest Power Pool, Inc. ("SPP"). NIMECA and the NIMECA Members must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements ("ATRR") for Network Integration Transmission Service and the revenue requirements for Scheduling, System Control and Dispatch Service ("Schedule 1 Service"), as well as the SPP Base Plan Zonal and Region-Wide Charge ("Schedule 11 Service") under the SPP Open Access Transmission Tariff ("OATT" or "SPP Tariff"). Corn Belt's ATRR includes the annual transmission revenue requirements associated with the facilities of NIMECA and the NIMECA Members that are incorporated within the Formula Rate. NIMECA's and the NIMECA Members' revenue requirements, as included in the Corn Belt ATRR will be calculated pursuant to these Protocols. Corn Belt will act as the agent for NIMECA and the NIMECA Members associated with the implementation of these Protocols.

2. The ATRR calculated pursuant to the Formula Rate, as well as the SPP-derived rates, shall be applicable to service on and after June 1 of each calendar year through May 31 of the following calendar year ("Rate Year"), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before June 1 of each calendar year, Corn Belt shall:

   (a) recalculate the revenue requirements applicable to Network Integration Transmission Service, Schedule 1 Service, and Schedule 11 Service for the new Rate Year in accordance with the Formula Rate ("Annual Update"); and

   (b) provide its Annual Update to SPP and request SPP to post such information on SPP's website and Open Access Same-Time Information System ("OASIS"). Within ten (10) days of such posting, Corn Belt shall provide notice of such posting via the SPP e-mail subscription ("Service List").[1] Interested Parties can subscribe to the Service List on the SPP website.

[1] As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP website. As of January 2016, the Exploder List was titled "Formula Rate Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

4. If the date for posting the Annual Update falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's "Publication Date." Any delay in the Publication Date will result in an equivalent extension of time for the submission of information requests and for Corn Belt's response to information requests as described in Sections III of these Protocols, and for the submission of Information Challenges and for Corn Belt's response to Informal Challenges as described in Section IV of these Protocols.

5. The Annual Update for the Rate Year shall:

(a) include a workable populated rate formula template with fully functional spreadsheets showing the calculation of the Annual Update and underlying workpapers in native format with all formulas and links intact;

(b) to the extent specified in the Formula Rate, be based on the most recently available audited financial statements for each respective member.

(c) as and to the extent specified in the Formula Rate, provide sufficiently detailed workpapers and supporting documentation for data (and all adjustments thereto or allocations thereof) that are used to develop the Formula Rate and are not otherwise available directly from the audited financial statements;

(d) provide sufficient information to enable Interested Parties (as that term is defined in Section II of these Protocols) to replicate the calculation of the formula results from the Formula Rate;

(e) identify any changes in the formula references (page and line numbers);

(f) identify all material adjustments made to the Formula Rate data in determining formula inputs, including relevant footnotes to the audited financial statements and any adjustments not shown in the audited financial statements;

(g) With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

a. The initial implementation of an accounting standard or policy;

b. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

c. correction of errors and prior period adjustments that impact the revenue requirement;

d. the implementation of new estimation methods or policies that change prior estimates; and

e. changes to income tax elections if applicable.

ii. Identify items included in the Formula Rate at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Formula Rate;

iv. Provide, for each item identified pursuant to items I.5.g.i.a - I.5.g.i.c of these Protocols, a narrative explanation of the individual impact of such changes on charges billed under the Formula Rate.

(h) Identify the equity component of the capital structure used for the calculation of the Weighted Average Cost of Capital ("WACC").

(i) NIMECA and the NIMECA Members will not seek to modify the Formula Rate, as any modification to the Formula Rate will require filing under Section 205 or 206 of the Federal Power Act.

## II. Review of Annual Update

Corn Belt shall host an open meeting among Interested Parties, no earlier than July 1 and no later than September 1 each year ("Annual Meeting"). No less than seven (7) days prior to such Annual Meeting, Corn Belt shall provide Interested Parties notice on SPP's website and OASIS of the time, date, and location of the Annual Meeting and shall provide notice of such meeting via the Service List. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

The Annual Meeting shall (i) permit Corn Belt to explain and clarify its Annual Update and (ii) provide Interested Parties an opportunity to seek information and clarifications from Corn Belt about the Annual Update. The Annual Meeting may be held as solely as a "remote access" meeting (web and voice) to limit travel costs and ease burdens.

If NIMECA or the NIMECA Members are responsible for the construction of any transmission projects that utilize a regional cost sharing mechanism, Corn Belt, NIMECA, and the NIMECA Members shall participate in a joint informational meeting with other transmission owners using formula rates to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. The purpose of the meeting is to enable all interested parties to understand how those Transmission Owners are implementing their formula rates for cost recovery of such projects. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP website and OASIS and distributed to Interested Parties via the Service List no less than seven (7) days prior to such meetings.

## III. Information Exchange Procedures

1. Interested Parties shall have until September 15 following the Publication Date (unless such period is extended with the written consent of Corn Belt, by FERC order, or by operation of Section I.4) to serve reasonable information and document requests on Corn Belt ("Information Exchange Period"). If September 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

   (a) the extent or effect of an Accounting Change;

   (b) whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

   (c) the proper application of the Formula Rate and procedures in these Protocols;

   (d) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual Update;

   (e) the prudence of actual costs and expenditures;

   (f) the effect of any change to the underlying Uniform System of Accounts or the Formula Rate template; or

   (g) any other information that may reasonably have substantive effect on the calculation of the Annual Update pursuant to the Formula Rate.

   The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

2. Corn Belt shall make a good faith effort to respond to information requests pertaining to the Annual Update within fifteen (15) business days of receiving such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day. Corn Belt shall respond to all information and document requests by no later than October 15 following the Publication Date, unless the Information Exchange Period is extended by Corn Belt or FERC, or by operation of Section I.4.

3. Corn Belt shall request SPP to post on SPP's website and OASIS all information requests from Interested Parties and Corn Belt's response(s) to such requests, and a link to the website will be electronically served upon the Service List; except, however, if responses to information and document requests include material deemed by Corn Belt to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Corn Belt and the requesting party.

4. Corn Belt shall not claim that responses to information and document requests provided pursuant to these Protocols are subject to any settlement confidentiality privilege; however, Corn Belt may require that Interested Parties execute a non-disclosure agreement to obtain access to material that Corn Belt deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

## IV. Challenge Procedures

1. Interested Parties shall have until November 15 following the Publication Date (unless such period is extended with the written consent of Corn Belt, by FERC order or by operation of Section I.4) to review the inputs, supporting explanations, allocations, and calculations ("Review Period") and to notify Corn Belt in writing, which may be made electronically, of any specific Informal Challenges. The period of time from the Publication Date until November 15 shall be referred to as the Review Period. If November 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges shall be extended to the next business day. Failure to pursue an issue through an Informal Challenge shall not bar pursuit of that issue as part of a Formal Challenge with respect to the same Annual Update as long as the Interested Party has included at least one issue as part of an Informal Challenge with respect to that Annual Update. If the Interested Party has not included any issues as part of an Informal Challenge for an Annual Update, the Interested Party is barred from pursing a Formal Challenge with respect to any issue for that Annual Update but is not barred from pursing an issue or from lodging a Formal Challenge as to such issue as it relates to a subsequent Annual Update.

2. A party submitting an Informal Challenge to Corn Belt must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Corn Belt shall make a good faith effort to respond to any Informal Challenge within

twenty (20) business days of notification of such challenge. Corn Belt, and where applicable, SPP, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If Corn Belt disagrees with such challenge, Corn Belt will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after November 15, and Corn Belt must respond to all Informal Challenges by no later than December 15, unless the Review Period is extended by Corn Belt or FERC or by operation of Section I.4.

3. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

(a) A Formal Challenge shall:

i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or Protocols;

ii. Explain how the action or inaction violates the filed rate formula or Protocols;

iii. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

a. The extent or effect of an Accounting Change;

b. Whether the Annual Update fails to include data properly recorded in accordance with these Protocols;

c. The proper application of the Formula Rate and procedures in these Protocols;

d. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying System of Accounts or the Applicable Form; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

(b) Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on Corn Belt. Service to Corn Belt must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on Corn Belt's Informational Filing required under Section VI of these Protocols.

4. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual Update fails to include data properly recorded in accordance with these Protocols; (3) the proper application of the Formula Rate and procedures in these Protocols; (4) the accuracy of data and consistency with the Formula Rate of the charges shown in the Annual Update; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying System of Accounts or the Applicable Form; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

5. Corn Belt will request SPP to post on SPP's website all Informal Challenges from Interested Parties and Corn Belt's response(s) to such Informal Challenges and a link to the website will be electronically served upon the Service List; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by Corn Belt to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by Corn Belt and the requesting party.

6. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge processes that are agreed to by Corn Belt will be reported in the Informational Filing required pursuant to Section VI of these Protocols and will be reflected in the Annual Update for the following Rate Year, as discussed in Section V of these Protocols.

7. An Interested Party shall have until March 1 following the Review Period (unless such date is extended with the written consent of Corn Belt to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on Corn Belt on the date of such filing as specified in Section IV.3.b above. A Formal Challenge shall be filed in the same docket as Corn Belt's Informational Filing discussed in Section VI of these Protocols. Corn Belt shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable Review Period.

8. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Corn Belt shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

9. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Corn Belt to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs, or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

10. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing.

11. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the System of Accounts or the Applicable Form, shall first raise the matter with Corn Belt in accordance with this Section IV before pursuing a Formal Challenge.

## V. Changes to Annual Update

1. A change to the Formula Rate fixed inputs related to rate of return on equity ("ROE"), depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than Pensions, and ROE incentives for SPP regional projects may not be made absent an appropriate filing with the FERC pursuant to Federal Power Act Section 205 or Section 206; provided, however, that Corn Belt may make a limited Section 205 filing on behalf of NIMECA or the NIMECA Members to change depreciation rates, amortization periods, the amount of expense for Post-Employment Benefits Other than

Pensions, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed change(s) are just and reasonable, and not unduly discriminatory. Any filing to change the ROE, or capital structure is not considered a limited filing.

2. If Corn Belt files any corrections to correct a Mistake in the audited financial statements during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year, with interest computed in accordance with 18 C.F.R. § 35.19a. See Worksheet 11 of the Formula Rate template. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as, but not limited to, arithmetic and other inadvertent computational errors, erroneous Form 12 references or the like. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process. Corrections to erroneous Form 12 references in the Formula Rate template may be made in the Annual Update without a Section 205 or 206 filing. There is no deadline for any Interested Party or Corn Belt to notify the other party of any mistake in the audited financial statements data or specific data applied in the Formula Rate template.

3. Any changes to the data inputs, including but not limited to revisions to the audited financial statements, or as the result of any FERC proceeding to consider the Annual Update, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a**.**

## VI. Informational Filings

1. By January 15 of each year, Corn Belt shall submit to FERC an informational filing ("Informational Filing") of its Annual Update, including the formula rate templates of Corn Belt, NIMECA, and the NIMECA Members. Corn Belt will submit all Informational Filings in the same docket assigned to Corn Belt's first Informational Filing. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that Corn Belt has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the ATRR and rates under review; and (4) the extent of accounting changes that affect Formula Rate inputs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. Within five (5) days of such Informational Filing, Corn Belt shall provide notice of the Informational Filing to Interested Parties via email and by posting the docket number assigned to Corn Belt's Informational Filing on SPP's website and OASIS and a link to the website will be electronically served upon the Service List.

2. Any challenges to the implementation of the Formula Rate of NIMECA and/or the NIMECA Members must be made through the Challenge Procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Corn Belt Informational Filing.

## ADDENDUM 28 TO ATTACHMENT H

## Northwest Iowa Power Cooperative

**Northwest Iowa Power Cooperative**

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| 4 | Worksheet C | Capital Structure, Rate of Return and Target Return |
| 5 | Worksheet D | Network Load |
| 6 | Worksheet E | Allocation Factors |
| 7 | Worksheet F | Input Section |
| 8 | Worksheet G | Depreciation Rates |
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**Northwest Iowa Power Cooperative**

**ATRR Revenue Requirement Summary**

**FY Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account Number** | **Description** | **Reference** | **Total Company** | **Adjustments** | **Adjusted Company** | **Allocation Factor** | **Allocation %** | **Transmission** |
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 37, Col J | | | | | | |
| 3 | | Revenue Credits-Operating | | | | | | | |
| 4 | 456 | Wheeling-Class B | Workpaper M, Line 16, Col D | $ - | $ - | $ - | T-Tran Plant | | |
| 5 | 456 | Wheeling (Terminated) | Workpaper M, Line 16, Col E | $ - | $ - | $ - | Direct | 100.00 0% | $ - |
| 6 | 456 | Wheeling (GFA) (Note A) | Workpaper M, Line 16, Col F | $ - | | $ - | Direct | 100.00 0% | $ - |
| 7 | 456 | Wheeling SPP P2P | Workpaper M, Line 16, Col G | $ - | | $ - | Direct | 100.00 0% | $ - |
| 8 | 456 | Rents | Workpaper M, Line 16, Col H | $ - | | $ - | Direct | 0.000% | $ - |
| 9 | 456 | Production | Workpaper M, Line 16, Col I | $ - | | $ - | Direct | 0.000% | $ - |
| 10 | 456 | Basin Facility Discount | Workpaper M, Line 16, Col J | $ - | | $ - | Direct | 100.00 0% | $ - |
| 11 | | Revenue Credits-Operating | Sum Lines 4 - 10 | $ - | $ - | $ - | | | |
| | | Non-Operating Revenue Credits | | | | | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 12 | | | | | | | | | |
| 13 | 415 | Fiber Revenues | Workpaper O, Line 61, Col H | $ - | | $ - | Direct | 0.000% | $ - |
| 14 | 403 | Depreciation | Workpaper O, Line 61, Col F | $ - | | $ - | Direct | 0.000% | $ - |
| 15 | 408 | Property Tax | Workpaper O, Line 61, Col G | $ - | | $ - | Direct | 0.000% | $ - |
| 16 | 427 | Interest Expense | Workpaper O, Line 61, Col I | $ - | | $ - | Direct | 0.000% | $ - |
| 17 | 560-935 | O&M Expense | Workpaper O, Line 61, Col J | $ - | | $ - | Direct | 0.000% | $ - |
| 18 | | Revenue Credits-Non-Operating | Line 13 - Sum Lines 14 - 17 | $ - | $ - | $ - | | | $ - |
| 19 | | Revenue Requirement | Line 2 - Line 11 - Line 18 | | | | | | |
| 20 | | SPP Upgrades | Worksheet H, Line 2, Col O | | | | Direct | 100.00 0% | |
| 21 | | Adjustments to SPP Regional Projects | Worksheet I, Line 12, Col J | | | $ - | Direct | 100.00 0% | $ - |
| 22 | | Reconciliation - Adjustment for Prior Year Corrections | Worksheet I, Line 6, Col J | | | $ - | Direct | 100.00 0% | $ - |
| 23 | | Sum | Line 19 - Line 20 + Line 21 + Line 22 | | | | | | |
| 24 | | **B. Point-To-Point Service (Divisor):** | | | | | | | |
| 25 | | Network Transmission Load (kW) | Worksheet D | | | | | | - |
| 26 | | **C. Rates** | | | | | | | |
| 27 | | Annual Point-to-Point Cost ($/kW-Yr) | Line 23 / Line 25 | | | | | | |
| 28 | | Monthly Point-to-Point ($/kW-Mo) | Line 27 / 12 months | | | | | | |
| 29 | | Weekly Point-to-Point ($/kW-Week) | Line 27 / 52 Weeks | | | | | | |
| | | Daily On-Peak Point-to-Point ($/kW- | Line 29 / 5 days | | | | | | |

| | | |
|---|---|---|
| 30 | Day) | |
| 31 | Daily Off-Peak Point-to-Point ($/kW-Day) | Line 29 / 7 days |
| 32 | Hourly On-Peak Point-to-Point ($/MWh) | Line 30 / 16 hours * 1,000 |
| 33 | Hourly Off-Peak Point-to-Point ($/MWh) | Line 31 / 24 hours * 1,000 |
| 34 | | |
| 35 | Note: | |
| 36 | A. The GFA revenue credit is subject to final Commission action on the issue concerning the ratemaking treatment of NIPCO's grandfathered agreements (GFA issue), which is not resolved by the Partial Settlement of 2020, and thus, remains contested in Docket No. ER15-2115. The 2020 Partial Settlement is based on the 2017 Settlement and resolve the cost-of-service issues in Docket No. ER15-2115. | |

**Northwest Iowa Power Cooperative**

**Calculation of Rate Base**

**FY Year Ending December 31, 20XX**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Beginning of Year | E<br>End of Year | F<br>Total Company | G<br>Allocation Factor | H<br>Allocation % | I<br>Notes | J<br>Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Plant in Service** | | | | | | | | |
| 2 | 301-303 Total Intangible Plant | Worksheet F, Line 41 Col D, E & F | $ - | $ - | $ - | T-Wages | | | |
| 3 | Total Production Plant | Worksheet F, Line 42 Col D, E & F | $ - | $ - | $ - | Direct | 0.000 % | | $ - |
| 4 | 350 Land and Land Rights | Worksheet F, Line 43 Col D, E & F | $ - | $ - | $ - | T-Tran Stations | | | |
| 5 | 352 Structures and Improvements | Worksheet F, Line 44 Col D, E & F | $ - | $ - | $ - | T-Tran Stations | | | |
| 6 | 353 Station Equipment - K Stations | Worksheet F, Line 5 Col D, E, F | $ - | $ - | $ - | Less 1/3 | 66.667 % | | $ - |
| 7 | 353 Station Equipment - Non-qualified Subs | Worksheet F, Line 6 Col D, E, F | $ - | $ - | $ - | Direct | 0.000 % | | $ - |
| 8 | 353 Communications boxes for 3rd party | Worksheet F, Line 7 Col D, E & F | $ - | $ - | $ - | Direct | 0.000 % | | $ - |
| 9 | 353 Station Equipment - Load Management | Worksheet F, Line 8 Col D, E & F | $ - | $ - | $ - | Direct | 0.000 % | | $ - |
| 10 | 353 Station Equipment | Worksheet F, Line 45 Col D, E & F-Sum (Lines 6 thru 9) | $ - | $ - | $ - | Direct | 100.000% | | $ - |
| 11 | 354 thru 359.1 Other Transmission Plant | Worksheet F, Line 46 Col D, E & F | $ - | $ - | $ - | T-Length | | | |
| 12 | Transmission Plant | Sum Lines 4 thru 11 | $ - | $ - | $ - | | | | |
| | Total Distribution Plant | Worksheet F, Line 47 Col D, E & F | $ | $ | $ | Direct | 0.000 | | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 13 | | | - | - | - | | % | - |
| 14 | 380-386 RTO/ISO Plant | Worksheet F, Line 48 Col D, E & F | $ - | $ - | $ - | Direct | 100.00 0% | $ - |
| 15 | 389 thru 399.1 Total General Plant | Worksheet F, Line 49 Col D, E & F | $ - | $ - | $ - | T-Wages | | |
| 16 | Gross Electric Plant in Service | Line 2 + Line 3 + Sum Lines 13 thru 15 | $ - | $ - | $ - | | | |
| 17 | 105 Electric Plant Held For Future Use | Workpaper Q, Line 17, Col E, F & G | $ - | $ - | $ - | Direct | 100.00 0% | $ - |
| 18 | 106 Completed Construction Not Classified | Workpaper R, Line 12, Col H, I & J | $ - | $ - | $ - | Direct | 100.00 0% | $ - |
| 19 | 107 Construction Work in Progress | Workpaper P, Line 42, Col I, J & L | $ - | $ - | $ - | Direct | 100.00 0% | $ - |
| 20 | Utility Plant | Sum Lines 16 thru 19 | $ - | $ - | $ - | | | |
| 21 | **Accumulated Depreciation** | | | | | | | |
| 22 | 108.1 Depreciation of Steam Plant | Worksheet F, Line 51 Col D, E & F | $ - | $ - | $ - | | | |
| 23 | 108.4 Depreciation of Other Production Plant | Worksheet F, Line 52 Col D, E & F | $ - | $ - | $ - | | | |
| 24 | 108.5 Depreciation of Transmission Plant | Worksheet F, Line 53 Col D, E & F | $ - | $ - | $ - | T-Tran Plant | | |
| 25 | 108.6 Depreciation of Distribution Plant | Worksheet F, Line 54 Col D, E & F | $ - | $ - | $ - | | | |
| 26 | 108.7 Depreciation of General Plant | Worksheet F, Line 55 Col D, E & F | $ - | $ - | $ - | T-Wages | | |
| 27 | 108.8 Retirement Work in Progress | Worksheet F, Line 56 Col D, E & F | $ - | $ - | $ - | T-Plant | | |
| 28 | 111 Amortization of Electric Plant in Service | Worksheet F, Line 57 Col D, E & F | $ - | $ - | $ - | T-Wages | | |
| 29 | Total Accumulated Depreciation | Sum Lines 22 thru 28 | $ - | $ - | $ - | | | |
| 30 | **Total Net Plant in Service** | | | | | | | |
| 31 | 301-303 Net Total Intangible Plant | Line 2 | $ - | $ - | $ - | | | |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | $ | $ | $ | | | | $ |
| 32 | Net Production Plant | Line 3 - Line 22 - Line 23 | - | - | - | | | | - |
| | | | $ | $ | $ | | | | |
| 33 | Net Transmission Plant | Line 12 + Line 14 - Line 24 | - | - | - | | | | |
| | | | $ | $ | $ | | | | $ |
| 34 | Net Distribution Plant | Line 13 - Line 25 | - | - | - | | | | - |
| | | | $ | $ | $ | | | | |
| 35 | Net General Plant | Line 15 - Line 26 | - | - | - | | | | |
| | Electric Plant Held For | | $ | $ | $ | | | | $ |
| 36 | Future Use | Line 17 | - | - | - | | | | - |
| | Completed Construction Not | | $ | $ | $ | | | | $ |
| 37 | Classified | Line 18 | - | - | - | | | | - |
| | Construction Work in | | $ | $ | $ | | 100.00 | | $ |
| 38 | Progress | Line 19 | - | - | - | Direct | 0% | | - |
| | | | $ | $ | $ | | | | |
| 39 | Retirement Work in Progress | Line 27 | - | - | - | | | | |
| | Amortization of Electric | | $ | $ | $ | | | | |
| 40 | Plant in Service | Line 28 | - | - | - | | | | |
| | | | $ | $ | $ | | | | |
| 41 | Total Net Plant in Service | Sum Lines 31 thru 40 | - | - | - | | | | |
| | | | | | | | | | |
| 42 | Adjustments to Rate Base | | | | | | | | |
| | | | | | | | | | |
| 43 | Working Capital | | | | | | | | |
| | Total Transmission O&M | | | | $ | | | | |
| 44 | Costs | Worksheet B, Line 26, Col F & J | | | - | | | | |
| | | | | | | | | | |
| 45 | Billing Lag in Days | Worksheet F, Line 3 Col F | | | | 45 | | | 45 |
| | | | | | $ | | | | |
| 46 | Working Capital | Line 44 * Line 45 / 365 | | | - | | | | |
| | | | | | | | | | |
| | | | $ | $ | $ | | | | |
| 47 | Prepayments | Worksheet F, Line 36 Col D, E & F | - | - | - | T-Plant | | | |
| | | | | | | | | | |
| | | | $ | $ | $ | | 0.000 | | $ |
| 48 | M&S Coal | Worksheet F, Line 59 Col D, E & F | - | - | - | Direct | % | | - |
| | | | $ | $ | $ | | 0.000 | | $ |
| 49 | M&S Other Fuel | Worksheet F, Line 60 Col D, E & F | - | - | - | Direct | % | | - |
| | M&S Production Plant Parts | Worksheet F, Line 61 Col D, E & F | $ | $ | $ | Direct | 0.000 | | $ |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 50 | | | - | - | - | % | - |
| | M&S Station Transformers | | $ | $ | $ | T-Tran | |
| 51 | & Equipment | Worksheet F, Line 62 Col D, E & F | - | - | - | Stations | |
| | M&S Line Materials & | | $ | $ | $ | | |
| 52 | Supplies | Worksheet F, Line 63 Col D, E & F | - | - | - | T-Length | |
| | | | $ | $ | $ | | |
| 53 | M&S Other | Worksheet F, Line 64 Col D, E & F | - | - | - | T-Plant | |
| 54 | Materials and Supplies | Sum Lines 48 thru 53 | - | - | - | | |
| | | Line 41 + Line 46 + Line 47 + Line | | $ | $ | | |
| 55 | Rate Base | 54 | | - | - | | |

**Northwest Iowa Power Cooperative**

Worksheet B

**O&M, Depreciation, and Return Expenses**
**FY Year Ending December 31, 20XX**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total Company | E | F<br>Total Company | G<br>Allocation Factor | H<br>Allocation % | I<br>Notes | J<br>Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Transmission Operation & Maintenance Expenses | | Lines | Stations | | | | | |
| 2 | 560 Supervision and Engineering | Workpaper J, Line 1, Col D & E | $ - | $ - | $ - | T-Tran Plant | | | |
| 3 | 561 Load Dispatching | Workpaper J, Line 2, Col D & E | $ - | $ - | $ - | Direct | 100.000% | | $ - |
| 4 | 562 Station Expenses | Workpaper J, Line 3, Col D & E | $ - | $ - | $ - | T-Tran Stations | | | |
| 5 | 563 Overhead Line Expenses | Workpaper J, Line 4, Col D & E | $ - | $ - | $ - | T-Length | | | |
| 6 | 564 Underground Line Expenses | Workpaper J, Line 5, Col D & E | $ - | $ - | $ - | T-Length | | | |
| 7 | 565 Transmission of Electricity by Others | Workpaper J, Line 8, Col D & E | $ - | $ - | $ - | Direct | 0.000% | | $ - |
| 8 | 566 Miscellaneous Expenses | Workpaper J, Line 6, Col D & E | $ - | $ - | $ - | T-Tran Plant | | | |
| 9 | 567 Rents | Workpaper J, Line 9, Col D & E | | | $ - | T-Tran Stations | | | |
| 10 | 568 Supervision and Engineering | Workpaper J, Line 11, Col D & E | $ - | $ - | $ - | T-Tran Plant | | | |
| 11 | 569 Structures | Workpaper J, Line 12, Col D & E | $ - | | $ - | Direct | 0.000% | | $ - |
| 12 | 570 Station Equipment | Workpaper J, Line 13, Col D & E | $ - | | $ - | T-Tran Stations | | | |
| | 571 Overhead Lines | Workpaper J, Line 14, Col D & E | | $ | $ | T-Length | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 13 | | | | - | - | | | |
| | | | $ | $ | $ | | | |
| 14 | 572 Underground Lines | Workpaper J, Line 15, Col D & E | - | - | - | T-Length | | |
| | 573 Miscellaneous | | $ | $ | $ | T-Tran | | |
| 15 | Transmission Plant | Workpaper J, Line 16, Col D & E | - | - | - | Plant | | |
| | 575.1-575.8 RTO/ISO | | | | $ | | | $ |
| 16 | Expense - Operation | Workpaper V, Line 10, Col E & G | | | - | Direct | | - |
| | 576.1-576.5 RTO/ISO | | | | $ | | | $ |
| 17 | Expense - Maintenance | Workpaper V, Line 10, Col H & J | | | - | Direct | | - |
| | | | $ | $ | $ | | | |
| 18 | Transmission O&M | Sum Lines 2 thru 17 | - | - | - | | | |
| | Administrative & General | | | | | | | |
| 19 | Expense | | | | | | | |
| | | | | | $ | | | $ |
| 20 | Customer Accounting Wages | Workpaper W, Line 10, Col D & F | | | - | Direct | | - |
| | Customer Accounting | | | | $ | | | $ |
| 21 | Computer Support | Workpaper W, Line 12, Col D & F | | | - | Direct | | - |
| | | Worksheet F, Line 21, Col F - | | | $ | | | |
| 22 | Admin and General Expense | Workpaper U, Line 10, Col F | | | - | T-Wages | | |
| | Maintenance Expense General | | | | $ | | | |
| 23 | Plant | Worksheet F, Line 26, Col F | | | - | T-Wages | | |
| | 928 Regulatory & Commission | | | | $ | | | $ |
| 24 | Expenses - SPP | Workpaper U, Line 10, Col D & F | | | - | Direct | | - |
| | | | | | $ | | | |
| 25 | Total A&G Expenses | Sum Lines 20 thru 24 | | | - | | | |
| | | | | | | | | |
| | | Line 18 + Line 20 + Line 21 + Line | | | $ | | | |
| 26 | Subtotal O&M | 25 | | | - | | | |

| | | | Total Company | Adjustment | Adjusted Total | | | |
|---|---|---|---|---|---|---|---|---|
| 27 | Depreciation Expense | | | | | | | |
| | Depreciation Expense- | | $ | | $ | | 0.000 | $ |
| 28 | Production | Workpaper L, Line 26, Col D | - | | - | Direct | % | - |
| | Depreciation Expense-Tran | | $ | | $ | T-Tran | | |
| 29 | Station | Workpaper L, Line 26, Col E | - | | - | Stations | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Depreciation Expense-Tran | | $ | | $ | | | |
| 30 | Lines | Workpaper L, Line 26, Col F | - | | - | T-Length | | |
| | Depreciation Expense- | | $ | | $ | | 0.000 | $ |
| 31 | Distribution | Workpaper L, Line 26, Col G | - | | - | Direct | % | - |
| | | | $ | | $ | | | |
| 32 | Depreciation Expense-General | Workpaper L, Line 26, Col H | - | | - | T-Wages | | |
| | Amortization of Other Electric | | $ | | $ | | | |
| 33 | Plant | Workpaper L, Line 26, Col I | - | | - | T-Wages | | |
| | Total Depreciation & | | $ | $ | $ | | | |
| 34 | Amortization | Sum Lines 28 thru 33 | - | - | - | | | |
| | | | | | | | | |
| | Tax - Gross Reciepts and | | | | $ | | | |
| 35 | Property Tax | Worksheet F, Line 27, Col F | | | - | T-Plant | | |
| 36 | Return | Worksheet C, Line 7, Col H | | | | | | |
| 37 | Revenue Requirement | Line 26 + Line 34 + Sum Lines 35 thru 36 | | | | | | |

Worksheet C

**Northwest Iowa Power Cooperative**

**Capital Structure, Rate of Return and Target Return**

**FY Year Ending December 31, 20XX**

| A<br>Line No | B<br>Description | C<br>Reference | D<br>Total Co EoY | E<br>Cap Str Weight | F<br>Interest Expense | G<br>Cost of Capital | H<br>Weighted Rate of Return |
|---|---|---|---|---|---|---|---|
| | Return Based on Defined | | | | | | |
| 1 | ROE | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Line 38, Col F & Line 28, Col F | $ - | | $ - | | |
| 3 | Notes Payable | Worksheet F, Line 39, Col F & Line 29, Col F | $ - | | $ - | | |
| 4 | Total Margins and Equities | Worksheet F, Line 37, Col F & Line 4, Col F | $ - | | | 10.100 % | |
| 5 | Total Capitalization | Sum Lines 2 thru 4 | $ - | | $ - | | |
| 6 | Rate Base | Worksheet A, Line 55, Col J | | | | | |
| 7 | Return | Line 5 * Line 6 | | | | | |

Worksheet D

**Northwest Iowa Power Cooperative**
**Network Load**
**FY Year Ending December 31, 20XX**

| A<br>Line No | B<br>Description | C<br>Total Class A | D<br>Class B | E<br>Other (Terminated) | F<br>Other (MEC) | G<br>Network Demand (KW) |
|---|---|---|---|---|---|---|
| 1 | January | 0 | 0 | 0 | 0 | - |
| 2 | February | 0 | 0 | 0 | 0 | - |
| 3 | March | 0 | 0 | 0 | 0 | - |
| 4 | April | 0 | 0 | 0 | 0 | - |
| 5 | May | 0 | 0 | 0 | 0 | - |
| 6 | June | 0 | 0 | 0 | 0 | - |
| 7 | July | 0 | 0 | 0 | 0 | - |
| 8 | August | 0 | 0 | 0 | 0 | - |
| 9 | September | 0 | 0 | 0 | 0 | - |
| 10 | October | 0 | 0 | 0 | 0 | - |
| 11 | November | 0 | 0 | 0 | 0 | - |
| 12 | December | 0 | 0 | 0 | 0 | - |
| 13 | Total (kW-Mo) | 0 | - | - | - | - |
| 14 | Average (kW-Mo) | - | - | - | - | - |

Worksheet
E

**Northwest Iowa Power Cooperative**

**Allocation Factors**

**FY Year Ending December 31, 20XX**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total | E<br>Allocation Factor | F<br>Allocation % | G<br>Allocated |
|---|---|---|---|---|---|---|
| 1 | Production Operations | Workpaper K, Line 124, Col O | $ - | | | |
| 2 | Production Maintenance | NA | $ - | | | |
| 3 | Transmission Supervision Operations | Workpaper K, Line 142, Col P | $ - | T-Tran Plant | | |
| 4 | Transmission Station Operations | Workpaper K, Line 142, Col Q | $ - | T-Tran Stations | | |
| 5 | Transmission Station Maintenance | Workpaper K, Line 142, Col T | $ - | T-Tran Stations | | |
| 6 | Transmission Supervision Maintenance | Workpaper K, Line 142, Col S | $ - | T-Tran Plant | | |
| 7 | Transmission Line Operations | Workpaper K, Line 142, Col R | $ - | T-Length | | |
| 8 | Transmission Line Maintenance | Workpaper K, Line 142, Col U | $ - | T-Length | | |
| 9 | Distribution - Operations | Workpaper K, Line 128, Col O | $ - | | | |
| 10 | Distribution - Maintenance | Workpaper K, Line 138, Col O | $ - | | | |
| 11 | Customer Accounts | Workpaper K, Line 130, Col O | $ - | | | |

| | | | | | |
|---|---|---|---|---|---|
| 12 | Account 901-905 SPP Expenses | Workpaper W, Line 10, Col F | $ - | Direct | $ - |
| 13 | Sales | Workpaper K, Line 132, Col O | $ - | | |
| 14 | Total Wages, excluding A&G | Sum | $ - | | |
| 15 | **T-Wages** | | | | |
| 16 | 350 Land and Land Rights | Worksheet F, Line 43, Col F | $ - | Direct | $ - |
| 17 | 352 Structures and Improvements | Worksheet F, Line 44, Col F | $ - | Direct | $ - |
| 18 | 353 Station Equipment | Worksheet F, Line 45, Col F | $ - | Direct | $ - |
| 19 | Less 353 Station Equipment - K Stations / 3 | Worksheet F, Line 5, Col F /3 | | Direct | $ - |
| 20 | Less 353 Station Equipment - Non-qualified Subs | Worksheet F, Line 6, Col F | | Direct | $ - |
| 21 | Less 353 Communications boxes for 3rd party | Worksheet F, Line 7, Col F | | Direct | $ - |
| 22 | Less 353 Station Equipment - Load Management | Worksheet F, Line 8, Col F | | Direct | $ - |
| 23 | Total | Sum | $ - | | $ - |
| 24 | **T-Tran Stations** | | | | |
| 25 | Transmission Qualifying Plant | Worksheet A, Line 12, Col F and J | $ - | | |
| 26 | **T-Tran Plant** | | | | |
| 27 | Plant in Service | Worksheet A, Line 16, Col F and J | $ - | | |
| 28 | **T-Plant** | | | | |
| 29 | Transmission Circuit Feet | Worksheet F, Line 2 and 1, Col F | - | | - |
| 30 | **T-Length** | Length Allocator | | | |

Works
heet F

**Northwest Iowa Power Cooperative**

**Input Section**
**FY Year Ending December 31, 20XX**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Total |
|---|---|---|---|---|---|
| 1 | Circuit Feet | Workpaper S, Line 3, Col D | | | 0 |
| 2 | Total Transmission Feet | Workpaper S, Line 6, Col D | | | 0 |
| 3 | Billing Lag in days | COS for NIPCO | | | 45 |
| 4 | Rate of Return | Settlement in Docket ER15-2115 | | | 10.10% |
| 5 | 353 Station Equipment - K Stations (full value) | NIPCO Station Asset Listing.xlsx; Tab Stations Asset Value Detail; Subtotal K Stations | | | $ - |
| 6 | 353 Non-Qualified Substations | NIPCO Station Asset Listing.xlsx; Tab Stations Asset Value Detail | | | $ - |
| 7 | 353 Communications boxes for 3rd parties | Company Records | | | $ - |
| 8 | 353 Station Equipment - Load Management | Company Records | | | $ - |

| | | | EoY |
|---|---|---|---|
| 9 | **Data from Form-12** | | |
| 10 | Electric Energy Revenues | Form 12, Part A, Sect A, L01b | |
| 11 | Other Operating Revenue & Income | Form 12, Part A, Sect A, L03b | |
| 12 | Op Exp-Production excluding fuel | Form 12, Part A, Sect A, L05b | |
| 13 | Op Exp-Production fuel | Form 12, Part A, Sect A, L06b | |
| 14 | Op Exp-Other Power Supply | Form 12, Part A, Sect A, L07b | |
| 15 | Op Exp-Transmission | Form 12, Part A, Sect A, L08b | |
| 16 | Op Exp-RTO/ISO | Form 12, Part A, Sect A, L09b | |
| 17 | Op Exp-Distribution | Form 12, Part A, Sect A, L10b | |
| 18 | Op Exp-Consumer Accounts | Form 12, Part A, Sect A, L11b | |
| 19 | Op Exp-Customer Service | Form 12, Part A, Sect A, L12b | |
| 20 | Op Exp-Sales | Form 12, Part A, Sect A, L13b | |
| 21 | Op Exp-Admin and General | Form 12, Part A, Sect A, L14b | |
| 22 | Maint Exp-Production | Form 12, Part A, Sect A, L16b | |
| 23 | Maint Exp-Transmission | Form 12, Part A, Sect A, L17b | |
| 24 | Maint Exp-RTO/ISO | Form 12, Part A, Sect A, L18b | |
| 25 | Maint Exp-Distribution | Form 12, Part A, Sect A, L19b | |
| 26 | Maint Exp-General Plant | Form 12, Part A, Sect A, L20b | |
| 27 | Tax - Gross Reciepts and Property Tax | Form 12, Part A, Sect A, L23b | |
| 28 | Interest on Long Term Debt | Form 12, Part A, Sect A, L24b | |
| 29 | Other Interest Expense | Form 12, Part A, Sect | |

| | | | | | |
|---|---|---|---|---|---|
| | | A, L26b | | | |
| 30 | Other Deductions | Form 12, Part A, Sect A, L28b | | | |
| 31 | Operating Margin | Form 12, Part A, Sect A, L30b | | | |
| 32 | Interest Income | Form 12, Part A, Sect A, L31b | | | |
| 33 | Other Non-Operating Income (Net) | Form 12, Part A, Sect A, L34b | | | |
| 34 | G&T Capital Credits Cash Payments | Form 12, Part A, Sect A, L35b | | | |
| 35 | Other Capital Credits and Patronage Dividends Cash Payments | Form 12, Part A, Sect A, L36b | | | |

| | | | BoY | EoY | Average |
|---|---|---|---|---|---|
| 36 | Prepayment | Form 12, Part A, Section B, Line 25 | | | $ - |

| | | | EoY |
|---|---|---|---|
| 37 | Total Margins and Equities | Form 12, Part A, Section B, Line 39 | |
| 38 | Total Long Term Debt | Form 12, Part A, Sect B, L46 | |
| 39 | Notes Payable | Form 12, Part A, Sect B, L50 | |

| | Plant in Service | | BoY | EoY | Average |
|---|---|---|---|---|---|
| 41 | 301-303 Total Intangible Plant | Form 12, Suppl, Part H, Section A, Line 1 | | | $ - |
| 42 | Total Production Plant | Form 12, Suppl, Part H, Section A, Line 6 | | | $ - |
| 43 | 350 Land and Land Rights | Form 12, Suppl, Part H, Section A, Line 7 | | | $ - |
| 44 | 352 Structures and Improvements | Form 12, Suppl, Part H, Section A, Line 8 | | | $ - |
| 45 | 353 Station Equipment | Form 12, Suppl, Part H, Section A, Line 9 | | | $ - |
| 46 | 354 thru 359.1 Other Transmission | Form 12, Suppl, Part H, | | | $ |

| | | | | | |
|---|---|---|---|---|---|
| | Plant | Section A, Line 10 | | | - |
| | | Form 12, Suppl, Part H, | | | $ |
| 47 | Total Distribution Plant | Section A, Line 16 | | | - |
| | | Form 12, Suppl, Part H, | | | $ |
| 48 | 380-386 RTO/ISO Plant | Section A, Line 17 | | | - |
| | | Form 12, Suppl, Part H, | | | $ |
| 49 | 389 thru 399.1 Total General Plant | Section A, Line 18 | | | - |
| | | | | | |
| | Depreciation and Amortization | | | | |
| 50 | Reserves | | BoY | EoY | Average |
| | | Form 12, Suppl, Part H, | | | $ |
| 51 | 108.1 Depr of Steam Plant | Section B, Line 1 | | | - |
| | 108.4 Depreciation of Other | Form 12, Suppl, Part H, | | | $ |
| 52 | Production Plant | Section B, Line 4 | | | - |
| | 108.5 Depreciation of Transmission | Form 12, Suppl, Part H, | | | $ |
| 53 | Plant | Section B, Line 5 | | | - |
| | 108.6 Depreciation of Distribution | Form 12, Suppl, Part H, | | | $ |
| 54 | Plant | Section B, Line 6 | | | - |
| | 108.7 Depreciation of General | Form 12, Suppl, Part H, | | | $ |
| 55 | Plant | Section B, Line 7 | | | - |
| | | Form 12, Suppl, Part H, | | | $ |
| 56 | 108.8 Retirement Work in Progress | Section B, Line 8 | | | - |
| | 111 Amort of Electric Plant in | Form 12, Suppl, Part H, | | | $ |
| 57 | Service | Section B, Line 12 | | | - |
| | | | | | |
| 58 | Materials and Supplies | | BoY | EoY | Average |
| | | Form-12, Part H, | | | $ |
| 59 | M&S Coal | Section G, Line 1 | | | - |
| | | Form-12, Part H, | | | $ |
| 60 | M&S Other Fuel | Section G, Line 2 | | | - |
| | | Form-12, Part H, | | | $ |
| 61 | M&S Production Plant Parts | Section G, Line 3 | | | - |
| | M&S Station Transformers & | Form-12, Part H, | | | $ |
| 62 | Equipment | Section G, Line 4 | | | - |
| | | Form-12, Part H, | | | $ |
| 63 | M&S Line Materials & Supplies | Section G, Line 5 | | | - |
| | | Form-12, Part H, | | | $ |
| 64 | M&S Other | Section G, Line 6 | | | - |
| 65 | Materials and Supplies | Sum Lines 59 thru 64 | | | |

| | | | | | |
|---|---|---|---|---|---|
| | | | - | - | - |
| 66 | 411.7 Loss-Utility Plant Disposition | Trial Balance | | | |
| 67 | 425 Misc Amortization | Trial Balance | | | |
| 68 | 426.1 Income Deductions - Donations | Trial Balance | | | |
| 69 | 426.4 Expend-Civic Political & Related | Trial Balance | | | |
| 70 | 426.5 Other Deductions | Trial Balance | | | |
| 71 | 428 Amort of Debt Discount & Exp | Trial Balance | | | |
| 72 | 429.1 Amort Debt Premium | Trial Balance | | | |
| 73 | Other Deductions (Other Expenses) | Sum Lines 66 thru 72 | | | $ - |

Worksheet G

**Northwest Iowa Power Cooperative**

**Depreciation Rates**
**FY Year Ending December 31, 20XX**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line No** | **GENERAL PLANT** | **Plant Account Number** | **Accumulated Provision for Depr Account Number** | **Depr Expense Account Number** | **Annual Depr Rate** |
| 1 | Land & Land Rights | 389.00 | N/A | N/A | N/A |

| | | | | | |
|---|---|---|---|---|---|
| 2 | Structures & Improvements | 390.00 | 108.70 | 403.70 | 1.800% |
| 3 | Structures & Improvements-Neal 4 | 390.40 | 108.704 | 403.74 | 3.360% |
| 4 | Office Furniture | 391.00 | 108.71 | 403.70 | 3.996% |
| 5 | Office Equipment | 391.01 | 108.71 | 403.70 | 9.996% |
| 6 | Computer/Electronic Equipment | 391.02 | 108.71 | 403.70 | 16.668% |
| 7 | Computer/Electronic Equipment (Composite Unit) | 391.12 | 108.71 | 403.70 | 16.668% |
| 8 | Computer Equipment | 391.03 | 108.71 | 403.70 | 25.000% |
| 9 | Computer Equipment (Composite Unit) | 391.13 | 108.71 | 403.70 | 25.000% |
| 10 | Application Software | 391.04 | 108.71 | 403.70 | 19.999% |
| 11 | Application Software (Composite Unit) | 391.14 | 108.71 | 403.70 | 19.999% |
| 12 | Application Software Upgrades | 391.05 | 108.71 | 403.70 | 33.332% |
| 13 | Application Software Upgrades (Composite Unit) | 391.15 | 108.71 | 403.70 | 33.332% |
| 14 | Office Furniture/Equip-Neal 4 | 391.40 | 108.714 | 403.74 | 12.480% |
| 15 | Transportation Equipment | 392.00 | 108.72 | 184.10 | Various/Unit |
| 16 | Transportation Equipment-Neal 4 | 392.40 | 108.724 | 403.74 | 16.080% |
| 17 | Stores Equipment-Neal 4 | 393.40 | 108.734 | 403.74 | 6.000% |
| 18 | Shop & Garage | 394.00 | 108.74 | 403.70 | 6.000% |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Equipment | | | | | |
| | Shop & Garage | 394.40 | 108.744 | 403.74 | | 6.000% |
| 19 | Equipment-Neal 4 | | | | | |
| | Laboratory | 395.00 | 108.75 | 403.70 | | 10.560% |
| 20 | Equipment | | | | | |
| | Laboratory | 395.01 | 108.75 | 403.70 | | 10.560% |
| | Equipment | | | | | |
| 21 | (Composite Unit) | | | | | |
| | Laboratory | 395.40 | 108.754 | 403.74 | | 10.560% |
| 22 | Equipment-Neal 4 | | | | | |
| | Heavy Work | 396.00 | 108.76 | 184.10 | | Various/Unit |
| 23 | Equipment | | | | | |
| | Power Operated | 396.01 | 108.76 | 403.70 | | 16.080% |
| 24 | Equipment-Tools | | 1 | | | |
| | Power Operated | 396.40 | 108.76 | 403.74 | | 5.400% |
| | Equipment-Tools- | | 4 | | | |
| 25 | Neal 4 | | | | | |
| | Communications | 397.00 | 108.77 | 403.70 | | 7.920% |
| 26 | Equipment | | | | | |
| | Communications | 397.40 | 108.77 | 403.74 | | 7.920% |
| 27 | Equipment-Neal 4 | | 4 | | | |
| | Miscellaneous | 398.00 | 108.78 | 403.70 | | 6.000% |
| 28 | Equipment | | | | | |
| | Miscellaneous | 398.40 | 108.78 | 403.74 | | 6.000% |
| 29 | Equipment-Neal 4 | | 4 | | | |
| | | | | | | |
| | **DISTRIBUTION** | | | | | |
| 30 | **PLANT** | | | | | |
| 31 | Land & Land Rights-Substations | 360.00 | N/A | N/A | N/A | |
| 32 | Station Equipment-Substations | 362.00 | 108.62 | 403.62 | 2.660% | |
| 33 | Unclassified New Transformers | 106.62677 | 108.62 | 403.62 | 2.660% | |
| 34 | **TRANSMISSION PLANT** | | | | | |
| 35 | Land & Land Rights-Transmission | 350.00 | N/A | N/A | N/A | |
| 36 | Land Rights-Neal 4 | 350.40 | N/A | N/A | N/A | |

| | | | | | |
|---|---|---|---|---|---|
| 37 | Structures & Improvements-Transmission | 352.00 | 108.52 | 403.52 | 2.280 % |
| 38 | Structures & Improvements-Neal 4 | 352.40 | 108.524 | 403.524 | 1.710 % |
| 39 | Station Equipment-Major,Minor Switch | 353.00 | 108.53 | 403.53 | 2.580 % |
| 40 | Station Equipment-Eagle/MidAmEnergy | 353.05 | 108.535 | 403.535 | 1.530 % |
| 41 | Station Equipment-Eagle T3/MidAmEnergy | 353.06 | 108.5306 | 403.5306 | 2.130 % |
| 42 | Station Equipment-5I Trans System | 353.20 | 108.532 | 403.532 | 3.530 % |
| 43 | Station Equipment-Load Management | 353.30 | 108.533 | 403.533 | 1.850 % |
| 44 | Station Equipment-Neal 4 | 353.40 | 108.534 | 403.534 | 1.310 % |
| 45 | Station Equipment-Fiber | 353.60 | 108.536 | 403.536 | 5.880 % |
| 46 | Towers & Fixtures-Neal 4 | 354.40 | 108.544 | 403.544 | 1.510 % |
| 47 | Poles & Fixtures-Transmission | 355.00 | 108.55 | 403.550 | 3.300 % |
| 48 | Poles & Fixtures-Transmission-Neal 4 | 355.40 | 108.554 | 403.554 | 2.890 % |
| 49 | O/H Conductor & Devices-Transmission | 356.00 | 108.56 | 403.56 | 3.210 % |
| 50 | O/H Conductor & Devices-Neal 4 | 356.40 | 108.564 | 403.564 | 2.110 % |
| 51 | Unclassified Transmission Plant | 106.353 | 108.53 | 403.53 | 2.580 % |
| 52 | **Production Neal 4** | | | | |
| 53 | Neal 4 Unclassified | 106.40 | 108.10 | 403.10 | 4.13% |
| 54 | Organization | 301.00 | N/A | N/A | N/A |
| 55 | Franchises & Consents | 302.00 | 111.00 | 404.00 | N/A |
| 56 | Misc. Intangible Plant | 303.00 | 111.00 | 404.00 | 2.61% |

| | | | | | |
|---|---|---|---|---|---|
| 57 | Misc. Intangible Plant-Neal 4 | 303.40 | 111.40 | 404.40 | N/A |
| 58 | Land & Land Rights-Neal 4 | 310.40 | N/A | N/A | N/A |
| 59 | Structures & Improvements-Neal 4 | 311.40 | 108.114 | 403.114 | 0.80% |
| 60 | Boiler Plant Equipment-Neal 4 | 312.40 | 108.124 | 403.124 | 1.42% |
| 61 | Coal Base-Neal 4 | 312.42 | 108.1242 | 403.1242 | 1.21% |
| 62 | Turbogenerator Units-Neal 4 | 314.40 | 108.144 | 403.144 | 1.16% |
| 63 | Accessory Elect Equip-Neal 4 | 315.40 | 108.154 | 403.154 | 1.12% |
| 64 | Misc. Power Plant Equip-Neal 4 | 316.40 | 108.164 | 403.164 | 0.86% |

65 Notes:

66 A. "Stated Values" are fixed and subject to change only pursuant to a FPA Section 205 or 206 filing.

Worksheet H

**Northwest Iowa Power Cooperative**

**SPP Upgrades**
**FY Year Ending**
**December 31, 20XX**

| A | B | C | D |
|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Company Total Transmission Amount** |

| | | |
|---|---|---|
| 1 | Gross Transmission Plant | Worksheet A, Line 12, Col J |
| 2 | Accumulated Depreciation & Amortization | Worksheet A, Line 24, Col J |
| 3 | Net Transmission Plant | (line 1 minus line 2) |
| 4 | Transmission O&M | Worksheet B, Line 18, Col J |
| 5 | **Annual Allocation Factor for Transmission O&M** | (line 4 / line 1) |
| 6 | General Plant Depreciation Expense | Worksheet B, Line 32, Col J |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | (line 6 / line 1) |
| 8 | Return on Rate Base | Worksheet B, Line 36, Col J |
| 9 | **Annual Allocation Factor for Return** | (line 8 / line 3) |

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project Name and #** | **Type** | **Project Gross Plant** | **Project Accumulated Depreciation** | **Transmission O&M Annual Allocation Factor** | **Allocation for Transmission O&M** | **General Plant Depreciation Annual Allocation Factor** | **Allocation for General Plant Depreciation Charge** | **Annual Expense Charge** | **Project Net Plant** | **Annual Allocation Factor for Return** | **Annual Return Charge** | **Project Depreciation and Amortization Expense** | **Project ATRR** |
| | | | Note A | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | Col G + Col I | Col D - Col E (Note B) | Line 9, Col D | Col K * Col L | (Note C) | Col J + Col M + Col N |
| 1a | | | | | | | | | | - | | | - | |
| 1b | | | - | - | | | | | | - | | | - | |
| 1c | | | - | - | | | | | | - | | | - | |
| 1d | | | - | - | | | | | | - | | | - | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| 1e | - | - | | - | | - | |
| 1f | - | - | | - | | - | |
| 1g | - | - | | - | | - | |
| … | - | - | | - | | - | |
| … | - | - | | - | | - | |
| | | | | | | | |

2 Total - - - -

3 Notes:
A. Project Gross Plant is the total capital investment for
4 the project calculated in the same method as the gross plant value in line 1.
This value includes subsequent capital investments required to maintain the facilities
5 to their original capabilities.
Gross Plant does not include CWIP, Unamortized Regulatory Asset or
6 Unamortized Abandoned Plant.

B. Net Plant is the Gross Plant less the associated Accumulated Depreciation.

C. Depreciation Expense is the depreciation amount associated with the specified line or sub.
Depreciation Expense includes the amortization of Abandoned Plant and any FERC approved Regulatory Asset.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation.
Additional line items will not require FPA Section 205 or 206 filings. NIPCO will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's Implementation Protocols. NIPCO may not change the columns or the formulas included in these Worksheets during the Annual Update.

Workshe
et I

**Northwest Iowa Power Cooperative**

**Reconciliation Items, Refunds and Surcharges**

**FY Year Ending December 31, 20XX**

**A B C D E F G H I J**

**ADJUSTMENTS TO GROSS ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| Line - | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Col H + Col I |
| 1 | | | | | | | | | 0 |
| 2 | | | | | | | | | 0 |
| 3 | | | | | | | | | 0 |
| 4 | | | | | | | | | 0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 5 | | | | | | | | | 0 |

| | | |
|---|---|---|
| 6 | **Total Adjustment to Gross ATRR:** | 0 |

**ADJUSTMENTS TO SPP REGIONAL PROJECTS' ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| Line - | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Col H + Col I |
| 7 | | | | | | | | | 0 |
| 8 | | | | | | | | | 0 |
| 9 | | | | | | | | | 0 |
| 10. | | | | | | | | | 0 |
| 11. | | | | | | | | | 0 |

| | | |
|---|---|---|
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | 0 |

13 Notes:

14 A. Rate Year in which the error occurred and affected the ATRR and rates paid by customers.
B. Interest is to be calculated at the lesser of NIPCO's short term debt costs or the amount calculated pursuant to 18 C.F.R.

15 § 35.19a.

Workpaper J

**Northwest Iowa Power Cooperative**

**O&M Input - From RUS Form 12**

**FY Year Ending December 31, 20XX**

| A | B | C | D | E |
|---|---|---|---|---|
| **SECTION A. EXPENSES AND COSTS** | | | | |
| **ITEM** | | **ACCOUNT NUMBER** | **LINES (a)** | **STATIONS (b)** |
| **Transmission Operations** | | | | |
| 1 | Supervision and Engineering | 560 | | |
| 2 | Load Dispatching | 561 | | |
| 3 | Station Expenses | 562 | | |
| 4 | Overhead Line Expenses | 563 | | |
| 5 | Underground Line Expenses | 564 | | |
| 6 | Miscellaneous Expenses | 566 | | |
| **7** | **Subtotal (1 thru 6)** | | **$ -** | **$ -** |
| 8 | Transmission of Electricity by Others | 565 | - | |
| 9 | Rents | 567 | | |
| **10** | **Total Transmission Operations (7 thru 9)** | | **$ -** | **$ -** |
| **Transmission Maintenance** | | | | |
| 11 | Supervision and Engineering | 568 | $ - | $ - |
| 12 | Structures | 569 | | |

| | | | | |
|---|---|---|---|---|
| 13 | Station Equipment | 570 | | |
| 14 | Overhead Lines | 571 | | |
| 15 | Underground Lines | 572 | $ - | |
| 16 | Miscellaneous Transmission Plant | 573 | $ - | $ - |
| **17** | **Total Transmission Maintenance (11 thru 16)** | | **$ -** | **$ -** |
| **18** | **Total Transmission Expense (10+17)** | | **$ -** | **$ -** |
| 19 | RTO/ISO Expense - Operation | 575.1-575.8 | $ - | $ - |
| 20 | RTO/ISO Expense - Maintenance | 576.1-576.5 | $ - | $ - |
| **21** | **Total RTO/ISO Expense (19+20)** | | **$ -** | **$ -** |
| 22 | Distribution Expense - Operation | 580-589 | $ - | |
| 23 | Distribution Expense - Maintenance | 590-598 | $ - | |
| **24** | **Total Distribution Expense (22+23)** | | **$ -** | **$ -** |
| **25** | **Total Operation and Maintenance (18+21+24)** | | **$ -** | **$ -** |
| **Fixed Costs** | | | | |
| 26 | Depreciation - Transmission | 403.5 | | |
| 27 | Depreciation - Distribution | 403.6 | | |
| 28 | Interest - Transmission | 427 | | |
| 29 | Interest - Distribution | 427 | | |
| **30** | **Total Transmission (18+26+28)** | | **$ -** | **$ -** |
| **31** | **Total Distribution (24+27+29)** | | **$ -** | **$ -** |
| **32** | **Total Lines and Stations (21+30+31)** | | **$ -** | **$ -** |

33 Notes

34 A. Lines can be added or removed from this Workpaper only if there are corresponding changes in the

RUS Form
35 12 Format.

Workpaper K

**Northwest Iowa Power Cooperative**

**Wages Input**
**FY Year Ending December 31, 20XX**

| | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Summary Labor Distribution** | **Account** | | | | | | | | | | | | | | Operations ----------> | | | Maintenance ----------> | | |
| | Labor MTD Distribution -Report plrlc | | January | February | March | April | May | June | July | August | September | October | November | December | Totals | 560 - Super | 562 - Stations | 563- Lines | 568- Super | 569 570- Stations | 571- Lines |
| 1 | Job Orders | 107.11000 | | | | | | | | | | | | | $ - | | | | | | |
| 2 | CWIP | 107.20000 | | | | | | | | | | | | | $ - | | | | | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Retire WIP | 108.80000 | | | | | | | | | | | | $ - | | | |
| 4 | Stores | 163.00000 | | | | | | | | | | | | $ - | | | |
| 5 | Trans Clear | 184.10000 | | | | | | | | | | | | $ - | | | |
| 6 | Other Clear | 184.60000 | | | | | | | | | | | | $ - | | | |
| 7 | Vacation | 242.30000 | | | | | | | | | | | | $ - | | | |
| 8 | | | | | | | | | | | | | | $ - | | | |
| 9 | Labor - Safety Program | 100.560.31 | | | | | | | | | | | | $ - | $ - | | |
| 10 | Admin & Gen - Salary - Non CTS | 100.920.10 | | | | | | | | | | | | $ - | | | |
| 11 | Admin & Gen - Salary - CTS | 100.921.10 | | | | | | | | | | | | $ - | | | |
| 12 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | | | | | | | | | | | | | | |
| 14 | Admin & Gen - Salary - Non CTS | 210.920.10 | | | | | | | | | | | | $ - |
| 15 | Admin & Gen - Salary - CTS | 210.921.10 | | | | | | | | | | | | $ - |
| 16 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 17 | | | | | | | | | | | | | | |
| 18 | Oper, Supervsn, Engineer-Neal 4 | 220.500. | | | | | | | | | | | | $ - |
| 19 | Admin & Gen - Salary - Non CTS | 220.920.10 | | | | | | | | | | | | $ - |
| 20 | Admin & Gen - Salary - CTS | 220.921.10 | | | | | | | | | | | | $ - |
| 21 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 22 | | | | | | | | | | | | | | |
| 23 | Admin & Gen - Salary - CTS | 230.921.10 | | | | | | | | | | | | $ - |
| 24 | Maint-Off Furn/Equip- | 230 | | | | | | | | | | | | $ - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Salary | .932.21 | | | | | | | | | | | | | | |
| 25 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 26 | | | | | | | | | | | | | | | | |
| 27 | Labor - Safety Program | 240.560.31 | | | | | | | | | | | $ - | $ - | | |
| 28 | Tran - Maint - Swtch, Towers - Salary | 240.570.11 | | | | | | | | | | | $ - | | | $ - |
| 29 | Dist - Oper - Sub - Salary | 240.582.11 | | | | | | | | | | | $ - | | | |
| 30 | Admin & Gen - Salary - CTS | 240.921.10 | | | | | | | | | | | $ - | | | |
| 31 | Maint-Struct/Improv - Salary | 240.932.11 | | | | | | | | | | | $ - | | | |
| 32 | Maint-Shop Equip - Salary | 240.932.41 | | | | | | | | | | | $ - | | | |
| 33 | Maint-Heavy Tools - | 240.93 | | | | | | | | | | | $ - | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Salary | 2.71 | | | | | | | | | | | | | | |
| 34 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 35 | | | | | | | | | | | | | | | | |
| 36 | Labor - Safety Program | 250.56 0.31 | | | | | | | | | | | | $ - | $ - | |
| 37 | Admin & Gen - Salary - CTS | 250.92 1.1 | | | | | | | | | | | | $ - | | |
| 38 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 39 | | | | | | | | | | | | | | | | |
| 40 | Oper, Supervsn, Engineer-Neal 4 | 310.50 0. | | | | | | | | | | | | $ - | | |
| 41 | Trans, Oper, Suprv, Eng - Salary | 310.56 0.11 | | | | | | | | | | | | $ - | $ - | |
| 42 | Labor - Safety Program | 310.56 0.31 | | | | | | | | | | | | $ - | $ - | |
| 43 | Dist - Oper, Suprv, Eng - Salary | 310.58 0.11 | | | | | | | | | | | | $ - | | |
| 44 | Dist - Oper, Sup, Eng, | 310 | | | | | | | | | | | | $ - | | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | LM - Salary | .580.21 | | | | | | | | | | | | | | | |
| 44<br>45 | Dist - Maint, Suprv, Eng - Salary | 310.590.11 | | | | | | | | | | | | | $ - | | |
| 46 | Customer Svc/Mkt - Salary | 310.908.1 | | | | | | | | | | | | | $ - | | |
| 47 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 48 | | | | | | | | | | | | | | | | | |
| 49 | Labor - Safety Program | 320.560.31 | | | | | | | | | | | | | $ - | $ - | |
| 50 | Oper-System Control - Salary | 320.561.11 | | | | | | | | | | | | | $ - | $ - | |
| 51 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | |
| 52 | | | | | | | | | | | | | | | | | |
| 53 | Trans, Oper, Suprv, Eng - Salary | 330.560.11 | | | | | | | | | | | | | $ - | $ - | |
| 54 | Trans-Suprv & Eng - Salary | 330.560.21 | | | | | | | | | | | | | $ - | $ - | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Labor - | 330.56 | | | | | |
| 55 | Safety Program | 0.31 | $ - | $ - | | | |
| 56 | Trans - Oper - Swtch, Towers - Salary | 330.56 2.11 | $ - | $ - | | | |
| 57 | Trans - Oper - LM - Salary | 330.56 2.21 | $ - | $ - | | | |
| 58 | Trans - Oper - Radio Tower - Salary | 330.56 2.31 | $ - | $ - | | | |
| 59 | Tran - Maint - Swtch, Towers - Salary | 330.57 0.11 | $ - | | | $ - | |
| 60 | Tran - Maint - LM - Salary | 330.57 0.21 | $ - | | | $ - | |
| 61 | Tran - Maint - Comm Tower - Salary | 330.57 0.31 | $ - | | | $ - | |
| 62 | Tran - Maint - 900 MHZ - Salary | 330.57 0.41 | $ - | | | $ - | |

| | | | | | |
|---|---|---|---|---|---|
| 63 | Tran - Maint - SCADA - Salary | 330.57 0.51 | $ - | $ - |
| 64 | Maint - Hdqtrs - SCADA - Salary | 330.57 0.71 | $ - | $ - |
| 65 | Dist - Oper - Sub - Salary | 330.58 2.11 | $ - | |
| 66 | Dist - Oper - LM - Salary | 330.58 2.21 | $ - | |
| 67 | Dist - Maint - Subs - Salary | 330.59 2.11 | $ - | |
| 68 | Dist - Maint - LM - Salary | 330.59 2.21 | $ - | |
| 69 | Dist - Maint - SCADA - Salary | 330.59 2.51 | $ - | |
| 70 | Maint - Struct/Improv - Salary | 330.93 2.11 | $ - | |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Maint - Comm - | 330 .93 | | | | | | | | | | | | | | | |
| 71 | Radios - Salary | 2.31 | | | | | | | | | | | $ - | | | | |
| | Maint - Lab | 330 .93 | | | | | | | | | | | | | | | |
| 72 | Equip - Salary | 2.51 | | | | | | | | | | | $ - | | | | |
| 73 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 74 | | | | | | | | | | | | | | | | | |
| | Trans - Oper - Swtch, | 332 .56 | | | | | | | | | | | | | | | |
| 75 | Towers - Salary | 2.11 | | | | | | | | | | | $ - | $ - | | | |
| | Oper - Crew - | 332 .56 | | | | | | | | | | | | | | | |
| 76 | Ovhd Line - Salary | 3.11 | | | | | | | | | | | $ - | | $ - | | |
| | Tran - Maint - Swtch, | 332 .57 | | | | | | | | | | | | | | | |
| 77 | Towers - Salary | 0.11 | | | | | | | | | | | $ - | | | $ - | |
| | Tran - Maint - Cndctr, | 332 .57 | | | | | | | | | | | | | | | |
| 78 | Devc - Salary | 1.31 | | | | | | | | | | | $ - | | | | $ - |
| | Admin & Gen - Salary | 332 .92 | | | | | | | | | | | | | | | |
| 79 | - CTS | 1.11 | | | | | | | | | | | $ - | | | | |
| | Maint - Lab | | | | | | | | | | | | | | | | |
| 80 | Equip - | 332 | | | | | | | | | | | $ - | | | | |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Salary | .932.51 | | | | | | | | | | | | | | | | |
| 81 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | |
| 82 | | | | | | | | | | | | | | | | | | |
| 83 | Trans, Oper, Suprv, Eng - Salary | 410.560.11 | | | | | | | | | | | $ - | $ - | | | | |
| 84 | Labor - Safety Program | 410.560.31 | | | | | | | | | | | $ - | $ - | | | | |
| 85 | Trans - Oper - Swtch, Towers - Salary | 410.562.11 | | | | | | | | | | | $ - | | $ - | | | |
| 86 | Oper - Crew - Ovhd Line - Salary | 410.563.11 | | | | | | | | | | | $ - | | | $ - | | |
| 87 | Tran - Maint - Swtch, Towers - Salary | 410.570.11 | | | | | | | | | | | $ - | | | | $ - | |
| 88 | Tran - Maint - LM - Salary | 410.570.21 | | | | | | | | | | | $ - | | | | $ - | |
| 89 | Tran - Maint - Pole, Fix - | 410.57 | | | | | | | | | | | $ - | | | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| | Salary | 1.21 | | | |
| 90 | Tran - Maint - Cndctr, Devc - Salary | 410.57 1.31 | $ - | | $ - |
| 91 | Dist - Oper, Suprv, Eng - Salary | 410.58 0.11 | $ - | | |
| 92 | Dist - Oper - Sub - Salary | 410.58 2.11 | $ - | | |
| 93 | Dist - Maint, Suprv, Eng - Salary | 410.59 0.11 | $ - | | |
| 94 | Dist - Maint - Subs - Salary | 410.59 2.11 | $ - | | |
| 95 | Maint - Struct/Improv - Salary | 410.93 2.11 | $ - | | |
| 96 | Maint - Small Tools - Salary | 410.93 2.61 | $ - | | |
| 97 | Maint - Heavy Tools - | 410.93 | $ - | | |

| | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Salary | 2.71 | | | | | | | | | | | | | | | | | |
| 98 | Maint - Struc/Improv-Onawa - Salary | 410.93.11 | | | | | | | | | | | | $ - | | | | | |
| 99 | Maint - Struc.Improv-Harlan - Salary | 410.93.11 | | | | | | | | | | | | $ - | | | | | |
| 100 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | | |
| 101 | | | | | | | | | | | | | | | | | | | |
| 102 | Trans, Oper, Suprv, Eng - Salary | 420.56.01 | | | | | | | | | | | | $ - | $ - | | | | |
| 103 | Labor - Safety Program | 420.56.03 | | | | | | | | | | | | $ - | $ - | | | | |
| 104 | Trans - Oper - Swtch, Towers - Salary | 420.56.21 | | | | | | | | | | | | $ - | | $ - | | | |
| 105 | Oper - Crew - Ovhd Line - Salary | 420.56.31 | | | | | | | | | | | | $ - | | | $ - | | |
| 110 | Tran - Maint - | 420 | | | | | | | | | | | | $ - | | | | $ - | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6 | Swtch, Towers - Salary | .57 0.1 1 | | | | | | | | | | | | |
| 10 7 | Dist - Oper, Suprv, Eng - Salary | 420 .58 0.1 1 | | | | | | | | | | | | $ - |
| 10 8 | Dist - Oper - Sub - Salary | 420 .58 2.1 1 | | | | | | | | | | | | $ - |
| 10 9 | Dist - Maint - Subs - Salary | 420 .59 2.1 1 | | | | | | | | | | | | $ - |
| 110 | Maint - Struct/Improv - Salary | 420 .93 2.1 1 | | | | | | | | | | | | $ - |
| 111 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 112 | | | | | | | | | | | | | | |
| 113 | Customer Svc/Mkt - Salary | 510 .90 8.1 0 | | | | | | | | | | | | $ - |
| 114 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 115 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 116 | Oper Exp - Sales - Salary | 520.91 2.10 | | | | | | | | | | | | $ - |
| 117 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 118 | | | | | | | | | | | | | | |
| 119 | Info, Instruct, Advert - Salary | 530.90 9.10 | | | | | | | | | | | | $ - |
| 120 | | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 121 | | | | | | | | | | | | | | |
| 122 | Total Salaries | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 123 | | | | | | | | | | | | | | |
| 124 | Operations Production | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 125 | | | | | | | | | | | | | | |
| 126 | Operations Transmission | | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | |
| 127 | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 128 | Operations Distribution | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 130 | Operations Consumer Services/Bonus Certificates | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 132 | Operations Sales IADG | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 134 | Operations A&G | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 136 | Maintenance Transmission | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 138 | Maintenance Distribution | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

| | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 140 | Maintenance General | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | | | |
| 142 | Total Wage Expense | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Notes:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. NIPCO will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's Implementation Protocols. NIPCO may not change the column or the formulas included in these Workpapers during the Annual Update.

Workpaper L

**Northwest Iowa Power Cooperative**

**Depreciation Functionalization**

**FY Year Ending December 31, 20XX**

| | A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|---|
| | **Account** | **Description** | **Total Expense (B)** | **Production** | **Tran-Station** | **Tran Lines** | **Distribution** | **General** | **Amort** |
| 1 | 403.1000 | Depre Exp Neal 4 Unclassified | | $ - | | | | | |
| 2 | 403.1140 | Depre Exp-Struct/Improv. Neal 4 | | $ - | | | | | |
| 3 | 403.1240 | Depre Exp-Boiler Plant Neal 4 | | $ - | | | | | |
| 4 | 403.1242 | Depre Exp-Coal Base Neal 4 | | $ - | | | | | |
| 5 | 403.1440 | Depre Exp Turbogenerator Neal 4 | | $ - | | | | | |
| 6 | 403.1540 | Depre Exp - Electric Equip Neal4 | | $ - | | | | | |
| 7 | 403.1640 | Depre Exp - Power Plant Neal 4 | | $ - | | | | | |
| 8 | 403.5200 | Depr Exp-Trans. Struct & Improv | | | $ - | | | | |
| 9 | 403.5240 | Depr Exp-Struct & Improv Neal 4 | | $ - | | | | | |
| 10 | 403.5300 | Depr Exp-Trans-Switch Sta 69 kV | | | $ - | | | | |
| 11 | 403.5306 | Depreciation Ex-Eagle T3/MEC | | | $ - | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | Depr Exp-Transmission-5I Equip | | | | $ - | | | | | | | |
| 2 | 403.5320 | | | | | | | | | | | | |
| 1 | | Depr Exp Transm Load Mgmt | | | | $ - | | | | | | | |
| 3 | 403.5330 | Equip | | | | | | | | | | | |
| 1 | | Depr Exp Station Equip - Neal 4 | | | $ - | | | | | | | | |
| 4 | 403.5340 | | | | | | | | | | | | |
| 1 | | Depr Exp-Eagle IPS | | | | $ - | | | | | | | |
| 5 | 403.5350 | | | | | | | | | | | | |
| 1 | | Depre Exp-Fiber Optics | | | | $ - | | | | | | | |
| 6 | 403.5360 | | | | | | | | | | | | |
| 1 | | Depr Exp-Towers & Fixtures N4 | | | $ - | | | | | | | | |
| 7 | 403.5440 | | | | | | | | | | | | |
| 1 | | Depr Exp-Transm-Pole & Fix 69 | | | | | | $ - | | | | | |
| 8 | 403.5500 | kV | | | | | | | | | | | |
| 1 | | Depr Exp-Poles & Fixtures-N4 | | | | | | $ - | | | | | |
| 9 | 403.5540 | | | | | | | | | | | | |
| 2 | | Depr Exp-Transm Cond-Devic 69 | | | | | | $ - | | | | | |
| 0 | 403.5600 | kV | | | | | | | | | | | |
| 2 | | Depr Exp-Cond & Devices Neal 4 | | | $ - | | | | | | | | |
| 1 | 403.5640 | | | | | | | | | | | | |
| 2 | | Depr Exp-Distribution Plant | | | | | | | | $ - | | | |
| 2 | 403.6200 | | | | | | | | | | | | |
| 2 | | Depr Exp - General Plant | | | | | | | | | | $ - | |
| 3 | 403.7000 | | | | | | | | | | | | |
| 2 | | Depr Exp-General Plant-N4 | | | $ - | | | | | | | | |
| 4 | 403.7400 | | | | | | | | | | | | |
| 2 | | Amort. of Other Electric Plant- | | | | | | | | | | | |
| 5 | 405.0000 | MBMECA | | | | | | | | | | | |
| 2 | | Totals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | | | | |
| 6 | | | | | | | | | | | | | |

2
7 Notes:
2 A. Lines representing detail and sub-accounts can be added only at the same depreciation rates shown in the
8 groupings originally listed.
2 B. Total expenses have been adjusted consistent with Trial Staff Settlement in ER15-2115. Depreciation expenses on NIPCO's Form 12
9 may not agree with
3
0 Settlement values.

Workpaper M

**Northwest Iowa Power Cooperative**

**Other Revenue**

**FY Year Ending December 31, 20XX**

| Line No. | A<br>Account No | B<br>Account Description | C<br>Total Company | D<br>Wheeling-Class B | E<br>Wheeling (Terminated) | F<br>Wheeling (GFA) | G<br>Wheeling SPP P2P | H<br>Rents | I<br>Production | J<br>Basin Facility Discount |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 456.0 | Other Misc Revenue | | | | | | $ - | | |
| 2 | 456.19 | Other Electric Rev-Everly | | | $ - | | | | | |
| | | Elec Rev-MBMECA | | $ - | | | | | | |
| 3 | 456.21 | Transmission | | | | | | | | |
| | | Other Elec.Rev.-Harlan | | | $ - | | | | | |
| 4 | 456.22 | Wheeling | | | | | | | | |
| | | Elec Rev-MPS | | | | $ - | | | | |
| 5 | 456.23 | Transmission | | | | | | | | |
| | | Other Rev-Land rent | | | | | | $ - | | |
| 6 | 456.242 | Onawa&Salix | | | | | | | | |
| | | Other Rev.-Rack Space | | | | | | $ - | | |
| 7 | 456.243 | Rental-Pio | | | | | | | | |
| | | Other Revenue-King St.- | | | | | | $ - | | |
| 8 | 456.244 | Rack Rent | | | | | | | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | SiouxLan Comm. Land | | | | | | | | | | $ | | | | |
| | 456.2 | Rent | | | | | | | | | | - | | | | |
| 9 | 45 | | | | | | | | | | | | | | | |
| | | Elec Rev-Amort | | | $ | | | | | | | | | | | |
| | 456.2 | MBMECA Payment | | | - | | | | | | | | | | | |
| 10 | 5 | | | | | | | | | | | | | | | |
| | | Elec Rev-SPP Point to | | | | | | | | $ | | | | | | |
| | 456.2 | Point | | | | | | | | - | | | | | | |
| 11 | 6 | | | | | | | | | | | | | | | |
| | 456.3 | Elec Rev-Basin Facility | | | | | | | | | | | | | | $ |
| 12 | | Discount | | | | | | | | | | | | | | - |
| | | Other Rev. Neal 4 Losses | | | | | | | | | | | $ | | | |
| | 456.3 | | | | | | | | | | | | - | | | |
| 13 | 1 | | | | | | | | | | | | | | | |
| | | Basin Load Data | | | | | | | | | | | $ | | | |
| | 456.3 | Acquisition Prog | | | | | | | | | | | - | | | |
| 14 | 5 | | | | | | | | | | | | | | | |
| | | Small Renew Energy Cr- | | | | | | | | | | | $ | | | |
| | 456.4 | Basin | | | | | | | | | | | - | | | |
| 15 | 5 | | | | | | | | | | | | | | | |
| | | Total | $ | | $ | | $ | | $ | $ | | $ | | $ | | $ | |
| 16 | | | - | | - | | - | | - | - | | - | | - | | | |

17 Note:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information,
18 and populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated
19 Form 12 data requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings.
20 NIPCO will describe such changes in
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21 NIPCO's Implementation Protocols.
NIPCO may not change the column or the formulas included in these Workpapers
22 during the Annual Update.

Workpa
per N

**Northwest Iowa Power Cooperative**

**Network Load**
**(KW)**

**FY Year Ending December 31, 20XX**

| Line No. | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Month | Class A Network | Class B Network | Alliant-Everly Network | Harlan Network | MEC Network | NIPCO Network Total | Class A MEC/MISO | Class A Harlan Muni | Grand Total | Total Class A |
| 1 | January | | | | | | 0 | | | 0 | 0 |
| 2 | February | | | | | | 0 | | | 0 | 0 |
| 3 | March | | | | | | 0 | | | 0 | 0 |
| 4 | April | | | | | | 0 | | | 0 | 0 |
| 5 | May | | | | | | 0 | | | 0 | 0 |
| 6 | June | | | | | | 0 | | | 0 | 0 |
| 7 | July | | | | | | 0 | | | 0 | 0 |
| 8 | August | | | | | | 0 | | | 0 | 0 |
| 9 | September | | | | | | 0 | | | 0 | 0 |
| 10 | October | | | | | | 0 | | | 0 | 0 |
| 11 | November | | | | | | 0 | | | 0 | 0 |
| 12 | December | | | | | | 0 | | | 0 | 0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 13 | Total | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 14 | Average | | | | | | 0 | | | 0 | 0 |

Workpaper O

**Northwest Iowa Power Cooperative**

**Fiber Expense and Income Input**

**FY Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | 403 | 408 | 415 | 427 | 560-935 |
| Line No. | Div | Account | Description | YTD Trans | Depreciation | Property Tax | Revenue | Interest Exp | O&M Expense |
| 1 | 2.0 | 403.5300 | Depreciation Exp-Station Equip-Fiber | | $ - | | | | |
| 2 | 2.0 | 403.5360 | Deprec Exp-Electronic Equip.-Fiber | | $ - | | | | |
| 3 | 2.0 | 403.5560 | Deprec Exp.-Poles-Fiber | | $ - | | | | |
| 4 | 2.0 | 403.5660 | Deprec Exp-Fiber OPGW | | $ - | | | | |
| 5 | 2.0 | 403.5661 | NE Deprec Exp-Fiber OPGW | | $ - | | | | |
| 6 | 2.0 | 403.5662 | Depr Exp-IRU Fiber(IA) | | $ - | | | | |
| 7 | 2.0 | 403.5663 | Depr Exp-IRU Fiber(NE) | | $ - | | | | |
| 8 | 2.0 | 403.7560 | Deprec Exp-Gen Plant Lab. Equip. | | $ - | | | | |
| 9 | 2.0 | 408.1000 | Property tax | | | $ - | | | |
| 10 | 2.0 | 415.1020 | Dark NonMem-SDN South Dakota Net | | | | $ - | | |
| 11 | | | Dark NonMem-Pioneer | | | | $ | | |

| | | | | | |
|---|---|---|---|---|---|
| | 2.0 | 415.1030 | | - | |
| | | | Dark NonMem-Jefferson | $ | |
| 12 | 2.0 | 415.1040 | Telephone | - | |
| | | | Lite Capacity-Member- | $ | |
| 13 | 2.0 | 415.2010 | Northwest REC | - | |
| | | | Lite Capacity-Member-Iowa | $ | |
| 14 | 2.0 | 415.2011 | Lakes | - | |
| | | | Lite Capacity-Member- | $ | |
| 15 | 2.0 | 415.2012 | Harrison | - | |
| | | | Lite Capacity-Member- | $ | |
| 16 | 2.0 | 415.2013 | WIPCO | - | |
| | | | Lite Capacity-Member-Basin | $ | |
| 17 | 2.0 | 415.2014 | | - | |
| | | | Liet Capacity-NonMember- | $ | |
| 18 | 2.0 | 415.2100 | Pioneer | - | |
| | | | Lite Capacity-NonMember- | $ | |
| 19 | 2.0 | 415.2120 | RACOM | - | |
| | | | Lite Capacity-NonMember- | $ | |
| 20 | 2.0 | 415.2130 | Fibercom | - | |
| | | | Lit Capacity-Prairie Energy | $ | |
| 21 | 2.0 | 415.2200 | | - | |
| | | | Lite Capacity-Citizens | $ | |
| 22 | 2.0 | 415.2210 | Telecom | - | |
| | | | Lite Capacity-Butler REC | $ | |
| 23 | 2.0 | 415.2220 | | - | |
| | | | Lit Capacity-Midland Power | $ | |
| 24 | 2.0 | 415.2230 | | - | |
| | | | Lit Capacity-AAB | $ | |
| 25 | 2.0 | 415.2240 | | - | |
| | | | Lit Capacity-Grundy REC | $ | |
| 26 | 2.0 | 415.2250 | | - | |
| | | | Lit Capacity-Evertek | $ | |
| 27 | 2.0 | 415.2260 | | - | |
| | | | Lit Capacity-Siouxland | $ | |
| 28 | 2.0 | 415.2270 | Wireless | - | |
| | | | Lite Fiber/Rack Rent- | $ | |
| 29 | 2.0 | 415.2280 | MidAmerican | - | |
| | | | Other Revenue-Service to | $ | |
| 30 | 2.0 | 415.4000 | Others | - | |
| 31 | | | Interest on LTD | | $ |

| | | | | | |
|---|---|---|---|---|---|
| | 2.0 | 427.1000 | | - | |
| | | | Interest Expense-NCSC | $ | |
| 32 | 2.0 | 427.1200 | | - | |
| | | | Fiber Oper.-Stat.Elect.Equip- | | $ |
| 33 | 2.0 | 562.1100 | Sal | | - |
| | | | Fiber Oper.-Stat.Elec.Equip.- | | $ |
| 34 | 2.0 | 562.1300 | Tra | | - |
| | | | Fiber Oper.-Stat.Elec.Equip- | | $ |
| 35 | 2.0 | 562.1400 | Misc | | - |
| | | | Fiber Oper-Line-Salary | | $ |
| 36 | 2.0 | 563.1100 | | | - |
| | | | Fiber Oper-Line- | | $ |
| 37 | 2.0 | 563.1300 | Transportation | | - |
| | | | Fiber Oper-Line- Misc | | $ |
| 38 | 2.0 | 563.1400 | | | - |
| | | | Fiber Oper-Line-Fly Line | | $ |
| 39 | 2.0 | 563.1500 | | | - |
| | | | Wapa Eagle to SF Fiber | | $ |
| 40 | 2.0 | 566.1000 | Amort | | - |
| | | | Orpheum Building to SC | | $ |
| 41 | 2.0 | 566.2000 | Airport | | - |
| | | | WAPA-SDN Amort/SDN | | $ |
| 42 | 2.0 | 566.4000 | Xconnect | | - |
| | | | POP Leases | | $ |
| 43 | 2.0 | 567.0100 | | | - |
| | | | Fiber Maint-Stat.Elec- | | $ |
| 44 | 2.0 | 570.1100 | Salary | | - |
| | | | Fiber Maint-Stat.Elec.Equip- | | $ |
| 45 | 2.0 | 570.1200 | Emp | | - |
| | | | Fiber Maint-Stat.Elec. | | $ |
| 46 | 2.0 | 570.1300 | Equip-Tra | | - |
| | | | Fiber Maint-Stat.Elec.Equip- | | $ |
| 47 | 2.0 | 570.1400 | Misc | | - |
| | | | Fiber Maint-Line & Pole- | | $ |
| 48 | 2.0 | 571.3100 | Salary | | - |
| | | | Fiber Maint-Line & Pole- | | $ |
| 49 | 2.0 | 571.3300 | Transp. | | - |
| | | | Fiber Maint-Line & Pole- | | $ |
| 50 | 2.0 | 571.3400 | Misc | | - |
| 51 | | | Fiber Maint-Line & Pole- | | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2.0 | 571.3500 | Material | | | | | | - |
| | | | Fiber A&G-Salary Expense | | | | | | $ |
| 52 | 2.0 | 921.1000 | | | | | | | - |
| | | | Fiber A&G-Misc | | | | | | $ |
| 53 | 2.0 | 921.4000 | | | | | | | - |
| | | | Attorney Fees | | | | | | $ |
| 54 | 2.0 | 923.1000 | | | | | | | - |
| | | | Misc Dues-Assoc. Org | | | | | | $ |
| 55 | 2.0 | 930.2000 | | | | | | | - |
| | | | Miscellaneous General | | | | | | $ |
| 56 | 2.0 | 930.4000 | Expense | | | | | | - |
| | | | Fiber Maint-Lab/Test Equip- | | | | | | $ |
| 57 | 2.0 | 932.5100 | Salar | | | | | | - |
| | | | Fiber Maint-Lab/Test Equip- | | | | | | $ |
| 58 | 2.0 | 932.5400 | Misc | | | | | | - |
| | | | Fiber Maint-Lab/Test Equip- | | | | | | $ |
| 59 | 2.0 | 932.5500 | Mater | | | | | | - |
| | | | Fiber Shop Supplies | | | | | | $ |
| 60 | 2.0 | 935.1500 | | | | | | | - |
| | | | | $ | $ | $ | $ | $ | |
| 61 | | | Total | - | - | - | - | - | |

62 Notes:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and
63 populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12
64 data requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. NIPCO
65 will describe such changes in
the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's
66 Implementation Protocols.
NIPCO may not change the column or the formulas included in these Workpapers during
67 the Annual Update.

Workp
aper P

**Northwest Iowa Power Cooperative**

**Construction Work in Progress**
**FY Year Ending December 31, 20XX**

| A<br>Line No. | B<br>Project Description | C<br>Approval Docket No. | D<br>% Recovery Approved (Note A) | E<br>Pricing Zone (Note B) | F<br>Project ID | G<br>Construction Start Date | H<br>In-Service Date (Estimated) | I<br>BoY Balance | J<br>EoY Balance | K<br>Average Balance (Col I through J) /2 | L<br>Includable in Rate Base (Note C) (Col D * Col K) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Eagle-J15 Tie Line - Key Contracting | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 2 | FEMA-HM Group 1 - IES | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 3 | FEMA-HM Group 2 - Watts | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 4 | FEMA-HM Group 3 - Watts | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 5 | FEMA-HM Post Award Costs | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 6 | Install Storm Guys, X-Braces, Anchors | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 7 | Temp Pole (K207-L8) Bridge Replacement | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 8 | Stations Berm Upgrades | ER15-2115 | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 9 | K227 - New Primghar Muni | ER15-2115 | 50.00% | Zone | | | | | | $ | $ |

| | | | | | | |
|---|---|---|---|---|---|---|
| | Switch | | | 19 | - | - |
| | Double Circuit Main Line for | | | Zone | $ | $ |
| 10 | K227 | ER15-2115 | 50.00% | 19 | - | - |
| | K423 - New Afton Tap | | | Zone | $ | $ |
| 11 | Switch | ER15-2115 | 50.00% | 19 | - | - |
| | Double Circuit Main Line for | | | Zone | $ | $ |
| 12 | K423 | ER15-2115 | 50.00% | 19 | - | - |
| | Eagle - Upgrade 230KV | | | Zone | $ | $ |
| 13 | Relay Panels | ER15-2115 | 50.00% | 19 | - | - |
| | Salix Junction - Add 161KV | | | Zone | $ | $ |
| 14 | Bay for MEC | ER15-2115 | 50.00% | 19 | - | - |
| | | | | Zone | $ | $ |
| 15 | L1 Upgrade Station Relaying | ER15-2115 | 50.00% | 19 | - | - |
| | J3 - Replace & Relocate | | | Zone | $ | $ |
| 16 | RadioTowers | ER15-2115 | 50.00% | 19 | - | - |
| | | | | Zone | $ | $ |
| 17 | K302 - Moville Tap Switch | ER15-2115 | 50.00% | 19 | - | - |
| | | | | Zone | $ | $ |
| 18 | L3 - Replace Motor Operators | ER15-2115 | 50.00% | 19 | - | - |
| | Le Mars Tower - New Tower | | | Zone | $ | $ |
| 19 | and Related Equipment | ER15-2115 | 50.00% | 19 | - | - |
| | Line 2 East of J15 - Relocated | | | Zone | $ | $ |
| 20 | 1/2 Mile of Line | ER15-2115 | 50.00% | 19 | - | - |
| | | | | Zone | $ | $ |
| 21 | K424 - Sanborn REC Switch | ER15-2115 | 50.00% | 19 | - | - |
| | J2 to J3 - Communication | | | Zone | $ | $ |
| 22 | Update | ER15-2115 | 50.00% | 19 | - | - |
| | Line 4 - South of Sanborn | | | Zone | $ | $ |
| 23 | Substation | ER15-2115 | 50.00% | 19 | - | - |
| | Update 48V Battery Chargers | | | Zone | $ | $ |
| 24 | & Banks at 10 sites | ER15-2115 | 50.00% | 19 | - | - |
| | Replace 12V Supply/Charger | | | Zone | $ | $ |
| 25 | Systems | ER15-2115 | 50.00% | 19 | - | - |
| | Reroute Line 1 near Little | | | Zone | $ | $ |
| 26 | Sioux Sub | ER15-2115 | 50.00% | 19 | - | - |
| | Migrate T1s from Turin | | | Zone | $ | $ |
| 27 | platform to Positron platform | ER15-2115 | 50.00% | 19 | - | - |
| | K125 to K126 Line Move - | | | Zone | $ | $ |
| 28 | Culvert Work | ER15-2115 | 50.00% | 19 | - | - |
| 29 | Woodbine Lightning Tower - | ER15-2115 | 50.00% | Zone | $ | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Lightning Damage | | | 19 | | | | - | - |
| | Eagle Substation - T1 | | | Zone | | | | $ | $ |
| 30 | upgrades | ER15-2115 | 50.00% | 19 | | | | - | - |
| | J7 Upgrade Battery Charger & | | | Zone | | | | $ | $ |
| 31 | Batteries | ER15-2115 | 50.00% | 19 | | | | - | - |
| | Security Cameras - J3, Salix | | | Zone | | | | $ | $ |
| 32 | Junction, NIPCO HQ | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 33 | K318 - Replace Tecoruptors | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 34 | J15 Switch Station | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 35 | J6 - Add Bay & Cap Bank | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 36 | Eagle - Add 69kV Bays | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 37 | Eagle to J15 Tie Line | ER15-2115 | 50.00% | 19 | | | | - | - |
| | J5 Cap Bank, Breakers, | | | Zone | | | | $ | $ |
| 38 | Relays & Building | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 39 | FEMA-HM Group 1 | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 40 | FEMA-HM Group 2 | ER15-2115 | 50.00% | 19 | | | | - | - |
| | | | | Zone | | | | $ | $ |
| 41 | FEMA-HM Group 3 | ER15-2115 | 50.00% | 19 | | | | - | - |
| | Total CWIP Includable in | | | | | $ | $ | $ | $ |
| 42 | Rate Base | | | | | - | - | - | - |
| | Total CWIP Not Included in | | | | | | | | |
| 43 | Rate Base | | | | | | | | |
| | | | | | | $ | $ | | |
| 44 | Total CWIP | | | | | - | - | | |

45 Notes:

46 A. Percentage recovery cannot be added or changed absent approval from FERC

47 B. CWIP amounts should be directly assigned to pricing zone on Summary

48 C. AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization.

Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized. Projects are transmission related only.

D. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheet with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items will not require FPA Section 205 or 206 filings. NIPCO will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's Implementation Protocols. NIPCO may not change the columns or the formulas included in these Worksheets during the Annual Update.

E. For new facilities which are approved through the SPP planning process or otherwise added and satisfy Attachment AI criteria, the facilities and CWIP (up to the 50% level) can be included and added. The related costs are subject to the annual update process, including the data review procedures, per the NIPCO Implementation Protocols.

Workpaper Q

**Northwest Iowa Power Cooperative**

**Plant Held for Future Use**

**FY Year Ending December 31, 20XX**

| A<br>Line No | B<br>Facility No. | C<br>Asset No. | D<br>Description | E<br>BoY Investment | F<br>EOY Investment | G<br>Average Investment |
|---|---|---|---|---|---|---|
| 1 | | | Production Future Use Assets | $ - | $ - | $ - |
| 2 | | | | | | |
| 3 | | | Transmission Future Use Assets | | | |
| 4 | | 105.89400 | Land Held for Future Use - W Fiscus | | | $ - |
| 5 | | 105.89405 | Land Held for Future Use - Henry | | | $ - |
| 6 | | 105.89410 | Land Held for Future Use - Garfield | | | $ - |
| 7 | | 105.89415 | Land Held for Future Use - K403 | | | $ - |
| 8 | | 105.89420 | Land Held for Future Use - Pilot | | | $ - |
| 9 | | 105.89425 | Land Held for Future Use - K201 | | | $ - |
| 10 | | 105.89430 | Land Held for Future Use - K101 | | | $ - |
| 11 | | | | | | $ - |
| 12 | | | | | | $ - |
| 13 | | | | | | $ - |
| 14 | | | | | | $ - |
| 15 | | | | | | $ - |
| 16 | | | | | | $ - |

| | | | | |
|---|---|---|---|---|
| 17 | Subtotal Transmission Future Use Assets | $ - | $ - | $ - |
| 18 | | | | |
| 19 | Distribution Future Use Assets | $ - | $ - | $ - |
| 20 | | | | |
| 21 | General Plant Future Use Assets | $ - | $ - | $ - |
| 22 | | | | |
| 23 | Intangible Plant Future Use Assets | $ - | $ - | $ - |
| 24 | | | | |
| 25 | Total Plant Held for Future Use | $ - | $ - | $ - |

26 Notes:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and
27 populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data
28 requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. NIPCO will
29 describe such changes in
the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's
30 Implementation Protocols.

31 NIPCO may not change the columns or the formulas included in these Workpapers during the Annual Update.

**Northwest Iowa Power Cooperative**

Workpaper R

**SPP Completed Not Classified**

**FY Year Ending December 31, 20XX**

| A<br>Line<br>No. | B<br>Fac<br>ID | C<br>Work<br>Order | D<br>Project | E<br>BoY<br>Balance | F<br>EoY<br>Balance | G<br>% SPP<br>Eligible | H<br>BoY<br>Amount | I<br>EoY<br>Amount | J<br>Average |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | 106.353 | Switch Station Equipment - Unclassified | | | | $ - | $ - | $ - |
| 2 | | 106.4 | Neal 4 - Unclassified | | | | $ - | $ - | $ - |
| 3 | | 106.62677 | New Transformers - Unclassified | | | | $ - | $ - | $ - |
| 4 | | | | | | | $ - | $ - | $ - |
| 5 | | | | | | | $ - | $ - | $ - |
| 6 | | | | | | | $ - | $ - | $ - |
| 7 | | | | | | | $ - | $ - | $ - |
| 8 | | | | | | | $ - | $ - | $ - |
| 9 | | | | | | | $ - | $ - | $ - |
| 10 | | | | | | | $ - | $ - | $ - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | | $ | $ | $ |
| 11 | | | | | - | - | - |
| | | | $ | $ | $ | $ | $ |
| 12 | | Total | - | - | - | - | - |

Notes:

A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. NIPCO will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's Implementation Protocols.

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Workpaper S

**Northwest Iowa Power Cooperative**

**Line Segment Ratios**

**FY Year Ending December 31, 20XX**

| A | B | C | D | E |
|---|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Segment (feet)** | **Ratio** |
| 1 | Loop | Workpaper T, Line 241, Col L | 0 | |
| 2 | Common Radial | Workpaper T, Line 241, Col M | 0 | |
| 3 | Subtotal qualifying | | **0** | |
| 4 | Normal Open Segment (Non-Qualifying) | Workpaper T, Line 241, Col N | 0 | |
| 5 | Radial (non-qualifying) | Workpaper T, Line 241, Col O | 0 | |
| 6 | Total | | **0** | |
| 7 | Note: | | | |
| 8 | A. Source data is from Workpaper T | | | |

Work paper T

**Northwest Iowa Power Cooperative**

**Qualifying Facilities Circuit Feet Ratio**

**FY Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Grid | From Bus Name | To Bus Name | Segment Description | Feet | Comments | Loop (Qualifying) | Common Radial (Qualifying) | Normal Open Segment (Non-Qualifying) | Radial (non-qualifying) | Loop (Qualifying) | Common Radial (Qualifying) | Normal Open Segment (Non-Qualifying) | Radial (non-qualifying) |
| 1 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 2 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 3 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 4 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 5 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 6 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 7 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 8 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 9 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 10 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 11 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 12 | | | | | | | | | | | 0 | 0 | 0 | 0 |
| 13 | | | | | | | | | | | 0 | 0 | 0 | 0 |

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|---|---|---|---|---|
| 14 | 0 | 0 | 0 | 0 |
| 15 | 0 | 0 | 0 | 0 |
| 16 | 0 | 0 | 0 | 0 |
| 17 | 0 | 0 | 0 | 0 |
| 18 | 0 | 0 | 0 | 0 |
| 19 | 0 | 0 | 0 | 0 |
| 20 | 0 | 0 | 0 | 0 |
| 21 | 0 | 0 | 0 | 0 |
| 22 | 0 | 0 | 0 | 0 |
| 23 | 0 | 0 | 0 | 0 |
| 24 | 0 | 0 | 0 | 0 |
| 25 | 0 | 0 | 0 | 0 |
| 26 | 0 | 0 | 0 | 0 |
| 27 | 0 | 0 | 0 | 0 |
| 28 | 0 | 0 | 0 | 0 |
| 29 | 0 | 0 | 0 | 0 |
| 30 | 0 | 0 | 0 | 0 |
| 31 | 0 | 0 | 0 | 0 |
| 32 | 0 | 0 | 0 | 0 |
| 33 | 0 | 0 | 0 | 0 |
| 34 | 0 | 0 | 0 | 0 |
| 35 | 0 | 0 | 0 | 0 |
| 36 | 0 | 0 | 0 | 0 |
| 37 | 0 | 0 | 0 | 0 |
| 38 | 0 | 0 | 0 | 0 |
| 39 | 0 | 0 | 0 | 0 |
| 40 | 0 | 0 | 0 | 0 |
| 41 | 0 | 0 | 0 | 0 |
| 42 | 0 | 0 | 0 | 0 |
| 43 | 0 | 0 | 0 | 0 |
| 44 | 0 | 0 | 0 | 0 |
| 45 | 0 | 0 | 0 | 0 |

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| 46 | 0 | 0 | 0 | 0 |
| 47 | 0 | 0 | 0 | 0 |
| 48 | 0 | 0 | 0 | 0 |
| 49 | 0 | 0 | 0 | 0 |
| 50 | 0 | 0 | 0 | 0 |
| 51 | 0 | 0 | 0 | 0 |
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| 53 | 0 | 0 | 0 | 0 |
| 54 | 0 | 0 | 0 | 0 |
| 55 | 0 | 0 | 0 | 0 |
| 56 | 0 | 0 | 0 | 0 |
| 57 | 0 | 0 | 0 | 0 |
| 58 | 0 | 0 | 0 | 0 |
| 59 | 0 | 0 | 0 | 0 |
| 60 | 0 | 0 | 0 | 0 |
| 61 | 0 | 0 | 0 | 0 |
| 62 | 0 | 0 | 0 | 0 |
| 63 | 0 | 0 | 0 | 0 |
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| 65 | 0 | 0 | 0 | 0 |
| 66 | 0 | 0 | 0 | 0 |
| 67 | 0 | 0 | 0 | 0 |
| 68 | 0 | 0 | 0 | 0 |
| 69 | 0 | 0 | 0 | 0 |
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| 71 | 0 | 0 | 0 | 0 |
| 72 | 0 | 0 | 0 | 0 |
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| 74 | 0 | 0 | 0 | 0 |
| 75 | 0 | 0 | 0 | 0 |
| 76 | 0 | 0 | 0 | 0 |
| 77 | 0 | 0 | 0 | 0 |

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| 78 | 0 | 0 | 0 | 0 |
| 79 | 0 | 0 | 0 | 0 |
| 80 | 0 | 0 | 0 | 0 |
| 81 | 0 | 0 | 0 | 0 |
| 82 | 0 | 0 | 0 | 0 |
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| 84 | 0 | 0 | 0 | 0 |
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| 86 | 0 | 0 | 0 | 0 |
| 87 | 0 | 0 | 0 | 0 |
| 88 | 0 | 0 | 0 | 0 |
| 89 | 0 | 0 | 0 | 0 |
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| 95 | 0 | 0 | 0 | 0 |
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| 104 | 0 | 0 | 0 | 0 |
| 105 | 0 | 0 | 0 | 0 |
| 106 | 0 | 0 | 0 | 0 |
| 107 | 0 | 0 | 0 | 0 |
| 108 | 0 | 0 | 0 | 0 |
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| 111 | 0 | 0 | 0 | 0 |
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| 115 | 0 | 0 | 0 | 0 |
| 116 | 0 | 0 | 0 | 0 |
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| 122 | 0 | 0 | 0 | 0 |
| 123 | 0 | 0 | 0 | 0 |
| 124 | 0 | 0 | 0 | 0 |
| 125 | 0 | 0 | 0 | 0 |
| 126 | 0 | 0 | 0 | 0 |
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| 139 | 0 | 0 | 0 | 0 |
| 140 | 0 | 0 | 0 | 0 |
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| 143 | 0 | 0 | 0 | 0 |
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| 147 | 0 | 0 | 0 | 0 |
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| 150 | 0 | 0 | 0 | 0 |
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| 152 | 0 | 0 | 0 | 0 |
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| 200 | 0 | 0 | 0 | 0 |
| 201 | 0 | 0 | 0 | 0 |
| 202 | 0 | 0 | 0 | 0 |
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| 204 | 0 | 0 | 0 | 0 |
| 205 | 0 | 0 | 0 | 0 |

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| 218 | 0 | 0 | 0 | 0 |
| 219 | 0 | 0 | 0 | 0 |
| 220 | 0 | 0 | 0 | 0 |
| 221 | 0 | 0 | 0 | 0 |
| 222 | 0 | 0 | 0 | 0 |
| 223 | 0 | 0 | 0 | 0 |
| 224 | 0 | 0 | 0 | 0 |
| 225 | 0 | 0 | 0 | 0 |
| 226 | 0 | 0 | 0 | 0 |
| 227 | 0 | 0 | 0 | 0 |
| 228 | 0 | 0 | 0 | 0 |
| 229 | 0 | 0 | 0 | 0 |
| 230 | 0 | 0 | 0 | 0 |
| 231 | 0 | 0 | 0 | 0 |
| 232 | 0 | 0 | 0 | 0 |
| 233 | 0 | 0 | 0 | 0 |
| 234 | 0 | 0 | 0 | 0 |
| 235 | 0 | 0 | 0 | 0 |
| 236 | 0 | 0 | 0 | 0 |
| 237 | 0 | 0 | 0 | 0 |

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 238 | | | | | | | | 0 | 0 | 0 | 0 |
| 239 | | | | | | | | 0 | 0 | 0 | 0 |
| 240 | | | | | | | | 0 | 0 | 0 | 0 |
| 241 | Total feet: | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 242 | | | | | | 0 | | | | | 0 |

Notes:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. NIPCO will describe such changes in the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in NIPCO's Implementation Protocols. NIPCO may not change the columns or the formulas included in these Workpapers during the Annual Update.

Workpaper
U

**Northwest Iowa Power Cooperative**

**Regulatory and Commission Expenses**

**FY Year Ending December 31, 20XX**

| A<br>Line No. | B<br>Account 928 | C<br>Description | D<br>Total Company | E<br>Non-SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | Total | $ - | $ - | $ - |

11 Notes:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information,
12 and populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12
13 data requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. NIPCO
14 will describe such changes in

the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in
15 NIPCO's Implementation Protocols.

16 NIPCO may not change the columns or the formulas included in these Workpapers during the Annual Update.

Workpaper V

**Northwest Iowa Power Cooperative**

**RTO Expenses - Operation & Maintenance**
**FY Year Ending**
**December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account 575-576** | **Description** | **Total Company** | **575.1-575.8 Total Company Expenses** | **575.1-575.8 Non-SPP Expenses** | **575.1-575.8 SPP Expenses** | **576.1-576.5 Total Company Expenses** | **576.1-576.5 Non-SPP Expenses** | **576.1-576.5 SPP Expenses** |
| 1 | | | | | | | | | |
| 2 | | | | | | | | | |
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

11 Notes:

12 A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and

populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form
13 12 data requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings.
14 NIPCO will describe such changes in
the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in
15 NIPCO's Implementation Protocols.
NIPCO may not change the columns or the formulas included in these
16 Workpapers during the Annual Update.
B. RTO/ISO expenses may only be recovered in accounts 575 and 576 following a change in accounting procedures
17 classifying these expenses as eligible
for transmission rate
18 recovery.

Workpaper
W

**Northwest Iowa Power Cooperative**

**Customer Accounting**

**FY Year Ending December 31, 20XX**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line No.** | **Account 901-905** | **Description** | **Total Company** | **901-905 Non-SPP Expenses** | **901-905 SPP Expenses** |
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | Customer Accounting Wages | $ - | $ - | $ - |
| 11 | | | | | |
| 12 | | Customer Accounting Computer Support | $ - | $ - | $ - |
| 13 | | | | | |
| 14 | | Total Customer Accounting | $ - | $ - | $ - |

15 Notes:
A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information,
16 and populate or remove data in
the Workpaper with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form
17 12 data requirements or other
similar supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings.
18 NIPCO will describe such changes in
the Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in
19 NIPCO's Implementation Protocols.
20 NIPCO may not change the columns or the formulas included in these Workpapers during the Annual Update.

**NIPCO Transmission Formula Rate Implementation Protocols**

Section I Annual Update

1. The transmission formula rate template (Formula Rate Template) of Northwest Iowa Power Cooperative (NIPCO) and these Transmission Formula Rate Implementation Protocols (Protocols) together comprise the filed rate (Formula Rate) of NIPCO for transmission service in Zone 19 of the Southwest Power Pool, Inc. (SPP) footprint. NIPCO must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements (ATRR) and the revenue requirements for Scheduling, System Control and Dispatch Service (Schedule 1 Service), as well as the SPP Base Plan Zonal and Region-Wide Charge (Schedule 11 Service) under the SPP Open Access Transmission Tariff (OATT or SPP Tariff).

   Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and the SPP Tariff. The ATRR shall be determined for January 1 to December 31 of a given calendar year. The Formula Rate shall become effective for recovery of NIPCO's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission (FERC) under section 205 of the Federal Power Act (FPA).

2. The Formula Rate shall be applicable to service on and after July 1 of each calendar year through June 30 of the following calendar year (Rate Year), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

3. On or before April 15 of each calendar year (the Publication Date), NIPCO shall:

   (a) Recalculate the revenue requirements applicable to Network Integration Transmission Service for the new Rate Year in accordance with the Formula Rate (Annual Update); and

   (b) Provide its Annual Update to SPP and request that SPP post such information to the SPP Open Access Same-Time Information System (OASIS) (the Initial Posting); and

   (c) If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the Initial Posting shall be due on the next Business Day. The date on which such posting occurs shall be that year's Publication Date. Any delay in the Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

4. Concurrent with the Initial Posting, NIPCO shall provide the Annual Update to SPP to serve electronically upon the Formula Rate Posting Information Notification List.[1]

5. The Annual Update shall:

(a) Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

(b) Be based on the independently-audited books and records of NIPCO for the most recent fiscal year including its certified Rural Utilities Services (RUS) Form 12 or successor reports including the Financial and Operating Report Electric Power Supply (Op. Report –Power Supply), (January 1 through December 31);

(c) Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

(d) With respect to any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate, NIPCO shall identify:

i. Any Accounting Changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR. Any items included in the Formula Rate at an amount other than a historic cost basis.

ii. Individual impact of any changes in i. above on charges billed under the Formula Rate.

iii. Accounting Changes related to any reorganization or merger transaction.

(e) Not seek to modify the Formula Rate, as any modification to the Formula Rate will require filing under section 205 or 206 of the FPA.

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[1] As used in these Protocols, "Formula Rate Posting Information Notification List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification List through the "Exploder List" link on the SPP website. As of September 2019, the Exploder List was titled "Formula Rate Posting Information Notification" and could accessed at http://www.spp.org/ stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

## Section II Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

(a) "Accounting Change" means any change in NIPCO's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

(i) revisions to FERC's Uniform System of Accounts (USofA); (ii) revisions to RUS Form 12 data and the requirement to report certain values within it; (iii) correction of errors and prior period adjustments that impact the ATRR; (iv) the implementation of new estimation methods or policies; (v) changes to income tax elections; (vi) changes in accounting practices or policies mandated by FERC or a state regulatory authority with jurisdiction over NIPCO that could impact the Formula Rate or calculations under the Formula; (vii) implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction; (viii) a change in NIPCO's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor); (ix) NIPCO's own Accounting Changes (which constitute a change to the ATRR greater than or equal to $50,000) such as the addition or deletion of a subaccount not specified by FERC's USofA; or (x) a change in NIPCO's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

(b) "Annual Transmission Revenue Requirement" (ATRR) means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by NIPCO for informational purposes with FERC and posted on the SPP OASIS on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

(c) "Annual Meeting" means the meeting hosted by NIPCO for the purpose of exchanging information with Interested Parties regarding the Formula Rate.

(d) "Annual Update" means NIPCO's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

(e) "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

(f) "Calendar Year" means January 1 through December 31 of a given year.

(g) "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and which NIPCO has filed with FERC (*e.g.*, if the Annual

Update is filed on April 15, 2015, the Current Rate Year is July 1, 2015 through June 30, 2016).

(h) "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS service, service under Grandfathered Agreements, or point-to-point (PTP) service.

(i) "FERC" or "Commission" means the Federal Energy Regulatory Commission.

(j) "Final Posting" means the Annual Update information which NIPCO requests that SPP post to the SPP OASIS with changes agreed to during the Review Period.

(k) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with FERC, and served on NIPCO by electronic service on the date of such filing.

(l) "Formula Rate" has the meaning defined herein.

(m) "FPA" means Federal Power Act.

(n) "Informal Challenge" means written notification by an Interested Party to NIPCO of any specific challenge to the Annual Update.

(o) "Information Request" means a written request submitted by an Interested Party to NIPCO.

(p) "Informational Filing" means NIPCO's annual filing at the Commission with the information stipulated in these Protocols.

(q) "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a or successor regulation.

(r) "Interested Party" includes but is not limited to, Customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

(s) "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

(t) "OASIS" means Open Access Same-Time Information System.

(u) "OATT" or "SPP Tariff "means SPP's Open Access Transmission Tariff.

(v) "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is July 1, 2015 through June 30, 2016, then the Prior Rate Year is July 1, 2014 through June 30, 2015).

(w) "PTP Rates" means the point-to-point rates derived from the Formula Rate.

(x) "Publication Date" means the date on which NIPCO posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2016 shall be no later than April 15, provided, however, that if April 15 should fall on a weekend or a holiday recognized by FERC, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

(y) "Rate Year" means July 1 of a given year through June 30 of the subsequent year.

(z) "Review Period" means unless otherwise extended in writing by NIPCO, 60 days after the Publication Date.

(aa) "RUS" means Rural Utilities Service.

(bb) "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity (ROE); (ii) depreciation and amortization rates; and (iii) other similar fixed values. Stated Values may be changed only pursuant to FPA Section 205 or 206.

(cc) "USofA" means FERC's Uniform System of Accounts.

## Section III Review of Annual Update

Within twenty (20) days of the posting of NIPCO's Annual Update, NIPCO will host a meeting for Interested Parties to discuss the Annual Update (Annual Meeting). NIPCO shall provide notice of this meeting concurrent with the posting of the Annual Update accessible on the SPP OASIS. The notice shall include the date, time and location of the Annual Meeting and also shall be provided to Interested Parties through the Formula Rate Posting Information Notification List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically.

### A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Update and will have until sixty (60) days after the Publication Date to serve reasonable Information Requests on NIPCO for information and work papers supporting the Annual Update (the Review Period). Such Information Requests shall be limited to that what is necessary to determine:

   (a) The extent or effect of an Accounting Change;

   (b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

   (c) The proper application of the Formula Rate and procedures in these Protocols;

   (d) The accuracy of data and consistency with the Formula Rate of the calculation shown in the Annual Update;

(e) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

(f) The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

(g) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. NIPCO will not claim that responses to information and document requests pursuant the Protocols are subject to any settlement confidentiality provision however, NIPCO may require that Interested Parties execute a non-disclosure agreement to obtain access to material that NIPCO deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 C.F.R. § 388.113(c)(1).

2. NIPCO shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within seven (7) Business Days.

3. NIPCO shall request to be posted on a publicly accessible portion of the SPP OASIS all Information Requests from Interested Parties and NIPCO's response(s) to such requests, and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Information Requests contain information deemed by NIPCO to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and NIPCO.

4. If the deadline for Interested Parties falls on a weekend or holiday recognized by the Commission the deadline will be extended to the next Business Day.

B. Informal Challenge Procedures

1. Interested Parties shall have until May 15 (or the first Business Day after May 15 if May 15 falls on a weekend or holiday) to notify NIPCO in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. NIPCO will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. NIPCO, and, if appropriate, SPP, shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. NIPCO will request that SPP post on the SPP OASIS all Informal Challenges from Interested Parties and NIPCO's responses to the Informal Challenges and a link to the posting will be electronically served on all Interested Parties via the Formula Rate Posting Information Notification List. If responses to Informal Challenges contain information deemed by NIPCO to be confidential, such information will not be publicly

posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and NIPCO.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by NIPCO and resolved prior to the end of the Review Period shall be reported in the Final Posting on the SPP OASIS. Any changes or adjustments agreed to by NIPCO after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Update for the following Rate Year.

C. Formal Challenges.

1. A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The accuracy of data and consistency with the Formula Rate of the calculation shown in the Annual Update;

v. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

vi. The effect of any change to the underlying Uniform System of Accounts or Formula Rate Template; or

vii. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via section 206 of the FPA, and shall be served upon NIPCO contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with § 385.2010(f) (3), by facsimile, express delivery or messenger to the individual listed as the contact person in NIPCO' Informational Filing.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of return on equity (ROE), depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA, sections 205 or 206. Any modification to the Formula Rate will require a filing under section 205 or 206 of the FPA.

3. If NIPCO makes a correction to a Mistake in its financial information during the Current Rate Year that would affect the Formula Rate for the Current Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with 18 C.F.R. § 35.19a or successor regulation. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate Template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with 18 C.F.R. § 35.19a or successor regulation. Refunds arising from NIPCO's first rate case in Docket No. ER15-2115, shall be calculated at the

lesser of NIPCO's short-term debt costs or the amount calculated pursuant to 18 C.F.R. § 35.19a or successor regulation.

5. Any Commission orders specifically applicable to NIPCO's calculation of its annual revenue requirements.

E. Informational Filing.

1. By August 15 of each year, NIPCO shall submit to FERC an informational filing (Informational Filing) of its Annual Update under a separate docket number.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   (a) That input data under the Formula Rate is properly recorded in any underlying work papers;

   (b) That NIPCO has properly applied the Formula Rate and these procedures;

   (c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   (d) The extent of Accounting Changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, NIPCO shall provide notice of the Informational Filing to Interested Parties via the Formula Rate Posting Information Notification List and request that SPP post the notice and the docket number assigned to the Informational filing on the SPP OASIS.

## Section IV Joint SPP Transmission Owners' Meeting.

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, NIPCO intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP OASIS and distributed to Interested Parties via the Formula Rate Posting Information Notification List no less than seven (7) days prior to such meetings.

Example NIPCO Schedule

| **Action** | **Date** |
|---|---|
| Data Available | March 1 |
| Initial Posting | April 15 |
| Annual Meeting, Interested Parties | May 5 |
| Interested Parties Review Period | April 15 – June 15 |
| Final Posting | June 20 |
| FERC Informational Filing | August 15 |
| Rate Year | July 1 – June 30 |

## ADDENDUM 29 TO ATTACHMENT H

## Harlan Municipal Utilities

Harlan Municipal Utilities
For the Year ended 6/30/20XX



Formula Rate Template - Cash Flow | Formula Rate Template | 6/30/20XX

Harlan Municipal Utilities

| Line No. | | | | | | Allocated Amount |
|---|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | (page 2, line 24) | | | | #DIV/0! |
| | REVENUE CREDITS | (Note Q) | Total | Allocator | | |
| 2 | Account No. 454 | (page 3, line 34) | 0 | TP | 0.00 % | 0 |
| 3 | Account No. 456 | (page 3, line 37) | 0 | TP | 0.00 % | 0 |
| 4 | Revenues from Grandfathered Interzonal Transactions | | 0 | TP | 0.00 % | 0 |
| 5 | Revenues from service provided by the ISO at a discount | | 0 | TP | 0.00 % | 0 |
| 6 | TOTAL REVENUE CREDITS (sum lines 2-5) | | | | | 0 |
| 7 | NET REVENUE REQUIREMENT | (line 1 - line 6) | | | | #DIV/0! |
| | DIVISOR | | | | | |
| 8 | Average of 12 coincident system peaks for requirements (RQ) service | | | | (Note A) | 0 |
| 9 | Plus 12 CP of firm bundled sales over one year not in line 8 | | | | (Note B) | 0 |
| 10 | Plus 12 CP of Network Load not in line 8 | | | | (Note C) | 0 |

| | | | |
|---|---|---|---|
| 11 | Less 12 CP of firm P-T-P over one year (enter negative) | (Note D) | 0 |
| 12 | Plus Contract Demand of firm P-T-P over one year | | 0 |
| 13 | Less Contract Demand from Grandfathered Interzonal transactions over one year (enter negative) (Note P) | | 0 |
| 14 | Less 12 CP or Contract Demands from service over one year provided by ISO at a discount (enter negative) | | 0 |
| 15 | Divisor (sum lines 8-14) | | 0 |



Formula Rate Template - Cash Flow | Formula Rate Template | 6/30/20XX

Harlan Municipal Utilities

| Line No. | (1) | (2) Reference | (3) Company Total | Allocator | (4) | (5) Transmission (Col 3 times Col 4) |
|---|---|---|---|---|---|---|
| | O&M | | | | | |
| 1 | Transmission | | 0 | TE | 0.00% | 0 |
| 1a | Less LSE Expenses included in Transmission O&M Accounts (Note R) | | 0 | | | |
| 2 | Less Account 565 | | 0 | TE | 0.00% | 0 |
| 3 | A&G | | 0 | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | | 0 | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note F) | | 0 | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note F) | | 0 | TE | 0.00% | 0 |
| 6 | Common | | 0 | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | | 0 | | 100.00% | 0 |
| 8 | TOTAL O&M (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | | 0 | | | #DIV/0! |
| | DEBT SERVICE | | | | | |
| 9 | Debt Service (Note S) | | 0 | GP | #DIV/0! | #DIV/0! |
| 10 | Amortization of premium or discount (Note T) | | 0 | GP | #DIV/0! | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| 11 | TOTAL DEBT SERVICE (Sum lines 9 - 10) | 0 | | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note G) | | | | |
| | LABOR RELATED | | | | |
| 12 | Payroll | 0 | W/S | #DIV/0! | #DIV/0! |
| 13 | Highway and vehicle | 0 | W/S | #DIV/0! | #DIV/0! |
| 14 | PLANT RELATED | | | | |
| 15 | Property | 0 | GP | #DIV/0! | #DIV/0! |
| 16 | Gross Receipts | 0 | | zero | 0 |
| 17 | Other | 0 | GP | #DIV/0! | #DIV/0! |
| 18 | Payments in lieu of taxes | 0 | GP | #DIV/0! | #DIV/0! |
| 19 | TOTAL OTHER TAXES (sum lines 12 - 18) | 0 | | | #DIV/0! |
| 20 | SUBTOTAL (sum lines 8, 11, 19) | 0 | | | #DIV/0! |
| 21 | MARGIN REQUIREMENT (Note H) | 0 | GP | #DIV/0! | #DIV/0! |
| 22 | REV. REQUIREMENT (sum lines 20, 21) | 0 | | | #DIV/0! |
| 23 | REV. REQUIREMENT TO BE COLLECTED UNDER ATTACHMENT H | 0 | | | #DIV/0! |



Formula Rate Template - Cash Flow | Formula Rate Template | 6/30/20XX

Harlan Municipal Utilities

Line No. | **SUPPORTING CALCULATIONS AND NOTES**

| | | Reference | Company Total | | Allocator | | Transmission | |
|---|---|---|---|---|---|---|---|---|
| | GROSS PLANT IN SERVICE (Note U) | | | | | | | |
| 1 | Production | | 0 | | NA | | | |
| 2 | Transmission | | 0 | | TP | 0.00 % | 0 | 0 |
| 3 | Distribution | | 0 | | NA | | | |
| 4 | General & Intangible | | 0 | | W/S | #DIV/0! | #DIV/0! | |
| 5 | Common | | 0 | | CE | #DIV/0! | #DIV/0! | |
| 6 | TOTAL GROSS PLANT (sum lines 1-5) | | 0 | | GP= | #DIV/0! | #DIV/0! | |
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | | | |
| 7 | Total transmission plant (line 2) | | | | | | 0 | |
| 8 | Less transmission plant excluded from ISO rates (Notes J and V) | | | | | | 0 | |
| 9 | Less transmission plant included in OATT Ancillary Services (Notes K and V ) | | | | | | 0 | |
| 10 | Transmission plant included in ISO rates (line 7 less lines 8 & 9) | | | | | | 0 | |
| 11 | Percentage of transmission plant included in ISO Rates (line 10 divided by line 7) | | | | | TP = | 0.00 % | |
| | TRANSMISSION EXPENSES | | | | | | | |
| 12 | Total transmission expenses (page 2, line 1, column 3) | | | | | | 0 | |
| 13 | Less transmission expenses included in OATT Ancillary Services (Note I) | | | | | | 0 | |
| 14 | Included transmission expenses (line 12 less line 13) | | | | | | 0 | |
| 15 | Percentage of transmission expenses after adjustment (line 14 divided by line 12) | | | | | | 0.00 % | |
| 16 | Percentage of transmission plant included in ISO Rates (line 11) | | | | | TP = | 0.00 % | |
| 17 | Percentage of transmission expenses included in ISO Rates (line 15 times line 16) | | | | | TE = | 0.00 % | |
| | WAGES & SALARY ALLOCATOR (W&S) (Note L) | | | | | | | |
| | | | $ | | | Allocation | | |
| 18 | Production | | 0 | 0% | | 0 | | |
| 19 | Transmission | | 0 | 0% | | 0 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 20 | Distribution | 0 | 0% | 0 | | W&S Allocator ($ / Allocation) |
| 21 | Other | 0 | 0% | 0 | | |
| 22 | Total (sum lines 18-21) | 0 | | 0 | = | #DIV/0! |

COMMON PLANT ALLOCATOR (CE)
(Note M)

| | | $ | | % Electric (line 23 / line 26) | | Labor Ratio (line 22) | | CE |
|---|---|---|---|---|---|---|---|---|
| 23 | Electric | 0 | | | | | | |
| 24 | Gas | 0 | | 0.0000 | * | #DIV/0! | = | #DIV/0! |
| 25 | Water | 0 | | | | | | |
| 26 | Total (sum lines 23-25) | 0 | | | | | | |

REVENUE CREDITS

| | | | Load |
|---|---|---|---|
| | ACCOUNT 447 (SALES FOR RESALE) | | |
| 31 | a. Bundled Non-RQ Sales for Resale | (Note N) | 0 |
| 32 | b. Bundled Sales for Resale included in Divisor on page 1 | | 0 |
| 33 | Total of (a)-(b) | | 0 |
| 34 | ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note O) | | $0 |
| | ACCOUNT 456 (OTHER ELECTRIC REVENUES) | | |
| 35 | a. Transmission charges for all transmission transactions | | $0 |
| 36 | b. Transmission charges for all transmission transactions included in Divisor on page 1 | | $0 |
| 37 | Total of (a)-(b) | | $0 |

Harlan Municipal Utilities

| Note Letter | |
|---|---|
| A | The utility's maximum monthly megawatt load (60-minute integration) for RQ service at time of applicable pricing zone coincident monthly peaks. RQ service is service which the supplier plans to provide on an on-going basis (i.e., the supplier includes projected load for this service in its system resource planning). |
| B | Includes LF, IF, LU, IU service. LF means "firm service" (cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions), and long-term (duration of at least five years); does not meet definition of RQ service. IF is "firm service" for a term longer than one but less than five years. LU is service from a designated generating unit, of a term no less than five years. LI is service from a designated generating unit for a term between one and five years. Measured at time of applicable pricing zone coincident monthly peaks. |
| C | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| D | LF as defined above at time of applicable pricing zone coincident monthly peaks. |
| E | The FERC's annual charges for the year assessed the Transmission Owner for service under this tariff, if any. |
| F | Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising. Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting. |
| G | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula |
| H | Template, since they are recovered elsewhere. The Margin Requirement is consistent with the margin the utility uses in calculating rates applicable to its native load sales. |
| I | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including all of Account No. 561.1, 561.2, 561.3 and 561.BA. |
| J | Removes transmission plant determined by |

| | |
|---|---|
| | Commission order to be state-jurisdictional according to the seven-factor test. |
| K | Removes dollar amount of transmission plant related to assets included in OATT Ancillary Services. |
| L | If the utility has more employees assigned to A&G than to the sum of production, transmission, and distribution, set the W&S allocator at page 3, line 22 equal to the gross plant allocator (GP) at page 3, line 6. |
| M | Enter dollar amounts. |
| N | Line 33 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456 and all other uses are to be included in the divisor. |
| O | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. |
| P | Grandfathered agreements whose rates have been changed to eliminate or mitigate pancaking - the revenues are included in line 4 page 1 and the loads are included in line 13, page 1. |
| Q | Grandfathered agreements whose rates have not been changed to eliminate or mitigate pancaking - the revenues are not included in line 4, page 1 nor are the loads included in line 13, page 1. The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. |
| R | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| S | revenue requirements. Debt service calculation is supported by the debt service work paper. |
| T | Includes amounts recorded to accounts 428 and 429. |
| U | Gross Plant in Service amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet A**

**Attachment H divisor**

**Report the CP of your load in the Pricing Zone for Each Month in KWs**

| | |
|---|---|
| Jul | - |
| Aug | - |
| Sep | - |
| Oct | - |
| Nov | - |
| Dec | - |
| Jan | - |
| Feb | - |
| Mar | - |
| Apr | - |
| May | - |
| Jun | - |
| Sub total | - |
| Average | - |

Do the above numbers include any GFA related load? If yes, provide the following by month for each GFA:
the GFA #, the GFA load, and the GFA transmission revenues.

| | Jan | Feb | Mar | Apr | May | June | Jul | Aug | Sep | Oct | Nov | Dec | Total | Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GFA # | | | | | | | | | | | | | | |
| GFA Load | | | | | | | | | | | | | - | - |
| GFA Trans Rev | | | | | | | | | | | | | - | |

-

GFA #

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |

GFA #

| | | |
|---|---|---|
| GFA Load | - | - |
| GFA Trans Rev | - | - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet B**

**Plant Summary**

| | Gross Plant | Accumulated Depreciation | Net Plant | Depreciation Expense |
|---|---|---|---|---|
| **Production Plant** | | | | |
| **Steam Production Plant** | $ - | $ - | $ - | $ - |
| 310 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 311 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 312 – Boiler Plant Equipment | $ - | $ - | $ - | $ - |
| 313 – Engines and Engine-Driven Generators | $ - | $ - | $ - | $ - |
| 314 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 315 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 316 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| Total Steam Production Plant | $ - | $ - | $ - | $ - |
| **Nuclear Production Plant** | | | | |
| 320 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 321 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 322 – Reactor Plant Equipment | $ - | $ - | $ - | $ - |
| 323 – Turbogenerator Units | $ - | $ - | $ - | $ - |
| 324 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 325 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 326 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Nuclear Production Plant | | | | |
| **Hydraulic Production Plant** | | | | |
| 330 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 331 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 332 – Reservoirs, Dams, and Waterways | $ - | $ - | $ - | $ - |
| 333 – Water Wheels, Turbines, and Generators | $ - | $ - | $ - | $ - |
| 334 - Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 335 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 336 – Roads, Railroads, and Bridges | $ - | $ - | $ - | $ - |
| 337 – Asset Retirement Costs for Hydraulic Production | $ - | $ - | $ - | $ - |
| Total Hydraulic Production Plant | $ - | $ - | $ - | $ - |
| **Other Production Plant** | | | | |
| 340 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 341 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 342 – Fuel Holders, Products, and Accessories | $ - | $ - | $ - | $ - |
| 343 – Prime Movers | $ - | $ - | $ - | $ - |
| 344 – Generators | $ - | $ - | $ - | $ - |
| 345 – Accessory Electric Equipment | $ - | $ - | $ - | $ - |
| 346 – Misc. Power Plant Equipment | $ - | $ - | $ - | $ - |
| 347 – Asset Retirement Costs for Nuclear Production | $ - | $ - | $ - | $ - |
| Total Other Production Plant | $ - | $ - | $ - | $ - |
| **Total Production Plant** | $ - | $ - | $ - | $ - |
| **Transmission Plant** | | | | |
| 350 – Land and Land Rights | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| 352 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 353 – Station Equipment | $ - | $ - | $ - | $ - |
| 354 – Towers and Fixtures | $ - | $ - | $ - | $ - |
| 355 – Poles and Fixtures | $ - | $ - | $ - | $ - |
| 356 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 357 – Underground Conduit | $ - | $ - | $ - | $ - |
| 358 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 359 – Roads and Trails | $ - | $ - | $ - | $ - |
| 359.1 – Asset Retirement Costs for Transmission Plant | $ - | $ - | $ - | $ - |
| **Total Transmission Plant** | $ - | $ - | $ - | $ - |

**Distribution Plant**

| | | | | |
|---|---|---|---|---|
| 360 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 361 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 362 – Station Equipment | $ - | $ - | $ - | $ - |
| 363 – Storage Battery Equipment | $ - | $ - | $ - | $ - |
| 364 – Poles, Towers, and Fixtures | $ - | $ - | $ - | $ - |
| 365 – Overhead Conductors and Devices | $ - | $ - | $ - | $ - |
| 366 – Underground Conduit | $ - | $ - | $ - | $ - |
| 367 – Underground Conductors and Devices | $ - | $ - | $ - | $ - |
| 368 – Line Transformers | $ - | $ - | $ - | $ - |
| 369 – Services | $ - | $ - | $ - | $ - |
| 370 – Meters | $ - | $ - | $ - | $ - |
| 371 – Installations on Customer Premises | $ - | $ - | $ - | $ - |
| 372 – Leased Property on Customers Premises | $ - | $ - | $ - | $ - |
| 373 – Street lighting and Signal Systems | $ - | $ - | $ - | $ - |
| 374 – Asset Retirement Costs for Distribution Plant | $ - | $ - | $ - | $ - |
| Total Distribution Plant | $ - | $ - | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| **Intangible Plant** | | | | |
| 301 Organization | $ - | $ - | $ - | $ - |
| 302 Franchises and Consents | $ - | $ - | $ - | $ - |
| 303 Miscellaneous Intangible Plant | $ - | $ - | $ - | $ - |
| Total Intangible Plant | $ - | $ - | $ - | $ - |
| **General Plant** | | | | |
| 389 – Land and Land Rights | $ - | $ - | $ - | $ - |
| 390 – Structures and Improvements | $ - | $ - | $ - | $ - |
| 391 – Office Furniture and Equipment | $ - | $ - | $ - | $ - |
| 392 – Transportation Equipment | $ - | $ - | $ - | $ - |
| 393 – Stores Equipment | $ - | $ - | $ - | $ - |
| 394 – Tools, Shop and Garage Equipment | $ - | $ - | $ - | $ - |
| 395 – Laboratory Equipment | $ - | $ - | $ - | $ - |
| 396 – Power Operated Equipment | $ - | $ - | $ - | $ - |
| 397 – Communication Equipment | $ - | $ - | $ - | $ - |
| 398 – Miscellaneous Equipment | $ - | $ - | $ - | $ - |
| 399 – Other Tangible Property | | $ - | $ - | $ - |
| 399.1 – Asset Retirement Costs for General Plant | $ - | $ - | $ - | $ - |
| **Total General Plant** | $ - | $ - | $ - | $ - |
| **Grand Total Plant In-Service** | $ - | $ - | $ - | $ - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet C**

Land Held For Future Use

| | |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

**Below -** Provide a brief but descriptive list of the Transmission land held for future use

and the amounts related to each item of Transmission land held for future use

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet D**

Materials and Supplies

| | |
|---|---|
| Production | $ - |
| Transmission | - |
| Distribution | - |
| Other | - |
| | $ - |

**Below** - Provide a brief but descriptive list of the Transmission related Materials and Supplies

and the amounts related to each item of Transmission related Materials and Supplies

**Transmission Materials & Supplies**

| **Material Group** | **Amount** |
|---|---|
| Insulators | $ - |
| Relays | $ - |
| Substation Misc Part | $ - |
| Transmission wires | $ - |
| Trans. Line Hardware | $ - |
| Transducers | $ - |
| | $ - |
| **Total** | **$ -** |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet E**

| Pre Payment Description | Amount |
|---|---|
| Prepaid Insurance | $ - |
| Prepaid accounts payable | - |
| Accrued payroll | - |
| XXXXX | - |
| Total Pre Payments | $ - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet F**

| Transmission O&M Expenses | Amount |
|---|---|
| Operation | |
| 560 – Operation Supervision and Engineering | - |
| 561 – Load Dispatching | - |
| 561.1 – Load Dispatch – Reliability | - |
| 561.2 – Load Dispatch – Monitor and Operate Transmission System | - |
| 561.3 – Load Dispatch – Transmission Service and Scheduling | - |
| 561.4 – Scheduling, System Control and Dispatch Services | - |
| 561.5 – Reliability, Planning and Standards Development | |
| 561.6 – Transmission Service Studies | |
| 561.7 – Generation Interconnection Studies | - |
| 561.8 – Reliability, Planning and Standards Development Service | - |
| 562 – Station Expenses | - |
| 563 – Overhead Lines Expenses | - |
| 564 – Underground Lines Expenses | - |
| 565 – Transmission of Electricity by Others | - |
| 566 – Miscellaneous Transmission Expenses | - |
| 567 – Rents | - |
| Total Operations | - |
| Maintenance | |
| 568 – Maintenance Supervision and Engineering | - |
| 569 – Maintenance of Structures | - |
| 569.1 – Maintenance of Computer Hardware | - |
| 569.2 – Maintenance of Computer Software | - |
| 569.3 – Maintenance of Communication Equipment | - |
| 569.4 – Maintenance of Miscellaneous Regional Transmission Plant | - |

| | |
|---|---|
| 570 – Maintenance of Station Equipment | - |
| 571 – Maintenance of Overhead Lines | - |
| 572 – Maintenance of Underground Lines | - |
| 573 – Maintenance of Miscellaneous Transmission Plant | - |
| Total Maintenance | - |
| Total Transmission O&M Expense | - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet G**

| **Customer Accts & Admin and General Expenses** | **Amount** |
|---|---|
| **Customer Accounts Expenses** | |
| 901 – Supervision | - |
| 902 – Meter Reading Expenses | - |
| 903 – Customer Records and Collection Expenses | - |
| 904 – Uncollectible Accounts | - |
| 905 – Miscellaneous Customer Accounts Expenses | - |
| **Total Customer Accounts Expense** | - |
| **Customer Service and Informational Expenses** | |
| 907 – Supervision | - |
| 908 – Customer Assistance Expenses | - |
| 909 – Informational and Instructional Expenses | - |
| 910 – Miscellaneous Customer Service and Informational Expenses | - |
| **Total Customer Service and Informational Expenses** | - |
| **Sales Expenses** | |
| 911 – Supervision | - |
| 912 – Demonstrating and Selling Expenses | - |
| 913 – Advertising Expenses | - |
| 916 – Miscellaneous Sales Expenses | - |
| **Sales Expenses** | - |
| **Administrative and General Expenses** | |

| | |
|---|---|
| 920 – Administrative and General Salaries | - |
| 921 – Office Supplies and Expenses | - |
| 922 – Administrative Expenses Transferred Credit | - |
| 923 – Outside Services Employed | - |
| 924 – Property Insurance | - |
| 925 – Injuries and Damages | - |
| 926 – Employee Pension and Benefits | - |
| 927 – Franchise Requirements | - |
| 928 – Regulatory Commission Expenses | - |
| 929 – Duplicate Charges Credit | - |
| 930.1 – General Advertising Expenses | - |
| 930.2 – Miscellaneous General Expenses | - |
| 931 – Rents | - |
| Total Operations A&G | - |
| 935 – Maintenance of General Plant | - |
| Total Maintenance A&G | - |
| **Total Administrative and General Expenses** | - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet H**

| **FERC fees recorded to expense during the year** | **Account Charged** | **Amount** |
|---|---|---|
| FERC fees payable to FERC | - | $ - |
| FERC fees paid to an RTO | - | - |
| Other FERC fees paid | - | - |
| Total | $ - | $ - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet I**

**Taxes Other Than Income Taxes**

| | |
|---|---|
| Payroll | $ - |
| Highway & Vehicle | - |
| Property | - |
| Gross | - |
| Other - please explain | - |
| Payments in lieu of taxes | - |
| Fed & State income Tax | - |
| Total | $ - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet J**

| | | |
|---|---|---|
| EPRI Costs | $ - | recorded in Usof A account _____, reflected in I/S in _____ exp |

Regulatory Commission Expense (provide a brief but descriptive list of charges) **Indicate by yellow highlight if Transmission Related**

| | | |
|---|---|---|
| Rate case - docket XX | $ - | recorded in UsofA account _____, reflected in I/S in _____ exp |
| Fuel adjustment clause docket XX | - | recorded in USofA account _____, reflected in I/S in _____ exp |
| | - | |

Non Safety Advertising (provide a brief but descriptive list of charges)

| | | |
|---|---|---|
| Admin & General Advertising | $ - | recorded in USofA account _____ , reflected in I/S in _____exp |
| Xxxxxxxx | | |
| | - | |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet K**

| | Wages |
|---|---|
| Production | $ - |
| Transmisssion | - |
| Distribution | - |
| Other _1/ | - |
| | $ - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet L**

| Debt Detail - Electric only | Principle Balance at For the Year ended 6/30/20XX | Principle Payment | Interest Expense |
|---|---|---|---|
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |

| | | | |
|---|---|---|---|
| | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| | $ - | $ - | $ - |
| Total | $ - | $ - | $ - |
| **Principle & Interest Grand Total** | **$ -** | **$ -** | **$ -** |

| | | |
|---|---|---|
| **Total Debt Service** | $ - | |
| **Margin Requirement** | | **75.00%** |
| **Total Margin Requirement** | $ - | |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet M**

**Account 454 (Rent from Electric Property)**

| **Property Description** | **Amount** |
|---|---|
| XXXXX | $ - |
| XXXXX | - |
| XXXXX | - |
| XXXXX | - |

| | |
|---|---|
| Total Rent Income | $ - |

**Harlan Municipal Utilities**

**For the Year ended 6/30/20XX**

**Worksheet N**

| **Account 456.1 (Other Electric Revenues)** | **Account 456.1 Revenue** |
|---|---|
| Revenue from Network Integration Transmission Service (NITS) | $ - |
| Revenue point-to-point transmision service | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| xxxxx | $ - |
| Total Transmission Revenue | $ - |

# HARLAN MUNICIPAL UTILITIES
# FORMULA RATE IMPLEMENTATION PROTOCOLS

## Section I. Applicability

The following procedures shall apply to Harlan Municipal Utilities' ("HMU") Formula Rate Template ("FRT").

## Section II. Annual ATRR Update

A. Beginning on or before May 1, 2016, and on or before each subsequent May 1, HMU shall determine its annual transmission revenue requirement ("ATRR") to be effective on June 1, 2016 and each subsequent June 1.

B. On or before May 1, 2016, and on or before each subsequent May 1, HMU shall post its populated FRT and supporting documentation at a publicly accessible location on the SPP website and OASIS. Within five (5) days of such posting, HMU shall provide notice of such posting via an e-mail distribution list. Interested Parties may contact HMU to request to be added to the e-mail distribution list.

C. If the date for posting the FRT falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the FRT shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the FRT will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

D. The FRT shall:

1. Include a workable data-populated FRT and underlying work papers in native format with all formulas intact;

2. Be based on HMU's audited financial statements for the prior fiscal year;

3. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the FRT that are not otherwise available in audited financial statements;

4. Identify all material adjustments made to the audited financial statements data in determining formula inputs;

5. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Material Accounting Change"):

a. Identify:

i. The initial implementation of an accounting standard or policy;
ii. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;
iii. Correction of errors and prior period adjustments that affect the FRT calculations;
iv. The implementation of new estimation methods or policies that change prior estimates; and
v. changes to income tax elections (if applicable);

b. Identify items included in the FRT at an amount other than on a historic cost basis (e.g., fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the FRT;

d. Provide, for each item identified pursuant to items II.D.5.a - II.D.5.c of these protocols, a narrative explanation of the individual impact of such changes on the FRT.

E. HMU shall hold an open meeting among Interested Parties ("ATRR Update Meeting") between the Publication Date and May 31 of each year. HMU shall make available to Interested Parties remote access to the ATRR Update Meeting. No less than seven (7) days prior to such ATRR Update Meeting, HMU shall provide notice at a publicly accessible location on the SPP website and OASIS of the time, date, location and remote access information of the ATRR Update Meeting and shall provide notice of such meeting via the e-mail distribution list described in II.B of these protocols. For purposes of these Protocols, the term "Interested Parties" includes, but is not limited to, customers under the Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The FRT Update Meeting shall (i) permit HMU to explain and clarify its ATRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from HMU about the ATRR.

F. Each year HMU shall endeavor to coordinate with other Transmission Owners in the SPP using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects.

## Section III. Information Exchange Procedures

Each FRT update shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have until July 1 following the Publication Date (unless such period is extended with the written consent of HMU or by FERC order) to serve reasonable information and document requests on HMU ("Information Exchange Period"). If July 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

(1) The extent or effect of an Accounting Change;

(2) Whether the FRT fails to include data properly recorded in accordance with these protocols;

(3) The proper application of the formula rate and procedures in these protocols;

(4) The accuracy of data and consistency with the formula rate of the calculations shown in the FRT;

(5) The prudence of actual costs and expenditures;

(6) The effect of any change to the underlying Uniform System of Accounts; or

(7) Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

B. HMU shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Information requests received after 4 p.m. Central Prevailing Time shall be considered received the next business day. HMU shall respond to all information and document requests received on or before July 1 by no later than August 10 following the Publication Date, unless the Information Exchange Period is extended by HMU or FERC.

C. HMU will cause to be posted at a publicly accessible location on the SPP website and OASIS all information requests regarding HMU's FRT in SPP from Interested Parties and HMU's response(s) to such requests; except, however, if responses to information and document requests include material deemed by HMU to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by HMU and the requesting party.

D. HMU shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing HMU's ATRR.

**Section IV. Resolution of Issues and Challenges to the ATRR Update**

No later than October 10 of each year, any Interested Party may notify HMU in writing of any specific challenge(s) to any component of the most recently posted FRT ("Preliminary Challenge"). A party submitting a Preliminary Challenge to HMU must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Within five (5) business days of receiving notice of such challenge(s), HMU shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) at a publicly accessible location on the SPP website and OASIS.

HMU and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations. Any modification to the ATRR that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the ATRR for the next Rate Year and incorporated into HMU's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the ATRR, such changes shall be incorporated into the ATRR for the next rate year.

HMU shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which HMU agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the ATRR will result. If HMU disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.

If HMU and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of HMU's response to the issue(s), senior management representatives of HMU and the Interested Parties shall meet to try to resolve the issue(s).

If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, unless this period is extended with the written consent of HMU to continue efforts to resolve the Informal Challenge, any Interested Party that has not resolved any Informal Challenge may then file with FERC a Formal Challenge pursuant to these Implementation Procedures ("Formal Challenge").

A Formal Challenge must be submitted to FERC no later than March 1. A Formal Challenge shall be filed in the same docket as HMU's Informational Filing discussed in Section VI of these Protocols. The HMU shall respond to the Formal Challenge by the

deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable review period.

Failure to pursue an issue through a Informal Challenge or to lodge a Formal Challenge regarding any issue as to the FRT in a given year shall bar pursuit of such issue with respect to that year's ATRR, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent year's FRT.

A Formal Challenge shall:

A. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;

B. Explain how the action or inaction violates the filed rate formula or protocols;

C. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:
(1) The extent or effect of an Accounting Change;
(2) Whether the Annual Update fails to include data properly recorded in accordance with these protocols;
(3) The proper application of the formula rate and procedures in these protocols;
(4) The accuracy of data and consistency with the formula rate of the charges shown in the Annual Update;
(5) The prudence of actual costs and expenditures; or
(6) Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

D. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(E) State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(F) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

(G) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

(H) State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

In any proceeding ordered by the FERC in response to a Formal Challenge raised under these Implementation Procedures, HMU shall bear the burden of demonstrating the justness and reasonableness of the charges resulting from its application of the Formula Rate, and of proving that it properly applied the Formula Rate, properly calculated the challenged ATRR pursuant to the FRT, and that adoption of any material change is just and reasonable. Nothing herein is intended to alter the burden applied by FERC with respect to prudence challenges. Nothing herein is intended to alter the burden applied by FERC with respect to FERC's review of the rates of non-jurisdictional entities that are incorporated into a jurisdictional rate.

No party shall seek to modify the FRT under the Challenge Procedures set forth in these Protocols and the Annual Update shall not be subject to challenge by anyone for the purpose of modifying the FRT.

**Section V. Changes to the ATRR**

Any changes to the ATRR as a result of a FERC proceeding to consider the ATRR, or as a result of the procedures set forth herein, shall be incorporated into the FRT for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VI of these protocols. The fixed margin percentage of 75% set forth in HMU's FRT will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act.

**Section VI. Informational Filings**

By January 15 of each year, HMU shall submit to FERC an informational filing ("Informational Filing") of its FRT for the Rate Year. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that HMU has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. The transmittal letter accompanying the Informational Filing shall inform the Commission that the Informational Filing is not intended to be subject to the Commission's notice requirements, and that it is not being submitted for the purpose of having the Commission assign a docket number to the filing nor for the purpose of obtaining Commission acceptance, approval or other review of the filing. Within five (5) days of such Informational Filing, HMU shall provide notice of the Informational Filing via the e-mail distribution list described in II.B of these protocols.

# ADDENDUM 30 TO ATTACHMENT H

## Moorhead Public Service

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Index

13 Months Ended December 31, 2XXX

| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |

**Moorhead (Minnesota) Public Service**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 21 | | | #DIV/0! |
| | REVENUE CREDITS (Note I) | | | | |
| 2 | Account No. 454 (Note H) | EIA Form 412 | - | TP 0.000% | - |
| 3a | Transmission charges for all transmission transactions | EIA Form 412 | - | TP 0.000% | - |
| 3b | Transmission charges for all transmission transactions included in Native Load | EIA Form 412 | - | TP 0.000% | - |
| 3c | Account No. 456.1 | (line 3a less line 3b) | - | TP 0.000% | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | EIA Form 412 | - | TP 0.000% | - |
| 5 | Revenues from service provided by the ISO at a discount | EIA Form 412 | - | TP 0.000 | - |

| | | | | | |
|---|---|---|---|---|---|
| | | | | % | |
| 6 | TOTAL REVENUE CREDITS | (sum lines 2, 3c, 4, 5) | | | - |
| 7 | ATRR for SPP Directed Projects | Schedule 1, line 2, col 9 | | | #DIV/0! |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus lines 6 and 7) | | | #DIV/0! |



**Moorhead (Minnesota) Public Service**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| | **RATE BASE** | | | | |
| | GROSS PLANT IN SERVICE (Note L) | | | | |
| 1 | Production | Schedule 4, Column G, Line 6 | - | NA 0.000% | - |
| 2 | Transmission | Schedule 4, Column G, Line 7 | - | TP 0.000% | - |
| 3 | Distribution | Schedule 4, Column G, Line 8 | - | NA 0.000% | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | General & Intangible | Schedule 4, Column G, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Common | Schedule 4, Column G, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 6 | TOTAL GROSS PLANT | (sum lines 1-5) | - | **GP=** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note L) | | | | | |
| 7 | Production | Schedule 4, Column N, Line 6 | - | NA | 0.00% | - |
| 8 | Transmission | Schedule 4, Column N, Line 7 | - | TP | 0.00% | - |
| 9 | Distribution | Schedule 4, Column N, Line 8 | - | NA | 0.00% | - |
| 10 | General & Intangible | Schedule 4, Column N, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 11 | Common | Schedule 4, Column N, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL ACCUM. DEPRECIATION | (sum lines 7-11) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | - | | | - |
| 14 | Transmission | (line 2 - line 8) | - | | | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - |
| 16 | General & Intangible | (line 4 - line 10) | - | | | #DIV/0! |
| 17 | Common | (line 5 - line 11) | - | | | #DIV/0! |
| 1 | TOTAL NET PLANT | (sum lines | | **N** | # | #DI |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | 13-17) | - | **P =** | **DIV/0!** | V/0! |
| 19 | LAND HELD FOR FUTURE USE (Note A) | EIA Form 412 | - | TP | 0.000% | - |
| | WORKING CAPITAL (Note B) | | | | | |
| 20 | CWC | (1/8 * page 3, line 8) | - | | | #DIV/0! |
| 21 | Materials & Supplies (Note A) | EIA Form 412 | | TE | 0.000% | - |
| 22 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 23 | TOTAL WORKING CAPITAL | (sum lines 20-22) | - | | | #DIV/0! |
| 24 | RATE BASE | (sum lines 18, 19, and 23) | - | | | #DIV/0! |



**Moorhead (Minnesota) Public Service**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | **Transmission Amount ($)** |
| | O&M (Note M) | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Transmission | Schedule 7, Column E, Line 8 | - | TE | 0.000% | - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts | EIA Form 412 | - | TE | 100.000% | - |
| 2 | Less Account 565 | Schedule 7, Column C, Line 8 | - | TE | 0.000% | - |
| 3 | A&G | Schedule 7, Column E, Line 13 | - | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note C) | EIA Form 412 | | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note C) | EIA Form 412 | - | TE | 0.000% | - |
| 6 | Common | Schedule 7, Column E, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | EIA Form 412 | - | TE | 0.000% | - |
| 8 | TOTAL O&M | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note L) | | | | | |
| 9 | Transmission | Schedule 4, Column O, Line 7 | - | TP | 0.000% | - |
| 10 | General & Intangible | Schedule 4, Column | - | W/ | #DI | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | O, Line 1 and Line 9 | | S | V/0! | |
| 11 | Common | Schedule 4, Column O, Line 17 | - | CE | #DIV/0! | |
| 12 | TOTAL DEPRECIATION | (Sum lines 9 - 11) | - | | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note D) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S | #DIV/0! | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S | #DIV/0! | #DIV/0! |
| | PLANT RELATED | | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP | #DIV/0! | #DIV/0! |
| 16 | Gross Receipts | Schedule 5, Column B, Line 5 | - | NA | 0.00% | - |
| 17 | Other | Not Used | | NA | 0.00% | - |
| 18 | Payments in lieu of taxes | Schedule 5, Columns B and E, Line 17 | - | DA | N/A | #DIV/0! |
| 19 | TOTAL OTHER TAXES | (sum lines 13-14 and 15-18) | - | | | #DIV/0! |
| 20 | RETURN | (page 2, line 24 * R) | #DIV/0! | | | #DIV/0! |
| 21 | GROSS REVENUE REQUIREMENT | (sum lines 8, 12, 19, and 20) | #DIV/0! | | | #DIV/0! |

**Moorhead (Minnesota) Public Service**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) | |
|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, column 5 | | | - | |
| 2 | Less transmission plant excluded from ISO rates (Note F) | EIA Form 412 | | | - | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note G ) | EIA Form 412 | | | - | |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | - | |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | | **0.00 %** | **= TP** |
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses | page 3, line 1, column 3 | | | - | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note E) | EIA Form 412 | | | - | |
| 8 | Included transmission expenses | (line 6 less line 7) | | | - | |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | 0.00 % | |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line | | | **0.00 %** | **= TE** |

5)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | WAGES & SALARIES | | | | | | |
| 11 | Production | Schedule 8, Column G, Line 4 | - | NA | 0.000% | - | |
| 12 | Transmission | Schedule 8, Column G, Line 11 | - | TP | 0.000% | - | |
| 13 | Distribution | Schedule 8, Column G, Line 33 | - | NA | 0.000% | - | |
| 14 | Other | Schedule 8, Column G, Line 41 | - | NA | 0.000% | - | |
| 15 | Total | (sum lines 11-14) | - | | | - | |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | |
| 17 | Wages & Salaries Allocator (Note N) | (line 15, col 5 divided by col 3) | | | | **#DIV/0!** | **= W/S** |
| | COMMON PLANT | | | | | | |
| 18 | Electric | Schedule 4, Column G, Line 16 | | | | 0 | |
| 19 | Gas | EIA Form 412 | | | | 0 | |
| 20 | Water | EIA Form 412 | | | | | |
| 21 | Total | (sum lines 18-20) | | | | 0 | |
| 22 | Percentage of Electric Common Plant | (line 17 divided by line 21) | | | | #DIV/0! | |
| 23 | Common Plant Allocator (CE) | (line 22 times line 17) | | | | **#DIV/0!** | **= CE** |
| | RETURN (R) | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 24 | Long Term Interest (Note J) | Schedule 3, Column B, Line 16 | - | | | | | |
| | | | $ Amount | % | Cost (Note O) | Weighted | | |
| 25 | Long Term Debt | Schedule 2, Column D, Line 37 | - | #DIV/0! | 0.00% | #DIV/0! | | |
| 26 | Proprietary Capital | Schedule 2, Column D, Line 32 | - | #DIV/0! | 10.10% | #DIV/0! | | |
| 27 | Total | (sum lines 25, 26) | - | #DIV/0! | | #DIV/0! | = | R |



**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H (Utilizing EIA Form 412 - Nonlevelized)

12 Months Ended December 31, 2XXX

Notes:

A Transmission related only.

B Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.

C Prepayments are the electric related prepayments booked to Account No. 165.
Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission

| | |
|---|---|
| | Expenses directly related to transmission service, ISO filings or transmission siting. |
| D | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| E | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA. |
| F | Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test). |
| G | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| H | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. |
| I | The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. |
| J | Include only the amount from Accounts 427, 428, 429 and 430. |
| K | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| L | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |

| | |
|---|---|
| M | Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate. |
| N | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| O | The cost of proprietary capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The cost of long-term debt is calculated by dividing long-term interest (line 24) by the amount of long-term debt (line 25, col 3). The cost of proprietary capital included an incentive adder of 50 basis points approved in Docket No. ER15-2324. |

**Moorhead (Minnesota) Public Service**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 1: SPP Directed Projects ATRR
13 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Transmission Amount ($) |
|---|---|---|---|
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, page 2, line 2 col 5 | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, page 2, line 8 col 5 | - |
| 3 | Net Transmission Plant - SPP (Note B) | (line 1 less line 2) | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 3, line 8 col 5 | #DIV/0! |
| **5** | **Annual Allocation Factor for O&M** | **(line 3 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, page 3, line 19 col 5 | #DIV/0! |
| **7** | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| **8** | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, p 3, line 12 | #DIV/ |

| | | | |
|---|---|---|---|
| | | col 5 | 0! |
| 1 | | Attach H, p 3, line 20 | #DIV/ |
| 0 | Return | col 5 | 0! |
| 1 | | | #DIV/ |
| 1 | Depreciation plus return | (line 9 plus line 10) | 0! |
| | **Annual Allocation Factor for** | | |
| **1** | **Depreciation and** | **(line 12 divided by** | **#DIV/** |
| **2** | **Return** | **line 3)** | **0!** |



**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Upgrade Name** | **Upgrade ID** | **Upgrade Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Upgrade Net Plant** | **Annual Allocation Factor for Depreciation & Return** | **Annual Charge for Depreciation & Return** | **Net Annual Revenue Requirement** |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | Note D | (Page 1 line 12) | (Col. 6 * Col. 7) | (Sum Col. 5 & 8) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1<br>f | Project 6 | Proje<br>ct 6 | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| … | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | | | | | | | |
| 2 | Annual Totals | | | | | | | | #DIV/<br>0! |

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 4- Line 14.

D Net Plant is derived from Schedule 4- Line 42 and includes all CWIP

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1a: SPP Directed Projects

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **13 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | | |
| 2 | **Total Gross Plant in Service** | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3a | Project 1 | | | | | | | | | | | | | | - |
| 3b | Project 2 | | | | | | | | | | | | | | - |
| 3c | Project 3 | | | | | | | | | | | | | | - |
| 3d | Project 4 | | | | | | | | | | | | | | - |
| 3e | Project 5 | | | | | | | | | | | | | | - |
| 3f | Project 6 | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| 4 | **Total Accumulated Depreciation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Net Plant in Service** | | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| 6 | **Total Net Plant in Service** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Electric Balance Sheet (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | | C | E |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| | **ELECTRIC PLANT** | | | **PROPIETARY CAPITAL** | |
| 1 | Electric Plant & Adjustments (101-106,114,116) | | 29 | Investment of Municipality (208) | $ - |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | $ - |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and Depletion (108,111,115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | |
| 7 | **Net Electric Plant including Nuclear Fuel** | **$ -** | 34 | Advances from Municipality and Other Long Term Debt (223, 224) | |
| | **OTHER PROPERTY & INVESTMENTS** | | 35 | Unamortized Premium on Long Term | |
| 8 | Non-Electric Plant Property (121) | $ - | | Debt (225) | $ - |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | $ - | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | $ - | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| 13 | **CURRENT & ACCRUED ASSETS** Cash, Working Funds & Investments (131-136) | | 38 | Accumulated Operating Provisions (228.1-.4) | $ - |
| | | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Recevable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | $ - | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | $ - |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | $ - |
| 26 | Miscellaneous Debt, Research and | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Development Expenses & Unamortized Losses (184-191) | $ - | 51 | Unamortized gain on Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | $ - |
| 8 | **NET ELECTRIC OPERATING INCOME** | $ - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | $ - |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | $ - |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | $ - |
| 15 | Electric Income | $ - |
| 16 | Income Deductions from Interest on Long Term Debt (427) | |
| 17 | Other Income Deductions (428-431) | $ - |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | $ - |
| 19 | Total Income Deductions | $ - |

| | | |
|---|---|---|
| 20 | Income Before Extraordinary Items | **$ -** |
| 21 | Extraordinary Items (434) | |
| 22 | Extraordinary Deductions (435) | $ - |
| 23 | **NET INCOME** | **$ -** |

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended December 31, 2XXX

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjusted BOY | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Accumulated Depreciation | Adjusted BOY | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | | $ - | $ - | $ - | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | $ - |
| | | | | | | | | | | | | | | | | |
| 2 | Steam Production (310- | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | $ - |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 316) | | | | | | | | | | | | | | | | | |
| 3 | Nuclear Production (320-325) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | $ - | | |
| 4 | Hydraulic Production (330-336) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | $ - | | |
| 5 | Other Production (340-346) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 6 | **Total Production Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | |
| | | | | | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 8 | Distribution Plant (360-373) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 9 | General Plant (389-399) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 10 | **Total Electric Plant In** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Service** | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | | | | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 16 | **Total Electric Plant & Adj's** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | $ - | **$ -** | **$ -** | **$ -** |
| 17 | Common Plant Electri | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |

c Plant
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Use

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 5: Taxes other than Income Taxes (EIA Form 412)

12 Months Ended December 31, 2XXX

| Line No. | A<br>Description | Source | B<br>Total Amount ($) | C<br>Allocator | D<br>ATTR Prior to Gross-UP | E<br>ATRR Amount | Notes/Comments |
|---|---|---|---|---|---|---|---|
| | **Taxes other than Income Taxes, Operating Income** | | | | | | |
| | **Payroll Taxes:** | | | | | | |
| 1 | FICA Taxes | | | | | | |
| 2 | Unemployment Taxes | | $ - | | | | |
| | **Plant Related Taxes:** | | | | | | |
| 3 | Highway Taxes | | $ - | | | | |
| 4 | Property Taxes | | $ - | | | | |
| 5 | Gross Receipts Taxes | | $ - | | | | |
| | **Payment In Lieu of Taxes (Transfer)** | | | | | | |
| | Note 6 in the Audit | | | | | | |
| 6 | General Fund Base Transfer | | | GF | #DIV/0! | #DIV/0! | Fixed dollar amount for 2014 based on City Council Request |
| 7 | General Fund One-Time Transfer | | | DA0 | 0.00% | $ - | Special City Council Request for 2014 only |
| 8 | General Fund One-Time Transfer | | | DA0 | 0.00% | $ - | One-time transfer to the general fund that reduced the capital improvement fund transfer |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 9 | Economic Development | | | GP | #DIV/0! | | #DIV/0! | City Council Request - it is the maximum allowed by state statute |
| 10 | Capital Improvement | | | CI | #DIV/0! | | #DIV/0! | 5% of operating revenues less exemptions (Council approved exemptions for service territory & economic development, lease revenues, uncollectible accounts, etc) |
| 11 | Transfer In from City | | | DA0 | 0.00% | | $ - #DIV/0! | Flood mitigation costs |
| 12 | Revenue Requirement (excluding PILOT) | Att. H, Page 3, Lines 8, 13-17 and 20 | #DIV/0! | DA | 100.00% | #DIV/0! | | |
| 13 | Economic Development Transfer | Column B, Line 9 | $0 | GP | #DIV/0! | #DIV/0! | | |
| 14 | Revenue Requirement Before Gross-Up for PILOT | | | | | #DIV/0! | | |
| | | | % of Revenue | | | Rev. Requirement Before PILOT | PILOT in ATRR | |
| 15 | General Fund Transfer % of Revenue | (Note A) | 20.0% | Gross Up Factor | 26.67% | #DIV/0! | #DIV/0! | |
| 16 | Capital Improvement Transfer % of Revenue | (Note B) | 5.0% | Gross Up Factor | 6.67% | #DIV/0! | #DIV/0! | |
| 17 | Total PILOT Included in ATRR Calculation | Column B & E, Lines 6, 9 and 10 | $ - | | | | #DIV/0! | |
| | | | GF Allo | (line 15, col. E / line | | GF= | #DIV/0! | |

| | | | |
|---|---|---|---|
| cator | 6, col. B) | | |
| CI Allocator | (line 16, col. E / line 10, col. B) | CI= | #DIV/0! |

Notes:

A General Fund Transfer Rate equals the maximum rate set by the Moorhead City Council Charter.

B Capital Improvement Transfer Rate equals the rate set by Minnesota State statute.

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended December 31, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | 0.00% |
| 3 | 351 | Energy Storage Equipment - Transmission | N/A | |
| 4 | 352 | Structures & Improvements | 33 | 3.03% |
| 5 | 353 | Station Equipment | 33 | 3.03% |
| 6 | 354 | Towers & Fixtures | 33 | 3.03% |
| 7 | 355 | Poles & Fixtures | see subsets | |
| 8 | | Transmission - Substations | 33 | 3.03% |
| 9 | | Transmission Lines | 33 | 3.03% |
| 10 | | SCADA- Transmission | 7 | 14.29% |
| 11 | 356 | Overhead Conductors and Devices | N/A | |
| 12 | 357 | Underground Conduit | N/A | |
| 13 | 358 | Underground Conductors and Devices | N/A | |
| 14 | 359 | Roads and Trails | 10 | 10.00% |
| 15 | | **General Plant** | | |
| 16 | 390 | Structures & Improvements | 50 | 2.00% |
| 17 | 391 | Office Furniture and Equipment | see subsets | |
| 18 | | IT Related | 7 | 14.29% |
| 19 | | Non-IT - Phone System, Security Systems | 10 | 10.00% |
| 20 | 392 | Transportation Equipment | see subsets | |
| 21 | | Pickup, Cars, Vans, etc | 10 | 10.00% |
| 22 | | Line trucks | 15 | 6.67% |
| 23 | | Trailers | 20 | 5.00% |

| | | | | |
|---|---|---|---|---|
| 24 | | Mowers | 5 | 20.00% |
| 25 | 393 | Stores Equipment | N/A | |
| 26 | 394 | Tools, Shop and Garage Equipment | 10 | 10.00% |
| 27 | 395 | Laboratory Equipment | N/A | |
| 28 | 396 | Power Operated Equipment | N/A | |
| 29 | 397 | Communication Equipment | see subsets | |
| 30 | | Fiber, Radio Systems | 15 | 6.67% |
| 31 | | GIS System | 10 | 10.00% |
| 32 | 398 | Miscellaneous Equipment | N/A | |
| 33 | | **Intangible Plant** | | |
| 34 | 301 | Organization | N/A | |
| 35 | 302 | Franchises and consents | N/A | |
| 36 | 303 | Miscelaaneous intangible plant | 20 | 5.00% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: O&M Expense (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | | | | $ - |
| 5 | Purchased Power (555) | | | | $ - |
| 6 | Other Production Expenses (556-557) | $ - | $ - | $ - | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-567, 568-573) | XXXXXXXXXXXXX | | | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXXXX | | | $ - |
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXXXX | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 11 | Customer Service & Information Expenses (907-910) | XXXXXXXXXXXXX | | | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXXX | | | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXXX | | | $ - |
| 14 | Total Electric Operation and Maintenance Expenses | $ - | $ - | $ - | $ - |

| | | |
|---|---|---|
| 15 | Total Number of Full Time Employees | |
| 16 | Total Number of Part Time Employees | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Common O&M Expense | $ - | $ - | $ - | $ - |

**Moorhead (Minnesota) Public Service**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E | F | G |
|---|---|---|---|---|---|---|---|
| Line No. | | | | Salaries Only | | | |
| | | | Accounts | Operation | Maintenance | Total | |
| 1 | Production / Generation | | | | | | |
| 2 | | | Operating Supervisor | $ - | $ - | $ - | |
| 3 | | | Maintanence | $ - | $ - | $ - | Production / Generation |
| 4 | | | Employee Benefits | $ - | $ - | $ - | $ - |
| 5 | Transmission: | | | | | | |
| | | | Maintenance | $ | $ | $ | |
| 6 | | | Supervision | - | - | - | |
| 7 | | | Load Dispatching | $ - | $ - | $ - | |
| 8 | | | Maintenance of Lines | $ - | $ - | $ - | |
| 9 | | | Station Expense | $ - | $ - | $ - | |
| | | | Equipment | $ | $ | $ | Transmission |
| 10 | | | Maintenance | - | - | - | |
| 11 | | | Employee Benefits | $ - | $ - | $ - | $ - |
| 12 | Distribution: | | | | | | |
| | | | Maintenance | $ | $ | $ | |
| 13 | | | Supervision | - | - | - | |
| 14 | | | Load Dispatching | $ - | $ - | $ - | |
| 15 | | | Distrib. Station Expense | $ | $ | $ | |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | |
| | | $ | $ | $ | |
| 16 | Overhead Line Expense | - | - | - | |
| | Underground Line | $ | $ | $ | |
| 17 | Expense | - | - | - | |
| | | $ | $ | $ | |
| 18 | Locating Expense | - | - | - | |
| | | $ | $ | $ | |
| 19 | Street Lighting Expense | - | - | - | |
| | | $ | $ | $ | |
| 20 | Traffic Signal Expense | - | - | - | |
| | | $ | $ | $ | |
| 21 | Metering Expense | - | - | - | |
| | | $ | $ | $ | |
| 22 | Fiber Expense | - | - | - | |
| | | $ | $ | $ | |
| 23 | GIS Expense | - | - | - | |
| | | $ | $ | $ | |
| 24 | Mtce of Station Equip | - | - | - | |
| | Mtce of | $ | $ | $ | |
| 25 | Controls/Alarms | - | - | - | |
| | | $ | $ | $ | |
| 26 | Mtce of OH | - | - | - | |
| | Mtce of OH - Tree | $ | $ | $ | |
| 27 | Trimming | - | - | - | |
| | | $ | $ | $ | |
| 28 | Mtce of UG | - | - | - | |
| | | $ | $ | $ | |
| 29 | Mtce of Transformers | - | - | - | |
| | | $ | $ | $ | |
| 30 | Mtce of Street Lighting | - | - | - | |
| | | $ | $ | $ | |
| 31 | Mtce of Traffic Signals | - | - | - | |
| | | $ | $ | $ | |
| 32 | Mtce of Meters | - | - | - | Distribution |
| | | $ | $ | $ | $ |
| 33 | Mtce of Fiber | - | - | - | - |

| | | | | |
|---|---|---|---|---|
| 34 | Customer Service & Information | | | |
| | Customer Records & | $ | $ | $ |
| 35 | Collection Salaries | - | - | - |
| 36 | Meter Reading Salaries | $ | $ | $ |

| | | | | | |
|---|---|---|---|---|---|
| | | - | - | - | |
| | Customer Installation | $ | $ | $ | |
| 37 | Expense Salaries | - | - | - | |
| | | $ | $ | $ | |
| 38 | Customer Assistance | - | - | - | |
| | | $ | $ | $ | |
| 39 | Info & Safety | - | - | - | |
| | | $ | $ | $ | Customer Service & |
| 40 | CIP | - | - | - | Information |
| | City of Moorhead Salary | $ | $ | $ | $ |
| 41 | Reimbursement | - | - | - | - |
| | | | | | |
| 42 | Administrative & General | | | | |
| | | $ | $ | $ | |
| 43 | Commission Salaries | - | - | - | |
| | | $ | $ | $ | Administrative & |
| 44 | Office Salaries | - | - | - | General |
| | | $ | $ | $ | $ |
| 45 | Employee Benefits | - | - | - | - |
| | | | | | |
| | | $ | $ | $ | $ |
| 46 | Total | - | - | - | - |

**MRES MEMBER UTILITIES**

**ANNUAL UPDATE PROTOCOLS**

**UNDER ATTACHMENT H OF SPP OPEN ACCESS TRANSMISSION TARIFF**

## Section I. Applicability

The following procedures shall apply to Moorhead Public Service ("MPS"), Orange City Municipal Utilities ("OCMU"), Pierre Municipal Utilities ("PMU"), Sioux Center Municipal Utilities ("SCMU") and Watertown Municipal Utility District ("WMUD") calculation of its annual transmission revenue requirement ("ATRR") pursuant to its Formula Rate Template ("FRT"). These utilities will be referred to as the "Members" in these protocols. The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the Federal Power Act.

## Section II. Annual ATRR Update

1. Beginning on or before May 1, 2016, and on or before each subsequent May 1, the Members shall determine their ATRRs to be effective on June 1, 2016 and each subsequent June 1.
2. On or before May 1, 2016, and on or before each subsequent May 1, the Members shall request SPP to post their FRTs and supporting documentation on the SPP OASIS, and shall notify Interested Parties of the website address where such information is posted via the SPP email exploder list titled "Formula Rate Posting Information Notification."
    A. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state

attorneys general ("Interested Parties"). Interested Parties can contact MRES to be included as an Interested Party.

B. MRES Members shall provide electronic notice of Annual ATRR Update postings to all Interested Parties within 10 days of such posting through an email to the Formula Rate Posting Information Notification exploder maintained by SPP.

C. As used in these Protocols, "Formula Rate Posting Information Notification" exploder shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification exploder through the link on the SPP website. The exploder list is titled "Formula Rate Posting Information Notification" and can be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include, but are not limited to, (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

3. If the date for posting the FRT falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the FRT shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the FRT will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

4. The Annual Update shall:

   A. Include a workable data-populated FRT and underlying work papers in native format with all formulas intact;

   B. Be based on the Member's audited financial statements for the either the prior fiscal or calendar year, as applicable. MPS, PMU and WMUD base their audited financial statements on a calendar year from January 1 to December 31. OCMU

and SCMU base their audited financial statements on a fiscal year from July 1 to June 30.

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the FRT that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;

D. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);

E. With respect to any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that affect the

4. ATRR calculation;

5. The implementation of new estimation methods or policies that change prior estimates; and

6. changes to income tax elections (if applicable);

ii. Identify items included in the FRT at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the FRT;

iv. Provide, for each item identified pursuant to items II.4.e.i - II.4.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the FRT.

5. Each of the Members shall hold an open meeting among Interested Parties ("Formula Rate Update Meeting") between the Publication Date and May 31 of each year. No less than seven (7) days prior to such Formula Rate Update Meeting, each Member shall provide notice on the Member Related Posting section of the SPP OASIS of the time, date, and location of its Formula Rate Update Meeting. The Formula Rate Update Meeting shall (i) permit the Member to explain and clarify its FRT and (ii) provide Interested Parties an opportunity to seek information and clarifications from the Member about the FRT. Each Member shall provide remote access for participation of Interested Parties at such meetings.

6. If a Member constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of Joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via email no less than 7 days prior to such meeting.

**Section III. Information Exchange Procedures**

Each Member's FRT shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until July 1 following the Publication Date (unless such period is extended with the written consent of the applicable Member or by FERC order) to serve reasonable information and document requests on the applicable Member ("Information Exchange Period"). If July 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

a. The extent or effect of an Accounting Change;

b. Whether the FRT fails to include data properly recorded in accordance with these protocols;

c. The proper application of the formula rate and procedures in these protocols;

d. The accuracy of data and consistency with the formula rate of the calculations shown in the FRT;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. The Members shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. The Members shall respond to all information and document requests received on or before July 1 by no later than August 10 following the Publication Date, unless the Information Exchange Period is extended by the Members or FERC.

3. Each Member will cause to be posted on the Member Related Postings section of the SPP OASIS all information requests regarding the Member's FRT in SPP from Interested Parties and the Member's response(s) to such requests; except, however, if responses to information and document requests include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the applicable Member and the requesting party.

4. Members shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the applicable Member's FRT. However, each Member may require that Interested Parties execute a non-disclosure agreement to

obtain access to material that the Member deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**Section IV. Challenge Procedures for the FRT Update**

1. No later than July 5 of each year, any Interested Party may notify a Member in writing of any specific challenge(s) to any component of the most recently posted FRT ("Preliminary Challenge"). A party submitting a Challenge to a Member must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Within five (5) business days of receiving notice of such challenge(s), any Member so notified shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) on the Member Related Posting section of the SPP OASIS. The Member and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations.
2. Each Member shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which the Member agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the FRT will result. If the Member disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.
3. If the Member and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of the Member's response to the issue(s), senior management representatives of the Member and the Interested Parties shall meet to try to resolve the issue(s). Each challenged Member shall appoint a senior representative to work with the party that submitted the Challenge (or its representative) toward a resolution of the challenge. If the Member disagrees with such challenge, the Member

will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. Any modification to the FRT that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the FRT for the next Rate Year and incorporated into the Member's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the ATRR, such changes shall be incorporated into the FRT for the next rate year.

4. If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, any Interested Party that has not resolved any Preliminary Challenge to the Formula Rate Update may then file with FERC a Formal Challenge to a Formula Rate Update pursuant to these Implementation Procedures ("Formal Challenge").

    a. A Formal Challenge shall:

        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        ii. Explain how the action or inaction violates the filed rate formula or protocols;
        iii. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

            1. The extent or effect of an Accounting Change;
            2. Whether the FRT fails to include data properly recorded in accordance with these protocols;
            3. The proper application of the formula rate and procedures in these protocols;
            4. The accuracy of data and consistency with the formula rate of the charges shown in the FRT;
            5. The prudence of actual costs and expenditures;

6. The effect of any change to the underlying Uniform System of Accounts; or

7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

b. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on the applicable Member. Service to a Member must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on a Member's Informational Filing required under Section VI of these protocols.

5. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the FRT fails to include data properly recorded in accordance with these protocols; (3) the proper

application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the FRT; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

6. Each Member will cause to be posted all Informal Challenges from Interested Parties and the Member's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Member and the requesting party.

7. Any changes or adjustments to the FRT resulting from the Information Exchange and Informal Challenge processes that are agreed to by a MRES Member will be reported in the Informational Filing required pursuant to Section VI of these protocols.

8. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of the Member to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on the Member on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as the Member's Informational Filing discussed in Section VI of these protocols. The Member shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

9. In any proceeding initiated by FERC concerning the FRT or in response to a Formal Challenge, the Member shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the FRT consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of a MRES Member to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the FRT under the Challenge Procedures set forth in these protocols and the FRT shall not be subject to challenge by anyone for the purpose of modifying the FRT. Any modifications to the FRT will require, as applicable, a Federal Power Act section 205 or section 206 filing.

    Any Interested Party seeking changes to the application of the FRT due to a change in the Uniform System of Accounts, shall first raise the matter with MRES in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to the ATRR**

Any changes to the data inputs, the result of any FERC proceeding to consider the FRT, or a result of the procedures set forth herein, shall be incorporated into the FRT for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of the Commission's regulations. The fixed base return on equity of 9.6% set forth in the Members' FRT will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act. The asset depreciation rates set forth in the Members' FRT filing will not be changed absent a filing pursuant to Section 205 or Section 206 of the Federal Power Act.

**Section VI. Informational Filings**

By March 15 of each year, each Member shall submit to FERC an informational filing

("Informational Filing") of its FRT for the Rate Year. Each Member shall submit each year's Informational Filing in the same docket assigned to its initial informational filing,[1] subject to the determination of the FERC's Secretary. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that the Member has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. The transmittal letter accompanying the Informational Filing shall inform the Commission that the Informational Filing is not intended to be subject to the Commission's notice requirements, and that it is not being submitted for the purpose of having the Commission assign a docket number to the filing nor for the purpose of obtaining Commission acceptance, approval or other review of the filing. Each Member shall provide notification of each Informational Filing through notification on the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

[1] In 2016, MPS submitted its Informational filing in ER16-1182, OCMU in ER16-1183, PMU in ER16-1184, SCMU in ER16-1185, and WMUD in in ER16-1186.

# ADDENDUM 36 TO ATTACHMENT H

## Tri-State Generation and Transmission Association, Inc.

# Tri-State Generation and Transmission Association, Inc.

**INDEX**

## Year Ending December 31, 20XX

| Line | Item | Description |
|---|---|---|
| 1 | Summary | Summary of Total ATRR Revenue Requirement |
| 2 | Schedule 1 | Schedule 1 Revenue Requirements |
| 3 | Worksheet A | Rate Base |
| 4 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 5 | Worksheet C | Return |
| 6 | Worksheet D | Load |
| 7 | Worksheet E | Allocation Factors |
| 8 | Worksheet F | Inputs |
| 9 | Worksheet G | O&M |
| 10 | Worksheet H | SPP Upgrades |
| 11 | Worksheet I | Depreciation Rates |
| 12 | Worksheet J | Reconciliation Items, Refunds and Surcharges |
| 13 | Worksheet K | Wages |
| 14 | Worksheet L | Annual Depreciation Expense |
| 15 | Worksheet M | Other Revenue |
| 16 | Worksheet N | Plant Held for Future Use |
| 17 | Worksheet O | Acct 565 - Transmission of Electricity by Others |
| 18 | Worksheet P | Account 575/576 Expenses |
| 19 | Worksheet Q | Completed Construction Not Classified |
| 20 | Worksheet R | Construction Work in Progress |
| 21 | Worksheet S | Regulatory and Commission Expenses |
| 22 | Worksheet T | Retirement Work in Progress |
| 23 | Worksheet U | SPP Qualified Transmission Substations |
| 24 | Worksheet V | SPP Qualified Transmission Lines |
| 25 | Worksheet W | Tax Adjustments |
| 26 | Worksheet X | (future use) |
| 27 | Worksheet Y | Deferred Tax Rollforward |
| 28 | Key | |
| 29 | | = Shaded cell, denoting manual input |

# Tri-State Generation and Transmission Association, Inc.

**Summary of Total ATRR Revenue Requirement**
**Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| Line | Account | Description | Reference | Total Company | Allocation Factor | Allocation % | Transmission |
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 39, Col G | | | | |
| 3 | | Revenue Credits-Operating | | | | | |
| 4 | 454 | Rental Income | Worksheet M, Line 34, Col D and E | $ - | Direct | | $ - |
| 5 | 456 | Other Elect Revenue-Admin Fee Trans Interconnect Study | Worksheet M, Line 35, Col D | $ - | T-Tran Plant | | |
| 6 | 456 | Wheeling SPP P2P | Worksheet M, Line 36, Col D | $ - | Direct 100 | 100.000% | $ - |
| 7 | 456 | Other Wheeling | Worksheet M, Line 38, Col D | $ - | Direct Zero | 0.000% | $ - |
| 8 | | Revenue Credits-Operating | Subtotal | $ - | | | |
| 9 | | SPP Upgrades | Worksheet H, Line 2, Col K | | | | |
| 10 | | Reconciliation Adjustments - Gross ATRR | Worksheet J, Line 6, Col J | | | | $ - |
| 11 | | Reconciliation Adjustments - SPP Upgrades | Worksheet J, Line 12, Col J | | | | $ - |

| | | | |
|---|---|---|---|
| 12 | Net Annual Transmission Revenue Requirement | Line 2 - Lines 8 & 9 + Lines 10 & 11 | |

# Tri-State Generation & Transmission Association, Inc.



**Schedule 1 Revenue Requirements**
**Year Ending December 31, 20XX**

| A<br>Line | B<br>Account | C<br>Description | D<br>Reference | E<br>Total Company | F<br>Allocation Factor | G<br>Allocation % | H<br>Total Schedule 1 |
|---|---|---|---|---|---|---|---|
| 1 | **DIRECT EXPENSE AMOUNTS** | | | | | | |
| 2 | 561 | Load Dispatching | Worksheet G, Line 2, Col E | $0 | T-Tran Plant | | |
| 3 | **ASSOCIATED LOAD DISPATCHING COSTS** | | | | | | |
| 4 | | **Expenses** | | | | | |
| 5 | | Total Company Customer Accounting Expense | Worksheet B, Line 19, Col D | $0 | T-Wage2 | | |
| 6 | | Total Company Administrative & General Expenses | Worksheet B, Line 28, Col D | $0 | T-Wage2 | | |
| 7 | | Total Company General Plant Depreciation Expense | Worksheet F, Line 116, Col F | $0 | T-Wage2 | | |
| 8 | | Total Company Intangible Plant Amortization Expense | Worksheet F, Line 127, Col F | $0 | T-Wage2 | | |
| 9 | | **Total Expenses** | Sum Lines 5 thru 8 | $0 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 10 | **Return on General & Intangible Plant** | | | | | |
| 11 | Total Company Net Intangible Plant in Service | Worksheet A, Line 35, Col F | $0 | T-Wage2 | | |
| 12 | Total Company Net General Plant in Service | Worksheet A, Line 39, Col F | $0 | T-Wage2 | | |
| 13 | Total General & Intangible Plant | Sum Lines 11 and 12 | $0 | | | |
| 14 | Weighted Rate of Return | Worksheet C, Line 5, Col K | | | | |
| 15 | Return on General & Intangible Plant | Line 13 * Line 14 | | | | |
| 16 | **Total Associated Load Dispatching Costs** | Line 9 + Line 15 | | | | |
| 17 | **SCHEDULE 1 REVENUE REQUIREMENT** | | | | | |
| 18 | **Net Schedule 1 Revenue Requirement for Zone** | Sum Lines 2 and 16 | | | | |
| 19 | Load Dispatching Wages and Salaries | Worksheet E, Line 3, Col D | $0 | T-Tran Plant | | |
| 20 | Total Wages and Salaries | Worksheet E, Line 8, Col D | $0 | Direct100 | 100.00% | $0 |
| 21 | Schedule 1 Wages & Salaries Allocator | Line 19 / Line 20 | | | **T-Wage2 =** | |

# Tri-State Generation and Transmission Association, Inc.

**Rate Base**
**Year Ending**
**December 31, 20XX**

| A | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| **Line** | **Description** | **Reference** | **Beginning of Year** | **End of Year** | **Total Company** | **Allocation Factor** | **Allocation %** | **Transmission** |
| 1 | **Plant in Service** | | | | | | | |
| 2 | 301-303 Total Intangible Plant | Worksheet F Line 56, Col D thru F | $ - | $ - | $ - | T-Wage Allocation | | |
| 3 | 310 Steam Production Plant | Worksheet F Line 57, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000% | $ - |
| 4 | 320 Nuclear Production Plant | Worksheet F Line 58, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000% | $ - |
| 5 | 330 Hydro Production Plant | Worksheet F Line 59, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000% | $ - |
| 6 | 340 Other Production Plant | Worksheet F Line 60, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000% | $ - |
| 7 | Total Production Plant | Subtotal | $ - | $ - | $ - | | | $ - |
| 8 | 350 Land and Land Rights | Worksheet F Line 62, Col D thru F | $ - | $ - | $ - | T-Transtions | | |
| 9 | 352 Structures and Improvements | Worksheet F Line 63, Col D thru F | $ - | $ - | $ - | T-Transtions | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 10 | 353 Station Equipment | Worksheet F Line 64, Col D thru F | $ - | $ - | $ - | T-Tran Statio ns | | |
| 11 | 354 thru 359.1 Other Transmission Plant | Worksheet F Line 65, Col D thru F | $ - | $ - | $ - | T-Tran Lines | | |
| 12 | Transmission Plant | Subtotal | $ - | $ - | $ - | | | |
| 13 | 360 Land and Land Rights | Worksheet F Line 67, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| 14 | 361 Structures and Improvements | Worksheet F Line 68, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| 15 | 362 Station Equipment | Worksheet F Line 69, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| 16 | 363-374 Other Distribution Plant | Worksheet F Line 70, Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| 17 | Total Distribution Plant | Subtotal | $ - | $ - | $ - | | | $ - |
| 18 | 380-386 RTO/ISO Plant | Worksheet F, Line 72 Col F | $ - | $ - | $ - | T-Tran Plant | | |
| 19 | 389 thru 399.1 Total General Plant | Worksheet F, Line 73 Col F | $ - | $ - | $ - | T-Wage s | | |
| 20 | 106 Completed Construction Not Classified | Worksheet F, Line 78 Col F and Worksheet Q Line 25 Col L | $ - | $ - | $ - | Direct | | $ - |
| 21 | Gross Electric Plant in Service | Subtotal | $ - | $ - | $ - | | | |
| 22 | **Accumulated Depreciation** | | | | | | | |
| 23 | 108.1 Depr Rsv. of Steam Plant | Worksheet F, Line 83 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| 24 | 108.2 Depr Rsv. of Nuclear Plant | Worksheet F, Line 84 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| 25 | 108.3 Depr Rsv. of Hydraulic Plant | Worksheet F, Line 85 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.0 00 % | $ - |
| | 108.4 Depr Rsv. of | Worksheet F, | $ | $ | $ | Direct | 0.0 | $ |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 26 | Other Prod Plant | Line 86 Col D thru F | - | - | - | Zero | 00 % | - |
| 27 | Total Production Reserve | Sum | $ - | $ - | $ - | | | $ - |
| 28 | 108.5 Depreciation of Transmission Plant | Worksheet F Line 87 Cols D -F and (Worksheet U Line 7 Cols K and M, Worksheet V Line 8 Cols K and M)/2 | $ - | $ - | $ - | Direct | | $ - |
| 29 | 108.6 Depreciation of Distribution Plant | Worksheet F, Line 88 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000 % | $ - |
| 30 | 108.7 Depreciation of General Plant | Worksheet F, Line 89 Col D thru F | $ - | $ - | $ - | T-Wage Allocation | | |
| 31 | 108.8 Retirement Work in Progress | Worksheet F Line 90 Cols D-F and Worksheet T Line 9 Col M | $ - | $ - | $ - | Direct | | $ - |
| 32 | 111 Amort of Electric Plant in Service | Worksheet F, Line 91 Col D thru F | $ - | $ - | $ - | T-Wage Allocation | | |
| 33 | Total Accumulated Depreciation | Sum | $ - | $ - | $ - | | | |
| 34 | **Total Net Plant in Service** | | | | | | | |
| 35 | 301-303 Net Total Intangible Plant | Line 2 - Line 32 | $ - | $ - | $ - | | | |
| 36 | Net Production Plant | Line 7 - Line 27 | $ - | $ - | $ - | | | $ - |
| 37 | Net Transmission Plant | Line 12 + Line 18 - Line 28 | $ - | $ - | $ - | | | |
| 38 | Net Distribution Plant | Line 17 - Line 29 | $ - | $ - | $ - | | | $ - |
| 39 | Net General Plant | Line 19 - Line 30 | $ - | $ - | $ - | | | |
| 40 | Net Completed Construction Not Classified | Line 20 | $ - | $ - | $ - | | | $ - |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 108.8 Retirement | | $ | $ | $ | | | $ | |
| 41 | Work in Progress | Line 31 | - | - | - | | | - | |
| | Total Net Plant in | | $ | $ | $ | | | | |
| 42 | Service | Sum | - | - | - | | | | |
| | | | | | | | | | |
| | Adjustments to | | | | | | | | |
| 43 | Rate Base | | | | | | | | |
| | 105 Electric Plant | | $ | $ | $ | | | | |
| | Held For Future | Worksheet N | - | - | - | Direct Zero | 0.000 % | $ | |
| 44 | Use - Production | Line 1 | | | | | | - | |
| | 105 Electric Plant | | $ | $ | $ | | | | |
| | Held For Future | Worksheet N | - | - | - | Direct | | $ | |
| 45 | Use - Transmission | Line 16 | | | | | | - | |
| | 105 Electric Plant | | $ | $ | $ | | | | |
| | Held For Future | Worksheet N | - | - | - | Direct Zero | 0.000 % | $ | |
| 46 | Use - Distribution | Line 18 | | | | | | - | |
| | | | $ | $ | $ | T- | | | |
| | 105 Electric Plant | | - | - | - | Wage | | | |
| | Held for Future Use | Worksheet N | | | | Allocat | | | |
| 47 | - General | Line 20 | | | | ion | | | |
| | | | $ | $ | $ | T- | | | |
| | 105 Electric Plant | | - | - | - | Wage | | | |
| | Held for Future Use | Worksheet N | | | | Allocat | | | |
| 48 | - Intangible | Line 22 | | | | ion | | | |
| | | Worksheet F | $ | $ | $ | | | | |
| | | Line 80 Cols | - | - | - | | | | |
| | | D thru F and | | | | | | | |
| | | Worksheet R | | | | | | | |
| | 107 Construction | Line 15 Cols | | | | | | | |
| 49 | Work in Progress | L | | | | Direct | | | |
| | | | | | | | | | |
| | Other Tax | Worksheet W | | | | | | | |
| | Adjustments | line17, Col G | | | | Direct | | $ - | |
| | | Worksheet Y | | | | | | | |
| | ADIT Balance – | Line 48, Cols | $ | $ | $ | | | $ | |
| | Transmission | P and S | - | - | - | Direct | | - | |
| | | | | | | | | | |
| | | | | | | | | | |
| 52 | Working Capital | | | | | | | | |
| | Total | Worksheet B, | | | | | | | |
| | Transmission O&M | Line 29, Col | | | $ | | | | |
| 53 | Costs | D and G | | | - | | | | |
| | Billing Lag in | Worksheet F, | | | | | | | |
| 54 | Days | Line 1 Col F | | | | 45 | | | 45 |
| | | Line 53 * | | | $ | | | | |
| 55 | Working Capital | Line 54 / 365 | | | - | | | | |
| | | | | | | | | | |
| | | Worksheet F, | | | | T- | | | |
| | | Line 45, Col | $ | $ | $ | Plant | | | |
| 56 | Prepayments | D thru F | - | - | - | Allocat | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | | ion | | |
| 57 | M&S Fuel Stock | Worksheet F, Line 95 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000 % | $ - |
| 58 | M&S Fuel Stock Expenses Undistributed | Worksheet F, Line 96 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000 % | $ - |
| 59 | M&S Production Plant | Worksheet F, Line 97 Col D thru F | $ - | $ - | $ - | Direct Zero | 0.000 % | $ - |
| 60 | M&S Transmission Plant | Worksheet F, Line 98 Col D thru F | $ - | $ - | $ - | T-Tran *Plant* | | |
| *61* | M&S Other Materials and | Worksheet F, Line 99 Col D thru F | $ - | $ - | $ - | T-Plant Allocation | | |
| *62* | Supplies | Sum | - | - | - | | | |
| 63 | Total Working Capital and Adjustments | | | | - | | | |
| *64* | Rate Base | Total | | | $ - | | | |

# Tri-State Generation and Transmission Association, Inc.

**O&M, Depreciation, and Return Expenses Year Ending December 31, 20XX**

| A | B | C | *D* | *E* | *F* | *G* |
|---|---|---|---|---|---|---|
| **Line** | **Description** | **Reference** | **Total Company** | **Allocation Factor** | **Allocation %** | **Transmission ATRR East** |
| 1 | Transmission Operation & Maintenance Expenses | | | | | |
| 2 | 560 Supervision and Engineering | Worksheet G, Line 1 Col E | $ - | T-Tran Plant | | |
| 3 | 561 Load Dispatching | Worksheet G, Line 2 Col E | $ - | Direct Zero | 0.00 0% | $ - |
| 4 | 562 Station Expenses | Worksheet G, Line 3 Col E | $ - | T-Tran Stations | | |
| 5 | 563 Overhead Line Expenses | Worksheet G, Line 4 Col E | $ - | T-Tran Lines | | |
| 6 | 564 Underground Line Expenses | Worksheet G, Line 5 Col E | $ - | T-Tran Lines | | |
| 7 | 565 Transmission of Electricity by others | Worksheet G, Line 8 Col E and Worksheet O Line 14 Col E | $ - | Direct | | $ - |
| 8 | 566 Miscellaneous Expenses | Worksheet G, Line 6 Col E | $ - | T-Tran Plant | | |
| 9 | 567 Rents | Worksheet G, Line 9 Col E | $ - | T-Tran Stations | | |
| 10 | 568 Supervision and Engineering | Worksheet G, Line 11 Col E | $ - | T-Tran Plant | | |
| 11 | 569 Structures | Worksheet G, Line 12 Col E | $ - | T-Tran Stations | | |
| 12 | 570 Station Equipment | Worksheet G, Line 13 Col E | $ - | T-Tran Stations | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 2 | | | | | | |
| 13 | 571 Overhead Lines | Worksheet G, Line 14 Col E | $ - | T-Tran Lines | | |
| 14 | 572 Underground Lines | Worksheet G, Line 15 Col E | $ - | T-Tran Lines | | |
| 15 | 573 Miscellaneous Transmission Plant | Worksheet G, Line 16 Col E | $ - | T-Tran Plant | | |
| 16 | 575.1-575.8 RTO/ISO Expense - Operation | Worksheet P, Line 2 Col F | $ - | Direct 100 | 100.000 % | $ - |
| 17 | 576.1-576.5 RTO/ISO Expense - Maintenance | Worksheet P, Line 4 Col F | $ - | Direct 100 | 100.000 % | $ - |
| 18 | Transmission O&M | Subtotal | $ - | | | |
| 19 | Customer Accounting | Worksheet F, Line 22 Col F | $ - | T-Wage Allocation | | |
| 20 | Customer Services & Information | Worksheet F, Line 23 Col F | $ - | Direct Zero | 0.000% | $ - |
| 21 | Sales | Worksheet F, Line 24 Col F | $ - | Direct Zero | 0.000% | $ - |
| 22 | Customer Related Expense | Subtotal | $ - | | | |
| 23 | Administrative & General Expense | | | | | |
| 24 | Admin and General Expense | Worksheet F, Line 25 Col F Less Line 25 and Line 26 | $ - | T-Wage Allocation | | |
| 25 | Account 928 Expenses - Non-SPP | Worksheet S, Line 4, Col E | $ - | Direct Zero | 0.000% | $ - |
| 26 | Account 928 Expenses - SPP | Worksheet S, Line 4, Col F | $ - | Direct | | $ - |
| 27 | Maintenance Expense General Plant | Worksheet F, Line 31 Col F | $ - | T-Wage Allocation | | |

| | | | | | |
|---|---|---|---|---|---|
| 28 | Total A&G Expenses | Subtotal | $ - | | |
| 29 | Subtotal O&M | | $ - | | |
| 30 | Depreciation Expense | | | | |
| 31 | Depreciation Expense-Trans | Worksheet L, Line 11 Col H | | Direct | $ - |
| 32 | Depreciation Expense-General | Worksheet L, Line 42 Col J | | Direct | |
| 33 | Amort of Intangible Plant | Worksheet L, Line 45 Col J | | Direct | |
| 34 | Total Depreciation & Amortization | Subtotal | | | |
| 35 | Taxes Other than Income Taxes (408.1) | Worksheet F, Line *34* Col F | $ - | T-Net Allocation | |
| 36 | Income Taxes (409.1) | Worksheet F, Line 35 Col F | $ - | T-Net Allocation | |
| 37 | Net Provision for Deferred Income Taxes (410.1 & 411.1) | Worksheet F, Line 36 Col F | $ - | T-Net Allocation | |
| 38 | Return | Worksheet C, Line 7, Col K | | | |
| 39 | Revenue Requirement before revenue credits | | | | |

# Tri-State Generation and Transmission Association, Inc.

**Return Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Description** | **Reference** | **Total Company EOY** | **Actual Cap Structure Weight (Note A)** | **Low Hypothetical Equity (Note A)** | **High Hypothetical Equity (Note A)** | **Applied Cap Structure (Note B)** | **Interest Expense** | **Cost of Capital (Note C)** | **Weighted Rate of Return (Note D)** |
| 1 | Return Based on Defined ROE | | | | | | | | | |
| 2 | Total Long Term Debt | Worksheet F, Lines 51 and 54, Col F and Line 37, Col F | $ - | | 64.76% | 31.14% | | $ - | | |
| 3 | Notes Payable (Note E) | Worksheet F, Line 53, Col F ; Worksheet F and Line 38, Col F if Balance is | $ - | | 0.00% | 0.00% | | $ - | 0.00% | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | >0 | | | | | |
| 4 | Total Margins and Equities | Worksheet F, Line 50, Col F | $ - | 35.24% | 68.86% | N/A | 9.80% |
| 5 | Total Capitalization | Subtotal | $ - | 100.00% | 100.00% | $ - | |
| 6 | Rate Base | Worksheet A, Line 64, Col I | | | | | |
| 7 | Return on Rate Base | Line 5 * Line 6 | | | | | |

8 Notes:
A.) The capital structure listed in Column (e) is calculated based on total capitalization amounts listed in Column (d). The capital structures listed in
9 Columns (f) and (g) are fixed and cannot be modified or deleted absent
10 authorization from FERC via a Section 205 or 206 filing.
B.) In the case where Tri-State's actual capital structure (Column (e)) contains a
11 Total Margins and Equities percentage between 35.24 percent and 68.86
11 percent, Column (h) should be populated with the actual capital structure. In the case where Tri-State's
12 actual Margins and Equities percentage is below 35.24 percent, Column
12 (h) should be populated with the the capital structure listed in Column (f). In the case where Tri-State's
13 actual Margins and Equities percentage is above 68.86 percent,
13 Column (h) should be populated with the capital
14 structure listed
14 in Column (g).
C.) The Cost of Capital for Total Margins and Equities (ROE) is fixed and cannot be
15 modified or deleted absent authorization from FERC via a Section 205 or 206 filing.
15 The Cost of Capital for Long Term Debt and Notes Payable is calculated by dividing the interest expense
16 in Column (i) by the total amount in Column (d). The ROE listed in
16 Column (j) reflects the addition of 50 basis

17 points for RTO participation per
17 Docket No. ER16-204-000.
D.) Column (k) values for lines 2-
18 4 equal Column (h) values
18 multiplied by Column (j) values.
E.) Only populate if the balance is
19 greater than zero.

9
2
0

F.) FF1 page 112, line 24 for long term debt and FF1 page 112, line 37 for notes payable.



# Tri-State Generation and Transmission Association, Inc.

**Load**
**Year Ending December 31, 20XX**

| A<br>Line | B<br>Description | C<br>Total CP Load - East | D<br>Less Adjustments | E<br>Other | F<br>Network Demand (KW) |
|---|---|---|---|---|---|
| 1 | January | - | | | - |
| 2 | February | - | | | - |
| 3 | March | - | | | - |
| 4 | April | - | | | - |
| 5 | May | - | | | - |
| 6 | June | - | | | - |
| 7 | July | - | | | - |
| 8 | August | - | | | - |
| 9 | September | - | | | - |
| 10 | October | - | | | - |
| 11 | November | - | | | - |
| 12 | December | - | | | - |
| 13 | Total (kW-Mo) | 0 | - | - | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 14 | Average (kW-Mo) | - | - | - | - | |



# Tri-State Generation and Transmission Association, Inc.

**Allocation Factors**
**Year Ending**
**December 31, 20XX**

| A<br>Line | B<br>Description | C<br>Reference | D<br>Total | E<br>Allocation Factor | F<br>Allocation | G<br>Allocated |
|---|---|---|---|---|---|---|
| 1 | Production Wages & Salaries | Worksheet K, Line 2, Col F | - | Direct Zero | 0.000 % | $ - |
| 2 | Transmission Wages & Salaries | Worksheet K, Line 3, Col F Less Line 14, Col F | - | T-Tran Plant | | |
| 3 | 561 Load Dispatch Salaries | Worksheet K, Line 14, Col F | - | Direct Zero | 0.000 % | $ - |
| 4 | Distribution Wages & Salaries | Worksheet K, Line 4, Col F | - | Direct Zero | 0.000 % | $ - |
| 5 | Customer Accounting | Worksheet K, Line 5, Col F | - | T-Tran Plant | | |
| 6 | Customer Service | Worksheet K, Line 6, Col F | - | Direct Zero | 0.000 % | $ - |
| 7 | Customer Sales | Worksheet K, Line 7, Col F | - | Direct Zero | 0.000 % | $ - |
| 8 | | Sum | $ - | | | |
| 9 | **T-Wage Allocation** | | | | | |
| 10 | 350-353 Transmission Stations | Worksheet F, Sum(Line 62 thru 64), Col F and Worksheet U, Line 10, (Cols J and L)/2 | $ - | | | $ - |
| 11 | **T-Tran Stations** | | | | | |

| | | | | |
|---|---|---|---|---|
| 12 | Transmission Lines | Worksheet F, Line 65, Col F and Worksheet V, Line 10, (Cols J and L)/2 | $ - | $ - |
| 13 | **T-Tran Lines** | | | |
| 14 | Transmission Qualifying Plant | Lines 10 and 12 above and Worksheet A, Line 12, Col I | $ - | $ - |
| 15 | **T-Tran Plant** | | | |
| 16 | Plant in Service | Worksheet A, Line 21, Col F and I | $ - | |
| 17 | **T-Plant Allocation** | | | |
| 18 | Net Plant in Service | Worksheet A, Line 42, Col F and I | $ - | |
| 19 | **T-Net Allocation** | | | |
| 20 | **Direct Zero** | | | **0.00%** |
| 21 | **Direct 100** | | | **100.00%** |

Workshe
et F

# Tri-State Generation and Transmission Association, Inc.

**Inputs**
**Year Ending December 31, 20XX**

| A<br>Line | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Total |
|---|---|---|---|---|---|
| 1 | Billing Lag in days | Industry Standard | | | 45 |
| 2 | **Monthly Load (East KW)** | | | | |
| 3 | Jan | Company Records | | | |
| 4 | Feb | Company Records | | | |
| 5 | Mar | Company Records | | | |
| 6 | Apr | Company Records | | | |
| 7 | May | Company Records | | | |
| 8 | Jun | Company Records | | | |
| 9 | Jul | Company Records | | | |
| 10 | Aug | Company Records | | | |
| 11 | Sep | Company Records | | | |
| 12 | Oct | Company Records | | | |
| 13 | Nov | Company Records | | | |
| 1 | Dec | Company | | | |

| | | | |
|---|---|---|---|
| 4 | | Records | |
| 1 5 | **RUSFOR Input** | | |
| 1 6 | Electric Energy Revenues | FF1 page 302, line 14 | |
| 1 7 | **Operating Expense** | | |
| 1 8 | Op Exp.-Other Power Supply | FF1 page 321, line 79 | |
| 1 9 | Op Exp.-Transmission | FF1 page 321, line 99 | |
| 2 0 | Op Exp.-RTO/ISO | FF1 page 322, line 123 | |
| 2 1 | Op Exp.-Distribution | FF1 page 322, line 144 | |
| 2 2 | Op Exp.-Consumer Accounts | FF1 page 322, line 164 | |
| 2 3 | Op Exp.-Customer Service | FF1 page 323, line 171 | |
| 2 4 | Op Exp.-Sales | FF1 page 323, line 178 | |
| 2 5 | Op Exp.-Admin and General | FF1 page 323, line 194 less trial balance GL Acct 42600 | |
| 2 6 | **Maintenance Expense** | | |
| 2 7 | Maint. Exp.-Production | FF1 page 320 & 321, lines 20, 40, 58, & 73 | |
| 2 8 | Maint. Exp.-Transmission | FF1 page 321, line 111 | |
| 2 9 | Maint. Exp.-RTO/ISO | FF1 page 322, line | |

| | | | | | |
|---|---|---|---|---|---|
| | | 130 | | | |
| 3 | | FF1 page 322, line | | | |
| 0 | Maint. Exp.-Distribution | 155 | | | |
| 3 | | FF1 page 323, line | | | |
| 1 | Maint. Exp.-General Plant | 196 | | | |
| 3 | | | | | |
| 2 | **Interest, Taxes and Other Deductions** | | | | |
| 3 | | FF1 page 336, lines 2-10 cols B&C plus FF1 page 114, lines 8, 9, | | | |
| 3 | Depreciation & Amortization Expense | 12, & 13 | | | |
| 3 | | FF1 page | | | |
| 4 | Taxes Other than Income Taxes (408.1) | 114, line14 | | | |
| 3 | | FFI page 114, lines | | | |
| 5 | Income Taxes (409.1) | 15 & 16 | | | |
| 3 | Net provision for Deferred Income Taxes | FFI page 114, lines | | | |
| 6 | (410.1 & 411.1) | 17 & 18 | | | |
| 3 | | FF1 page 117, line 62 Less Trial Balance GL Acct 42732 (entered as negative | | | |
| 7 | Interest on Long Term Debt | value) | | | |
| 3 | | FF1 page | | | |
| 8 | Other Interest Expense | 117, line 68 | | | |
| 3 | | FF1 page | | | |
| 9 | Asset Retirement Obligations | 114, line 24 | | | |
| 4 | | FF1 page | | | |
| 0 | Income (Loss) from Equity Investments | 117, line 36 | | | |
| 4 | | | | | |
| 1 | **Section B. Balance Sheet** | | | | |
| 4 | | | | | Average/EoY |
| 2 | **Assets** | | BoY | EoY | |
| 4 | Construction Work in Progress | FF1 page | | | $ |

| | | | | | |
|---|---|---|---|---|---|
| 3 | | 110, line 3 | | | - |
| 4 | | FF1 page | | | $ |
| 4 | Notes Receivable (Net) | 110, line 39 | | | - |
| 4 | | FF1 page | | | $ |
| 5 | Prepayments *(Acct 165)* | 111, line 57 | | | - |
| 4 | | FF1 page 111, lines | | | $ |
| 6 | Other Current and Accrued Assets | 58-62 | | | - |
| 4 | Accumulated Deferred Income Taxes | FF1 page | | | $ |
| 7 | *(Acct 190)* | 111, line 82 | | | - |
| 4 | | FF1 page | | | $ |
| 8 | Deferred Tax Asset | 232, line 1 | | | - |
| 4 | | | | | |
| 9 | **Liabilities** | | | | **Total** |
| 5 | | FF1 page | | | $ |
| 0 | Total Margins & Equities | 112, line 16 | | | - |
| 5 | | FF1 page | | | $ |
| 1 | Total Long Term Debt | 112, line 24 | | | - |
| 5 | Obligations Under Capital Leases - Non | FF1 page | | | $ |
| 2 | Current | 112, line 26 | | | - |
| 5 | | FF1 page | | | $ |
| 3 | Notes Payable | 112, line 37 | | | - |
| 5 | | FF1 page | | | $ |
| 4 | Current Maturities Long Term Debt | 112, line 45 | | | - |
| 5 | Accumulated Deferred Income Taxes | FF1 page 113, lines | | | $ |
| 5 | (Acct 282-283) | 63-64 | | | - |
| | | | BoY | EoY | Average |
| 5 | | FF1 pages 204 & 205, line 5 less Acct 106 allocation (Company | | | $ |
| 6 | 301-303 Total Intangible Plant | Records) | | | - |
| 5 | | FF1 pages 204 & 205, line 16 less Acct 106 allocation (Company | | | $ |
| 7 | 310 Steam Plant | Records) | | | - |

| | | | | | |
|---|---|---|---|---|---|
| 58 | 320 Nuclear Plant | FF1 pages 204 & 205, line 25 less Acct 106 allocation (Company Records) | | | $ - |
| 59 | 330 Hydro Plant | FF1 pages 204 & 205, line 35 less Acct 106 allocation (Company Records) | | | $ - |
| 60 | 340 Other Prod Plant | FF1 pages 204 & 205, line 45 less Acct 106 allocation (Company Records) | | | $ - |
| 61 | **Total Production Plant** | Subtotal | $ - | $ - | - |
| 62 | 350 Land & Land Rights | FF1 pages 206 & 207, line 48 less Acct 106 allocation (Company Records) | | | $ - |
| 63 | 352 Structures and Improvements | FF1 pages 206 & 207, line 49 less Acct 106 allocation (Company Records) | | | $ - |
| 64 | 353 Station Equipment | FF1 pages 206 & 207, line 50 less Acct 106 allocation (Company Records) | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 65 | 354 thru 359.1 Other Transmission Plant | FF1-pages 206 & 207, lines 51-57 less Acct 106 allocation (Company Records) | | | $ - |
| 66 | | Subtotal | $ - | $ - | 0 |
| 66 | **Total Transmission Plant** | | | | |
| 67 | 360 Land and Land Rights | FF1 pages 206 & 207, line 60 less Acct 106 allocation (Company Records) | | | $ - |
| 68 | 361 Structures and Improvements | FF1 pages 206 & 207, line 61 less Acct 106 allocation (Company Records) | | | $ - |
| 69 | 362 Station Equipment | FF1 pages 206 & 207, line 62 less Acct 106 allocation (Company Records) | | | $ - |
| 70 | 363-374 Other Distribution Plant | FF1 pages 206 & 207, lines 63-74 less Acct 106 allocation (Company Records) | | | $ - |
| 71 | | Subtotal | $ - | $ - | $ - |
| 71 | **Total Distribution Plant** | | | | |
| 72 | 380-386 RTO/ISO Plant | FF1 pages 206 & 207, line 84 less | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 73 | 389 thru 399.1 Total General Plant | Acct 106 allocation (Company Records) FF1 pages 206 & 207, line 99 less Acct 106 allocation (Company Records) | | | $ - |
| 74 | **Electric Plant In Service** | Subtotal | $ - | $ - | $ 0 |
| 75 | 102 Electric Plant Purchased or Sold | Current & Past Year FF1 pages 200 & 201, line 5 | | | $ - |
| 76 | 104 Electric Plant Leased to Others | Current & Past Year FF1 pages 200 & 201, line 9 | | | $ - |
| 77 | 105 Electric Plant Held For Future Use | Current & Past Year FF1 pages 200 & 201, line 10 | | | $ - |
| 78 | 106 Completed Construction Not Classified | Current & Past YearFF1 pages 200 & 201, line 6 | | | $ - |
| 79 | 114 Acquisition Adjustment | Current & Past YearFF1 pages 200 & 201, line 12 | | | $ - |
| 80 | 107 Construction Work in Progress | Current & Past YearFF1 pages 200 & 201, line 11 | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 81 | **Total Utility Plant** | Subtotal | $ - | $ - | 0 |
| 82 | Depreciation and Amortization Reserves | | | | Average |
| 83 | 108.1 Depr Rsv. of Steam Plant | Current & Past Year FF1 page 219, line 20 | | | $ - |
| 84 | 108.2 Depr Rsv. of Nuclear Plant | Current & Past YearFF1 page 219, line 21 | | | $ - |
| 85 | 108.3 Depr Rsv. of Hydraulic Plant | Current & Past Year FF1 page 219, lines 22 & 23 | | | $ - |
| 86 | 108.4 Depr Rsv. of Other Prod Plant | Current & Past Year FF1 page 219, line 24 | | | $ - |
| 87 | 108.5 Depreciation of Transmission Plant | Current & Past Year FF1 page 219, line 25 plus Trial Balance GL Accts 10881-10883 | | | $ - |
| 88 | 108.6 Depreciation of Distribution Plant | Current & Past Year FF1 page 219, line 26 | | | $ - |
| 89 | 108.7 Depreciation of General Plant | Current & Past Year FF1 page 219, line 28 | | | $ - |
| 90 | 108.8 Retirement Work in Progress | Trial Balance GL Accts 10881-10883 (enter as a | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| | | negative value) | | | |
| 91 | 111 Amort. of Electric Plant in Service | Trial Balance GL Acct 11100 (enter as a positive value) | | | $ - |
| 92 | 115 Amort. of Acquisition Adj. | Trial Balance GL Acct 11500 (enter as a positive value) | | | $ - |
| 93 | **Total Depr Reserves for Electric Plant** | Subtotal | $ - | $ - | 0 |
| 94 | Materials and Supplies | | | | Average |
| 95 | M&S Fuel Stock | FF1 page 227, line 1 | | | $ - |
| 96 | M&S Fuel Stock Expenses Undistributed | FF1 page 227, line 2 | | | $ - |
| 97 | M&S Production Plant | FF1 page 227, line 7 | | | $ - |
| 98 | M&STransmission Plant | FF1 page 227, line 8 | | | $ - |
| 99 | M&S Other | FF1 page 227, line 16 | | | $ - |
| 100 | Materials and Supplies | Subtotal | $ - | $ - | - |
| 101 | Depreciation Expense | | | | Total |
| 102 | 40360 Depreciation Expense - General Plant | Trial Balance GL Acct 40360 | | | |
| 103 | 40361 Depreciation Expense - EMS Equipment (Depreciation Accounts for 390 391 393 - 399) | Trial Balance GL Acct 40361 | | | |
| 104 | 40369 Depreciation Expense - General Plant Southern | Trial Balance GL Acct 40369 | | | |

| | | | |
|---|---|---|---|
| 105 | 40370 Depreciation Expense - Sedans, Compact Utility Vehicles, Compact Pick-ups | Trial Balance GL Acct 40370 | |
| 106 | 40371 Depreciation Expense - Vans and Wagons | Trial Balance GL Acct 40371 | |
| 107 | 40372 Depreciation Expense - Full-Size Pickups, Vans, Utility Vehicles | Trial Balance GL Acct 40372 | |
| 108 | 40373 Depreciation Expense - Bucket Trucks, Diggers | Trial Balance GL Acct 40373 | |
| 109 | 40374 Depreciation Expense - Company Aircraft | Trial Balance GL Acct 40374 | |
| 110 | 40375 Depreciation Expense - Small Heavy Trucks | Trial Balance GL Acct 40375 | |
| 111 | 40376 Depreciation Expense - Medium Trucks, Flatbeds, Knuckle Booms, Etc. | Trial Balance GL Acct 40376 | |
| 112 | 40377 Depreciation Expense - Snowcats | Trial Balance GL Acct 40377 | |
| 113 | 40378 Depreciation Expense - Equipment (Dozers, Backhoes, etc.) | Trial Balance GL Acct 40378 | |
| 114 | 40388 Depreciation Expense - AROs | Trial Balance GL Acct 40388 | |
| 115 | 40398 Depreciation Expense - AROs | Trial Balance GL Acct 40398 | |
| 116 | | | |
| 117 | | | $ |
| 118 | General Plant Depreciation Expense | Subtotal | - |
| 119 | | Trial | |
| 120 | 40400 Amortization - Franchises and Consents (Amortization Account for 302) | Balance GL Acct 40400 | |
| 121 | | Trial | |
| 122 | 40409 Amortization of Lmtd Term Electric Plant Southern Franchises | Balance GL Acct 40409 | |
| 123 | 40500 Amortization of Other Electric Plant (Amortization Account for Deferred Debit Accounts) | Trial Balance GL Acct 40500 | |
| 124 | 40509 Amortization of Other Electric | Trial | |

| | | | | |
|---|---|---|---|---|
| 2 | Plant Southern | Balance GL | | |
| 0 | | Acct 40509 | | |
| 1 | | Trial | | |
| 2 | 40510 Amortization Miscellaneous | Balance GL | | |
| 1 | Intangible Generation | Acct 40510 | | |
| 1 | | Trial | | |
| 2 | 40530 Amortization-Miscellaneous | Balance GL | | |
| 2 | Intangible Lines | Acct 40530 | | |
| 1 | | Trial | | |
| 2 | 40540 Amortization-Miscellaneous | Balance GL | | |
| 3 | Intangible Substations | Acct 40540 | | |
| 1 | 40600 Amortization of Electric Plant | Trial | | |
| 2 | Acquisition Adjustments (Amortization | Balance GL | | |
| 4 | Account for 114 301) | Acct 40600 | | |
| 1 | | Trial | | |
| 2 | 40609 Amortization of Electric Plant | Balance GL | | |
| 5 | Acquisition Adjust. Southern | Acct 40609 | | |
| 1 | | Trial | | |
| 2 | 40700 Amortization of Property Losses | Balance GL | | |
| 6 | Rollup | Acct 40700 | | |
| 1 | | | | |
| 2 | | | | $ |
| 7 | Amortization of Property | Subtotal | | - |
| | | | | |
| | General and Intangible Plant Inputs | | | |
| 1 | | Trial | | |
| 2 | | Balance GL | | $ |
| 8 | 390 - Structures and Improvements | Acct 39000 | | - |
| 1 | | | | |
| 2 | | Company | | $ |
| 9 | 391.1 - Personal Computers | Records | | - |
| 1 | | | | |
| 3 | | Company | | $ |
| 0 | 391.11 - Furniture | Records | | - |
| 1 | | | | |
| 3 | | Company | | $ |
| 1 | 391.12 - Office Equipment | Records | | - |
| 1 | | | | |
| 3 | | Company | | $ |
| 2 | 391.13 - Computer Hardware | Records | | - |
| 1 | | | | |
| 3 | | Company | | $ |
| 3 | 391.14 - LRS Office Equipment | Records | | - |
| 1 | | | | |
| 3 | | Company | | $ |
| 4 | 391.15 - EMS Office Equipment | Records | | - |

| | | | | |
|---|---|---|---|---|
| 135 | 391.16 - EMS Computer Equipment | Company Records | | $ - |
| 136 | 391.17 - CO41 OWNED AT JMS | Company Records | | $ - |
| 137 | 391.18 - SOFTWARE | Company Records | | $ - |
| 138 | 391.19 - Plains Furniture and Equipment | Company Records | | $ - |
| 139 | 392.1 - Transportation Equipment | Company Records | | $ - |
| 140 | 392.11 - Airplane | Company Records | | $ - |
| 141 | 392.12 - Snow Cats/Trailers | Company Records | | $ - |
| 142 | 392.13 - LRSVehicles | Company Records | | $ - |
| 143 | 392.14 - Plains Transportation Equipment | Company Records | | $ - |
| 144 | 392.15 - Diesel Trucks | Company Records | | $ - |
| 145 | 392.16 - Craig- Fuel Vehicles | Company Records | | $ - |
| 146 | 392.17 - Craig- Maintenance Vehicles | Company Records | | $ - |
| 147 | 392.18 - Craig- Operating Vehicles | Company Records | | $ - |
| 148 | 392.19 - Pickups | Company Records | | $ - |
| 149 | 392.2 - Autos | Company Records | | $ - |
| 151 | 392.21 - Heavy Duty Trucks | Company | | $ |

| | | | | |
|---|---|---|---|---|
| 5 | | Records | | - |
| 0 | | | | |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 1 | 393 - Stores Equipment | Acct 39300 | | - |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 2 | 394 - Tools, Shop and Garage Equipment | Acct 39400 | | - |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 3 | 395 - Lab & Testing Equipment | Acct 39500 | | - |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 4 | 396 - Power Operated Equipment | Acct 39600 | | - |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 5 | 397 - Communications Equipment | Acct 39700 | | - |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 6 | 398 - Miscellaneous | Acct 39800 | | - |
| 1 | | Trial | | |
| 5 | | Balance GL | | $ |
| 7 | 303 - Miscellaneous Intangible | Acct 30300 | | - |



# Tri-State Generation and Transmission Association, Inc.

**O&M**
**Year Ending December 31,**
**20XX**

| A | B | C | D | *E* |
|---|---|---|---|---|
| | | | | |
| | **Expenses and Costs** | | | |
| | **Item** | **Account Name** | **Reference** | **Total** |
| | **Transmissions Operations** | | | |
| 1 | Supervision and Engineering | 560 | FF1 page 321, line 83 | |

| | | | | |
|---|---|---|---|---|
| 2 | Load Dispatching | 561 | FF1 page 321, lines 85-92 | |
| 3 | Station Expenses | 562 | FF1 page 321, line 93 | |
| 4 | Overhead Line Expenses | 563 | FF1 page 321, line 94 | |
| 5 | Underground Line Expenses | 564 | FF1 page 321, line 95 | |
| 6 | Miscellaneous Expenses | 566 | FF1 page 321, line 97 | |
| **7** | **Subtotal (1 thru 6)** | | | **$ -** |
| 8 | Transmission of Electricity by others | 565 | FF1 page 321, line 96 | |
| 9 | Rents | 567 | FF1 page 321, line 98 | |
| **10** | **Total Transmission Operations (7 thru 9)** | | | **$ -** |
| | **Transmission Maintenance** | | | |
| 11 | Supervision and Engineering | 568 | FF1 page 321, line 101 | |
| 12 | Structures | 569 | FF1 page 321, lines 102-106 | |
| 13 | Station Equipment | 570 | FF1 page 321, line 107 | |
| 14 | Overhead Lines | 571 | FF1 page 321, line 108 | |
| 15 | Underground Lines | 572 | FF1 page 321, line 109 | |
| 16 | Miscellaneous Transmission Plant | 573 | FF1 page 321, line 110 | |
| **17** | **Total Transmission Maintenance (11 thru 16)** | | | **$ -** |
| **18** | **Total Transmission Expense (10+17)** | | | **$ -** |
| 19 | RTO/ISO Expense - Operation | 575.1-575.8 | FF1 page 322, line 123 | |
| 20 | RTO/ISO Expense - Maintenance | 576.1-576.5 | FF1 page 322, line 130 | |
| **21** | **Total RTO/ISO Expense (19+20)** | | | $ - |
| 22 | Distribution Expense - Operation | 580-589 | FF1 page 322, line 144 | |
| 23 | Distribution Expense - Maintenance | 590-598 | FF1 page 322, line 155 | |
| **24** | **Total Distribution Expense (22+23)** | | | **$ -** |
| **25** | **Total Operation and Maintenance (18+21+24)** | | | **$ -** |

# Tri-State Generation & Transmission Association, Inc.

**SPP Upgrades**
**Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|
| **Line** | **Project Name and No.** (Note A) | **Type (Line or Sub)** | **Project Gross Plant** (Note B) | **Project Accumulated Depreciation** (Note B) | **Project Net Plant** Col D - Col E | **Fixed Charge Rate** (Note C) | **Project Carrying Charge** Col D * Col G | **Project Depreciation Expense** (Note D) | **Project Return** (Note E) | **Project Revenue Requirement** H + I + J |
| 1a | | | | | $0 | | | $0 | | |
| 1b | | | | | $0 | | | $0 | | |
| 1c | | | | | $0 | | | $0 | | |
| 1d | | | | | $0 | | | $0 | | |
| 1e | | | | | $0 | | | $0 | | |
| 1f | | | | | $0 | | | $0 | | |
| 1g | | | | | $0 | | | $0 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| … | | | | $0 | | $0 |
| … | | | | $0 | | $0 |
| 2 | Total SPP Upgrade Revenue Requirements (sum lines 1a-1xx) | $0 | $0 | $0 | | $0 |

3 Notes:
A.) Transmission-related projects
4 only.
B.) Must reflect an average of BOY and EOY
5 balances.
C.) Fixed Charge Rate equals gross revenue requirement (Summary Page, line 2) less transmission depreciation expense (Worksheet B, line 31), less
6 revenue credits (Summary page 1, line 8) divided by gross transmission plant (Worksheet A, line 12,
7 column J):
Gross Revenue Requirement
8 (A):
Transmission Plant Depreciation
9 Expense (B): $0
Return on Transmission
1 Plant in Service
0 (C):
1 Revenue
1 Credits (D):
Gross
1 Transmission
2 Plant (E):
Fixed Charge
1 Rate = (A - B -
3 C - D) / E
D.) Project depreciation expense must
1 reflect the composite transmission
4 depreciation rate on Worksheet L.

E.) Project return must reflect the weighted cost of capital listed on Worksheet C, line 5, column K.

F.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

# Tri-State Generation & Transmission Association, Inc.

**Depreciation Rates**
**Year Ending December 31, 20XX**

| A | B | C | D |
|---|---|---|---|
| Line | Account No. | Description | Depreciation/Amortization Rate (Note A) |
| 1 | | **Intangible Plant** | |
| 2 | 303.0 | Miscellaneous Intangible | 2.75% |
| 3 | | **Transmission Plant** | |
| 4 | 352 | Structures & Improvements | 2.05% |
| 5 | 353 | Station Equipment | 1.69% |
| 6 | 354 | Towers and Fixtures | 1.32% |
| 7 | 355 | Poles & Fixtures | 1.88% |
| 8 | 356 | O/H Conductor & Devices | 1.73% |
| 9 | 357 | Underground Conduit | 1.66% |
| 10 | 358 | Underground Cables | 2.09% |
| 11 | 359 | Roads and Trails | 1.11% |
| 12 | | **Distribution Plant** | |
| 13 | 361 | Distribution Plant Structures | 1.52% |
| 14 | 362 | Distribution Plant Station Equipment | 1.38% |
| 15 | | **General Plant** | |
| 16 | 390 | Structures and Improvements | 1.46% |
| 17 | 391 | **OFFICE FURNITURE EQUIPMENT** | |
| 18 | 391.1 | Personal Computers | 9.53% |
| 19 | 391.11 | Furniture | 9.53% |
| 20 | 391.12 | Office Equipment | 9.53% |
| 21 | 391.13 | Computer Hardware | 9.53% |
| 22 | 391.14 | LRS Office Equipment | 9.53% |
| 23 | 391.15 | EMS Office Equipment | 9.53% |
| 24 | 391.16 | EMS Computer Equipment | 9.53% |
| 25 | 391.17 | CO41 OWNED AT JMS | 9.53% |
| 26 | 391.18 | SOFTWARE | 9.53% |
| 27 | 391.19 | Plains Furniture and Equipment | 9.53% |
| 28 | 392 | **TRANSPORTATION EQUIPMENT** | |
| 29 | 392.1 | Transportation Equipment | 2.93% |
| 30 | 392.11 | Airplane | 2.93% |
| 31 | 392.12 | Snow Cats/Trailers | 2.93% |
| 32 | 392.13 | LRSVehicles | 2.93% |
| 33 | 392.14 | Plains Transportation Equipment | 2.93% |
| 34 | 392.15 | Diesel Trucks | 2.93% |

| | | | |
|---|---|---|---|
| 35 | 392.16 | Craig- Fuel Vehicles | 2.93% |
| 36 | 392.17 | Craig- Maintenance Vehicles | 2.93% |
| 37 | 392.18 | Craig- Operating Vehicles | 2.93% |
| 38 | 392.19 | Pickups | 2.93% |
| 39 | 392.2 | Autos | 2.93% |
| 40 | 392.21 | Heavy Duty Trucks | 2.93% |
| 41 | 393 | Stores Equipment | 3.17% |
| 42 | 394 | Tools, Shop and Garage Equipment | 2.35% |
| 43 | 395 | Lab & Testing Equipment | 4.67% |
| 44 | 396 | Power Operated Equipment | 2.29% |
| 45 | 397 | Communications Equipment | 4.53% |
| 46 | 398 | Miscellaneous | 5.94% |

47 Notes:
A.) These rates are fixed and cannot be changed absent authorization from FERC via a Section
48 205 or 206 filing.

# Tri-State Generation and Transmission Association, Inc.

**Reconciliation Items, Refunds and Surcharges Year Ending December 31, 20XX**

**A B C D E F G H I J**

**Adjustments To ATRR Due To Error Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/ Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | $ - |
| 2 | | | | | | | | | 0 |
| 3 | | | | | | | | | 0 |
| 4 | | | | | | | | | 0 |
| 5 | | | | | | | | | 0 |
| 6 | **Total Adjustment to Gross ATRR:** | | | | | | | | $ - |

**Adjustments To SPP Regional Projects' ATRR Due To Corrections**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year (A) | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/ Chg | Calculated Interest (B) | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| 7 | | | | | | | | | 0 |
| 8 | | | | | | | | | 0 |
| 9 | | | | | | | | | 0 |
| 10 | | | | | | | | | 0 |
| 11 | | | | | | | | | 0 |
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | | | | | | | | 0 |

13 Notes:

14 A.) Rate Year in which the error occurred and affected the ATRR and rates paid by customers.

15 B.) Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.

| | Period Start | Period Ending | Year description | Beginning Balance | Accumulation or Payback | FERC Annual Interest Rate | Quarterly Interest Amount | Ending Balance |
|---|---|---|---|---|---|---|---|---|
| 16 | | | | | | | | |

**Interest calculation for Item #1**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Rate | | $ | | $ | $ |
| 17 | | Year | | - | | - | - |
| | | Rate | $ | $ | | $ | $ |
| 18 | | Year | - | - | | - | - |
| | | Rate | $ | $ | | $ | $ |
| 19 | | Year | - | - | | - | - |
| | | Rate | $ | $ | | $ | $ |
| 20 | | Year | - | - | | - | - |
| | | | $ | | | $ | $ |
| 21 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 22 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 23 | | | - | | | - | - |
| | | | $ | | | $ | $ |
| 24 | | | - | | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 25 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 26 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 27 | | Year | - | - | | - | - |
| | | True-Up | $ | $ | | $ | $ |
| 28 | | Year | - | - | | - | - |
| 29 | Total | | | | | $ - | |

**Interest calculation for Item #2…**

30

(Repeat interest calculation for other items as necessary.)

31

C.) Interest Note: The example interest calculation may need to be modified to recognize the implementation partial year.

32

D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

33

34

35

# Tri-State Generation and Transmission Association, Inc.

**Wages**
**Year Ending December 31, 20XX**

| A<br>Line | B<br>Function | C<br>Direct Labor | D<br>Sick, Vacation, Option, Holiday | E<br>Benefits | F<br>Total Labor Expense |
|---|---|---|---|---|---|
| 1 | **Expenses** | | | | |
| 2 | Production | | | | $ - |
| 3 | Transmission | | | | $ - |
| 4 | Distribution | | | | $ - |
| 5 | Customer Accounting | | | | $ - |
| 6 | Customer Service | | | | $ - |
| 7 | Customer Sales | | | | $ - |
| 8 | Total | $ - | $ - | $ - | $ - |
| 9 | | | | | |
| 10 | **Transmission O&M - Acct 561 - Load Dispatch** | | | | |
| 11 | 561.00 Operations | | | | $ - |
| 12 | 561.20 Transmission | | | | $ - |
| 13 | 561.25 South Trans | | | | $ - |
| 14 | Total | $ - | $ - | $ - | $ - |
| 15 | Notes | | | | |
| 16 | A.) Source: Company Records | | | | |

**Tri-State Generation & Transmission Association, Inc.**

Annual Depreciation Expense
Year Ending December 31, 20XX

| A | B | C | D | E | F | G | H |
|---|---|---|---|---|---|---|---|
| Line | Account | Description | SPP BOY Amount | SPP EOY Amount | SPP Transmission Amount (Avg) | Depreciation Rate | Depreciation Expense |
| 1 | | **Transmission Plant** | | | | | |
| 2 | 350 | Land and Land Rights | $0 | $0 | $0.00 | N/A | |
| 3 | 352 | Structures & Improvements | $0 | $0 | $0 | 2.05% | $0 |
| 4 | 353 | Station Equipment | $0 | $0 | $0 | 1.69% | $0 |
| 5 | 354 | Towers and Fixtures | $0 | $0 | $0 | 1.32% | $0 |
| 6 | 355 | Poles & Fixtures | $0 | $0 | $0 | 1.88% | $0 |
| 7 | 356 | O/H Conductor & Devices | $0 | $0 | $0 | 1.73% | $0 |
| 8 | 357 | Underground Conduit | $0 | $0 | $0 | 1.66% | $0 |
| 9 | 358 | Underground Cables | $0 | $0 | $0 | 2.09% | $0 |
| 10 | 359 | Roads and Trails | $0 | $0 | $0.00 | 1.11% | $0 |
| 11 | | Total Transmission Depreciation Expense | $0 | $0 | $0 | **1.69%** | $0 |

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| Line | Account | Description | Total Company BOY Amount | Total Company EOY Amount | Total Company Amount (Avg) | T-Wage Allocation Factor | SPP Zone 17 Amount | Depreciation Rate | Depreciation Expense |
| 12 | | **General Plant** | | | | | | | |
| 13 | 390 | Structures and Improvements | $0 | $0 | $0.00 | | | 1.46% | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 14 | 391.1 | Personal Computers | $0 | $0 | $0.00 | 9.53% |
| 15 | 391.11 | Furniture | $0 | $0 | $0.00 | 9.53% |
| 16 | 391.12 | Office Equipment | $0 | $0 | $0.00 | 9.53% |
| 17 | 391.13 | Computer Hardware | $0 | $0 | $0.00 | 9.53% |
| 18 | 391.14 | LRS Office Equipment | $0 | $0 | $0.00 | 9.53% |
| 19 | 391.15 | EMS Office Equipment | $0 | $0 | $0.00 | 9.53% |
| 20 | 391.16 | EMS Computer Equipment | $0 | $0 | $0.00 | 9.53% |
| 21 | 391.17 | CO41 OWNED AT JMS | $0 | $0 | $0 | 9.53% |
| 22 | 391.18 | SOFTWARE | $0 | $0 | $0 | 9.53% |
| 23 | 391.19 | Plains Furniture and Equipment | $0 | $0 | $0 | 9.53% |
| 24 | 392.1 | Transportation Equipment | $0 | $0 | $0 | 2.93% |
| 25 | 392.11 | Airplane | $0 | $0 | $0 | 2.93% |
| 26 | 392.12 | Snow Cats/Trailers | $0 | $0 | $0 | 2.93% |
| 27 | 392.13 | LRSVehicles | $0 | $0 | $0 | 2.93% |
| 28 | 392.14 | Plains Transportation Equipment | $0 | $0 | $0 | 2.93% |
| 29 | 392.15 | Diesel Trucks | $0 | $0 | $0 | 2.93% |
| 30 | 392.16 | Craig- Fuel Vehicles | $0 | $0 | $0 | 2.93% |
| 31 | 392.17 | Craig- Maintenance Vehicles | $0 | $0 | $0 | 2.93% |
| 32 | 392.18 | Craig- Operating Vehicles | $0 | $0 | $0 | 2.93% |
| 33 | 392.19 | Pickups | $0 | $0 | $0 | 2.93% |
| 34 | 392.2 | Autos | $0 | $0 | $0 | 2.93% |
| 35 | 392.21 | Heavy Duty Trucks | $0 | $0 | $0 | 2.93% |
| 36 | 393 | Stores Equipment | $0 | $0 | $0 | 3.17% |
| 37 | 394 | Tools, Shop and Garage Equipment | $0 | $0 | $0 | 2.35% |
| 38 | 395 | Lab & Testing Equipment | $0 | $0 | $0 | 4.67% |
| 39 | 396 | Power Operated Equipment | $0 | $0 | $0 | 2.29% |
| 40 | 397 | Communications Equipment | $0 | $0 | $0 | 4.53% |
| 41 | 398 | Miscellaneous | $0 | $0 | $0 | 5.94% |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 142 | | Total General Depreciation Expense | $0 | $0 | $0 | | |
| 143 | | **Intangible Plant** | | | | | |
| 144 | 303.0 | Miscellaneous Intangible | $0 | $0 | $0.00 | | 2.75% |
| 145 | | Total Intangible Amortization Expense | $0 | $0 | $0 | | |



# Tri-State Generation and Transmission Association, Inc.

**Other Revenue**
**Year Ending December 31, 20XX**

| A Line | B Account | C Description | D Total Company | E East ATRR |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
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| 22 | | | | |
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| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | | | | |
| | | | **$** | **$** |
| 32 | | Total Other Operating Revenue and Income | **-** | **-** |
| 33 | | **Summary:** | | |
| | | | $ | $ |
| 34 | 454 | Rent from Property | - | - |
| | | | $ | |
| 35 | 456 | Other Elect Rev | - | |
| | | | $ | $ |
| 36 | 456 | SPP P2P Wheeling | - | - |
| | | | $ | $ |
| 37 | | SPP P2P Schedule 1 | - | - |
| | | | $ | |
| 38 | 456 | Other Wheeling | - | |
| | | | $ | $ |
| 39 | | Other Revenues | - | - |
| 40 | | | | |

41 Notes:

42 A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns

43 and formulas contained with those columns cannot be changed absent a

44 Federal Power Act section 205 or 206 filing.

Page 16
Work sheet N

# Tri-State Generation and Transmission Association, Inc.

**Plant Held for Future Use**
**Year Ending**
**December 31, 20XX**

| | | | | Beginning of Year Investment | | | | Year End Investment | | | Average | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** | **I** | **J** | **K** | **L** | **M** |
| **Line** | **Facility No.** | **Asset No.** | **Description** | **Total** | **West** | **East** | **Total** | **West** | **East** | **Total** | **West** | **East** |
| 1 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 2 | | | | | | | | | | | | |
| 3 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 4 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 5 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 6 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 7 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 8 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 9 | | | | | $ - | | | $ - | | $ - | $ - | $ - |
| 10 | | | | | $ - | | | $ - | | $ - | $ - | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 11 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 12 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 13 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 14 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 15 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 16 | | | $ - | | $ - | | $ - | $ - | $ - | |
| 17 | | Subtotal Transmission Future Use Assets | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 18 | | | | | | | | | | |
| 19 | | Distribution Future Use Assets | | $ - | | $ - | | $ - | $ - | $ - | |
| 20 | | | | | | | | | | |
| 21 | | General Plant Future Use Assets | | $ - | | $ - | | $ - | $ - | $ - | |
| 22 | | | | | | | | | | |
| 23 | | Intangible Plant Future Use Assets | | $ - | | $ - | | $ - | $ - | $ - | |
| 24 | | | | | | | | | | |
| 25 | | Total Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Notes

A.) Source: Company Records

B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power

Page 17
Work sheet O

# Tri-State Generation and Transmission Association, Inc.

**Acct 565 - Transmission of Electricity by Others**
**Year Ending December 31, 20XX**

| Line | B Account (A) | C Account Description | D Total Company | E East |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | Total Account 565 | $ - | $ - |

15 Notes

1 A.) Source: Company Records

6
1 B.) MBPP - NETS: NPPD Transmission
7 payments under 496 GFA
1 C.) NPPD - NETS: NPPD Equalization
8 payment under 494 GFA
D.) The addition of new lines and the removal of outdated lines necessary to populate or
1 remove data in the work paper with the changes in future years does not require a Federal
9 Power
Act section 205 or 206 filing. The addition or removal of columns and formulas
2 contained with those columns cannot be changed absent a Federal Power Act section
0 205 or 206 filing.

2 Act section 205 or 206 filing. The addition or removal of columns and formulas
9 contained with those columns cannot be changed absent a Federal Power Act section
205 or 206 filing.

# Tri-State Generation & Transmission Association, Inc.

**Account 575/576 Expenses**
**Year Ending December 31, 20XX**

| A<br>Line | B<br>Account No. | C<br>Description | D<br>Annual Expense Amount | E<br>% Included in SPP | F<br>SPP Amount |
|---|---|---|---|---|---|
| | | **575.1-575.8 RTO/ISO Expense - Operation** | | | |
| 1a | | | | | - |
| 1b | | | | | - |
| … | | | | | - |
| 2 | | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note A)** | - | | - |
| | | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | |
| 3a | | | | | - |
| 3b | | | | | - |
| … | | | | | - |
| 4 | | **576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note B)** | - | | - |

5 Notes
A.) The total on line 2, column D must reconcile to
6 the amounts shown on FF1 page 322, line 123.
B.) The total on line 4, column D must reconcile to
7 the amounts shown on FF1 page 322, line 130.
C.) Amounts listed on lines 1a-1xx and 3a-3xx are only eligible for
8 inclusion in SPP Zone 17 ATRR following a change in
accounting procedures to the FERC Form 1 or Uniform System of
9 Accounts, which would classify amounts in these accounts
1 as eligible for transmission rate recovery. To the extent that this
0 occurs, Tri-State may file a single-issue Section 205 filing with the

Commission to seek recovery of these amounts in Zone 17 rates. Tri-State may not include any costs absent authorization from FERC via a Section 205 or 206 filing.

D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

# Tri-State Generation and Transmission Association, Inc.

**Completed Construction Not Classified**
**Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Fac ID | Work order | Project | SPP 106 BoY | SPP 106 EoY | Facility | SPP Eligible: | Yes | No | Partial (%) | Amount | Comments |
| 1 | | | | | | | | | | | $ - | |
| 2 | | | | | | | | | | | $ - | |
| 3 | | | | | | | | | | | $ - | |
| 4 | | | | | | | | | | | $ - | |
| 5 | | | | | | | | | | | $ - | |
| 6 | | | | | | | | | | | $ - | |
| 7 | | | | | | | | | | | $ - | |
| 8 | | | | | | | | | | | $ - | |
| 9 | | | | | | | | | | | $ - | |
| 10 | | | | | | | | | | | $ - | |
| 11 | | | | | | | | | | | $ - | |
| 12 | | | | | | | | | | | $ - | |

| | | | | | |
|---|---|---|---|---|---|
| 13 | | | | $ | - |
| 14 | | | | $ | - |
| 15 | | | | $ | - |
| 16 | | | | $ | - |
| 17 | | | | $ | - |
| 18 | | | | $ | - |
| 19 | | | | $ | - |
| 20 | | | | $ | - |
| 21 | | | | $ | - |
| 22 | | | | $ | - |
| 23 | | | | $ | - |
| 24 | | | | $ | - |
| 25 | 106 SPP Completed Not Classified Total | | | | $0 |

26 Notes

27 A.) Source: Acct 106 xx.xlsx spreadsheet.

28 B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power

29 Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

# Tri-State Generation and Transmission Association, Inc.

**Construction Work in Progress Year Ending December 31, 20XX**

| A | B | C | D | E | F | G | H | I | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Line | Project Description | Approval Docket | Recovery Approved (Note A) | Pricing Zone (Note B) | Project ID | Construction Start Date | In-Service Date (Estimated) | BOY Balance | EOY Balance | Average Balance (Col I through J) / 2 | Includable in Rate Base (Note C) (Col D * Col K) |
| 1 | | | 0.5 | Zone 17 | | | | | | | |
| 2 | | | 0.5 | Zone 17 | | | | | | | |
| 3 | | | 0.5 | Zone 17 | | | | | | | |
| 4 | | | 0.5 | Zone 17 | | | | | | | |
| 5 | | | 0.5 | Zone 17 | | | | | | | |
| 6 | | | 0.5 | Zo | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7 | | | 0.5 | Zone 17 | | | |
| 8 | | | 0.5 | Zone 17 | | | |
| 9 | | | 0.5 | Zone 17 | | | |
| 10 | | | 0.5 | Zone 17 | | | |
| 11 | | | 0.5 | Zone 17 | | | |
| 12 | | | 0.5 | Zone 17 | | | |
| 13 | | | 0.5 | Zone 17 | | | |
| 14 | | | | | $ - | $ - | |

15 Notes:

16 A.) Percentage recovery cannot be added or changed absent approval from FERC.

17 B.) CWIP amounts should be directly assigned to pricing zones in Column E.

18 C.) AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization.

19 Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.

20 D.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas

2 contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Page 21 Worksheet S

# Tri-State Generation and Transmission Association, Inc.

**Regulatory and Commission Expenses Year Ending December 31, 20XX**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line** | **Account 928** | **Description** | **Total Company** | **Non-SPP Expenses** | **SPP Expenses** |
| 1 | 928 | Outside Consultants | | | |
| 2 | 928 | Labor | | | |
| 3 | 928 | Travel | | | |
| 4 | | Total | $ - | $ - | $ - |
| 5 | | | | | |
| 6 | | Notes: A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a | | | |
| 7 | | Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 | | | |
| 8 | | filing. | | | |

# Tri-State Generation and Transmission Association, Inc.

**Retirement Work in Progress Year Ending December 31, 20XX**

| Line | A | B | C | D | E | F | G | H | I | J | K | L | M |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Fac ID | Facility | Workorder | Project | BoY Balance | EoY Balance | Average Balance | SPP Eligible: | 100% SPP | 0% SPP | SPP Portion if Less than 100% | Amount |
| 1 | | | | | | | | $ - | | | | | $ - |
| 2 | | | | | | | | $ - | | | | | $ - |
| 3 | | | | | | | | $ - | | | | | $ - |
| 4 | | | | | | | | $ - | | | | | $ - |
| 5 | | | | | | | | $ - | | | | | $ - |
| 6 | | | | | | | | $ - | | | | | $ - |
| 7 | | | | | | | | $ - | | | | | $ - |
| 8 | | | | | | | | $ - | | | | | $ - |
| 9 | | | Total | | | $ - | $ - | $ - | | | | | $ - |
| 10 | | Notes: | | | | | | | | | | | |

A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

# Tri-State Generation and Transmission Association, Inc.

**SPP Qualified Transmission Substations Year Ending December 31, 20XX**

| | | | | | Total Company Amount | | | | Amount included in Tri-State's ATRR | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M | N |
| Line | Account Number | Description of Asset | Type of Asset | % of asset included in Tri-State's Zone 17 ATRR | BOY Gross Plant Cost | BOY Accumulated Depreciation | EOY Gross Plant Cost | EOY Accumulated Depreciation | BOY Gross Plant Cost | BOY Accumulated Depreciation | EOY Gross Plant Cost | EOY Accumulated Depreciation | Comments |
| 1 | 350 | Land and Land Rights | Transmission Substation | #DIV/0! | | | | | | | | | |
| 2 | 352 | Structures and Improvements | Transmission Substation | #DIV/0! | | | | | | | | | |
| 3 | 353 | Station Equipment | Transmission | #DIV/0! | | | | | | | | | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Substation | | | | | | | | | | |
| 354 | Towers and Fixtures | Transmission Substation | #DIV/0! | | | | | | | | | |
| 355 | Poles and Fixtures | Transmission Substation | #DIV/0! | | | | | | | | | |
| 356 | Overhead Conductors and Devices | Transmission Substation | #DIV/0! | | | | | | | | | |
| 357 | Underground Conduit | Transmission Substation | 0% | | | | | | | | | |
| 358 | Underground Conductors and Devices | Transmission Substation | 0% | | | | | | | | | |
| 359 | Roads and Trails | Transmission Substation | #DIV/0! | | | | | | | | | |
| **Totals** | | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |

Notes:

A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

Page 24 Worksheet V

# Tri-State Generation and Transmission Association, Inc.

**SPP Qualified Transmission Lines**
**Year Ending December 31, 20XX**

| | | | | | Total Company Amount | | | | Amount included in Tri-State's ATRR | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | L | M | N |
| Line | Account Number | Description of Asset | Type of Asset | % of asset included in Tri-State's Zone 17 ATRR | BOY Gross Plant Cost | BOY Accumulated Depreciation | EOY Gross Plant Cost | EOY Accumulated Depreciation | BOY Gross Plant Cost | BOY Accumulated Depreciation | EOY Gross Plant Cost | EOY Accumulated Depreciation | Comments |
| 1 | 350 | Land and Land Rights | Transmission Line | #DIV/0! | | | | | | | | | |
| 2 | 352 | Structures and Improvements | Transmission Line | #DIV/0! | | | | | | | | | |
| 3 | 353 | Station | Trans | #DIV | | | | | | | | | |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Equipment | mission Line | /0! | | | | | | | | | |
| 4 | 354 | Tower and Fixtures | Transmission Line | #DIV/0! | | | | | | | | | |
| 5 | 355 | Poles and Fixtures | Transmission Line | #DIV/0! | | | | | | | | | |
| 6 | 356 | Overhead Conductors and Devices | Transmission Line | #DIV/0! | | | | | | | | | |
| 7 | 357 | Underground Conduit | Transmission Line | #DIV/0! | | | | | | | | | |
| 8 | 358 | Underground Conduit and Devices | Transmission Line | #DIV/0! | | | | | | | | | |
| 9 | 359 | Roads and Trails | Transmission Line | #DIV/0! | | | | | | | | | |
| 10 | **Totals** | | | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |

11
11
12 Notes:
A.) The addition of new lines and the removal of outdated lines necessary to populate or remove data
13 in the work paper with the changes in future years does not require a Federal Power
Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those
14 columns cannot be changed absent a Federal Power Act section 205 or 206 filing.

**Tri-State Generation and Transmission Association, Inc.**

Page 25

**Tax Adjustments**

**Year Ending December 31, 2019**

Worksheet W

| **A** | **B** | **C** | **D** | **E** | **F** | **G** | **H** |
|---|---|---|---|---|---|---|---|

| Line | Book/Tax Adjustments Includable in Rate Base | Reference | Funded End of Year Balance - Tax Effected | Allocation Factor | Transmission Allocator | Transmission Balance | Notes |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | - | |
| 2 | | | | | | - | |
| 3 | | | | | | - | |
| 4 | | | | | | - | |
| 5 | | | | | | - | |
| 6 | | | | | | - | |
| 7 | | | | | | - | |
| 8 | | | | | | - | |
| 9 | | | | | | - | |
| 10 | **Total Book/Tax Adjustments Includable in Rate Base** | | **-** | | | **-** | |

| | Provision for Deferred Income Tax Adjustments | Reference | Funded End of Year Balance - Tax Effected | Allocation Factor | Transmission Allocator | Transmission Balance | Notes |
|---|---|---|---|---|---|---|---|
| 11 | | | | | | - | |
| 12 | | | | | | - | |
| 13 | | | | | | - | |
| 14 | | | | | | - | |
| 15 | | | | | | - | |
| 16 | **Total Provision for Deferred Tax Adjustments** | | **-** | | | **-** | |

| | | | | |
|---|---|---|---|---|
| 17 | **Total Tax Adjustments** | Lines 10, 16 | **-** | **-** |

18 Notes:
A.) Source:
19 Company Records
B.) The addition of new lines and the removal of outdated lines necessary to populate or remove data in the work paper with the changes in future years does not require a Federal
20 Power Act section 205 or 206 filing. The addition or removal of columns and formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing.
C). The Allocation Factor and Transmission Allocator in Columns E and F are based on how the related items are recovered in the Formula Rate Template and, if recovered in the Formula Rate Template, the corresponding Allocation Factor listed on Worksheet E that is used for the related item in the Revenue Requirement will be applied in this worksheet. In
21 addition, consideration is made based on whether the tax balance is applicable to the total company or relates more specifically to a tariff transmission balance. The appropriate allocator is selected from Worksheet E, Allocation Factors. In the absence of an allocator for a corresponding expense in the OATT, and the item can reasonably assumed to have transmission-related costs, the default allocator is the T-Net allocator, which is the allocator that is applied to income tax expense for the company.

**Tri-State Generation and Transmission Association, Inc.**

Page 27

Worksheet Y

**Deferred Tax Rollforward**
**Year Ending December 31, 2019**

Fed Rate 21.00%

State Blended Rate 2.80%

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | (C+D+E) | | | (G+H) | | | (J+K) | (G+J) | (H+K) | (M+N) | See Note E | See Note D | | (M*R) | |

| Line | Description | Balance Beg. of Year | Return to Provision | Current Year Activity | Balance End of Year | Federal End of Year Balance | | | State End of Year Balance | | | Tot EOY Bal Funded | Tot EOY Bal Unfunded | Total EOY Bal. | Beg Funded Bal. Alloc. To Transmission | Transmission Allocator | Trans Alloc. Factor | Ending Funded Bal. Alloc. To Transmission | Notes |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Funded | Unfunded | Total | Funded | Unfunded | Beg Funded Bal. Alloc. To Transmission | | | | | | | | |
| | **Accumulated Deferred Income Taxes (Account 190)** | | | | | | | | | | | | | | | | | | |
| 1 | | | | | - | | | - | | | - | - | - | | | | | - | |
| 2 | | | | | - | | | - | | | - | - | - | | | | | - | |
| 3 | | | | | - | | | - | | | - | - | - | | | | | - | |

| | | |

| | | |

| | | |

| | |
|---|---|
| | formulas contained with those columns cannot be changed absent a Federal Power Act section 205 or 206 filing. |
| 51 | C.) The state rate is a blended rate. The effective state income tax rate (after deduction on the federal return) and the percent allocated to each state are used in calculating the state blended rate. |
| 52 | D.) The Transmission Allocator and Transmission Allocation Factor applied in Columns R and Q are based on how the related items are recovered in the Formula Rate Template and, if recovered in the Formula Rate Template, the corresponding Allocation Factor that is used for the related item in the Revenue Requirement will be applied in this worksheet. In addition, consideration is made based on whether the tax balance is applicable to the total company or relates more specifically to a tariff transmission balance. The appropriate allocator is selected from Worksheet E, Allocation Factors. In the absence of an allocator for a corresponding expense in the OATT, and the item can reasonably assumed to have transmission-related costs, the default allocator is the T-Net allocator, which is the allocator that is applied to income tax expense for the company. |
| 53 | E.) The beginning balance in Column P will be populated with the prior year ending funded balance allocated to transmission from Column S. For new items, the beginning balance will equal zero. |

# Tri-State Generation and Transmission Association, Inc.
# Transmission Formula Rate Implementation Protocols

## Section I Annual Update

1. The transmission formula rate template of Tri-State Generation and Transmission Association, Inc. (Tri-State) and these Transmission Formula Rate Implementation Protocols (Protocols) together comprise the filed rate (Formula Rate) of Tri-State for transmission service in Zone 17 of the Southwest Power Pool, Inc. (SPP) footprint. Tri-State must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements (ATRR) and the rates for Network Integration Transmission Service (NITS) and Point-to-Point (PTP) Transmission Service in Zone 17.

   Recovery of costs associated with existing facilities and new shall be consistent with the Formula Rate and Attachment AI and Attachment J, respectively, of the SPP Tariff. The ATRR shall be determined using the financial and usage data for January 1 to December 31 of a given calendar year. The Formula Rate shall become effective for recovery of Tri-State's ATRR upon the effective date authorized by the FERC under Section 205 of the FPA.

2. The Formula Rate shall be applicable to service on and after September 1 of each calendar year through August 31 of the following calendar year (Rate Year), subject to review, challenge and refunds or surcharges with interest including any modifications required to recognize any implementation due to a partial rate year, to the extent provided herein.

3. On or before June 15 of each calendar year, Tri-State shall:

   (a) Recalculate the ATRR and the rates for zonal NITS service for the new Rate Year in accordance with the Formula Rate (Annual Update); and

   (b) Provide its Annual Update to SPP and cause such information to be accessible on SPP's website; Post its Annual Update to the Tri-State website; and

   (c) If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's Initial Posting Date. Any delay in the Initial Posting Date shall result in an equivalent extension of time for the submission of Information Requests.

4. Concurrent with the Annual Update postings, Tri-State shall provide a notice of such posting via an email distribution list to all Interested Parties.

5. The Annual Update shall:

(a) Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

(b) Be based on the independently-audited books and records of Tri-State for the most recent fiscal year including its FERC Form 1 submitted to the Federal Energy Regulatory Commission ("Commission") or successor report(s);

(c) Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

(d) Identify any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate. Tri-State shall identify:

i. Any accounting changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR. Any items included in the Formula Rate at an amount other than a historic cost basis.

ii. Individual impact of any changes in i above on charges billed under the Formula Rate.

(e) Not seek to modify the Formula Rate.

## Section II Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

(a) "Accounting Change" means any change in Tri-State's accounting policies and practices from those in effect for the Calendar Year upon which the immediately preceding Annual Update was based and that could impact the ATRR calculations under the Formula. Accounting Changes include any changes resulting from:

(i) revisions to the USoA; (ii) revisions to FERC Form 1 data and the requirement to report certain values within it; (iii) correction of errors and prior period adjustments that impact the ATRR; (iv) the implementation of new estimation

methods or policies; (v) changes to income tax elections; (vi) changes in accounting practices or policies mandated by a state regulatory authority with jurisdiction over Tri-State that could impact the Formula Rate or calculations under the Formula; (vii) implementation of accounting practices for unusual or unconventional items where F E R C has not provided specific accounting direction; (viii) a change in Tri-State's accounting policies and practices (as such changes are defined by the Statement of Financial Accounting Board Standards No. 154 issued by the Financial Accounting Standards Board or its successor); (ix) Tri-State's own accounting changes (which constitute a change to the ATRR greater than or equal to $50,000) such as the addition or deletion of a subaccount not specified by the USoA; or (x) a change in Tri-State's inter-corporate cost allocation policies or practices from those policies and/or practices in effect in the Prior Rate Year, which change causes a result under the Formula Rate different than the result under the Formula Rate as calculated without such change.

(b) "Annual Transmission Revenue Requirement" (ATRR) means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by Tri-State for informational purposes with the Commission and posted on the SPP website on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

(c) "Annual Meeting" means the meeting hosted by Tri-State for the purpose of exchanging information with Interested Parties regarding the formula rate.

(d) "Annual Update" means Tri-State's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

(e) "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

(f) "Calendar Year" means January 1 through December 31 of a given year.

(g) "Current Calendar Year" means the Calendar Year in which the Annual Update is filed (*e.g.*, if the Annual Update is filed on September 1, 2021, the Current Calendar Year is 2021).

(h) "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP website and which Tri-State has filed with the Commission (*e.g.*, if the Annual Update is filed on September 1, 2021, the Current Rate Year is September 1, 2021 through August 31, 2022).

(i) "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS service, service under Grandfathered Agreements, or PTP service.

(j) "FERC" or "Commission" means the Federal Energy Regulatory Commission.

(k) "Final Posting" means the annual update information posted to the Tri-State web site and which Tri-State causes to be posted on the SPP web site with changes agreed to during the informal review process.

(l) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with the Commission, and served on Tri-State by electronic service on the date of such filing.

(m) "Formula Rate Template" means the Tri-State transmission formula rate template set forth herein.

(n) "Formula" means the Formula Rate Template set forth herein.

(o) "Formula Rate" means the Tri-State Implementation Protocols together with the Formula Rate Template.

(p) "FPA" means Federal Power Act.

(q) "Informal Challenge" means written notification by an Interested Party to Tri-State, during the Review Period, of any specific challenge to the Annual Update.

(r) "Information Request" means a written request submitted by an Interested Party to Tri-State.

(s) "Informational Filing" means Tri-State's annual filing at the Commission with the information stipulated in these Protocols.

(t) "Initial Posting" means the Annual Update data and information which Tri-State posts to the Tri-State website and which Tri-State causes to be posted to the SPP website. The Initial Posting date for each year beginning in 2021 shall be no later than June 15, provided, however, that if June 15 should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

(u) "Interest" means interest calculated pursuant to 18 C.F.R. § 35.19a (a) (2) (iii), or successor regulation.

(v) "Interested Party" includes but is not limited to, customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

(w) "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

(x) "OATT" or "SPP Tariff "means SPP's Open Access Transmission Tariff.

(y) "Preliminary Challenge" means written notification by an Interested Party to Tri-State, during the Review Period, of any specific challenge to the Annual Update.

(z) "Prior Calendar Year" means the year preceding the Current Calendar Year (*e.g.*, if the Annual Update is filed on September 1, 2021, the Prior Calendar Year is 2020).

(aa) "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is September 1, 2022 through August 31, 2023, then the Prior Rate Year is September 1, 2021 through August 31, 2022).

(bb) "PTP Rates" means the point-to-point rates derived from the Formula Rate.

(cc) "Rate Year" means September 1 of a given year through August 31 of the subsequent year.

(dd) "Review Period" means, unless otherwise extended in writing by Tri-State, 60 days after the Publication Date. During the Review Period Interested Parties may serve reasonable information requests on Tri-State.

(ee) "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity (ROE); (ii) Depreciation and amortization rates; and (iii) and other similar fixed values. Stated Values may be changed only pursuant to FPA Section 205 or 206.

(ff) "USoA" means Uniform System of Accounts.

(gg) "WAPA" means the Western Area Power Administration.

## Section III Review of Annual Update

Within twenty (20) days of the Initial Posting date of Tri-State' Annual Update, Tri-State will host a meeting for Interested Parties to discuss the Annual Update (Annual Meeting). Tri-State shall provide notice of this meeting concurrent with the posting of the Formula Rate Update accessible on SPP's website and Tri-State's website. The notice shall include the date, time and location of the Annual Meeting and also shall be provided via email distribution list of Interested Parties. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the web sites.

### A. Information Exchange

Interested Parties may begin submitting information requests immediately following the Initial Posting date of the Annual Rate Update and will have until sixty (60) days after the date of the Initial Posting to serve reasonable information requests on Tri-State for information and work papers supporting the Annual Rate Update. Such information

requests shall be limited to that what is necessary to determine:

(a) The extent or effect of an accounting change;

(b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

(c) The proper application of the Formula Rate and procedures in these Protocols;

(d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

(e) The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

(f) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable.

2. Tri-State shall make a good faith effort to respond to information requests pertaining to the Annual Update within seven (7) business days of receipt.

3. Tri-State shall post on its website and cause to be posted on a publicly accessible portion of the SPP website all information requests from Interested Parties and Tri-State' response(s) to such requests. If responses to information requests contain information deemed by Tri-State to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Tri-State.

B. Informal Challenge Procedures

1. Interested Parties shall have until August 14 (or the first Business Day after August 14 if August 14 falls on a weekend or holiday) to notify Tri-State in writing (which may be electronically) of any specific Informal Challenges. The Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. Tri-State will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. Tri-State, and if appropriate SPP, shall appoint representatives to work with the Interested Party to resolve the Informal Challenge.

2. Tri-State will post on its website and cause to be posted on a publicly accessible portion of the SPP website all Informal Challenges from Interested Parties and Tri-State' responses to the Informal Challenges. If responses to information requests contain information deemed by Tri-State to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Tri-State.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by Tri-State and resolved prior to the end of the review period shall be reported in the Final Posting on the Tri-State and SPP Web sites. Any changes or adjustments agreed to by Tri-State after this date will be reported in the Informational Filing made with FERC and will be reflected in the Annual Rate Update for the following Rate Year.

C. Formal Challenges.

1. A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the FPA, and shall be served upon Tri-State contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with § 385.2010(f) (3), by facsimile, express delivery or messenger to the individual listed as the contact person in Tri-State' Informational Filing.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of return on equity (ROE), depreciation and amortization rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA Sections 205 or 206.

3. If Tri-State makes a correction to a Mistake in its financial information during a

Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with interest computed in accordance with the SPP Tariff. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any interest on any refund shall be calculated in accordance with the SPP Tariff.

E. FERC Informational Filing.

1. By September 15th of each year, Tri-State shall submit to FERC an informational filing (Informational Filing) of its Annual Update.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   (a) That input data under the Formula Rate is properly recorded in any underlying work papers

   (b) That Tri-State has properly applied the Formula Rate and these procedures;

   (c) The accuracy of the data and the consistency with the Formula Rate of the ATRR and rates under review; and

   (d) The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Tri-State shall provide notice of the Informational Filing to Interested Parties via the email and by posting the docket number assigned to the Informational filing on Tri-State website and accessible on SPP's website.

## Section IV Joint SPP Transmission Owners' Meeting.

If the SPP Transmission Owners with transmission projects that utilize a regional cost-

sharing methodology implement a process to coordinate and hold joint meetings, Tri-State intends to participate in that process.

## Section V Tri-State Example Schedule (Nominal last dates):

| Action | Date |
|---|---|
| Data Available | April 15 |
| Initial Posting (Tri-State & SPP Websites) | June 15 |
| Annual Meeting, Interested Parties (20 days) | July 5 |
| Interested Parties Review Period (60 days) | August 14 |
| Informal Challenges Due Date Ending | August 14 |
| Final Posting (Tri-State & SPP Websites) | August 19 |
| Rate Year | September 1 – August 31 |
| Informational Filing | September 15 |

## Section VI Accounting Guidance

AFUDC will not be accrued on any construction work in progress included in the rates.

# ADDENDUM 37 TO ATTACHMENT H

## Central Power Electric Cooperative, Inc.

# INDEX


| Line No. | Item | Description |
|---|---|---|
| 1 | Rate Summary | Summary of Total ATRR Revenue Requirement |
| 2 | Worksheet A | Calculation of Rate Base |
| 3 | Worksheet B | O&M, Depreciation, and Return Expenses |
| 4 | Worksheet C | Return Based on Rate of Return Method |
| 5 | Worksheet D | Network Load |
| 6 | Worksheet E | Allocation Factors |
| 7 | Worksheet F | General Input Section |
| 8 | Worksheet G | O&M Input |
| 9 | Worksheet H | SPP Upgrades |
| 10 | Worksheet I | Depreciation Rates |
| 11 | Worksheet J | Reconciliation Items, Refunds and Surcharges |
| 12 | Worksheet K | Wages & 565 Transmission by Others |
| 13 | Worksheet L | Depreciation Expenses |
| 14 | Worksheet M | Other Revenue Input |
| 15 | Worksheet N | Construction Work in Progress |
| 16 | Worksheet O | Plant Held for Future Use |
| 17 | Worksheet P | Construction Completed Not Classified |
| 18 | Worksheet Q | Regulatory and Commission Expenses |
| 19 | Worksheet R | Accounts 575 and 576 Expense |
| 20 | Worksheet S | Customer Accounting |
| 21 | | |
| 22 | Key | Shaded cell, denoting manual input |

**Central Power Electric Cooperative, Inc.**
**Summary of Total ATRR Revenue Requirement**
**0**

| A<br>Line No. | B<br>FERC Account Number | C<br>Description | D<br>Reference | E<br>Total Company | F<br>Adjustments (1) | G<br>Adjusted Company | H<br>Allocation Factor | I<br>Allocation % | J<br>Transmission |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | **A. Gross Revenue Requirement for Network Service** | | | | | | | |
| 2 | | Transmission Costs | Worksheet B, Line 47 Col I | | | | Direct 100 | 100.000% | |
| 3 | | Revenue Credits- Operating Income from Leased | | | | | | | |
| 4 | 454 | Property | Worksheet M, Line 16, Col E | $ - | $ - | $ - | Direct 100 | 100.000% | $ - |
| 5 | 456 | Revenue Credits- Operating | | | | | | | |
| 6 | | Wheeling Existing | Worksheet M, Line 16, Col F | $ - | | $ - | T-Tran Lines | | |
| 7 | | Wheeling Schedule 7 & 8 Point to Point | Worksheet M, Line 16, Col G | $ - | | $ - | Direct 100 | 100.000% | $ - |
| 8 | | Transmission Rents | Worksheet M, Line 16, Col H | $ - | | $ - | Direct 100 | 100.000% | $ - |
| 9 | | Other Rents | Worksheet M, Line 16, Col I | $ - | | $ - | T-Net Allocation | | |
| 10 | | Production | Worksheet M, Line 16, Col J | $ - | | $ - | Direct 0 | 0.000% | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 454-456 | Revenue Credits-Operating | Sum Line 4 and Lines 6 thru 10 | $ - | $ - | $ - | | | | |
| 1 2 | | Revenue Requirement | Line 2 - Line 11 | | | | | | | |
| 1 3 | | SPP Upgrades | Worksheet H, Line 2, Col O | | | | Direct 0 | 100.000% | | |
| 1 4 | | Adjustments to SPP Regional Projects | Worksheet J, Line 12, Col J | | | $ - | Direct 100 | 100.000% | $ - | |
| 1 5 | | Reconciliation - Adjustment for Prior Year Corrections | Worksheet J, Line 6, Col J | | | $ - | Direct 100 | 100.000% | $ - | |
| 1 6 | | Sum | Line 12 - Line 13 + Line 14 + Line 15 | | | | | | | |
| 1 7 | | **B. Point-To-Point Service (Divisor):** | | | | | | | | |
| 1 8 | | Network Transmission Load (kW) | Worksheet D, Line 14, Col D * 1000 | | | | | | - | |
| 1 9 | | **C. Rates** | | | | | | | | |
| 2 0 | | Annual Point-to-Point Cost ($/kW-Yr) | Line 16 / Line 18 | | | | | | | |
| 2 1 | | Monthly Point-to-Point ($/kW-Mo) | Line 20 / 12 months | | | | | | | |
| 2 2 | | Weekly Point-to-Point ($/kW-Week) | Line 20 / 52 weeks | | | | | | | |
| 2 3 | | Daily On-Peak Point-to-Point ($/kW-Day) | Line 22 / 5 days | | | | | | | |
| 2 4 | | Daily Off-Peak Point-to-Point ($/kW-Day) | Line 22 / 7 days | | | | | | | |
| 2 5 | | Hourly On-Peak Point-to-Point ($/MWh) | Line 23 / 16 hours * 1,000 | | | | | | | |
| | | Hourly Off- | Line 24 / 24 | | | | | | | |

| | | |
|---|---|---|
| 2 6 | Peak Point-to-Point ($/MWh) | hours * 1,000 |

Notes:

1.) Adjustments to revenue credits permitted as agreed to in Docket No. ER16-209-000. Following the 2016 rate year (populated with 2014 Central Power data) and the 2017 rate year (populated with 2015 Central Power data) this adjustment column will no longer be necessary. For rate year 2018 and all rate years thereafter, all values in this column will be zero (0).

**Central Power Electric Cooperative, Inc.**
**Calculation of Rate Base**
**0**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Beginning of Year | E<br>End of Year | F<br>Total Company | G<br>Allocation Factor | H<br>Allocation % | I<br>Transmission |
|---|---|---|---|---|---|---|---|---|
| 1 | **Plant in Service** | | | | | | | |
| 2 | 301-303 Total Intangible Plant | RUS12.H.A.1 a & e | $ - | $ - | $ - | T-Wages | | |
| 3 | 310-317 Steam Production Plant | RUS12.H.A.2 a & e | $ - | $ - | $ - | Direct0 | 0.000 % | $ - |
| 4 | 320-326 Nuclear Production Plant | RUS12.H.A.3 a & e | $ - | $ - | $ - | Direct0 | 0.000 % | $ - |
| 5 | 330-337 Hydro Production Plant | RUS12.H.A.4 a & e | $ - | $ - | $ - | Direct0 | 0.000 % | $ - |
| 6 | 340-347 Other Production Plant | RUS12.H.A.5 a & e | $ - | $ - | $ - | Direct0 | 0.000 % | $ - |
| 7 | Total Production Plant | Sum Lines 3 - 6 | $ - | $ - | $ - | | | $ - |
| 8 | 350 Land and Land Rights | RUS12.H.A.7 a & e | $ - | $ - | $ - | T-Transtations | | |
| 9 | 352 Structures and Improvements | RUS12.H.A.8 a & e | $ - | $ - | $ - | T-Transtations | | |
| 10 | 353 Station Equipment | RUS12.H.A.9 a & e | $ - | $ - | $ - | T-Transtations | | |
| 11 | 354 thru 359.1 Other Transmission Plant | RUS12.H.A.10 a & e | $ - | $ - | $ - | T-TranLines | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | $ | $ | $ | | | |
| 1 | Transmission | | - | - | - | | | |
| 2 | Plant | Sum Lines 8 - 11 | | | | | | |
| | | | $ | $ | | | 0.0 | |
| 1 | 360 Land & | RUS12.H.A.12 a | - | - | $ | | 00 | $ |
| 3 | Land Rights | & e | | | - | Direct0 | % | - |
| | 361 Structures | | $ | $ | | | 0.0 | |
| 1 | and | RUS12.H.A.13 a | - | - | $ | | 00 | $ |
| 4 | Improvements | & e | | | - | Direct0 | % | - |
| | | | $ | $ | | | 0.0 | |
| 1 | 362 Station | RUS12.H.A.14 a | - | - | $ | | 00 | $ |
| 5 | Equipment | & e | | | - | Direct0 | % | - |
| | | | $ | $ | | | 0.0 | |
| 1 | 363-374 Other | RUS12.H.A.15 a | - | - | $ | | 00 | $ |
| 6 | Distribution Plant | & e | | | - | Direct0 | % | - |
| | | | $ | $ | $ | | | |
| 1 | Total Distribution | | - | - | - | | | $ |
| 7 | Plant | Sum Lines 13 - 16 | | | | | | - |
| | | | $ | $ | $ | | 100 | |
| 1 | 380-386 | RUS12.H.A.17 a | - | - | - | Direct1 | .00 | $ |
| 8 | RTO/ISO Plant | & e | | | | 00 | 0% | - |
| | 389 thru 399.1 | | $ | $ | $ | T- | | |
| 1 | Total General | RUS12.H.A.18 a | - | - | - | Wages | | |
| 9 | Plant | & e | | | | | | |
| | | Line 2+Line | $ | $ | $ | | | |
| | | 7+Line 12+Line | - | - | - | | | |
| 2 | Gross Electric | 17+Line 18+Line | | | | | | |
| 0 | Plant in Service | 19 | | | | | | |
| 2 | **Accumulated** | | | | | | | |
| 1 | **Depreciation** | | | | | | | |
| | | | $ | $ | $ | | 0.0 | |
| 2 | 108.1 Depr of | RUS12.H.B.1 a & | - | - | - | | 00 | $ |
| 2 | Steam Plant | e | | | | Direct0 | % | - |
| | | | $ | $ | $ | | 0.0 | |
| 2 | 108.2 Depr of | RUS12.H.B.2 a & | - | - | - | | 00 | $ |
| 3 | Nuclear Plant | e | | | | Direct0 | % | - |
| | | | $ | $ | $ | | 0.0 | |
| 2 | 108.1 Depr of | RUS12.H.B.3 a & | - | - | - | | 00 | $ |
| 4 | Hydro Plant | e | | | | Direct0 | % | - |
| | 108.4 | | $ | $ | $ | | | |
| | Depreciation of | | - | - | - | | 0.0 | |
| 2 | Other Production | RUS12.H.B.4 a & | | | | | 00 | $ |
| 5 | Plant | e | | | | Direct0 | % | - |
| | 108.5 | RUS12.H.B.5 a & | | | | Direct | | |
| 2 | Depreciation of | e and Worksheet | $ | $ | $ | Assign | | |
| 6 | Transmission | F Line 6 plus 9 | - | - | - | WS-F | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Plant | | | | | | | |
| 27 | 108.6 Depreciation of Distribution Plant | RUS12.H.B.6 a & e | $ - | $ - | $ - | Direct0 | 0.000 % | $ - |
| 28 | 108.7 Depreciation of General Plant | RUS12.H.B.7 a & e | $ - | $ - | $ - | T-Wages | | |
| 29 | 111 Amort of Electric Plant in Service | RUS12.H.B.12 a & e | $ - | $ - | $ - | T-Wages | | |
| 30 | Total Accumulated Depreciation | Sum Lines 22 - 29 | $ - | $ - | $ - | | | |
| 31 | **Total Net Plant in Service** | | | | | | | |
| 32 | 301-303 Net Total Intangible Plant | Line 2 | $ - | $ - | $ - | | | |
| 33 | Net Production Plant | Line 7 - Lines 22 thru 25 | $ - | $ - | $ - | | | $ - |
| 34 | Net Transmission Plant | Line 12 + Line 18 - Line 26 | $ - | $ - | $ - | | | |
| 35 | Net Distribution Plant | Line 17 - Line 27 | $ - | $ - | $ - | | | $ - |
| 36 | Net General Plant | Line 19 - Line 28 | $ - | $ - | $ - | | | |
| 37 | Total Net Plant in Service | Sum Lines 32 - 36 | $ - | $ - | $ - | | | |
| 38 | **Adjustments to Rate Base** | | | | | | | |
| 39 | 105 Electric Plant Held For Future Use | RUS12.H.A.22 a & e and Worksheet O, Line 16, Col G | $ - | $ - | $ - | Direct Assign from WS-O | | $ - |
| 40 | 106 Completed Construction Not Classified | RUS12.H.A.23 a & e and Worksheet P, Line 12, Col | $ - | $ - | $ - | Direct Assign from WS-P | | $ - |
| 41 | 107 Construction Work in | RUS12.H.A.28 a & e and | $ - | $ - | $ - | Direct Assign from WS-N | | $ - |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Progress | Worksheet N, Line 38, Col L | | | | | | | | |
| | 108.8 | | $ | $ | $ | | | | | |
| 4 | Retirement Work | -(RUS12.H.B.8 A | - | - | - | | | | | |
| 2 | in Progress | & e) | | | | | T-Plant | | | |
| | Total | | $ | $ | $ | | | | | |
| 4 | Adjustments to | | - | - | - | | | | | |
| 3 | Rate Base | Sum Lines 39 - 42 | | | | | | | | |
| 4 | | | | | | | | | | |
| 4 | Working Capital | | | | | | | | | |
| | Total | | | | | | | | | |
| 4 | Transmission | Worksheet B, Line | | | $ | | | | | |
| 5 | O&M Costs | 36 Col F and I | | | - | | | | | |
| 4 | Billing Lag in | Worksheet F Line | | | | | | | | |
| 6 | Days | 1 Col F | | | | 0 | | | | 0 |
| 4 | Working | Line 45 * Line 46 / | | | $ | | | | | |
| 7 | Capital | 365 | | | - | | | | | |
| 4 | | RUS12.A.B.25 (Current & Prior | $ | $ | $ | | T-Plant Allocati | | | |
| 8 | Prepayments | Year Form-12) | - | - | - | | on | | | |
| 4 | | RUS12.H.G.1 a & | $ | $ | $ | | | 0.000 | $ | |
| 9 | M&S Coal | d | - | - | - | | Direct0 | % | - | |
| 5 | M&S Other | RUS12.H.G.2 a & | $ | $ | $ | | | 0.000 | $ | |
| 0 | Fuel | d | - | - | - | | Direct0 | % | - | |
| 5 | M&S Production Plant | RUS12.H.G.3 a & | $ | $ | $ | | | 0.000 | $ | |
| 1 | Parts | d | - | - | - | | Direct0 | % | - | |
| | M&S Station | | | | | | T-Tran | | | |
| 5 | Transformers & | RUS12.H.G.4 a & | $ | $ | $ | | Station | | | |
| 2 | Equipment | d | - | - | - | | s | | | |
| | M&S Line | | | | | | | | | |
| 5 | Materials & | RUS12.H.G.5 a & | $ | $ | $ | | T-Tran | | | |
| 3 | Supplies | d | - | - | - | | Lines | | | |
| 5 | | RUS12.H.G.6 a & | $ | $ | $ | | T-Plant Allocati | | | |
| 4 | M&S Other | d | - | - | - | | on | | | |
| 5 | Materials and | | $ | $ | $ | | | | | |
| 5 | Supplies | Sum Lines 49 - 54 | - | - | - | | | | | |
| 5 | Rate Base | Line 37+Line 43+Line 47+Line | $ - | $ - | $ - | | | | | |

| | | |
|---|---|---|
| 6 | 48+Line 55 | |

**Central Power Electric Cooperative, Inc.**
**O&M, Depreciation, and Return Expenses**

**0**

| A<br>Line<br>No. | B<br>Description | C<br>Reference | D<br>Total Company | E<br>Total Company | F<br>Total Company | G<br>Allocation Factor | H<br>Allocation % | I<br>Network Transmission |
|---|---|---|---|---|---|---|---|---|
| 1 | Transmission Operation & Maintenance Expenses | | Lines | Stations | | | | |
| 2 | 560 Supervision and Engineering | Worksheet G, Line 1 Col D and E | $ - | $ - | $ - | T-Tran Plant | | |
| 3 | 561 Load Dispatching | Worksheet G, Line 2 Col D | $ - | $ - | $ - | T-Tran Plant | | |
| 4 | 562 Station Expenses | Worksheet G, Line 3 Col E | $ - | $ - | $ - | T-Tran Stations | | |
| 5 | 563 Overhead Line Expenses | Worksheet G, Line 4 Col D | $ - | $ - | $ - | T-Tran Lines | | |
| 6 | 564 Underground Line Expenses | Worksheet G, Line 5 Col D | $ - | $ - | $ - | T-Tran Lines | | |
| 7 | 565 Transmission of Electricity by Others | Worksheet G, Line 8 Col D | $ - | $ - | $ - | Direct 0 | 0.000 % | $ - |
| 8 | 566 Miscellaneous Expenses | Worksheet G, Line 6 Col D and E | $ - | $ - | $ - | T-Tran Plant | | |
| 9 | 567.01 Rents - Transmission Rents | Central Power Summary Trial Balance | $ - | $ - | $ - | Direct 0 | 0.000 % | $ - |
| 10 | 567.11 Rents - Transmission Railroads | Central Power Summary | $ - | $ - | $ - | Direct 100 | 100.000% | $ - |

| | | Trial Balance | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 1 | 568 Supervision and | Worksheet G, Line 11 Col D | $ | $ | $ | | | |
| 1 | Engineering | and E | - | - | - | T-Tran Plant | | |
| 1 | | Worksheet G, | $ | $ | $ | T-Tran Station | | |
| 2 | 569 Structures | Line 12 Col E | - | - | - | s | | |
| 1 | | Worksheet G, | $ | $ | $ | T-Tran Station | | |
| 3 | 570 Station Equipment | Line 13 Col E | - | - | - | s | | |
| 1 | | Worksheet G, | $ | $ | $ | T-Tran | | |
| 4 | 571 Overhead Lines | Line 14 Col D | - | - | - | Lines | | |
| 1 | | Worksheet G, | $ | $ | $ | T-Tran | | |
| 5 | 572 Underground Lines | Line 15 Col D | - | - | - | Lines | | |
| 1 | 573 Miscellaneous | Worksheet G, Line 16 Col D | $ | $ | $ | T-Tran | | |
| 6 | Transmission Plant | and E | - | - | - | Plant | | |
| 1 | 575.1-575.8 RTO/ISO | Worksheet R, | | $ | $ | Direct | 100.00 | $ |
| 7 | Expense - Operation | Line 2, Col F | | - | - | 100 | 0% | - |
| 1 | 576.1-576.5 RTO/ISO | Worksheet R, | | $ | $ | Direct | 100.00 | $ |
| 8 | Expense - Maintenance | Line 4, Col F | | - | - | 100 | 0% | - |
| 1 | | Sum Lines 2 - | $ | $ | $ | | | |
| 9 | Transmission O&M | 18 | - | - | - | | | |
| 2 | | | | | | | | |
| 0 | Distribution Expenses | | | | | | | |
| 2 | Distribution Operation | Worksheet G, Line 22 Col D | $ | $ | $ | Direct | 0.000 | $ |
| 1 | Expenses | and E | - | - | - | 0 | % | - |
| 2 | Distribution Maintenance | Worksheet G, Line 23 Col D | $ | $ | $ | Direct | 0.000 | $ |
| 2 | Expenses | and E | - | - | - | 0 | % | - |
| 2 | | Line 21 + | $ | $ | $ | | | $ |
| 3 | Distribution O&M | Line 22 | - | - | - | | | - |
| 2 | Customer Accounting, Sales | | | | | | | |
| 4 | & Service | | | | | | | |
| 2 | Op Exp-Consumer Accounts | Worksheet S, | | | $ | Direct Assign | 100.00 | $ |
| 5 | Payroll and OH | Line 10, Col F | | | - | WS-S | 0% | - |
| 2 | Op Exp-Consumer Accounts Other | Worksheet S, Line 15, Col F | | | $ - | Direct Assign | 100.00 | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 6 | | | | WS-S | 0% | |
| 27 | Op Exp-Customer Service | RUS12.A.A.12b | $ - | Direct 0 | 0.000 % | $ - |
| 28 | Op Exp-Sales | RUS12.A.A.13b | $ - | Direct 0 | 0.000 % | $ - |
| 29 | Subtotal Customer Accounting, Sales & Service | Sum Lines 25 - 28 | $ - | | | $ - |
| 30 | Administrative & General Expense | | | | | |
| 31 | Admin and General Operations Expense less Account 928 | RUS12.A.A.14b less Worksheet Q, Line 10, Col D | $ - | T-Wage Allocation | | |
| 32 | Account 928 Non-SPP Expenses | Worksheet Q, Line 10, Col E | $ - | Direct 0 | 0.000 % | $ - |
| 33 | Account 928 SPP Expenses | Worksheet Q, Line 10, Col F | $ - | Direct 100 | 100.000% | $ - |
| 34 | Maintenance Expense General Plant | RUS12.A.A.20b | $ - | T-Wage Allocation | | |
| 35 | Total A&G Expenses | Sum Lines 31 - 34 | $ - | | | |
| 36 | Subtotal O&M | Line 19 + Line 23 + Line 29 + Line 35 | $ - | | | |
| 37 | Depreciation Expense | | | | | |
| 38 | Depreciation Expense-Production | RUS12.H.B lines 1-4 Col C | $ - | $ - | Direct 0 | 0.000 % | $ - |
| 39 | Depreciation Expense-Transmission | RUS12.H.B.5c | $ - | $ - | Direct Assign WS-F | | |
| 40 | Depreciation Expense-Distribution | RUS12.H.B.6c | $ - | $ - | Direct 0 | 0.000 % | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 41 | Depreciation Expense-General | RUS12.H.B.7c | $ - | $ - | T-Wage Allocation |
| 42 | Less General Depreciation Recovered in O&M/A&G | (Enter Negative, Note 1) | $ - | $ - | T-Wage Allocation |
| 43 | Amortization of Other Electric Plant | RUS12.H.B.12c | $ - | $ - | T-Wage Allocation |
| 44 | Total Depreciation & Amortization | Sum Lines 38 - 43 | $ - | $ - | |
| 45 | Tax - Gross Reciepts and Property Tax | RUS12.A.A.23b | | $ - | T-Net Allocation |
| 46 | Return | Worksheet C, Line 7, Col J | | | |
| 47 | Revenue Requirement before credits | Line 36 + Line 44 + Line 45 + Line 46 | | | |

48 Notes:

1.) General plant depreciation expense recovered in O&M and A&G
49 expenses. These amounts are charged to 184.1 (Clearing Account) and 163 (Stores Expense Undistributed).

The amount listed must equal -1 * (the sum of RUS12.H.B.18.c 38 thru 41 less RUS12.A.22.b).

**Central Power Electric Cooperative, Inc.**
**Return Based on Rate of Return Method**
**0**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| **Line No** | **Description** | **Reference** | **Year End** | **Cap Str Weight** | **Cap Str Hypothetical** | **Higher Equity Cap Structure** | **Annual Interest Expense (3)** | **Cost of Capital (4)** | **Weighted Rate of Return** |
| 1 | Return Based on Defined ROE | | | | | | | | |
| 2 | Total Long Term Debt | RUS12.A.B 46+52+53 | $ - | | 64.76 0% | | $ - | | |
| 3 | Notes Payable | RUS12.A.B. 50 | $ - | | 0.000 % | | $ - | | |
| 4 | Total Margins and Equities (1, 2) | Worksheet F, Line 2, Line 3, Line 42, Col F | $ - | | 35.24 0% | | | 10.000 % | |
| 5 | Total Capitalization | Sum Lines 2 - 4 | $ - | | 100.000% | | $ - | | |
| 6 | Rate Base | Worksheet A, Line 56, Col I | | | | | | | |
| 7 | Return | Line 5 * Line 6 | | | | | | | |

8 Notes:
1. In accordance with the settlement agreement in Docket No. ER16-209, the "Total Margins and Equities" percentage under Hypothetical Capital Structure
9 may only be
change pursuant to an order issued
1 under section 205 or 206 of the Federal
0 Power Act.
2. In accordance with the settlement agreement in Docket No. ER16-209, line
1 4, column G shall reflect the higher of the amounts in line 4 of column E or F.

1

3. Annual Interest on Long-Term Debt taken from RUS Form 12, Part A, Section 1 A, Line 24b. Annual Other Interest Expense taken from RUS Form 12, Part A, 2 Section A,

1 Line 26b.
3

4. In accordance with the settlement agreement in Docket No. ER16-209, Cost 1 of Capital for Total Margins and Equities ("ROE") (Column I, line 4) may only be 4 changed
pursuant to an order issued under section 205 or 206 of the Federal Power 1 Act. Cost of capital for Notes Payable and Total Long Term Debt are calculated 5 by dividing
the annual interest expense in Column H by the total amount shown in Column D. The ROE shown includes any Commission-approved incentive points.

**Central Power Electric Cooperative, Inc.**
**Network Load**
**0**

| A | B | C | D |
|---|---|---|---|
| Line No | Description | Total Class A (MW) | Network Demand (MW) |
| 1 | January | | - |
| 2 | February | | - |
| 3 | March | | - |
| 4 | April | | - |
| 5 | May | | - |
| 6 | June | | - |
| 7 | July | | - |
| 8 | August | | - |
| 9 | September | | - |
| 10 | October | | - |
| 11 | November | | - |
| 12 | December | | - |
| 13 | Total (MW-Yr) | 0 | - |
| 14 | Average (MW-Mo) | - | - |

**Central Power Electric Cooperative, Inc.**

**Allocation Factors**

**0**

| A<br>Line No. | B<br>Description | C<br>Reference | D<br>Total | E<br>Allocation Factor | F<br>Allocation | G<br>Allocated |
|---|---|---|---|---|---|---|
| 1 | Production Operations | Worksheet K, Line 144, Col X | - | Direct0 | 0.000 % | $ - |
| 2 | Production Maintenance | Worksheet K, Line 144, Col Y | - | Direct0 | 0.000 % | $ - |
| 3 | Transmission Supervision Operations & Misc | Worksheet K, Line 144, Col K | - | T-Tran Plant | | |
| 4 | Transmission Load Management | Worksheet K, Line 144, Col L | - | T-Tran Plant | | |
| 5 | Transmission Station Operations | Worksheet K, Line 144, Col M | - | T-Tran Stations | | |
| 6 | Transmission Line Operations | Worksheet K, Line 144, Col N | - | T-Tran Lines | | |
| 7 | Transmission Supervision Maintenance | Worksheet K, Line 144, Col O | - | T-Tran Plant | | |
| 8 | Transmission Station Maintenance | Worksheet K, Line 144, Col P | - | T-Tran Stations | | |
| 9 | Transmission Line Maintenance | Worksheet K, Line 144, Col Q | - | T-Tran Lines | | |
| 10 | Distribution - Operations | Worksheet K, Line 144, Col R | - | Direct0 | 0.000 % | $ - |
| 11 | Distribution - Maintenance | Worksheet K, Line 144, Col S | - | Direct0 | 0.000 % | $ - |
| 12 | 901-905 Cust Acct-Wages | Worksheet S, Line 10, Col D AND F | - | Direct Assign WS-S | | $ - |
| 13 | 907-910 Cust Service-Wages | Worksheet K, Line 144, Col U | - | Direct0 | 0.000 % | $ - |
| 14 | 911-916 Cust Sales-Wages | Worksheet K, Line 144, Col V | - | Direct0 | 0.000 % | $ - |
| 15 | Total Wages, excluding A&G | Sum Lines 1 - 14 | $ - | | | |
| 16 | **T-Wage Allocation** | | | **T-Wages** | | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | 350-353 Transmission Stations | Worksheet F, Line 54 thru 56 Col F and Worksheet F, Line 5 Col F | $ - | | |
| 18 | **T-Tran Stations** | | | | |
| 19 | 354-359 Transmission Lines | Worksheet F, Line 57 Col F and Worksheet F, Line 8 Col F | - | | |
| 20 | **T-Tran Lines** | | | | |
| 21 | Transmission Qualifying Gross Plant | Worksheet A, Line 12 Col F and I | $ - | | |
| 22 | **T-Tran Plant** | | | | |
| 23 | Gross Electric Plant in Service | Worksheet A, Line 20 Col F and I | $ - | | |
| 24 | **T-Plant Allocation** | | | | |
| 25 | Net Plant in Service | Worksheet A, Line 37 Col F and I | $ - | | |
| 26 | **T-Net Allocation** | | | | |
| 27 | Average System Load (MW) | Worksheet D, Line 14, Col D | - | - | |
| 28 | **T-Load** | | | | |
| 29 | **Direct100** | | | | **100.000 %** |
| 30 | **Direct0** | | | | **0.000%** |

Workshe
et F

**Central Power Electric Cooperative, Inc.**

**General Input Section**

**0**

| A<br>Line<br>No. | B<br>Description | C<br>Reference | D<br>BoY | E<br>EoY | F<br>Total/Average |
|---|---|---|---|---|---|
| 1 | Billing Lag in days | Industry Standard | | | |
| 2 | Return on Equity per terms of Settlement Agreement 9.5% plus 50 basis point adder for RTO participation | | | | 10.00% |
| 3 | Hypothetical Equity Level per terms of the Settlement Agreement | | | | 35.24% |
| 4 | Information from Supporting Worksheets | | | | |
| 5 | Qualified Substations Gross Cost | SPP Facitilities Listing RevXX.xlsx; Tab: Summary | | | |
| 6 | Qualified Substations Depr Reserve | SPP Facitilities Listing RevXX.xlsx; Tab: Summary | | | |
| 7 | Qualified Substations Depr Expense | SPP Facitilities Listing RevXX.xlsx; Tab: Summary | | | |
| 8 | Qualified Lines Gross Cost | SPP Facitilities Listing RevXX.xlsx; Tab: Summary | | | |
| 9 | Qualified Lines Depr Reserve | SPP Facitilities Listing RevXX.xlsx; Tab: Summary | | | |
| 10 | Qualified Lines Depr Expense | SPP Facitilities Listing RevXX.xlsx; Tab: Summary | | | |
| 11 | 567.01 Rents - Transmission Rents | Central Power Summary Trial Balance | | | |
| 12 | 567.11 Rents - Transmission - Railroads | Central Power Summary Trial Balance | | | |
| 1 | Information From RUS Form | | | | |

| | | | |
|---|---|---|---|
| 3 | 12 | | |
| 1 | | RUS Form 12, Part A, Sect | |
| 4 | Electric Energy Revenues | A, L01b | |
| 1 | Income from Leased | RUS Form 12, Part A, Sect | |
| 5 | Property | A, L02b | |
| 1 | Other Operating Revenue & | RUS Form 12, Part A, Sect | |
| 6 | Income | A, L03b | |
| 1 | Op Exp-Production | RUS Form 12, Part A, Sect | |
| 7 | excluding fuel | A, L05b | |
| 1 | | RUS Form 12, Part A, Sect | |
| 8 | Op Exp-Production fuel | A, L06b | |
| 1 | | RUS Form 12, Part A, Sect | |
| 9 | Op Exp-Other Power Supply | A, L07b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 0 | Op Exp-Transmission | A, L08b | |
| 2 | | RUS Form 12, Part A, Sect | $ |
| 1 | Op Exp-RTO/ISO | A, L09b | - |
| 2 | | RUS Form 12, Part A, Sect | |
| 2 | Op Exp-Distribution | A, L10b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 3 | Op Exp-Consumer Accounts | A, L11b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 4 | Op Exp-Customer Service | A, L12b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 5 | Op Exp-Sales | A, L13b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 6 | Op Exp-Admin and General | A, L14b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 7 | Maint Exp-Production | A, L16b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 8 | Maint Exp-Transmission | A, L17b | |
| 2 | | RUS Form 12, Part A, Sect | |
| 9 | Maint Exp-RTO/ISO | A, L18b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 0 | Maint Exp-Distribution | A, L19b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 1 | Maint Exp-General Plant | A, L20b | |
| 3 | Tax - Gross Reciepts and | RUS Form 12, Part A, Sect | |
| 2 | Property Tax | A, L23b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 3 | Interest on Long Term Debt | A, L24b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 4 | Other Interest Expense | A, L26b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 5 | Other Deductions | A, L28b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 6 | Operating Margin | A, L30b | |
| 3 | | RUS Form 12, Part A, Sect | |
| 7 | Interest Income | A, L31b | |
| 3 | Other Non-Operating | RUS Form 12, Part A, Sect | |
| 8 | Income (Net) | A, L34b | |

| | | | |
|---|---|---|---|
| 3 9 | G&T Capital Credits | RUS Form 12, Part A, Sect A, L35b | |
| 4 0 | Other Capital Credits and Patronage Dividends | RUS Form 12, Part A, Sect A, L36b | |

| | | | BoY | EoY | Average |
|---|---|---|---|---|---|
| 4 1 | Prepayment | RUS Form 12, Part A, Section B, Line 25 (Current & Prior Year Form-7) | | | $ - |

| | | | |
|---|---|---|---|
| 4 2 | Total Margins and Equities | RUS Form 12, Part A, Sect B, Line 39 | |
| 4 3 | Total Long Term Debt | RUS Form 12, Part A, Sect B, Line 46 | |
| 4 4 | Current Maturities Long Term Debt | RUS Form 12, Part A, Sect B, Line 52 | |
| 4 5 | Current Maturities Long Term Debt - Rural Development | RUS Form 12, Part A, Sect B, Line 53 | |
| 4 6 | Notes Payable | RUS Form 12, Part A, Sect B, Line 50 | |

| | | | BoY | EoY | Average |
|---|---|---|---|---|---|
| 4 7 | Plant in Service | | | | |
| 4 8 | 301-303 Total Intangible Plant | RUS Form 12, Suppl, Part H, Section A, Line 1 | | | $ - |
| 4 9 | 310-317 Steam Production Plant | RUS Form 12, Suppl, Part H, Section A, Line 2 | | | $ - |
| 5 0 | 320-326 Nuclear Production Plant | RUS Form 12, Suppl, Part H, Section A, Line 3 | | | $ - |
| 5 1 | 330-337 Hydro Production Plant | RUS Form 12, Suppl, Part H, Section A, Line 4 | | | $ - |
| 5 2 | 340-347 Other Production Plant | RUS Form 12, Suppl, Part H, Section A, Line 5 | | | $ - |
| 5 3 | Total Production Plant | Sum Lines 49 - 52 | $ - | $ - | $ - |
| 5 4 | 350 Land and Land Rights | RUS Form 12, Suppl, Part H, Section A, Line 7 | | | $ - |
| 5 5 | 352 Structures and Improvements | RUS Form 12, Suppl, Part H, Section A, Line 8 | | | $ - |
| 5 6 | 353 Station Equipment | RUS Form 12, Suppl, Part H, Section A, Line 9 | | | $ - |
| 5 7 | 354 thru 359.1 Other Transmission Plant (1.) | RUS Form 12, Suppl, Part H, Section A, Line 10 | | | $ - |
| 5 8 | Total Transmission Plant | Sum Lines 54 - 57 | $ - | $ - | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5 | | RUS Form 12, Suppl, Part | | | | $ |
| 9 | 360 Land & Land Rights | H, Section A, Line 12 | | | | - |
| 6 | 361 Structures and | RUS Form 12, Suppl, Part | | | | $ |
| 0 | Improvements | H, Section A, Line 13 | | | | - |
| 6 | | RUS Form 12, Suppl, Part | | | | $ |
| 1 | 362 Station Equipment | H, Section A, Line 14 | | | | - |
| 6 | 363-374 Other Distribution | RUS Form 12, Suppl, Part | | | | $ |
| 2 | Plant | H, Section A, Line 15 | | | | - |
| 6 | | | $ | $ | $ | |
| 3 | Total Distribution Plant | Sum Lines 59 - 62 | - | - | - | |
| | | | | | | |
| 6 | | RUS Form 12, Suppl, Part | | | | $ |
| 4 | 380-386 RTO/ISO Plant | H, Section A, Line 17 | | | | - |
| 6 | 389 thru 399.1 Total | RUS Form 12, Suppl, Part | | | | $ |
| 5 | General Plant | H, Section A, Line 18 | | | | - |
| 6 | 105 Electric Plant Held For | RUS Form 12, Suppl, Part | | | | $ |
| 6 | Future Use | H, Section A, Line 22 | | | | - |
| 6 | 106 Completed Construction | RUS Form 12, Suppl, Part | | | | $ |
| 7 | Not Classified | H, Section A, Line 23 | | | | - |
| 6 | 107 Construction Work in | RUS Form 12, Suppl, Part | | | | $ |
| 8 | Progress | H, Section A, Line 28 | | | | - |
| 6 | | Line 48+Line 53+Line 58+Line 63+ Sum Lines 64 | $ | $ | $ | |
| 9 | Total Utility Plant | - 68 | - | - | - | |
| | | | | | | |
| 7 | Depreciation and | | | | | |
| 0 | Amortization Reserves | | BoY | EoY | Average | |
| 7 | | RUS Form 12, Suppl, Part | | | | $ |
| 1 | 108.1 Depr of Steam Plant | H, Section B, Line 1 | | | | - |
| 7 | | RUS Form 12, Suppl, Part | | | | $ |
| 2 | 108.2 Depr of Nuclear Plant | H, Section B, Line 2 | | | | - |
| 7 | | RUS Form 12, Suppl, Part | | | | $ |
| 3 | 108.3 Depr of Hydro Plant | H, Section B, Line 3 | | | | - |
| 7 | 108.4 Depreciation of Other | RUS Form 12, Suppl, Part | | | | $ |
| 4 | Production Plant | H, Section B, Line 4 | | | | - |
| 7 | 108.5 Depreciation of | RUS Form 12, Suppl, Part | | | | $ |
| 5 | Transmission Plant | H, Section B, Line 5 | | | | - |
| 7 | 108.6 Depreciation of | RUS Form 12, Suppl, Part | | | | $ |
| 6 | Distribution Plant | H, Section B, Line 6 | | | | - |
| 7 | 108.7 Depreciation of | RUS Form 12, Suppl, Part | | | | $ |
| 7 | General Plant | H, Section B, Line 7 | | | | - |
| 7 | 108.8 Retirement Work in | RUS Form 12, Suppl, Part | | | | $ |
| 8 | Progress | H, Section B, Line 8 | | | | - |
| 7 | 111 Amort of Electric Plant | RUS Form 12, Suppl, Part | | | | $ |
| 9 | in Service | H, Section B, Line 12 | | | | - |
| 8 | Depreciation and | | $ | $ | | $ |
| 0 | Amortization Reserves | Sum Lines 71 - 79 | - | - | | - |
| | | | | | | |
| 8 | Depreciation Expense | | | | | |

| | | | |
|---|---|---|---|
| 18 | Depreciation Expense - Steam Production Plant | RUS Form 12, Suppl, Part H, Section B, Line 1, Col C | |
| 28 | Depreciation Expense - Nuclear Production Plant | RUS Form 12, Suppl, Part H, Section B, Line 2, Col C | |
| 38 | Depreciation Expense - Hydraulic Production Plant | RUS Form 12, Suppl, Part H, Section B, Line 3, Col C | |
| 48 | Depreciation Expense - Other Production Plant | RUS Form 12, Suppl, Part H, Section B, Line 4, Col C | |
| 58 | Depreciation Expense - Transmission | RUS Form 12, Suppl, Part H, Section B, Line 5, Col C | |
| 68 | Depreciation Expense - Distribution | RUS Form 12, Suppl, Part H, Section B, Line 6, Col C | |
| 78 | Depreciation Expense - General Plant | RUS Form 12, Suppl, Part H, Section B, Line 7, Col C | |

| | | | | | |
|---|---|---|---|---|---|
| 89 | Materials and Supplies | | BoY | EoY | Average |
| 90 | M&S Coal | RUS Form 12, Part H, Section G, Line 1 | | | $ - |
| 91 | M&S Other Fuel | RUS Form 12, Part H, Section G, Line 2 | | | $ - |
| 92 | M&S Production Plant Parts | RUS Form 12, Part H, Section G, Line 3 | | | $ - |
| 93 | M&S Station Transformers & Equipment | RUS Form 12, Part H, Section G, Line 4 | | | $ - |
| 94 | M&S Line Materials & Supplies | RUS Form 12, Part H, Section G, Line 5 | | | $ - |
| 95 | M&S Other | RUS Form 12, Part H, Section G, Line 6 | | | $ - |
| 96 | Materials and Supplies | Sum Lines 90 - 95 | $ - | $ - | $ - |

Notes

1. Note: Includes 46 KV line miles booked in Accts 354 & 355.

**Central Power Electric Cooperative, Inc.**
**O&M Input**
**0**

| A | B | C | D | E |
|---|---|---|---|---|

**SECTION A. EXPENSES AND COSTS**

| | ITEM | ACCOUNT NUMBER | LINES (a) | STATIONS (b) |
|---|---|---|---|---|
| | **Transmission Operations** | | | |
| 1 | Supervision and Engineering | 560 | | |
| 2 | Load Dispatching | 561 | | |
| 3 | Station Expenses | 562 | | |
| 4 | Overhead Line Expenses | 563 | | |
| 5 | Underground Line Expenses | 564 | | |
| 6 | Miscellaneous Expenses | 566 | | |
| **7** | **Subtotal (1 thru 6)** | | **$ -** | **$ -** |
| 8 | Transmission of Electricity by Others | 565 | | |
| 9 | Rents | 567 | | |
| **10** | **Total Transmission Operations (7 thru 9)** | | **$ -** | **$ -** |
| | **Transmission Maintenance** | | | |
| 11 | Supervision and Engineering | 568 | | |
| 12 | Structures | 569 | | |
| 13 | Station Equipment | 570 | | |
| 14 | Overhead Lines | 571 | | |
| 15 | Underground Lines | 572 | | |
| 16 | Miscellaneous Transmission Plant | 573 | | |
| **17** | **Total Transmission Maintenance (11 thru 16)** | | **$ -** | **$ -** |
| **18** | **Total Transmission Expense (10+17)** | | **$ -** | **$ -** |
| 19 | RTO/ISO Expense - Operation | 575.1-575.8 | | |
| 20 | RTO/ISO Expense - Maintenance | 576.1-576.5 | | |
| **2** | **Total RTO/ISO Expense (19+20)** | | $ | $ |

| | | | | |
|---|---|---|---|---|
| **1** | | | - | - |
| 22 | Distribution Expense - Operation | 580-589 | | |
| 23 | Distribution Expense - Maintenance | 590-598 | | |
| **24** | **Total Distribution Expense (22+23)** | | **$ -** | **$ -** |
| **25** | **Total Operation and Maintenance (18+21+24)** | | **$ -** | **$ -** |
| | **Fixed Costs** | | | |
| 26 | Depreciation - Transmission | 403.5 | | |
| 27 | Depreciation - Distribution | 403.6 | | |
| 28 | Interest - Transmission | 427 | | |
| 29 | Interest - Distribution | 427 | | |
| **30** | **Total Transmission (18+26+28)** | | **$ -** | **$ -** |
| **31** | **Total Distribution (24+27+29)** | | **$ -** | **$ -** |
| **32** | **Total Lines and Stations (21+30+31)** | | **$ -** | **$ -** |

Source: Form-12, Part I, Section A.

**Central Power Electric Cooperative, Inc.**

**SPP Upgrades 0**

| A | B | C | D |
|---|---|---|---|
| **Line No.** | **Description** | **Reference** | **Company Qualified Facilities** |
| 1 | Gross Transmission Plant | Worksheet A, Line 12, Col I | |
| 2 | Accumulated Depreciation & Amortization | Worksheet A, Line 26, Col I | |
| 3 | Net Transmission Plant | (Line 1 - Line 2) | |
| 4 | Transmissio | Work | |

| | | | |
|---|---|---|---|
| | n O&M | sheet B, Line 19, Col I | |
| 5 | **Annual Allocation Factor for Transmission O&M** | (Line 4 / Line 1) | |
| 6 | General Plant Depreciation Expense | Worksheet B, Line 41, Col I | |
| 7 | **Annual Allocation Factor for General Plant Depreciation** | (Line 6 / Line 1) | |
| 8 | Return on Rate Base | Worksheet B, Line 46, Col I | |
| 9 | **Annual Allocation Factor for Return** | (Line 8 / Line 3) | |
| 10 | **Depreciation Rates** | | |
| 11 | Line | Worksheet I, Line 3, Col D | 2.750% |
| 12 | Sub | Worksheet | 2.750% |

I, Line 1, Col D

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Line No. | Project Name and # | Type | Project Gross Plant | Project Accumulated Depreciation | Transmission O&M Annual Allocation Factor | All | Allocation for Transmission O&M | General Plant Depreciation Annual Allocation Factor | Allocation for General Plant Depreciation | Annual Expense Charge | Project Net Plant | Annual Allocation Factor for Return | Annual Return Charge | Project Depreciation and Amortization Expense | Project ATRR |
| | | | Note A | | Line 5, Col D | Col D * Col F | Line 7, Col D | Col D * Col H | | Col G + Col I | Col D - Col E (Note B) | Line 9, Col D | Col K * Col L | (Note C) | Col J + Col M + Col N |
| 1a | | | | | | | | | | | $ - | | | $ - | |
| 1b | | | | | | | | | | | $ - | | | $ - | |
| 1 | | | | | | | | | | | $ | | | $ | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| c | | | | | | | | | | - | | | - | | |
| 1d | | | | | | | | | | $ - | | | $ - | | |
| 1e | | | | | | | | | | $ - | | | $ - | | |
| 1f | | | | | | | | | | $ - | | | $ - | | |
| 1g | | | | | | | | | | $ - | | | $ - | | |
| … | | | | | | | | | | $ - | | | $ - | | |
| … | | | | | | | | | | $ - | | | $ - | | |
| | | | | | | | | | | | | | | | |
| 2 | Total | | $ - | $ - | | | | | | $ - | | | $ - | | |

Note Letter

A Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1.

This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross Plant does not include CWIP, Unamortized Regulatory Asset or Unamortized Abandoned Plant.

B Net Plant is the Gross Plant less the associated Accumulated Depreciation.

C Depreciation Expense is the depreciation amount associated with the specified line or sub. Depreciation Expense includes the amortization of any FERC approved Abandoned Plant or Regulatory Asset.

**Central Power Electric Cooperative, Inc.**
**Depreciation**
**Rates**
**0**

| A | B | C | D |
|---|---|---|---|
| Line | RUS Account Number | Description | Depreciation Rates (%)[1] |
| 1 | 353.00 | Transmission Stations | 2.41% |
| 2 | 355.00 | Tran Poles & Fixtures | 3.18% |
| 3 | 356.00 | Tran OH Conductors & Devices | 2.72% |
| 4 | 357.00 | Tran-UG Conduit | 2.75% |
| 5 | 358.00 | Tran-UG Conductors & Devices | 2.15% |
| 6 | 362.00 | Distribution Stations | 2.74% |
| 7 | 362.20 | Load Management Equipment | 0.13% |
| 8 | 390.00 | Structures and Improvements | 2.56% |
| 9 | 391.00 | Office Equipment - Furniture | 6.67% |
| 10 | 391.00 | Office Equipment - Misc Equipment | 20.00% |
| 11 | 391.00 | Office Equipment - Computers | 33.33% |
| 12 | 392.00 | Vehicles - Pickups & Light Vehicles | 20.00% |
| 13 | 392.00 | Vehicles - Line Trucks | 14.30% |
| 14 | 392.00 | Vehicles - Semi's, bucket & digger trucks, misc vehicles & trailers | 8.00% |
| 15 | 397.00 | Communication - MDS Radios & Equipment | 10.00% |
| 16 | 397.00 | Communication - TAIT Radio Equipment | 5.00% |
| 17 | 390.00 | Headquarters Building | 2.03% |
| 18 | 398.00 | Miscellaneous Equipment | 10.00% |
| 19 | 394.00 | Tools & Shop | 10.00% |
| 20 | 396.00 | Power Operated Equip. | 6.67% |
| 21 | 395.00 | Lab Equipment | 10.00% |
| 22 | 393.00 | Stores Equipment | 6.67% |

| | | | |
|---|---|---|---|
| 22 | 350.00 | Land & Land Rights -Transmission | n/a |
| 23 | 360.00 | Land & Land Rights - Distribution | n/a |
| 24 | 389.00 | Land & Land Rights -General | n/a |

[1] These depreciation and amortization rates will not change absent Commission approval under a Section 205 or 206 filing.

**Central Power Electric Cooperative, Inc.**
**Reconciliation Items, Refunds and Surcharges**

**0**

**A B C D E F G H I J**

**ADJUSTMENTS TO GROSS ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year [1] | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/ Chg | Calculated Interest [2] | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Col H + Col I |
| 1 | | | | | | | | | $ - |
| 2 | | | | | | | | | $ - |
| 3 | | | | | | | | | $ - |
| 4 | | | | | | | | | $ - |
| 5 | | | | | | | | | $ - |
| 6 | **Total Adjustment to Gross ATRR:** | | | | | | | | $ - |

**ADJUSTMENTS TO SPP REGIONAL PROJECTS' ATRR DUE TO ERROR CORRECTIONS RESULTING IN REFUNDS OR SURCHARGES:**

| Line | ERROR IDENTIFICATION | Formula Reference | Rate Year [1] | Incorrect Amount | Correct Amount | Difference (Cred)/ Chg | Impact on ATRR (Cred)/ Chg | Calculated Interest [2] | Total Adjustment to ATRR |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Col H + Col I |
| 7 | | | | | | | | | $ - |
| 8 | | | | | | | | | $ - |
| 9 | | | | | | | | | $ - |
| 10 | | | | | | | | | $ - |
| 11 | | | | | | | | | $ - |
| 12 | **Total Adjustment to SPP Regional Projects' ATRR:** | | | | | | | | $ - |

Notes:

[1] Rate Year in which the error occurred and affected the ATRR and rates paid by customers.
[2] Each ATRR adjustment shall include interest based on Section 35.19a of the Commission Regulations.

Workshee
t K

**Central Power Electric Cooperative, Inc.**
**Wages & 565**
**Transmission by Others**
**0**

| A | B | C | D | E | F | G | H | I | J | K | L | M | N | O | P | Q | R | S | T | U | V | W | X | Y |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | General Ledger | | | | | Page 1 | | | | | | | | | | | | | | | | |
| | | | Summary Trial Balance | | | | | | | | | | | | | | | | | | | | | |
| | | | | | | -------- Current Month Balance - ------- | | ---------- Year-To-Date Balance ---- ------ | | | | | | | | | | | | | | | | |
| Line No. | Div | Account | Description | Balance Forw | YTD Trans | Debit | Credit | Debit | Credit | 560 Trans Ops | 561 Load Mgm | 562 Station- | 563 OH Lines | 568 Trans Mai | 569-570 Str | 571 OH Line | 580-589 Dist | 590-598 Dist | 901-905 Cust | 907-910 Cust | 911-916 Cust | 565 Trans by | Production O | Production M |

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| 9 | | | |
| 10 | 0 | | |
| 0 | | | |
| 11 | 0 | | |
| 1 | | | |
| 12 | 0 | | |
| 2 | | | |
| | 0 | | |
| | | | $ |
| 13 | | | - |
| | 0 | | |
| | | | $ |
| 14 | | | - |
| 1 | | | |
| 15 | 0 | | |
| 1 | | | |
| 16 | 0 | | |
| 1 | | | |
| 17 | 0 | | |
| 1 | | | |
| 18 | 0 | | |
| 1 | | | |
| 19 | 0 | | |
| 2 | | | |
| 20 | 0 | | |
| 2 | | | |
| 21 | 0 | | |
| 2 | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 22 | | | | | | |
| 23 | 0 | | | | | |
| 24 | 0 | | | | | |
| 25 | 0 | | | | | |
| 26 | 0 | | | | | |
| | | | | | $ | |
| 27 | | | | | - | |
| 28 | 0 | | | | | |
| | 0 | | | | | |
| | | | | | $ | |
| 29 | | | | | - | |
| 30 | 0 | | | | | |
| 31 | 0 | | | | | |
| 32 | 0 | | | | | |
| 33 | 0 | | | | | |
| 34 | 0 | | | | | |
| 35 | 0 | | | | | |
| 36 | | | | | | $ |

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| | 0 | | | | |
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| 48 | | | | - | |
| 49 | 0 | | | | |
| | 0 | | | | |
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| 51 | 0 | | | | |
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| 53 | 0 | | | | |
| 54 | 0 | | | | |
| 55 | 0 | | | | |
| 56 | 0 | | | | |
| 57 | 0 | | | | |
| 58 | | | | | |
| | 0 | | | | |
| | | | | | $ |
| 59 | | | | | - |
| 60 | 0 | | | | |
| 60 | 0 | | | | |
| 6 | 0 | | | | |

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| 73 | 0 | | | | | | |
| 74 | 0 | | | | | | |
| 75 | 0 | | | | | | |
| 76 | 0 | | | | | | |
| | | | | | $ | | |
| 77 | | | | | - | | |
| 78 | 0 | | | | | | |
| | | | | | $ | | |
| 79 | | | | | - | | |
| 80 | 0 | | | | | | |
| 81 | 0 | | | | | | |
| 82 | 0 | | | | | | |
| 83 | 0 | | | | | | |
| 84 | 0 | | | | | | |
| | | | | | | $ | |
| 85 | | | | | | - | |

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|---|---|---|---|
| 86 | 0 | | |
| | 0 | | $ |
| 87 | | | - |
| 88 | 0 | | |
| 89 | 0 | | |
| 90 | 0 | | |
| 91 | 0 | | |
| 92 | 0 | | |
| 93 | 0 | | |
| | 0 | | $ |
| 94 | | | - |
| 95 | 0 | | |
| | 0 | | $ |
| 96 | | | - |
| 97 | 0 | | |
| 98 | 0 | | |

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|---|---|---|---|
| 99 | 0 | | |
| 100 | 0 | | |
| 101 | 0 | | |
| 102 | 0 | | |
| | 0 | | |
| 103 | | $ | - |
| | 0 | | |
| 104 | | $ | - |
| 105 | 0 | | |
| 106 | 0 | | |
| 107 | 0 | | |
| 108 | 0 | | |
| 109 | | $ | |

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| 2 | | | - |
| 5 | | | |
| 1 | 0 | | |
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| 6 | | | |
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| 7 | | | |
| 1 | 0 | | |
| 2 | | | |
| 8 | | | |
| 1 | 0 | | |
| 2 | | | |
| 9 | | | |

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| | | |

c
e

Worksheet L

**Central Power Electric Cooperative, Inc.**
**Depreciation Expense Inputs**
**0**

| A Line No. | B Account | C Description (1) | D YTD Trans | E Production - Depr Expense | F Trans Subs-Depr Exp | G Trans Lines-Depr Exp | H Distb Subs-Depr Exp | I Load Mgmt-Depr Exp | J Radio-Depr Exp | K General-Depr Exp | L Amort |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | $ - | | | | | | |
| 2 | | | | | | $ - | | | | | |
| 3 | | | | | | | | | | $ - | |
| 4 | | | | | | | $ - | | | | |
| 5 | | | | | | | | $ - | | | |
| 6 | | | | | | | | | $ - | | |
| 7 | | | | | | | | | | $ - | |
| 8 | | | | | | | | | | | $ - |
| 9 | | | | | | | | | | | $ - |
| 10 | | | | | | | | | | | $ - |
| 11 | | Totals | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

Notes:

1. From Central Power Financial Statement and RUS Bulletin 183-1.



Worksheet M

**Central Power Electric Cooperative, Inc.**

**Other Revenue Input**

**0**

| A | B | C | D | E | F | G | H | I | J |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Account** | **Description** | **Total Company** | **454 - Other Revenue** | **456-Wheeling Existing** | **456-Wheeling SPP P2P** | **456-Trans Rents** | **456-Other Rents** | **456-Production** |
| 1 | | | | | | | | $ - | |
| 2 | | | | $ - | | | | | |
| 3 | | | | | | | | | |
| 4 | | | | | | | | | |
| 5 | | | | | | | | | |
| 6 | | | | | | | | | |
| 7 | | | | | | | | | |
| 8 | | | | | | | | | |
| 9 | | | | | | | | | |
| 10 | | | | | | | | | |
| 11 | | | | | | | | | |
| 12 | | | | | | | | | |
| 13 | | | | | | | | | |
| 14 | | | | | | | | | |
| 15 | | | | | | | | | |
| 16 | | Total | $ - | $ - | $ - | $ - | $ - | $ - | $ - |

1 Source: Trial Balance

7

Page 15 Work sheet N

**Central Power Electric Cooperative, Inc.**
**Construction Work in Progress**
**0**

| A<br>Line No. | B<br>Project Description | C<br>Approval Docket No. | D<br>% Recovery Approved (Note A) | E<br>Pricing Zone (Note B) | F<br>Project ID | G<br>Construction Start Date | H<br>In-Service Date (Estimated) | I<br>EoY Balance Dec. 31 2013 | J<br>EoY Balance Dec. 31 2014 | K<br>Average Balance (Col I through J) /2 | L<br>Includable in Rate Base (Note C) (Col D * Col K) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 2 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 3 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 4 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 5 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 6 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 7 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 8 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 9 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |
| 10 | | | 50.00% | Zone 19 | | | | | | $ - | $ - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | | 50.00 % | Zone 19 | | $ - | $ - |
| 12 | | 50.00 % | Zone 19 | | $ - | $ - |
| 13 | | 50.00 % | Zone 19 | | $ - | $ - |
| 14 | | 50.00 % | Zone 19 | | $ - | $ - |
| 15 | | 50.00 % | Zone 19 | | $ - | $ - |
| 16 | | 50.00 % | Zone 19 | | $ - | $ - |
| 17 | | 50.00 % | Zone 19 | | $ - | $ - |
| 18 | | 50.00 % | Zone 19 | | $ - | $ - |
| 19 | | 50.00 % | Zone 19 | | $ - | $ - |
| 20 | | 50.00 % | Zone 19 | | $ - | $ - |
| 21 | | 50.00 % | Zone 19 | | $ - | $ - |
| 22 | | 50.00 % | Zone 19 | | $ - | $ - |
| 23 | | 50.00 % | Zone 19 | | $ - | $ - |
| 24 | | 50.00 % | Zone 19 | | $ - | $ - |
| 25 | | 50.00 % | Zone 19 | | $ - | $ - |
| 26 | | 50.00 % | Zone 19 | | $ - | $ - |
| 27 | | 50.00 % | Zone 19 | | $ - | $ - |
| 28 | | 50.00 % | Zone 19 | | $ - | $ - |
| 29 | | 50.00 % | Zone 19 | | $ - | $ - |
| 30 | | 50.00 % | Zone 19 | | $ - | $ - |
| 31 | | 50.00 % | Zone 19 | | $ - | $ - |
| 32 | | 50.00 % | Zone 19 | | $ - | $ - |
| 33 | | 50.00 % | Zone 19 | | $ - | $ - |
| 34 | | 50.00 % | Zone 19 | | $ - | $ - |
| 35 | | 50.00 % | Zone 19 | | $ - | $ - |
| 36 | | 50.00 % | Zone 19 | | $ - | $ - |
| 37 | | 50.00 % | Zone 19 | | $ - | $ - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 6 | | % | e 19 | | | | - | - |
| 3 | | 50.00 | Zon | | | | $ | $ |
| 7 | | % | e 19 | | | | - | - |
| 3 | Total CWIP Includable | | | | $ | $ | $ | $ |
| 8 | in Rate Base | | | | - | - | - | - |

Notes:

A. Percentage recovery cannot be added or changed absent approval from FERC.
B. CWIP amounts should be directly assigned to pricing zones in Column E.
C. AFUDC ceases when CWIP is recovered in rate base. No CWIP will be included in rate base absent FERC authorization. Accounting procedures must be provided during the annual update to ensure that there is no duplicate recovery of CWIP and corresponding AFUDC capitalized.

**Central Power Electric Cooperative, Inc.**

**Plant Held for Future Use**

**0**

| A Line No | B Facility No. | C Asset No. | D Description | E BoY Investment $ | F EOY Investment $ | G Average Investment $ |
|---|---|---|---|---|---|---|
| 1 | | | | | | $ - |
| 2 | | | | | | $ - |
| 3 | | | | | | $ - |
| 4 | | | | | | $ - |
| 5 | | | | | | $ - |
| 6 | | | | | | $ - |
| 7 | | | | | | $ - |
| 8 | | | | | | $ - |
| 9 | | | | | | $ - |
| 10 | | | | | | $ - |
| 11 | | | | | | $ - |
| 12 | | | | | | $ - |
| 13 | | | | | | $ - |
| 14 | | | | | | $ - |
| 15 | | | | | | $ - |

| | | | | |
|---|---|---|---|---|
| 16 | Subtotal Transmission Future Use Assets | $ - | $ - | $ - |
| 17 | | | | |
| 18 | Distribution Future Use Assets | | | $ - |
| 19 | | | | |
| 20 | General Plant Future Use Assets | | | $ - |
| 21 | | | | |
| 22 | Intangible Plant Future Use Assets | | | $ - |
| 23 | | | | |
| 24 | Total Plant Held for Future Use | $ - | $ - | $ - |

**Central Power Electric Cooperative, Inc.**
**Construction Completed Not Classified**
**0**

| A Line No. | B Fac ID | C Work Order | D Project | E BoY Balance | F EoY Balance | G SPP 106 | H Facility | I % SPP Eligible: | J BoY Amount | K EoY Amount | L Average | M Comments |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | $ - | - | $ - | |
| 2 | | | | | | | | | $ - | - | $ - | |
| 3 | | | | | | | | | $ - | - | $ - | |
| 4 | | | | | | | | | $ - | - | $ - | |
| 5 | | | | | | | | | $ - | - | $ - | |
| 6 | | | | | | | | | $ - | - | $ - | |
| 7 | | | | | | | | | $ - | - | $ - | |
| 8 | | | | | | | | | $ - | - | $ - | |
| 9 | | | | | | | | | $ - | - | $ - | |
| 10 | | | | | | | | | $ - | - | $ - | |
| 11 | | | | | | | | | $ - | - | $ - | |
| 12 | | | 106 SPP Completed Not Classified Total | | | | | | $ - | $ - | $ - | |

**Central Power Electric Cooperative, Inc.**
**Regulatory and Commission Expenses**
**0**

| A<br>Line No. | B<br>Account 928 | C<br>Description | D<br>Total Company | E<br>Non-SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | Total | $ - | $ - | $ - |

**Central Power Electric Cooperative, Inc.**
**Accounts 575 and 576 Expenses**
**0**

| A | B | C | D | E | F |
|---|---|---|---|---|---|
| **Line no.** | **Account No.** | **Description** | **Annual Expense Amount** | **% Included in SPP** | **SPP Zone 19 Amount** |
| | | | | | **Col D * Col E** |
| | | **575.1-575.8 RTO/ISO Expense - Operation** | | | |
| 1a | | | | | $ - |
| 1b | | | | | $ - |
| … | | | | | $ - |
| 2 | | **Total 575.1-575.8 RTO/ISO Expense - Operation (sum lines 1a-1xx) (Note 1)** | $ - | | $ - |
| | | **576.1-576.5 RTO/ISO Expense - Maintenance** | | | |
| 3a | | | | | $ - |
| 3b | | | | | $ - |
| … | | | | | $ - |
| 4 | | **Total 576.1-576.5 RTO/ISO Expense - Maintenance (sum lines 3a-3xx) (Note 2)** | $ - | | $ - |

Note: 1.) The total on line 2, column D must reconcile to the amounts shown on RUS12.I.A.19b
2.) The total on line 4, column D must reconcile to to the amounts shown on RUS 12.I.A.20b

**Central Power Electric Cooperative, Inc.**

**Customer Accounting**

**0**

| A<br>Line | B<br>Account 901 - 905 | C<br>Description | D<br>Total Expenses | E<br>Non-SPP Expenses | F<br>SPP Expenses |
|---|---|---|---|---|---|
| 1 | | | | | |
| 2 | | | | | |
| 3 | | | | | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | | | | | |
| 8 | | | | | |
| 9 | | | | | |
| 10 | | Total Wages (Less Distribution Costs) | $ - | $ - | $ - |
| 11 | | | | | |
| 12 | | | | | |
| 13 | | | | | |
| 14 | | | | | |
| 15 | | Total Customer Accounting - Other | $ - | $ - | $ - |
| 16 | | | | | |
| 17 | | Total (Line10 + Line 15) | $ - | $ - | $ - |

Note: A. The addition of new lines and the removal of outdated lines may be necessary in order to accurately provide information, and populate or remove data in the Worksheets with changes in future years. Where appropriate, these changes will provide detail and linkage to updated Form 12 data requirements or other similar

supporting documentation. Additional line items or line deletions will not require FPA Section 205 or 206 filings. Central Power will describe such changes in the Additional line items or line deletions will not require FPA Section 205 or 206 filings. Central Power will describe such changes in the Annual Annual Update, and the changes will be subject to the review of Interested Parties under the procedures set forth in Central Power's Implementation Protocols. Central Power may not change the columns or the formulas included in these Work Papers during the Annual Update.

# Central Power Electric Cooperative, Inc.
# Transmission Formula Rate Implementation Protocols

## Section I Annual Update

A. The transmission formula rate template (Formula Rate Template) of Central Power Electric Cooperative Inc. (Central Power) and these Transmission Formula Rate Implementation Protocols (Protocols) together comprise the filed rate (Formula Rate) of Central Power for transmission service in Zone 19 of the Southwest Power Pool, Inc. (SPP) footprint. Central Power must follow the instructions specified in the Formula Rate to calculate its Annual Transmission Revenue Requirements (ATRR) and the rates for Network Integration Transmission Service (NITS) and Point-to-Point (PTP) Transmission Service in Zone 19.

Recovery of costs associated with existing and new facilities shall be consistent with the Formula Rate and the SPP Open Access Transmission Tariff (Tariff). The Formula Rate shall become effective for recovery of Central Power's ATRR upon the effective date authorized by the Federal Energy Regulatory Commission (FERC) under Section 205 of the Federal Power Act (FPA).

B. The Formula Rate shall be applicable to service on and after July 1 of each calendar year through June 30 of the following calendar year (Rate Year), subject to review, challenge and refunds or surcharges with interest, to the extent provided herein.

C. On or before April 15 of each calendar year, Central Power shall:

1. Recalculate the ATRR and the rates for zonal NITS service for the new Rate Year in accordance with the Formula Rate (Annual Update); and

2. Provide its Annual Update to SPP and cause such information to be accessible on the SPP Open Access Same-Time Information System ("OASIS").

3. If the date for posting the Annual Update falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which such posting occurs shall be that year's Publication Date. Any delay in the Publication Date shall result in an equivalent extension of time for the submission of Information Requests.

D. Concurrent with the Annual Update postings, Central Power shall provide a notice concerning that posting to SPP to serve electronically upon the Service List.[1]

E. The Annual Update shall:

1. Include a workable populated Formula Rate Template with fully functional spreadsheets showing the calculation of the Annual Update and underlying work papers in native format with links and formulas intact, including sufficiently detailed work papers and supporting documentation for data;

2. Be based on the independently-audited books and records of Central Power for the most recent fiscal year including its certified Rural Utilities Services (RUS) Form 12 or successor reports including the Financial and Operating Report Electric Power Supply (Op. Report – Power Supply) (January 1 through December 31);

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the formula results from the Formula Rate;

4. Identify any change in accounting that affects the inputs to the Formula Rate or the resulting charges billed under the Formula Rate. Central Power shall identify:

   i. Any accounting changes, such as the initial implementation of an accounting standard or policy; the initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific direction; or the correction of errors and prior period adjustments that impact the ATRR.

   ii Any items included in the Formula Rate at an amount other than a historic cost basis.

   iii. Individual impact of any changes in 4i above on charges billed under the Formula Rate.

   iv. Any accounting changes related to a reorganization or merger transaction.

5. Not seek to modify the Formula Rate.

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[1] As used in these Protocols, "Service List" shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Service List through the "Exploder List" link on the SPP OASIS. As of January 2016, the Exploder List was titled "Formula Rate Information Notification" and could be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

## Section II Definitions

For purposes of these Protocols, the following capitalized terms shall have the meanings set forth below.

(a) "Annual Transmission Revenue Requirement" (ATRR) means the net revenue requirement for the Transmission Services calculated in accordance with the Formula Rate filed by Central Power for informational purposes with the Commission and posted on the SPP OASIS on or before the annual Publication Date, subject to review pursuant to the provisions of these Protocols.

(b) "Annual Meeting" means the meeting hosted by Central Power for the purpose of exchanging information with Interested Parties regarding the formula rate.

(c) "Annual Update" means Central Power's annual filing of its Formula Rate, in a working Excel™ format. The Annual Update is submitted as described in these Protocols.

(d) "Business Day" means from 9:00 AM to 5:00 PM Central Prevailing Time other than weekends and Federal Holidays.

(e) "Calendar Year" means January 1 through December 31 of a given year.

(f) "Current Calendar Year" means the Calendar Year in which the Annual Update is filed (*e.g.*, if the Annual Update is filed on July 1, 2014, the Current Calendar Year is 2014).

(g) "Current Rate Year" means the Rate Year for which the Annual Update is posted on the SPP OASIS and which Central Power has filed with the Commission (*e.g.*, if the Annual Update is filed on July 1, 2015, the Current Rate Year is July 1, 2015 through June 30, 2016).

(h) "Customer(s)" or "Transmission Customer(s)" means the customers taking NITS service, service under Grandfathered Agreements, or PTP service.

(i) "FERC" or "Commission" means the Federal Energy Regulatory Commission.

(j) "Final Posting" means the annual update information posted to the SPP OASIS with changes agreed to during the informal review process.

(k) "Formal Challenge" means a challenge by an Interested Party to an aspect of the Annual Update that is filed with the Commission, and served on Central Power by electronic service on the date of such filing.

(l) "Formula Rate Template" means the Central Power transmission formula rate

template set forth herein.

(m) "Formula" means the Formula Rate Template set forth in Addendum 37 to Attachment H of the SPP Tariff.

(n) "Formula Rate" means the Central Power Implementation Protocols together with the Formula Rate Template.

(o) "FPA" means Federal Power Act.

(p) "Informal Challenge" means written notification by an Interested Party to Central Power, during the Review Period, of any specific challenge to the Annual Update.

(q) "Information Request" means a written request submitted by an Interested Party to Central Power.

(r) "Informational Filing" means Central Power's annual filing at the Commission with the information stipulated in these Protocols.

(s) "Interest" shall be calculated pursuant to 18 C.F.R. § 35.19a, or any successor regulation.

(t) "Interested Party" includes but is not limited to, customers under the SPP Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general.

(u) "Information Request Period" means a period of sixty (60) days after each annual Publication Date (unless such period is extended with the written agreement of Central Power) during which Interested Parties may serve reasonable information requests on Central Power.

(v) "NITS" means Network Integration Transmission Service as defined in the SPP Tariff.

(w) "OASIS" means Open Access Same-Time Information System

(x) "OATT" or "SPP Tariff" means SPP's Open Access Transmission Tariff.

(y) "Preliminary Challenge" means written notification by an Interested Party to Central Power, during the Review Period, of any specific challenge to the Annual Update.

(z) "Prior Calendar Year" means the year preceding the Current Calendar Year (*e.g.*, if the Annual Update is filed on July 1, 2015, the Prior Calendar Year is 2014).

(aa) "Prior Rate Year" means the Rate Year prior to the Current Rate Year (*e.g.*, if the Current Rate Year is July 1, 2015 through June 30, 2016, then the Prior Rate Year is July 1, 2014 through June 30, 2015).

(bb) "PTP Rates" means the point-to-point rates derived from the Formula Rate.

(cc) "Publication Date" means the date on which Central Power posts the Annual Update to the SPP OASIS. The Publication Date for each year beginning in 2017 shall be no later than April 15, provided, however, that if April 15 should fall on a weekend or a holiday recognized by the Commission, then the posting shall be due no later than the next Business Day, and the Publication Date shall correspond to the actual posting date.

(dd) "Rate Year" means July 1 of a given year through June 30 of the subsequent year.

(ee) "Review Period" means, unless otherwise extended in writing by Central Power, 60 days after the Publication Date. During the Review Period Interested Parties may serve reasonable Information Requests on Central Power.

(ff) "RUS" means Rural Utilities Service.

(gg) "Stated Values" means values that are fixed and not subject to change in an Annual Update. Stated values include: (i) the authorized return on equity (ROE); (ii) depreciation and amortization rates; and (iii) other similar fixed values. Stated Values may be changed only pursuant to FPA Section 205 or 206.

(hh) "USoA" means RUS Uniform System of Accounts.

## Section III Review of Annual Update

Within twenty (20) days of the Publication Date of Central Power' Annual Update, Central Power will host a meeting for Interested Parties to discuss the Annual Update (Annual Meeting). Central Power shall provide notice of this meeting concurrent with the posting of the Formula Rate Update accessible on SPP's OASIS. The notice shall include the date, time and location of the Annual Meeting and also shall be provided to Interested Parties via the Service List. The Annual Meeting shall also be available by telephone and/or web access with all meeting materials provided electronically from the OASIS.

A. Information Exchange

1. Interested Parties may begin submitting Information Requests immediately following the Publication Date of the Annual Rate Update and will have until sixty (60) days after the Publication Date to serve reasonable Information Requests on Central Power for information and work papers supporting the Annual Rate Update. Such Information Requests shall be limited to those that are necessary to determine:

(a) The extent or effect of an accounting change;

(b) Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

(c) The proper application of the Formula Rate and procedures in these Protocols;

(d) The prudence of actual costs and expenditures, including information on procurement methods and cost control methodologies;

(e) The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

(f) Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

The Information Requests shall not otherwise be directed to ascertain whether the Formula Rate is just and reasonable. Central Power will not claim that responses to information and document request pursuant to the Protocols are subject to any settlement confidentiality provision however; Central Power may require that Interested Parties execute a non-disclosure agreement to obtain access to material that Central Power deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR § 388.113(c)(1).

2. Central Power shall make a good faith effort to respond to Information Requests pertaining to the Annual Update within seven (7) business days.

3. Central Power shall cause to be posted on the SPP OASIS all Information Requests from Interested Parties and Central Power's response(s) to such requests. Central Power also shall request that SPP serve a link to the postings on the Service List. If responses to Information Requests contain information deemed by Central Power to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Central Power.

4. If the deadline for Interested Parties to submit Information Requests falls on a weekend or holiday recognized by the Commission the deadline will be extended to the next business day.

B. Informal Challenge Procedures

1. Interested Parties shall have until June 15 (or the first Business Day after June 15 if June 15 falls on a weekend or holiday recognized by the Commission) to notify Central Power in writing (which may be electronically) of any specific Informal Challenges. The

Informal Challenge must specify the inputs, supporting explanations, allocations calculations, or other information to which the Interested Party objects and provide an appropriate explanation and documents to support its Informal Challenge. Central Power will make a good faith effort to respond to any Informal Challenge within twenty (20) days of notification of such Informal Challenge. Central Power and, if appropriate, SPP, shall appoint senior representatives to work with the Interested Party to resolve the Informal Challenge.

2. Central Power will cause to be posted on a publicly accessible portion of the SPP OASIS all Informal Challenges from Interested Parties and Central Power's responses to the Informal Challenges. Central Power shall provide a notice concerning that posting to SPP to serve electronically upon the Service List. If Informal Challenges contain information deemed by Central Power to be confidential, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement executed by the requesting party and Central Power.

3. Any changes or adjustments to the Annual Update resulting from the Information Exchange and Informal Challenge procedures that are agreed to by Central Power and resolved 30 days prior to the Informational Filing shall be included in the Informational Filing made with FERC and will be reflected in the Annual Rate Update for the following Rate Year.

C. Formal Challenges.

1. A Formal Challenge shall:

(a) Clearly identify the action or inaction which is alleged to violate the filed Formula Rate or Protocols;

(b) Explain how the action or inaction violates the filed Formula Rate or Protocols;

(c) Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an accounting change;

ii. Whether the Annual Update fails to include data properly recorded in accordance with the Protocols and the accuracy and consistency of data;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The prudence of actual costs and expenditures, including information on

procurement methods and cost control methodologies;

v. The effect of any change to the underlying Uniform System of Accounts or Formula Rate template; or

vi. Any other information that may reasonably have a substantive effect on the calculation of the charges pursuant to the Formula Rate.

(d) Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

(e) State whether the issues presented are pending in an existing proceeding in any forum in which the Interested Party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

(f) State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that belief;

(g) Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the Interested Party, including, but not limited to, contracts and affidavits; and

(h) State whether the filing party utilized the Informal Challenge procedures described in these Protocols with regard to any issue.

2. Formal Challenges shall be filed with FERC, either in the FERC Docket assigned to the Informational Filing or via Section 206 of the FPA, and shall be served upon Central Power contemporaneously with the filing at FERC. Service can be accomplished by electronic mail in accordance with § 385.2010(f) (3), by facsimile, express delivery or messenger to the individual listed as the contact person in Central Power's Informational Filing.

3. In any proceeding initiated by FERC concerning the Annual Update or in response to a Formal Challenge, Central Power shall bear the burden, consistent with section 205 of the FPA, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols in that year's Annual Update. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

D. Modification of Formula Rate or Annual Update

1. No party shall seek to modify the Formula Rate under the Challenge procedures (either Formal or Informal) set forth in these Protocols and the Annual Update shall not be subject to challenge for the purpose of modifying the Formula Rate.

2. A change to the Formula Rate fixed inputs related to rate of return on equity (ROE), depreciation rates, capital structure, amortization periods, and any ROE incentives for SPP regional projects may not be made absent the appropriate filing with FERC pursuant to the FPA Sections 205 or 206, provided, however, that Central Power may make a limited Section 205 filing to change depreciation rates, amortization periods, and/or ROE incentives for SPP regional projects, in which the sole issue for examination shall be whether the proposed changes(s) are just and reasonable, and not unduly discriminatory.

3. If Central Power makes a correction to a Mistake in its financial information during a Rate Year that would affect the Formula Rate for that Rate Year, such corrections and any resulting refunds or surcharges shall be reflected in the Annual Update for the next effective Rate Year with Interest. For purposes of these Protocols, "Mistake" shall mean errors or omissions regarding the values inputted into the Formula Rate template, such as arithmetic or computational errors. Mistakes shall not include matters involving exercise of judgment or substantive differences of opinion regarding the derivation of an input that is more properly the subject of the annual review process.

4. Any changes to the data inputs or as the result of a FERC proceeding shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the Annual Update for the next effective Rate Year. Any Interest on any refund shall be calculated in accordance with section II(s) above.

E. Informational Filing.

1. By July 15 of each year, Central Power shall submit to FERC an informational filing (Informational Filing) of its Annual Update.

2. This Informational Filing must include the information that is reasonably necessary to determine:

   (a) That input data under the Formula Rate is properly recorded in any underlying work papers;

   (b) That Central Power has properly applied the Formula Rate and these procedures;

   (c) That the data are accurate and the ATRR and rates under review were calculated in accordance with the Formula Rate; and

   (d) The extent of accounting changes that affect Formula Rate inputs.

3. The Informational Filing must also describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures.

4. Contemporaneous with the making of such Informational Filing, Central Power shall provide notice of the Informational Filing to Interested Parties via the Service List and by posting the docket number assigned to the Informational filing on SPP's OASIS.

5. Central Power shall submit all Informational Filings in the same docket assigned to Central Power's first Informational Filing, and shall request that SPP provide notification of the filing through Service List within 10 days of posting the Annual Update.

## Section IV Joint SPP Transmission Owners' Meeting.

If the SPP Transmission Owners with transmission projects that utilize a regional cost-sharing methodology implement a process to coordinate and hold joint meetings, Central Power intends to participate in that process. Notice of joint informational meetings, including the time, date, and location, shall be posted on the SPP website and OASIS and distributed to Interested Parties via the email "exploder" list maintained by SPP no less than seven (7) days prior to such meetings.

# Section V Central Power Example Schedule

| Action | Central Power | Days since Initial Posting |
|---|---|---|
| Data Available | March 1 | |
| Initial Posting (SPP OASIS) | April 15 | - |
| Annual Meeting with Interested Parties (20 days) | May 5 | 20 |
| Interested Parties Review Period ending (60 days) | June 15 | 61 |
| Informal Challenges Due date ending | June 15 | 61 |
| Final Posting (SPP OASIS) | June 20 | 66 |
| Rate Year | July 1 – June 30 | |
| Informational Filing | July 15 | |

# ADDENDUM 31 TO ATTACHMENT H

## Orange City Municipal Utilities

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Index

13 Months Ended June 30, 2XXX


| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |

**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 21 | | | #DIV/0! |
| | REVENUE CREDITS (Note I) | | | | |
| 2 | Account No. 454 (Note H) | EIA Form 412 | - | TP 0.000% | - |
| 3a | Transmission charges for all transmission transactions | EIA Form 412 | - | TP 0.000% | - |
| 3b | Transmission charges for all transmission transactions included in Native Load | EIA Form 412 | - | TP 0.000% | - |
| 3c | Account No. 456.1 | (line 3a less line 3b) | - | TP 0.000% | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | EIA Form 412 | - | TP 0.000% | - |
| 5 | Revenues from service provided by the ISO at a discount | EIA Form 412 | - | TP 0.000 | - |

| | | | | % | |
|---|---|---|---|---|---|
| 6 | TOTAL REVENUE CREDITS | (sum lines 2, 3c, 4, 5) | | | - |
| 7 | ATRR for SPP Directed Projects | Schedule 1, line 2, col 9 | | | #DIV/0! |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus lines 6 and 7) | | | #DIV/0! |



**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| | **RATE BASE** | | | | |
| | GROSS PLANT IN SERVICE (Note L) | | | | |
| 1 | Production | Schedule 4, Column G, Line 6 | - | NA 0.000% | - |
| 2 | Transmission | Schedule 4, Column G, Line 7 | - | TP 0.000% | - |
| 3 | Distribution | Schedule 4, Column G, Line 8 | - | NA 0.000% | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | General & Intangible | Schedule 4, Column G, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Common | Schedule 4, Column G, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 6 | TOTAL GROSS PLANT | (sum lines 1-5) | - | **GP=** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note L) | | | | | |
| 7 | Production | Schedule 4, Column N, Line 6 | - | NA | 0.00% | - |
| 8 | Transmission | Schedule 4, Column N, Line 7 | - | TP | 0.00% | - |
| 9 | Distribution | Schedule 4, Column N, Line 8 | - | NA | 0.00% | - |
| 10 | General & Intangible | Schedule 4, Column N, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 11 | Common | Schedule 4, Column N, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL ACCUM. DEPRECIATION | (sum lines 7-11) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | - | | | - |
| 14 | Transmission | (line 2 - line 8) | - | | | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - |
| 16 | General & Intangible | (line 4 - line 10) | - | | | #DIV/0! |
| 17 | Common | (line 5 - line 11) | - | | | #DIV/0! |
| 1 | TOTAL NET PLANT | (sum lines | | **N** | # | #DI |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | 13-17) | - | **P =** | **DIV/0!** | V/0! |
| 19 | LAND HELD FOR FUTURE USE (Note A) | EIA Form 412 | - | TP | 0.000% | - |
| | WORKING CAPITAL (Note B) | | | | | |
| 20 | CWC | (1/8 * page 3, line 8) | - | | | #DIV/0! |
| 21 | Materials & Supplies (Note A) | EIA Form 412 | | TE | 0.000% | - |
| 22 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 23 | TOTAL WORKING CAPITAL | (sum lines 20-22) | - | | | #DIV/0! |
| 24 | RATE BASE | (sum lines 18, 19, and 23) | - | | | #DIV/0! |



**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | **Transmission Amount ($)** |
| | O&M (Note M) | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Transmission | Schedule 7, Column E, Line 8 | - | TE | 0.000% | - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts | EIA Form 412 | - | TE | 100.000% | - |
| 2 | Less Account 565 | Schedule 7, Column C, Line 8 | - | TE | 0.000% | - |
| 3 | A&G | Schedule 7, Column E, Line 13 | - | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note C) | EIA Form 412 | | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note C) | EIA Form 412 | - | TE | 0.000% | - |
| 6 | Common | Schedule 7, Column E, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | EIA Form 412 | - | TE | 0.000% | - |
| 8 | TOTAL O&M | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note L) | | | | | |
| 9 | Transmission | Schedule 4, Column O, Line 7 | - | TP | 0.000% | - |
| 10 | General & Intangible | Schedule 4, Column | - | W/ | #DI | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| | | O, Line 1 and Line 9 | | S | V/0! |
| 11 | Common | Schedule 4, Column O, Line 17 | - | CE | #DIV/0! |
| 12 | TOTAL DEPRECIATION | (Sum lines 9 - 11) | - | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note D) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S | #DIV/0! |
| | PLANT RELATED | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP | #DIV/0! |
| 16 | Gross Receipts | Schedule 5, Column B, Line 5 | - | NA | 0.00% - |
| 17 | Other | Not Used | | NA | 0.00% - |
| 18 | Payments in lieu of taxes | Schedule 3, Column B, Line 6 | - | GP | #DIV/0! |
| 19 | TOTAL OTHER TAXES | (sum lines 13-14 and 15-18) | - | | #DIV/0! |
| 20 | RETURN | (page 2, line 24 * R) | #DIV/0! | | #DIV/0! |
| 21 | GROSS REVENUE REQUIREMENT | (sum lines 8, 12, 19, and 20) | #DIV/0! | | #DIV/0! |

**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) | |
|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, column 5 | | | - | |
| 2 | Less transmission plant excluded from ISO rates (Note F) | EIA Form 412 | | | - | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note G ) | EIA Form 412 | | | - | |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | - | |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | | **0.00 %** | **= TP** |
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses | page 3, line 1, column 3 | | | - | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note E) | EIA Form 412 | | | - | |
| 8 | Included transmission expenses | (line 6 less line 7) | | | - | |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | 0.00 % | |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line | | | **0.00 %** | **= TE** |

5)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | WAGES & SALARIES | | | | | | |
| 11 | Production | Schedule 8, Column E, Line 2 | - | NA | 0.000% | - | |
| 12 | Transmission | Schedule 8, Column E, Line 5 | - | TP | 0.000% | - | |
| 13 | Distribution | Schedule 8, Column E, Line 8 | - | NA | 0.000% | - | |
| 14 | Other | Schedule 8, Column E, Line 11 | - | NA | 0.000% | - | |
| 15 | Total | (sum lines 11-14) | - | | | - | |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | |
| 17 | Wages & Salaries Allocator (Note N) | (line 15, col 5 divided by col 3) | | | | **#DIV/0!** | **= W/S** |
| | COMMON PLANT | | | | | | |
| 18 | Electric | Schedule 4, Column G, Line 16 | | | | 0 | |
| 19 | Gas | EIA Form 412 | | | | | |
| 20 | Water | EIA Form 412 | | | | | |
| 21 | Total | (sum lines 18-20) | | | | 0 | |
| 22 | Percentage of Electric Common Plant | (line 17 divided by line 21) | | | | #DIV/0! | |
| 23 | Common Plant Allocator (CE) | (line 22 times line 17) | | | | **#DIV/0!** | **= CE** |
| | RETURN (R) | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 24 | Long Term Interest (Note J) | Schedule 3, Column B, Line 16 | - | | | | | |
| | | | $ Amount | % | Cost (Note O) | Weighted | | |
| 25 | Long Term Debt | Schedule 2, Column D, Line 37 | - | #DIV/0! | 0.00% | #DIV/0! | | |
| 26 | Proprietary Capital | Schedule 2, Column D, Line 32 | - | #DIV/0! | 10.10% | #DIV/0! | | |
| 27 | Total | (sum lines 25, 26) | - | #DIV/0! | | #DIV/0! | = | R |



**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

Notes:

A Transmission related only.

B Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165.

C Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission

| | |
|---|---|
| | Expenses directly related to transmission service, ISO filings or transmission siting. |
| D | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| E | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA. |
| F | Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test). |
| G | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| H | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. |
| I | The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. |
| J | Include only the amount from Accounts 427, 428, 429 and 430. |
| K | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| L | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |

| | |
|---|---|
| M | Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate. |
| N | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| O | The cost of proprietary capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The cost of long-term debt is calculated by dividing long-term interest (line 24) by the amount of long-term debt (line 25, col 3). The cost of proprietary capital included an incentive adder of 50 basis points approved in Docket No. ER15-2324. |

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended June 30, 2XXX

| | 1 | 2 | 3 |
|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Transmission Amount ($)** |
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, page 2, line 2 col 5 | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, page 2, line 8 col 5 | - |
| 3 | Net Transmission Plant - SPP (Note B) | (line 1 less line 2) | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 3, line 8 col 5 | #DIV/0! |
| **5** | **Annual Allocation Factor for O&M** | **(line 3 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, page 3, line 19 col 5 | #DIV/0! |
| **7** | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| **8** | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, p 3, line 12 | #DIV/ |

| | | | |
|---|---|---|---|
| | | col 5 | 0! |
| 1 0 | Return | Attach H, p 3, line 20 col 5 | #DIV/ 0! |
| 1 1 | Depreciation plus return | (line 9 plus line 10) | #DIV/ 0! |
| **1 2** | **Annual Allocation Factor for Depreciation and Return** | **(line 12 divided by line 3)** | **#DIV/ 0!** |



**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended June 30, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Upgrade Name** | **Upgrade ID** | **Upgrade Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Upgrade Net Plant** | **Annual Allocation Factor for Depreciation & Return** | **Annual Charge for Depreciation & Return** | **Net Annual Revenue Requirement** |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | Note D | (Page 1 line 12) | (Col. 6 * Col. 7) | (Sum Col. 5 & 8) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1<br>f | Project 6 | Proje<br>ct 6 | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| … | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | | | | | | | |
| 2 | Annual Totals | | | | | | | | #DIV/<br>0! |

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 4- Line 14.

D Net Plant is derived from Schedule 4- Line 42 and includes all CWIP

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1a: SPP Directed Projects

13 Months Ended June 30, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **13 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | | |
| **2** | **Total Gross Plant in Service** | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3a | Project 1 | | | | | | | | | | | | | | - |
| 3b | Project 2 | | | | | | | | | | | | | | - |
| 3c | Project 3 | | | | | | | | | | | | | | - |
| 3d | Project 4 | | | | | | | | | | | | | | - |
| 3e | Project 5 | | | | | | | | | | | | | | - |
| 3f | Project 6 | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| 4 | **Total Accumulated Depreciation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Net Plant in Service** | | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| 6 | **Total Net Plant in Service** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 2: Electric Balance Sheet (EIA Form 412)
12 Months Ended June 30, 2XXX

| Column | A | B | | C | E |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| | **ELECTRIC PLANT** | | | **PROPIETARY CAPITAL** | |
| 1 | Electric Plant & Adjustments | | | | |
| | (101-106,114,116) | | 29 | Investment of Municipality (208) | |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and | | 31 | Retained Earnings | |
| | Depletion (108,111,115) | | | (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel | | | | |
| | Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | |
| 7 | **Net Electric Plant including Nuclear** | | 34 | Advances from Municipality and Other | |
| | **Fuel** | **$ -** | | Long Term Debt (223, 224) | $ - |
| 8 | **OTHER PROPERTY & INVESTMENTS** Non-Electric Plant Property (121) | $ - | 35 | Unamortized Premium on Long Term Debt (225) | $ - |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| | **CURRENT & ACCRUED ASSETS** | | 38 | Accumulated Operating Provisions (228.1-.4) | $ - |
| 13 | Cash, Working Funds & Investments (131-136) | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Recevable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | $ - | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | $ - | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | $ - |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | $ - |
| 26 | Miscellaneous Debt, Research and Development Expenses | | 51 | Unamortized gain on | |

| | | | | | |
|---|---|---|---|---|---|
| | & Unamortized Losses (184-191) | $ - | | Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | $ - |
| 8 | **NET ELECTRIC OPERATING INCOME** | $ - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | $ - |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | |
| 15 | Electric Income | $ - |
| 16 | Income Deductions from Interest on Long Term Debt (427) | |
| 17 | Other Income Deductions (428-431) | |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | |
| 19 | Total Income Deductions | $ - |
| 20 | Income Before Extraordinary Items | $ - |
| 21 | Extraordinary Items (434) | $ - |

| | | |
|---|---|---|
| 22 | Extraordinary Deductions (435) | $ - |
| 23 | **NET INCOME** | **$ -** |

**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended June 30, 2XXX



**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjusted BOY | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Accumulated Depreciation | Adjusted BOY | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| | | | | | | | | | | | | | | | | |
| 2 | Steam Productio | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | n (310-316) | | | | | | | | | | | | | | | |
| 3 | Nuclear Production (320-325) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 4 | Hydraulic Production (330-336) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 5 | Other Production (340-346) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 6 | **Total Production Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | $ - | $ - | $ - | $ - | **$ -** | | | | $ - | $ - | $ - | **$ -** | |
| 8 | Distribution Plant (360-373) | | | $ - | $ - | $ - | $ - | **$ -** | | | | $ - | $ - | $ - | **$ -** | |
| 9 | General Plant (389-399) | | | $ - | $ - | $ - | $ - | **$ -** | | | | $ - | $ - | $ - | **$ -** | |
| 10 | **Total Electric Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **In Service** | | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | | |
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |
| | | | | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | | | | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | |
| 16 | **Total Electric Plant & Adj's** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | |
| 17 | Common Plant | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | |

**City of Orange City (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 5: Taxes other than Income Taxes (EIA Form 412)
12 Months Ended June 30, 2XXX

| Line No. | A Description | B Amount ($) | C Notes/Comments |
|---|---|---|---|
| | **Taxes other than Income Taxes, Operating Income** | | |
| | **Payroll Taxes:** | | |
| 1 | FICA Taxes | $ - | |
| 2 | Unemployment Taxes | $ - | |
| | **Plant Related Taxes:** | | |
| 3 | Highway Taxes | $ - | |
| 4 | Property Taxes | $ - | |
| 5 | Gross Receipts Taxes | $ - | |
| 6 | Payment In Lieu of Taxes (Transfer) | | |

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended June 30, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | 0.00% |
| 3 | 351 | Energy Storage Equipment - Transmission | 30 | 3.3% |
| 4 | 352 | Structures & Improvements | 30 | 3.3% |
| 5 | 353 | Station Equipment | 30 | 3.3% |
| 6 | 354 | Towers & Fixtures | 30 | 3.3% |
| 7 | 355 | Poles & Fixtures | 30 | 3.3% |
| 8 | 356 | Overhead Conductors and Devices | 30 | 3.3% |
| 9 | 357 | Underground Conduit | 30 | 3.3% |
| 10 | 358 | Underground Conductors and Devices | 30 | 3.3% |
| 11 | 359 | Roads and Trails | 30 | 3.3% |
| 12 | | **General Plant** | | |
| 13 | 390 | Structures & Improvements | 10 | 10.0% |
| 14 | 391 | Office Furniture and Equipment | 10 | 10.0% |
| 15 | 392 | Transportation Equipment | 10 | 10.0% |
| 16 | 393 | Stores Equipment | 10 | 10.0% |
| 17 | 394 | Tools, Shop and Garage Equipment | 10 | 10.0% |
| 18 | 395 | Laboratory Equipment | 10 | 10.0% |
| 19 | 396 | Power Operated Equipment | 10 | 10.0% |
| 20 | 397 | Communication Equipment | 10 | 10.0% |
| 21 | 398 | Miscellaneous Equipment | 10 | 10.0% |

| | | | | | |
|---|---|---|---|---|---|
| 22 | | **Intangible Plant** | | | |
| 23 | 301 | Organization | 30 | 3.3% | |
| 24 | 302 | Franchises and consents | 30 | 3.3% | |
| 25 | 303 | Miscellaneous intangible plant | 30 | 3.3% | |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: O&M Expense (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | $ - | $ - | $ - | $ - |
| 5 | Purchased Power (555) | $ - | | $ - | $ - |
| 6 | Other Production Expenses (556-557) | $ - | $ - | $ - | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-567, 568-573) | XXXXXXXXXXXX | | | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXXX | | | $ - |
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXX | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| | | XX | | | |
| 11 | Customer Service & Information | | | | |
| | Expenses (907-910) | XXXXXXXXXXXX | | | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXX | | | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXX | | | $ - |
| 14 | Total Electric Operation and Maintenance Expenses | **$ -** | **$ -** | **$ -** | **$ -** |

| | | |
|---|---|---|
| 15 | Total Number of Full Time Employees | |
| 16 | Total Number of Part Time Employees | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Common O&M Expense | $ - | $ - | $ - | $ - |

**City of Orange City (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | | Accounts | Salaries | |
| 1 | | | Production / Generation | | |
| 2 | | | Salaries | $ - | $ - |
| 3 | | | | | |
| 4 | | | Transmission: | | |
| 5 | | | Salaries | $ - | $ - |
| 6 | | | | | |
| 7 | | | Distribution: | | |
| 8 | | | Salaries | | $ - |
| 9 | | | | | |
| 10 | | | Customer Service & Information | | |
| 11 | | | Salaries | | $ - |
| 12 | | | | | |
| 13 | | | Administrative & General | | |
| 14 | | | Salaries | | $ - |
| 15 | | | | | |
| 16 | | | **Total** | $ - | $ - |

# MRES MEMBER UTILITIES

# ANNUAL UPDATE PROTOCOLS

# UNDER ATTACHMENT H OF SPP OPEN ACCESS TRANSMISSION TARIFF

## Section I. Applicability

The following procedures shall apply to Moorhead Public Service ("MPS"), Orange City Municipal Utilities ("OCMU"), Pierre Municipal Utilities ("PMU"), Sioux Center Municipal Utilities ("SCMU") and Watertown Municipal Utility District ("WMUD") calculation of its annual transmission revenue requirement ("ATRR") pursuant to its Formula Rate Template ("FRT"). These utilities will be referred to as the "Members" in these protocols. The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the Federal Power Act.

## Section II. Annual ATRR Update

1. Beginning on or before May 1, 2016, and on or before each subsequent May 1, the Members shall determine their ATRRs to be effective on June 1, 2016 and each subsequent June 1.
2. On or before May 1, 2016, and on or before each subsequent May 1, the Members shall request SPP to post their FRTs and supporting documentation on the SPP OASIS, and shall notify Interested Parties of the website address where such information is posted via the SPP email exploder list titled "Formula Rate Posting Information Notification."
    A. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state

attorneys general ("Interested Parties"). Interested Parties can contact MRES to be included as an Interested Party.

B. MRES Members shall provide electronic notice of Annual ATRR Update postings to all Interested Parties within 10 days of such posting through an email to the Formula Rate Posting Information Notification exploder maintained by SPP.

C. As used in these Protocols, "Formula Rate Posting Information Notification" exploder shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification exploder through the link on the SPP website. The exploder list is titled "Formula Rate Posting Information Notification" and can be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include, but are not limited to, (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

3. If the date for posting the FRT falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the FRT shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the FRT will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

4. The Annual Update shall:

   A. Include a workable data-populated FRT and underlying work papers in native format with all formulas intact;

   B. Be based on the Member's audited financial statements for the either the prior fiscal or calendar year, as applicable. MPS, PMU and WMUD base their audited financial statements on a calendar year from January 1 to December 31. OCMU

and SCMU base their audited financial statements on a fiscal year from July 1 to June 30.

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the FRT that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;

D. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);

E. With respect to any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that affect the

4. ATRR calculation;

5. The implementation of new estimation methods or policies that change prior estimates; and

6. changes to income tax elections (if applicable);

ii. Identify items included in the FRT at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the FRT;

iv. Provide, for each item identified pursuant to items II.4.e.i - II.4.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the FRT.

5. Each of the Members shall hold an open meeting among Interested Parties ("Formula Rate Update Meeting") between the Publication Date and May 31 of each year. No less than seven (7) days prior to such Formula Rate Update Meeting, each Member shall provide notice on the Member Related Posting section of the SPP OASIS of the time, date, and location of its Formula Rate Update Meeting. The Formula Rate Update Meeting shall (i) permit the Member to explain and clarify its FRT and (ii) provide Interested Parties an opportunity to seek information and clarifications from the Member about the FRT. Each Member shall provide remote access for participation of Interested Parties at such meetings.

6. If a Member constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of Joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via email no less than 7 days prior to such meeting.

**Section III. Information Exchange Procedures**

Each Member's FRT shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until July 1 following the Publication Date (unless such period is extended with the written consent of the applicable Member or by FERC order) to serve reasonable information and document requests on the applicable Member ("Information Exchange Period"). If July 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

a. The extent or effect of an Accounting Change;

b. Whether the FRT fails to include data properly recorded in accordance with these protocols;

c. The proper application of the formula rate and procedures in these protocols;

d. The accuracy of data and consistency with the formula rate of the calculations shown in the FRT;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. The Members shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. The Members shall respond to all information and document requests received on or before July 1 by no later than August 10 following the Publication Date, unless the Information Exchange Period is extended by the Members or FERC.

3. Each Member will cause to be posted on the Member Related Postings section of the SPP OASIS all information requests regarding the Member's FRT in SPP from Interested Parties and the Member's response(s) to such requests; except, however, if responses to information and document requests include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the applicable Member and the requesting party.

4. Members shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the applicable Member's FRT. However, each Member may require that Interested Parties execute a non-disclosure agreement to

obtain access to material that the Member deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**Section IV. Challenge Procedures for the FRT Update**

1. No later than July 5 of each year, any Interested Party may notify a Member in writing of any specific challenge(s) to any component of the most recently posted FRT ("Preliminary Challenge"). A party submitting a Challenge to a Member must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Within five (5) business days of receiving notice of such challenge(s), any Member so notified shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) on the Member Related Posting section of the SPP OASIS. The Member and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations.
2. Each Member shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which the Member agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the FRT will result. If the Member disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.
3. If the Member and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of the Member's response to the issue(s), senior management representatives of the Member and the Interested Parties shall meet to try to resolve the issue(s). Each challenged Member shall appoint a senior representative to work with the party that submitted the Challenge (or its representative) toward a resolution of the challenge. If the Member disagrees with such challenge, the Member

will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. Any modification to the FRT that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the FRT for the next Rate Year and incorporated into the Member's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the ATRR, such changes shall be incorporated into the FRT for the next rate year.

4. If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, any Interested Party that has not resolved any Preliminary Challenge to the Formula Rate Update may then file with FERC a Formal Challenge to a Formula Rate Update pursuant to these Implementation Procedures ("Formal Challenge").

    a. A Formal Challenge shall:

        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        ii. Explain how the action or inaction violates the filed rate formula or protocols;
        iii. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

            1. The extent or effect of an Accounting Change;
            2. Whether the FRT fails to include data properly recorded in accordance with these protocols;
            3. The proper application of the formula rate and procedures in these protocols;
            4. The accuracy of data and consistency with the formula rate of the charges shown in the FRT;
            5. The prudence of actual costs and expenditures;

6. The effect of any change to the underlying Uniform System of Accounts; or

7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

b. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on the applicable Member. Service to a Member must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on a Member's Informational Filing required under Section VI of these protocols.

5. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the FRT fails to include data properly recorded in accordance with these protocols; (3) the proper

application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the FRT; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

6. Each Member will cause to be posted all Informal Challenges from Interested Parties and the Member's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Member and the requesting party.

7. Any changes or adjustments to the FRT resulting from the Information Exchange and Informal Challenge processes that are agreed to by a MRES Member will be reported in the Informational Filing required pursuant to Section VI of these protocols.

8. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of the Member to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on the Member on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as the Member's Informational Filing discussed in Section VI of these protocols. The Member shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

9. In any proceeding initiated by FERC concerning the FRT or in response to a Formal Challenge, the Member shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the FRT consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of a MRES Member to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the FRT under the Challenge Procedures set forth in these protocols and the FRT shall not be subject to challenge by anyone for the purpose of modifying the FRT. Any modifications to the FRT will require, as applicable, a Federal Power Act section 205 or section 206 filing.

    Any Interested Party seeking changes to the application of the FRT due to a change in the Uniform System of Accounts, shall first raise the matter with MRES in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to the ATRR**

Any changes to the data inputs, the result of any FERC proceeding to consider the FRT, or a result of the procedures set forth herein, shall be incorporated into the FRT for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of the Commission's regulations. The fixed base return on equity of 9.6% set forth in the Members' FRT will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act. The asset depreciation rates set forth in the Members' FRT filing will not be changed absent a filing pursuant to Section 205 or Section 206 of the Federal Power Act.

**Section VI. Informational Filings**

By March 15 of each year, each Member shall submit to FERC an informational filing

("Informational Filing") of its FRT for the Rate Year. Each Member shall submit each year's Informational Filing in the same docket assigned to its initial informational filing,[1] subject to the determination of the FERC's Secretary. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that the Member has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. The transmittal letter accompanying the Informational Filing shall inform the Commission that the Informational Filing is not intended to be subject to the Commission's notice requirements, and that it is not being submitted for the purpose of having the Commission assign a docket number to the filing nor for the purpose of obtaining Commission acceptance, approval or other review of the filing. Each Member shall provide notification of each Informational Filing through notification on the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

[1] In 2016, MPS submitted its Informational filing in ER16-1182, OCMU in ER16-1183, PMU in ER16-1184, SCMU in ER16-1185, and WMUD in in ER16-1186.

# ADDENDUM 32 TO ATTACHMENT H

## City of Pierre, South Dakota

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Index

13 Months Ended December 31, 2XXX

| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |

**Pierre (South Dakota) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 21 | | | #DIV/0! |
| | REVENUE CREDITS (Note I) | | | | |
| 2 | Account No. 454 (Note H) | EIA Form 412 | - | TP 0.000% | - |
| 3a | Transmission charges for all transmission transactions | EIA Form 412 | - | TP 0.000% | - |
| 3b | Transmission charges for all transmission transactions included in Native Load | EIA Form 412 | - | TP 0.000% | - |
| 3c | Account No. 456.1 | (line 3a less line 3b) | - | TP 0.000% | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | EIA Form 412 | - | TP 0.000% | - |
| 5 | Revenues from service provided by the ISO at a discount | EIA Form 412 | - | TP 0.000 | - |

| | | | | % | |
|---|---|---|---|---|---|
| 6 | TOTAL REVENUE CREDITS | (sum lines 2, 3c, 4, 5) | | | - |
| 7 | ATRR for SPP Directed Projects | Schedule 1, line 2, col 9 | | | #DIV/0! |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus lines 6 and 7) | | | #DIV/0! |



**Pierre (South Dakota) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | **Transmission Amount ($)** |
| | **RATE BASE** | | | | |
| | GROSS PLANT IN SERVICE (Note L) | | | | |
| 1 | Production | Schedule 4, Column G, Line 6 | - | NA 0.000% | - |
| 2 | Transmission | Schedule 4, Column G, Line 7 | - | TP 0.000% | - |
| 3 | Distribution | Schedule 4, Column G, Line 8 | - | NA 0.000% | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | General & Intangible | Schedule 4, Column G, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Common | Schedule 4, Column G, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 6 | TOTAL GROSS PLANT | (sum lines 1-5) | - | **GP=** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note L) | | | | | |
| 7 | Production | Schedule 4, Column N, Line 6 | - | NA | 0.00% | - |
| 8 | Transmission | Schedule 4, Column N, Line 7 | - | TP | 0.00% | - |
| 9 | Distribution | Schedule 4, Column N, Line 8 | - | NA | 0.00% | - |
| 10 | General & Intangible | Schedule 4, Column N, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 11 | Common | Schedule 4, Column N, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL ACCUM. DEPRECIATION | (sum lines 7-11) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | - | | | - |
| 14 | Transmission | (line 2 - line 8) | - | | | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - |
| 16 | General & Intangible | (line 4 - line 10) | - | | | #DIV/0! |
| 17 | Common | (line 5 - line 11) | - | | | #DIV/0! |
| 1 | TOTAL NET PLANT | (sum lines | | **N** | # | #DI |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | 13-17) | - | **P =** | **DIV/0!** | V/0! |
| 19 | LAND HELD FOR FUTURE USE (Note A) | EIA Form 412 | - | TP | 0.000% | - |
| | WORKING CAPITAL (Note B) | | | | | |
| 20 | CWC | (1/8 * page 3, line 8) | - | | | #DIV/0! |
| 21 | Materials & Supplies (Note A) | EIA Form 412 | - | TE | 0.000% | - |
| 22 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 23 | TOTAL WORKING CAPITAL | (sum lines 20-22) | - | | | #DIV/0! |
| 24 | RATE BASE | (sum lines 18, 19, and 23) | - | | | #DIV/0! |



**Pierre (South Dakota) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | **Transmission Amount ($)** |
| | O&M (Note M) | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Transmission | Schedule 7, Column E, Line 8 | - | TE | 0.000% | - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts | EIA Form 412 | - | TE | 100.000% | - |
| 2 | Less Account 565 | Schedule 7, Column C, Line 8 | - | TE | 0.000% | - |
| 3 | A&G | Schedule 7, Column E, Line 13 | - | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note C) | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note C) | EIA Form 412 | - | TE | 0.000% | - |
| 6 | Common | Schedule 7, Column E, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | EIA Form 412 | - | TE | 0.000% | - |
| 8 | TOTAL O&M | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note L) | | | | | |
| 9 | Transmission | Schedule 4, Column O, Line 7 | - | TP | 0.000% | - |
| 10 | General & Intangible | Schedule 4, Column | - | W/ | #DI | #DIV/0! |

| | | | | | |
|---|---|---|---|---|---|
| | | O, Line 1 and Line 9 | | S | V/0! |
| 11 | Common | Schedule 4, Column O, Line 17 | - | CE | #DIV/0! |
| 12 | TOTAL DEPRECIATION | (Sum lines 9 - 11) | - | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note D) | | | | |
| | LABOR RELATED | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S | #DIV/0! |
| | PLANT RELATED | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP | #DIV/0! |
| 16 | Gross Receipts | Schedule 5, Column B, Line 5 | - | NA | 0.00% - |
| 17 | Other | Not Used | | NA | 0.00% - |
| 18 | Payments in lieu of taxes | Schedule 3, Column B, Line 6 | - | GP | #DIV/0! |
| 19 | TOTAL OTHER TAXES | (sum lines 13-14 and 15-18) | - | | #DIV/0! |
| 20 | RETURN | (page 2, line 24 * R) | #DIV/0! | | #DIV/0! |
| 21 | GROSS REVENUE REQUIREMENT | (sum lines 8, 12, 19, and 20) | #DIV/0! | | #DIV/0! |

**Pierre (South Dakota) Municipal Utilities**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) | |
|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, column 5 | | | - | |
| 2 | Less transmission plant excluded from ISO rates (Note F) | EIA Form 412 | | | - | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note G ) | EIA Form 412 | | | - | |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | - | |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | | **0.00 %** | **= TP** |
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses | page 3, line 1, column 3 | | | - | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note E) | EIA Form 412 | | | - | |
| 8 | Included transmission expenses | (line 6 less line 7) | | | - | |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | 0.00 % | |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line | | | **0.00 %** | **= TE** |

5)

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | WAGES & SALARIES | | | | | | | |
| 11 | Production | Schedule 8, Column E, Line 2 | - | NA | 0.000% | - | | |
| 12 | Transmission | Schedule 8, Column E, Line 5 | - | TP | 0.000% | - | | |
| 13 | Distribution | Schedule 8, Column E, Line 8 | - | NA | 0.000% | - | | |
| 14 | Other | Schedule 8, Column E, Line 11 | - | NA | 0.000% | - | | |
| 15 | Total | (sum lines 11-14) | - | | | - | | |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | | |
| 17 | Wages & Salaries Allocator (Note N) | (line 15, col 5 divided by col 3) | | | | **#DIV/0!** | = | **W/S** |
| | COMMON PLANT | | | | | | | |
| 18 | Electric | Schedule 4, Column F, Line 10 | | | | 0 | | |
| 19 | Gas | EIA Form 412 | | | | 0 | | |
| 20 | Water | EIA Form 412 | | | | | | |
| 21 | Total | (sum lines 18-20) | | | | 0 | | |
| 22 | Percentage of Electric Common Plant | (line 17 divided by line 21) | | | | #DIV/0! | | |
| 23 | Common Plant Allocator (CE) | (line 22 times line 17) | | | | **#DIV/0!** | = | **CE** |
| | RETURN (R) | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 24 | Long Term Interest (Note J) | Schedule 3, Column B, Line 16 | - | | | | | |
| | | | $ Amount | % | Cost (Note O) | Weighted | | |
| 25 | Long Term Debt | Schedule 2, Column D, Line 37 | - | #DIV/0! | 0.00% | #DIV/0! | | |
| 26 | Proprietary Capital | Schedule 2, Column D, Line 32 | - | #DIV/0! | 10.10% | #DIV/0! | | |
| 27 | Total | (sum lines 25, 26) | - | #DIV/0! | | #DIV/0! | = | R |



**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H (Utilizing EIA Form 412 - Nonlevelized)

12 Months Ended December 31, 2XXX

Notes:

A Transmission related only.

B Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165.

C Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety related advertising.
Line 5a - Regulatory Commission

| | |
|---|---|
| | Expenses directly related to transmission service, ISO filings or transmission siting. |
| D | Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere. |
| E | Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA. |
| F | Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account balances are adjusted to reflect application of seven-factor test). |
| G | Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down. |
| H | Includes income related only to transmission facilities, such as pole attachments, rentals and special use. |
| I | The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. |
| J | Include only the amount from Accounts 427, 428, 429 and 430. |
| K | Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements. |
| L | Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |

| | |
|---|---|
| M | Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate. |
| N | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| O | The cost of proprietary capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The cost of long-term debt is calculated by dividing long-term interest (line 24) by the amount of long-term debt (line 25, col 3). The cost of proprietary capital included an incentive adder of 50 basis points approved in Docket No. ER15-2324. |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 |
|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Transmission Amount ($)** |
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, page 2, line 2 col 5 | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, page 2, line 8 col 5 | - |
| 3 | Net Transmission Plant - SPP (Note B) | (line 1 less line 2) | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 3, line 8 col 5 | #DIV/0! |
| **5** | **Annual Allocation Factor for O&M** | **(line 3 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, page 3, line 19 col 5 | #DIV/0! |
| **7** | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| **8** | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, p 3, line 12 | #DIV/ |

| | | | |
|---|---|---|---|
| | | col 5 | 0! |
| 1 0 | Return | Attach H, p 3, line 20 col 5 | #DIV/ 0! |
| 1 1 | Depreciation plus return | (line 9 plus line 10) | #DIV/ 0! |
| **1 2** | **Annual Allocation Factor for Depreciation and Return** | **(line 12 divided by line 3)** | **#DIV/ 0!** |



**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Upgrade Name** | **Upgrade ID** | **Upgrade Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Upgrade Net Plant** | **Annual Allocation Factor for Depreciation & Return** | **Annual Charge for Depreciation & Return** | **Net Annual Revenue Requirement** |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | Note D | (Page 1 line 12) | (Col. 6 * Col. 7) | (Sum Col. 5 & 8) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1<br>f | Project 6 | Proje<br>ct 6 | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| … | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | $<br>- | #DIV/<br>0! | #DIV/<br>0! | $<br>- | #DIV/<br>0! | #DIV/<br>0! | #DIV/0<br>! |
| | | | | | | | | | |
| 2 | Annual Totals | | | | | | | | #DIV/<br>0! |

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 4- Line 14.

D Net Plant is derived from Schedule 4- Line 42 and includes all CWIP

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1a: SPP Directed Projects

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **13 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | | |
| **2** | **Total Gross Plant in Service** | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3a | Project 1 | | | | | | | | | | | | | | - |
| 3b | Project 2 | | | | | | | | | | | | | | - |
| 3c | Project 3 | | | | | | | | | | | | | | - |
| 3d | Project 4 | | | | | | | | | | | | | | - |
| 3e | Project 5 | | | | | | | | | | | | | | - |
| 3f | Project 6 | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| 4 | **Total Accumulated Depreciation** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Net Plant in Service** | | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| 6 | **Total Net Plant in Service** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Electric Balance Sheet (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | | C | E |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| 1 | **ELECTRIC PLANT** Electric Plant & Adjustments (101-106,114,116) | | 29 | **PROPIETARY CAPITAL** Investment of Municipality (208) | |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and Depletion (108,111,115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | |
| 7 | **Net Electric Plant including Nuclear Fuel** | **$ -** | 34 | Advances from Municipality and Other Long Term Debt (223, 224) | $ - |
| | **OTHER PROPERTY & INVESTMENTS** | | 35 | Unamortized Premium on Long Term | |
| 8 | Non-Electric Plant Property (121) | $ - | | Debt (225) | $ - |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | $ - | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | $ - | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| 13 | **CURRENT & ACCRUED ASSETS** Cash, Working Funds & Investments (131-136) | | 38 | Accumulated Operating Provisions (228.1-.4) | $ - |
| | | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Recevable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | $ - |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | $ - |
| 26 | Miscellaneous Debt, Research and | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Development Expenses & Unamortized Losses (184-191) | $ - | 51 | Unamortized gain on Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | $ - |
| 8 | **NET ELECTRIC OPERATING INCOME** | $ - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | $ - |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | $ - |
| 15 | Electric Income | $ - |
| 16 | Income Deductions from Interest on Long Term Debt (427) | |
| 17 | Other Income Deductions (428-431) | $ - |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | $ - |
| 19 | Total Income Deductions | $ - |
| 20 | Income Before Extraordinary Items | $ |

| | | |
|---|---|---|
| | | - |
| 21 | Extraordinary Items (434) | $ - |
| 22 | Extraordinary Deductions (435) | |
| 23 | **NET INCOME** | **$ -** |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended December 31, 2XXX

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjusted BOY | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Accumulated Depreciation | Adjusted BOY | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| | | | | | | | | | | | | | | | | |
| 2 | Steam Production (310-316) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Nuclear Production (320-325) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 4 | Hydraulic Production (330-336) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 5 | Other Production (340-346) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 6 | **Total Production Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |
| | | | | | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 8 | Distribution Plant (360-373) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 9 | General Plant (389-399) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | | | |
| 10 | **Total Electric Plant In Service** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | | | | | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 16 | **Total Electric Plant & Adj's** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| 17 | Common Plant | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 5: Taxes other than Income Taxes (EIA Form 412)

12 Months Ended December 31, 2XXX

| Line No. | A<br>Description | B<br>Amount ($) | C<br>Notes/Comments |
|---|---|---|---|
| | **Taxes other than Income Taxes, Operating Income** | | |
| | **Payroll Taxes:** | | |
| 1 | FICA Taxes | $ - | |
| 2 | Unemployment Taxes | $ - | |
| | **Plant Related Taxes:** | | |
| 3 | Highway Taxes | $ - | |
| 4 | Property Taxes | $ - | 0 |
| 5 | Gross Receipts Taxes | $ - | |
| 6 | Payment In Lieu of Taxes (Transfer) | | |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended December 31, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | 0.00% |
| 3 | 351 | Energy Storage Equipment - Transmission | N/A | 0.00% |
| 4 | 352 | Structures & Improvements | 32.4 | 3.09% |
| 5 | 353 | Station Equipment | N/A | 0.00% |
| 6 | 354 | Towers & Fixtures | N/A | 0.00% |
| 7 | 355 | Poles & Fixtures | 32 | 3.13% |
| 8 | 356 | Overhead Conductors and Devices | N/A | 0.00% |
| 9 | 357 | Underground Conduit | N/A | 0.00% |
| 10 | 358 | Underground Conductors and Devices | N/A | 0.00% |
| 11 | 359 | Roads and Trails | N/A | 0.00% |
| 12 | | **General Plant** | | |
| 13 | 390 | Structures & Improvements | N/A | 0.00% |
| 14 | 391 | Office Furniture and Equipment | N/A | 0.00% |
| 15 | 392 | Transportation Equipment | 13.83 | 7.23% |
| 16 | 393 | Stores Equipment | N/A | 0.00% |
| 17 | 394 | Tools, Shop and Garage Equipment | 12.5 | 8.00% |
| 18 | 395 | Laboratory Equipment | N/A | 0.00% |
| 19 | 396 | Power Operated Equipment | 13.67 | 7.32% |
| 20 | 397 | Communication Equipment | 10 | 10.00% |
| 21 | 398 | Miscellaneous Equipment | N/A | 0.00% |

| | | | | | |
|---|---|---|---|---|---|
| 22 | | **Intangible Plant** | | | |
| 23 | 301 | Organization | 5 | 20.0% |
| 24 | 302 | Franchises and consents | N/A | 0.0% |
| 25 | 303 | Miscellaneous intangible plant | N/A | 0.0% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: O&M Expense (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | $ - | $ - | $ - | $ - |
| 5 | Purchased Power (555) | $ - | | $ - | $ - |
| 6 | Other Production Expenses (556-557) | $ - | $ - | $ - | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-567, 568-573) | XXXXXXXXXXXXX | | $ - | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXXXX | | $ - | $ - |
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXXXX | | $ - | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 11 | Customer Service & Information Expenses (907-910) | XXXXXXXXXXXXX | | $ - | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXXX | | $ - | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXXX | | $ - | $ - |
| 14 | Total Electric Operation and Maintenance Expenses | **$ -** | **$ -** | **$ -** | **$ -** |

| | | |
|---|---|---|
| 15 | Total Number of Full Time Employees | |
| 16 | Total Number of Part Time Employees | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Common O&M Expense | $ - | $ - | $ - | $ - |

**Pierre (South Dakota) Municipal Utilities**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | | Accounts | Salaries | |
| 1 | | | Production / Generation | | |
| 2 | | | Salaries | $ - | $ - |
| 3 | | | | | |
| 4 | | | Transmission: | | |
| 5 | | | Salaries | $ - | $ - |
| 6 | | | | | |
| 7 | | | Distribution: | | |
| 8 | | | Salaries | | $ - |
| 9 | | | | | |
| 10 | | | Customer Service & Information | | |
| 11 | | | Salaries | | $ - |
| 12 | | | | | |
| 13 | | | Administrative & General | | |
| 14 | | | Salaries | | $ - |
| 15 | | | | | |
| 16 | | | **Total** | $ - | $ - |

# MRES MEMBER UTILITIES

# ANNUAL UPDATE PROTOCOLS

# UNDER ATTACHMENT H OF SPP OPEN ACCESS TRANSMISSION TARIFF

## Section I. Applicability

The following procedures shall apply to Moorhead Public Service ("MPS"), Orange City Municipal Utilities ("OCMU"), Pierre Municipal Utilities ("PMU"), Sioux Center Municipal Utilities ("SCMU") and Watertown Municipal Utility District ("WMUD") calculation of its annual transmission revenue requirement ("ATRR") pursuant to its Formula Rate Template ("FRT"). These utilities will be referred to as the "Members" in these protocols. The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the Federal Power Act.

## Section II. Annual ATRR Update

1. Beginning on or before May 1, 2016, and on or before each subsequent May 1, the Members shall determine their ATRRs to be effective on June 1, 2016 and each subsequent June 1.
2. On or before May 1, 2016, and on or before each subsequent May 1, the Members shall request SPP to post their FRTs and supporting documentation on the SPP OASIS, and shall notify Interested Parties of the website address where such information is posted via the SPP email exploder list titled "Formula Rate Posting Information Notification."
    A. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state

attorneys general ("Interested Parties"). Interested Parties can contact MRES to be included as an Interested Party.

B. MRES Members shall provide electronic notice of Annual ATRR Update postings to all Interested Parties within 10 days of such posting through an email to the Formula Rate Posting Information Notification exploder maintained by SPP.

C. As used in these Protocols, "Formula Rate Posting Information Notification" exploder shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification exploder through the link on the SPP website. The exploder list is titled "Formula Rate Posting Information Notification" and can be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include, but are not limited to, (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

3. If the date for posting the FRT falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the FRT shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the FRT will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

4. The Annual Update shall:

   A. Include a workable data-populated FRT and underlying work papers in native format with all formulas intact;

   B. Be based on the Member's audited financial statements for the either the prior fiscal or calendar year, as applicable. MPS, PMU and WMUD base their audited financial statements on a calendar year from January 1 to December 31. OCMU

and SCMU base their audited financial statements on a fiscal year from July 1 to June 30.

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the FRT that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;

D. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);

E. With respect to any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that affect the

4. ATRR calculation;

5. The implementation of new estimation methods or policies that change prior estimates; and

6. changes to income tax elections (if applicable);

ii. Identify items included in the FRT at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the FRT;

iv. Provide, for each item identified pursuant to items II.4.e.i - II.4.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the FRT.

5. Each of the Members shall hold an open meeting among Interested Parties ("Formula Rate Update Meeting") between the Publication Date and May 31 of each year. No less than seven (7) days prior to such Formula Rate Update Meeting, each Member shall provide notice on the Member Related Posting section of the SPP OASIS of the time, date, and location of its Formula Rate Update Meeting. The Formula Rate Update Meeting shall (i) permit the Member to explain and clarify its FRT and (ii) provide Interested Parties an opportunity to seek information and clarifications from the Member about the FRT. Each Member shall provide remote access for participation of Interested Parties at such meetings.

6. If a Member constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of Joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via email no less than 7 days prior to such meeting.

**Section III. Information Exchange Procedures**

Each Member's FRT shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until July 1 following the Publication Date (unless such period is extended with the written consent of the applicable Member or by FERC order) to serve reasonable information and document requests on the applicable Member ("Information Exchange Period"). If July 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

a. The extent or effect of an Accounting Change;

b. Whether the FRT fails to include data properly recorded in accordance with these protocols;

c. The proper application of the formula rate and procedures in these protocols;

d. The accuracy of data and consistency with the formula rate of the calculations shown in the FRT;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. The Members shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. The Members shall respond to all information and document requests received on or before July 1 by no later than August 10 following the Publication Date, unless the Information Exchange Period is extended by the Members or FERC.

3. Each Member will cause to be posted on the Member Related Postings section of the SPP OASIS all information requests regarding the Member's FRT in SPP from Interested Parties and the Member's response(s) to such requests; except, however, if responses to information and document requests include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the applicable Member and the requesting party.

4. Members shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the applicable Member's FRT. However, each Member may require that Interested Parties execute a non-disclosure agreement to

obtain access to material that the Member deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**Section IV. Challenge Procedures for the FRT Update**

1. No later than July 5 of each year, any Interested Party may notify a Member in writing of any specific challenge(s) to any component of the most recently posted FRT ("Preliminary Challenge”). A party submitting a Challenge to a Member must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Within five (5) business days of receiving notice of such challenge(s), any Member so notified shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) on the Member Related Posting section of the SPP OASIS. The Member and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations.
2. Each Member shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which the Member agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the FRT will result. If the Member disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.
3. If the Member and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of the Member’s response to the issue(s), senior management representatives of the Member and the Interested Parties shall meet to try to resolve the issue(s). Each challenged Member shall appoint a senior representative to work with the party that submitted the Challenge (or its representative) toward a resolution of the challenge. If the Member disagrees with such challenge, the Member

will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. Any modification to the FRT that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the FRT for the next Rate Year and incorporated into the Member's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the ATRR, such changes shall be incorporated into the FRT for the next rate year.

4. If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, any Interested Party that has not resolved any Preliminary Challenge to the Formula Rate Update may then file with FERC a Formal Challenge to a Formula Rate Update pursuant to these Implementation Procedures ("Formal Challenge").

    a. A Formal Challenge shall:

        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        ii. Explain how the action or inaction violates the filed rate formula or protocols;
        iii. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

            1. The extent or effect of an Accounting Change;
            2. Whether the FRT fails to include data properly recorded in accordance with these protocols;
            3. The proper application of the formula rate and procedures in these protocols;
            4. The accuracy of data and consistency with the formula rate of the charges shown in the FRT;
            5. The prudence of actual costs and expenditures;

6. The effect of any change to the underlying Uniform System of Accounts; or

7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

b. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on the applicable Member. Service to a Member must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on a Member's Informational Filing required under Section VI of these protocols.

5. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the FRT fails to include data properly recorded in accordance with these protocols; (3) the proper

application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the FRT; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

6. Each Member will cause to be posted all Informal Challenges from Interested Parties and the Member's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Member and the requesting party.

7. Any changes or adjustments to the FRT resulting from the Information Exchange and Informal Challenge processes that are agreed to by a MRES Member will be reported in the Informational Filing required pursuant to Section VI of these protocols.

8. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of the Member to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on the Member on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as the Member's Informational Filing discussed in Section VI of these protocols. The Member shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

9. In any proceeding initiated by FERC concerning the FRT or in response to a Formal Challenge, the Member shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the FRT consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of a MRES Member to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the FRT under the Challenge Procedures set forth in these protocols and the FRT shall not be subject to challenge by anyone for the purpose of modifying the FRT. Any modifications to the FRT will require, as applicable, a Federal Power Act section 205 or section 206 filing.

    Any Interested Party seeking changes to the application of the FRT due to a change in the Uniform System of Accounts, shall first raise the matter with MRES in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to the ATRR**

Any changes to the data inputs, the result of any FERC proceeding to consider the FRT, or a result of the procedures set forth herein, shall be incorporated into the FRT for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of the Commission's regulations. The fixed base return on equity of 9.6% set forth in the Members' FRT will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act. The asset depreciation rates set forth in the Members' FRT filing will not be changed absent a filing pursuant to Section 205 or Section 206 of the Federal Power Act.

**Section VI. Informational Filings**

By March 15 of each year, each Member shall submit to FERC an informational filing

("Informational Filing") of its FRT for the Rate Year. Each Member shall submit each year's Informational Filing in the same docket assigned to its initial informational filing,[1] subject to the determination of the FERC's Secretary. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that the Member has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. The transmittal letter accompanying the Informational Filing shall inform the Commission that the Informational Filing is not intended to be subject to the Commission's notice requirements, and that it is not being submitted for the purpose of having the Commission assign a docket number to the filing nor for the purpose of obtaining Commission acceptance, approval or other review of the filing. Each Member shall provide notification of each Informational Filing through notification on the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

[1] In 2016, MPS submitted its Informational filing in ER16-1182, OCMU in ER16-1183, PMU in ER16-1184, SCMU in ER16-1185, and WMUD in in ER16-1186.

# ADDENDUM 33 TO ATTACHMENT H

## City of Sioux Center, Iowa

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Index

13 Months Ended June 30, 2XXX


| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |

**City of Sioux Center (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 21 | | | #DIV/0! |
| | REVENUE CREDITS (Note I) | | | | |
| 2 | Account No. 454 (Note H) | EIA Form 412 | - | TP 0.000% | - |
| 3a | Transmission charges for all transmission transactions | EIA Form 412 | - | TP 0.000% | - |
| 3b | Transmission charges for all transmission transactions included in Native Load | EIA Form 412 | - | TP 0.000% | - |
| 3c | Account No. 456.1 | (line 3a less line 3b) | - | TP 0.000% | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | EIA Form 412 | - | TP 0.000% | - |
| 5 | Revenues from service provided by the ISO at a discount | EIA Form 412 | - | TP 0.000 | - |

| | | | | | |
|---|---|---|---|---|---|
| | | | | % | |
| 6 | TOTAL REVENUE CREDITS | (sum lines 2, 3c, 4, 5) | | | - |
| 7 | ATRR for SPP Directed Projects | Schedule 1, line 2, col 9 | | | #DIV/0! |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus lines 6 and 7) | | | #DIV/0! |



**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H (Utilizing EIA Form 412 - Nonlevelized)

12 Months Ended June 30, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| | **RATE BASE** | | | | |
| | GROSS PLANT IN SERVICE (Note L) | | | | |
| 1 | Production | Schedule 4, Column G, Line 6 | - | NA 0.000% | - |
| 2 | Transmission | Schedule 4, Column G, Line 7 | - | TP 0.000% | - |
| 3 | Distribution | Schedule 4, Column G, Line 8 | - | NA 0.000% | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | General & Intangible | Schedule 4, Column G, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Common | Schedule 4, Column G, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 6 | TOTAL GROSS PLANT | (sum lines 1-5) | - | **GP=** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note L) | | | | | |
| 7 | Production | Schedule 4, Column N, Line 6 | - | NA | 0.00% | - |
| 8 | Transmission | Schedule 4, Column N, Line 7 | - | TP | 0.00% | - |
| 9 | Distribution | Schedule 4, Column N, Line 8 | - | NA | 0.00% | - |
| 10 | General & Intangible | Schedule 4, Column N, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 11 | Common | Schedule 4, Column N, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL ACCUM. DEPRECIATION | (sum lines 7-11) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | - | | | - |
| 14 | Transmission | (line 2 - line 8) | - | | | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - |
| 16 | General & Intangible | (line 4 - line 10) | - | | | #DIV/0! |
| 17 | Common | (line 5 - line 11) | - | | | #DIV/0! |
| 1 | TOTAL NET PLANT | (sum lines | | **N** | # | #DI |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | 13-17) | - | **P =** | **DIV/0!** | V/0! |
| 19 | LAND HELD FOR FUTURE USE (Note A) | EIA Form 412 | - | TP | 0.000% | - |
| | WORKING CAPITAL (Note B) | | | | | |
| 20 | CWC | (1/8 * page 3, line 8) | - | | | #DIV/0! |
| 21 | Materials & Supplies (Note A) | EIA Form 412 | - | TE | 0.000% | - |
| 22 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 23 | TOTAL WORKING CAPITAL | (sum lines 20-22) | - | | | #DIV/0! |
| 24 | RATE BASE | (sum lines 18, 19, and 23) | - | | | #DIV/0! |



**City of Sioux Center (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | **Transmission Amount ($)** |
| | O&M (Note M) | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Transmission | Schedule 7, Column E, Line 8 | - | TE | 0.000% | - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts | EIA Form 412 | - | TE | 100.000% | - |
| 2 | Less Account 565 | Schedule 7, Column C, Line 8 | - | TE | 0.000% | - |
| 3 | A&G | Schedule 7, Column E, Line 13 | - | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note C) | EIA Form 412 | | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note C) | EIA Form 412 | - | TE | 0.000% | - |
| 6 | Common | Schedule 7, Column E, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | EIA Form 412 | - | TE | 0.000% | - |
| 8 | TOTAL O&M | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note L) | | | | | |
| 9 | Transmission | Schedule 4, Column O, Line 7 | - | TP | 0.000% | - |
| 10 | General & Intangible | Schedule 4, Column | - | W/ | #DI | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | O, Line 1 and Line 9 | | S | V/0! | |
| 11 | Common | Schedule 4, Column O, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL DEPRECIATION | (Sum lines 9 - 11) | - | | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note D) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S | #DIV/0! | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S | #DIV/0! | #DIV/0! |
| | PLANT RELATED | | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP | #DIV/0! | #DIV/0! |
| 16 | Gross Receipts | Schedule 5, Column B, Line 5 | - | NA | 0.00% | - |
| 17 | Other | Not Used | | NA | 0.00% | - |
| 18 | Payments in lieu of taxes | Schedule 3, Column B, Line 6 | - | GP | #DIV/0! | #DIV/0! |
| 19 | TOTAL OTHER TAXES | (sum lines 13-14 and 15-18) | - | | | #DIV/0! |
| 20 | RETURN | (page 2, line 24 * R) | #DIV/0! | | | #DIV/0! |
| 21 | GROSS REVENUE REQUIREMENT | (sum lines 8, 12, 19, and 20) | #DIV/0! | | | #DIV/0! |

**City of Sioux Center (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended June 30, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) | |
|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, column 5 | | | - | |
| 2 | Less transmission plant excluded from ISO rates (Note F) | EIA Form 412 | | | - | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note G ) | EIA Form 412 | | | - | |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | - | |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | | **0.00 %** | **= TP** |
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses | page 3, line 1, column 3 | | | - | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note E) | EIA Form 412 | | | - | |
| 8 | Included transmission expenses | (line 6 less line 7) | | | - | |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | 0.00 % | |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line | | | **0.00 %** | **= TE** |

5)

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | WAGES & SALARIES | | | | | | | |
| 11 | Production | Schedule 8, Column E, Line 2 | - | NA | 0.000% | - | | |
| 12 | Transmission | Schedule 8, Column E, Line 5 | - | TP | 0.000% | - | | |
| 13 | Distribution | Schedule 8, Column E, Line 8 | - | NA | 0.000% | - | | |
| 14 | Other | Schedule 8, Column E, Line 11 | - | NA | 0.000% | - | | |
| 15 | Total | (sum lines 11-14) | - | | | - | | |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | | |
| 17 | Wages & Salaries Allocator (Note N) | (line 15, col 5 divided by col 3) | | | | **#DIV/0!** | = | **W/S** |
| | COMMON PLANT | | | | | | | |
| 18 | Electric | Schedule 4, Column G, Line 16 | | | | 0 | | |
| 19 | Gas | EIA Form 412 | | | | 6,403,332 | | |
| 20 | Water | EIA Form 412 | | | | 12,677,727 | | |
| 21 | Total | (sum lines 18-20) | | | | 19,081,059 | | |
| 22 | Percentage of Electric Common Plant | (line 17 divided by line 21) | | | | 0.00% | | |
| 23 | Common Plant Allocator (CE) | (line 22 times line 17) | | | | **#DIV/0!** | = | **CE** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | RETURN (R) | | | | | | | |
| 24 | Long Term Interest (Note J) | Schedule 3, Column B, Line 16 | - | | | | | |
| | | | $ Amount | % | Cost (Note O) | Weighted | | |
| 25 | Long Term Debt | Schedule 2, Column D, Line 37 | - | #DIV/0! | 0.00% | #DIV/0! | | |
| 26 | Proprietary Capital | Schedule 2, Column D, Line 32 | - | #DIV/0! | 10.10% | #DIV/0! | | |
| 27 | Total | (sum lines 25, 26) | - | #DIV/0! | | #DIV/0! | = | R |



**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Attachment H (Utilizing EIA Form 412 - Nonlevelized)

12 Months Ended June 30, 2XXX

Notes:

A Transmission related only.

B Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165.

C Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety

related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

D Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

E Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

F Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account

balances are adjusted to reflect application of seven-factor test).

G Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation

step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up

facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

H Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

I The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements)

or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include

revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct

assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

J Include only the amount from Accounts 427, 428, 429 and 430.

K Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

L Plant in Service, Accumulated Depreciation, and

| | |
|---|---|
| | Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| M | Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate. |
| N | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| O | The cost of proprietary capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The cost of long-term debt is calculated by dividing long-term interest (line 24) by the amount of long-term debt (line 25, col 3). The cost of proprietary capital included an incentive adder of 50 basis points approved in Docket No. ER15-2324. |

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended June 30, 2XXX

| | 1 | 2 | 3 |
|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Transmission Amount ($)** |
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, page 2, line 2 col 5 | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, page 2, line 8 col 5 | - |
| 3 | Net Transmission Plant - SPP (Note B) | (line 1 less line 2) | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 3, line 8 col 5 | #DIV/0! |
| **5** | **Annual Allocation Factor for O&M** | **(line 3 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, page 3, line 19 col 5 | #DIV/0! |
| **7** | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| **8** | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, p 3, line 12 | #DIV/ |

| | | | |
|---|---|---|---|
| | | col 5 | 0! |
| 1 0 | Return | Attach H, p 3, line 20 col 5 | #DIV/ 0! |
| 1 1 | Depreciation plus return | (line 9 plus line 10) | #DIV/ 0! |
| **1 2** | **Annual Allocation Factor for Depreciation and Return** | **(line 12 divided by line 3)** | **#DIV/ 0!** |



**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended June 30, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Upgrade Name** | **Upgrade ID** | **Upgrade Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Upgrade Net Plant** | **Annual Allocation Factor for Depreciation & Return** | **Annual Charge for Depreciation & Return** | **Net Annual Revenue Requirement** |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | Note D | (Page 1 line 12) | (Col. 6 * Col. 7) | (Sum Col. 5 & 8) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | |
| f | Project 6 | Project 6 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| … | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | | | | | | | |
| 2 | Annual Totals | | | | | | | | #DIV/0! |

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 4- Line 14.

D Net Plant is derived from Schedule 4- Line 42 and includes all CWIP

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1a: SPP Directed Projects

13 Months Ended June 30, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **13 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | | |
| 2 | **Total Gross Plant in Service** | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3a | Project 1 | | | | | | | | | | | | | | - |
| 3b | Project 2 | | | | | | | | | | | | | | - |
| 3c | Project 3 | | | | | | | | | | | | | | - |
| 3d | Project 4 | | | | | | | | | | | | | | - |
| 3e | Project 5 | | | | | | | | | | | | | | - |
| 3f | Project 6 | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| 4 | **Total Accumulated Depreciation** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Net Plant in Service** | | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| 6 | **Total Net Plant in Service** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Electric Balance Sheet (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | | C | E |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| | **ELECTRIC PLANT** | | | **PROPIETARY CAPITAL** | |
| 1 | Electric Plant & Adjustments (101-106,114,116) | | 29 | Investment of Municipality (208) | $ - |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | $ - |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and Depletion (108,111,115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | $ - |
| 7 | **Net Electric Plant including Nuclear Fuel** | **$ -** | 34 | Advances from Municipality and Other Long Term Debt (223, 224) | $ - |
| | **OTHER PROPERTY & INVESTMENTS** | | 35 | Unamortized Premium on Long Term Debt (225) | $ - |
| 8 | Non-Electric Plant Property (121) | $ - | | | |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| | **CURRENT & ACCRUED ASSETS** | | 38 | Accumulated Operating Provisions (228.1-.4) | $ - |
| 13 | Cash, Working Funds & Investments (131-136) | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Recevable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | $ - |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | $ - |
| 26 | Miscellaneous Debt, Research and Development Expenses | | 51 | Unamortized gain on | |

| | | | | | |
|---|---|---|---|---|---|
| | & Unamortized Losses (184-191) | $ - | | Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | $ - |
| 8 | **NET ELECTRIC OPERATING INCOME** | $ - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | $ - |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | $ - |
| 15 | Electric Income | $ - |
| 16 | Income Deductions from Interest on Long Term Debt (427) | $ - |
| 17 | Other Income Deductions (428-431) | $ - |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | $ - |
| 19 | Total Income Deductions | $ - |

| | | |
|---|---|---|
| 20 | Income Before Extraordinary Items | **$ -** |
| 21 | Extraordinary Items (434) | $ - |
| 22 | Extraordinary Deductions (435) | $ - |
| 23 | **NET INCOME** | **$ -** |

**City of Sioux Center (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 4: Electric Plant (EIA Form 412)
12 Months Ended June 30, 2XXX



**City of Sioux Center (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 4: Electric Plant (EIA Form 412)
12 Months Ended June 30, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjusted BOY | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Accumulated Depreciation | Adjusted BOY | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| | | | | | | | | | | | | | | | | |
| 2 | Steam Production (310- | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 316) | | | | | | | | | | | | | | | |
| 3 | Nuclear Production (320-325) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 4 | Hydraulic Production (330-336) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 5 | Other Production (340-346) | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 6 | **Total Production Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | |
| 8 | Distribution Plant (360-373) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | |
| 9 | General Plant (389-399) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | |
| 10 | **Total Electric Plant In** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |

| | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Service** | | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | | | |
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| | | | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | | | | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |
| 16 | **Total Electric Plant & Adj's** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** |
| 17 | Common Plant | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | $ - |

**City of Sioux Center (Iowa)**
Formula Rate Template for SPP Zone 19 Transmission
Schedule 5: Taxes other than Income Taxes (EIA Form 412)
12 Months Ended June 30, 2XXX

| Line No. | A<br>Description | B<br>Amount ($) | C<br>Notes/Comments |
|---|---|---|---|
| | **Taxes other than Income Taxes, Operating Income** | | |
| | **Payroll Taxes:** | | |
| 1 | FICA Taxes | $ - | |
| 2 | Unemployment Taxes | $ - | |
| | **Plant Related Taxes:** | | |
| 3 | Highway Taxes | $ - | |
| 4 | Property Taxes | $ - | 0 |
| 5 | Gross Receipts Taxes | $ - | |
| 6 | Payment In Lieu of Taxes (Transfer) | | |

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended June 30, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | |
| 3 | 351 | Energy Storage Equipment - Transmission | N/A | |
| 4 | 352 | Structures & Improvements | 20 | 5.0% |
| 5 | 353 | Station Equipment | 20 | 5.0% |
| 6 | 354 | Towers & Fixtures | 20 | 5.0% |
| 7 | 355 | Poles & Fixtures | 20 | 5.0% |
| 8 | 356 | Overhead Conductors and Devices | 20 | 5.0% |
| 9 | 357 | Underground Conduit | 20 | 5.0% |
| 10 | 358 | Underground Conductors and Devices | 20 | 5.0% |
| 11 | 359 | Roads and Trails | 20 | 5.0% |
| 12 | | **General Plant** | | |
| 13 | 390 | Structures & Improvements | 20 | 5.0% |
| 14 | 391 | Office Furniture and Equipment | 5 | 20.0% |
| 15 | 392 | Transportation Equipment | 5 | 20.0% |
| 16 | 393 | Stores Equipment | 5 | 20.0% |
| 17 | 394 | Tools, Shop and Garage Equipment | 5 | 20.0% |
| 18 | 395 | Laboratory Equipment | 5 | 20.0% |
| 19 | 396 | Power Operated Equipment | 5 | 20.0% |
| 20 | 397 | Communication Equipment | 5 | 20.0% |
| 21 | 398 | Miscellaneous Equipment | 5 | 20.0% |

| | | | | | |
|---|---|---|---|---|---|
| 22 | | **Intangible Plant** | | | |
| 23 | | 301 | Organization | N/A | |
| 24 | | 302 | Franchises and consents | N/A | |
| 25 | | 303 | Miscellaneous intangible plant | N/A | |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: O&M Expense (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | $ - | $ - | $ - | $ - |
| 5 | Purchased Power (555) | $ - | | $ - | $ - |
| 6 | Other Production Expenses (556-557) | $ - | $ - | $ - | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-567, 568-573) | XXXXXXXXXXXX | | $ - | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXXX | | $ - | $ - |
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXX | | $ - | $ - |

| | | | | | |
|---|---|---|---|---|---|
| | | XX | | | |
| 11 | Customer Service & Information | | | | |
| | Expenses (907-910) | XXXXXXXXXXXX | | $ - | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXX | | $ - | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXX | | $ - | $ - |
| 14 | Total Electric Operation and Maintenance Expenses | $ - | $ - | $ - | $ - |

| | | |
|---|---|---|
| 15 | Total Number of Full Time Employees | |
| 16 | Total Number of Part Time Employees | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Common O&M Expense | $ - | $ - | $ - | $ - |

**City of Sioux Center (Iowa)**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended June 30, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | | Accounts | Salaries | |
| 1 | | | Production / Generation | | |
| 2 | | | Salaries | $ - | $ - |
| 3 | | | | | |
| 4 | | | Transmission: | | |
| 5 | | | Salaries | $ - | $ - |
| 6 | | | | | |
| 7 | | | Distribution: | | |
| 8 | | | Salaries | | $ - |
| 9 | | | | | |
| 10 | | | Customer Service & Information | | |
| 11 | | | Salaries | | $ - |
| 12 | | | | | |
| 13 | | | Administrative & General | | |
| 14 | | | Salaries | | $ - |
| 15 | | | | | |
| 16 | | | **Total** | $ - | $ - |

# MRES MEMBER UTILITIES

# ANNUAL UPDATE PROTOCOLS

# UNDER ATTACHMENT H OF SPP OPEN ACCESS TRANSMISSION TARIFF

## Section I. Applicability

The following procedures shall apply to Moorhead Public Service ("MPS"), Orange City Municipal Utilities ("OCMU"), Pierre Municipal Utilities ("PMU"), Sioux Center Municipal Utilities ("SCMU") and Watertown Municipal Utility District ("WMUD") calculation of its annual transmission revenue requirement ("ATRR") pursuant to its Formula Rate Template ("FRT"). These utilities will be referred to as the "Members" in these protocols. The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the Federal Power Act.

## Section II. Annual ATRR Update

1. Beginning on or before May 1, 2016, and on or before each subsequent May 1, the Members shall determine their ATRRs to be effective on June 1, 2016 and each subsequent June 1.
2. On or before May 1, 2016, and on or before each subsequent May 1, the Members shall request SPP to post their FRTs and supporting documentation on the SPP OASIS, and shall notify Interested Parties of the website address where such information is posted via the SPP email exploder list titled "Formula Rate Posting Information Notification."
    A. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state

attorneys general ("Interested Parties"). Interested Parties can contact MRES to be included as an Interested Party.

B. MRES Members shall provide electronic notice of Annual ATRR Update postings to all Interested Parties within 10 days of such posting through an email to the Formula Rate Posting Information Notification exploder maintained by SPP.

C. As used in these Protocols, "Formula Rate Posting Information Notification" exploder shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification exploder through the link on the SPP website. The exploder list is titled "Formula Rate Posting Information Notification" and can be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include, but are not limited to, (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

3. If the date for posting the FRT falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the FRT shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the FRT will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

4. The Annual Update shall:

   A. Include a workable data-populated FRT and underlying work papers in native format with all formulas intact;

   B. Be based on the Member's audited financial statements for the either the prior fiscal or calendar year, as applicable. MPS, PMU and WMUD base their audited financial statements on a calendar year from January 1 to December 31. OCMU

and SCMU base their audited financial statements on a fiscal year from July 1 to June 30.

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the FRT that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;

D. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);

E. With respect to any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that affect the

4. ATRR calculation;

5. The implementation of new estimation methods or policies that change prior estimates; and

6. changes to income tax elections (if applicable);

ii. Identify items included in the FRT at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the FRT;

iv. Provide, for each item identified pursuant to items II.4.e.i - II.4.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the FRT.

5. Each of the Members shall hold an open meeting among Interested Parties ("Formula Rate Update Meeting") between the Publication Date and May 31 of each year. No less than seven (7) days prior to such Formula Rate Update Meeting, each Member shall provide notice on the Member Related Posting section of the SPP OASIS of the time, date, and location of its Formula Rate Update Meeting. The Formula Rate Update Meeting shall (i) permit the Member to explain and clarify its FRT and (ii) provide Interested Parties an opportunity to seek information and clarifications from the Member about the FRT. Each Member shall provide remote access for participation of Interested Parties at such meetings.

6. If a Member constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of Joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via email no less than 7 days prior to such meeting.

**Section III. Information Exchange Procedures**

Each Member's FRT shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until July 1 following the Publication Date (unless such period is extended with the written consent of the applicable Member or by FERC order) to serve reasonable information and document requests on the applicable Member ("Information Exchange Period"). If July 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

a. The extent or effect of an Accounting Change;

b. Whether the FRT fails to include data properly recorded in accordance with these protocols;

c. The proper application of the formula rate and procedures in these protocols;

d. The accuracy of data and consistency with the formula rate of the calculations shown in the FRT;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. The Members shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. The Members shall respond to all information and document requests received on or before July 1 by no later than August 10 following the Publication Date, unless the Information Exchange Period is extended by the Members or FERC.

3. Each Member will cause to be posted on the Member Related Postings section of the SPP OASIS all information requests regarding the Member's FRT in SPP from Interested Parties and the Member's response(s) to such requests; except, however, if responses to information and document requests include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the applicable Member and the requesting party.

4. Members shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the applicable Member's FRT. However, each Member may require that Interested Parties execute a non-disclosure agreement to

obtain access to material that the Member deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**Section IV. Challenge Procedures for the FRT Update**

1. No later than July 5 of each year, any Interested Party may notify a Member in writing of any specific challenge(s) to any component of the most recently posted FRT ("Preliminary Challenge”). A party submitting a Challenge to a Member must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Within five (5) business days of receiving notice of such challenge(s), any Member so notified shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) on the Member Related Posting section of the SPP OASIS. The Member and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations.
2. Each Member shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which the Member agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the FRT will result. If the Member disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.
3. If the Member and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of the Member’s response to the issue(s), senior management representatives of the Member and the Interested Parties shall meet to try to resolve the issue(s). Each challenged Member shall appoint a senior representative to work with the party that submitted the Challenge (or its representative) toward a resolution of the challenge. If the Member disagrees with such challenge, the Member

will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. Any modification to the FRT that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the FRT for the next Rate Year and incorporated into the Member's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the ATRR, such changes shall be incorporated into the FRT for the next rate year.

4. If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, any Interested Party that has not resolved any Preliminary Challenge to the Formula Rate Update may then file with FERC a Formal Challenge to a Formula Rate Update pursuant to these Implementation Procedures ("Formal Challenge").

    a. A Formal Challenge shall:

        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        ii. Explain how the action or inaction violates the filed rate formula or protocols;
        iii. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

            1. The extent or effect of an Accounting Change;
            2. Whether the FRT fails to include data properly recorded in accordance with these protocols;
            3. The proper application of the formula rate and procedures in these protocols;
            4. The accuracy of data and consistency with the formula rate of the charges shown in the FRT;
            5. The prudence of actual costs and expenditures;

6. The effect of any change to the underlying Uniform System of Accounts; or

7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

b. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on the applicable Member. Service to a Member must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on a Member's Informational Filing required under Section VI of these protocols.

5. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the FRT fails to include data properly recorded in accordance with these protocols; (3) the proper

application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the FRT; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

6. Each Member will cause to be posted all Informal Challenges from Interested Parties and the Member's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Member and the requesting party.

7. Any changes or adjustments to the FRT resulting from the Information Exchange and Informal Challenge processes that are agreed to by a MRES Member will be reported in the Informational Filing required pursuant to Section VI of these protocols.

8. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of the Member to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on the Member on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as the Member's Informational Filing discussed in Section VI of these protocols. The Member shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

9. In any proceeding initiated by FERC concerning the FRT or in response to a Formal Challenge, the Member shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the FRT consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of a MRES Member to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the FRT under the Challenge Procedures set forth in these protocols and the FRT shall not be subject to challenge by anyone for the purpose of modifying the FRT. Any modifications to the FRT will require, as applicable, a Federal Power Act section 205 or section 206 filing.

    Any Interested Party seeking changes to the application of the FRT due to a change in the Uniform System of Accounts, shall first raise the matter with MRES in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to the ATRR**

Any changes to the data inputs, the result of any FERC proceeding to consider the FRT, or a result of the procedures set forth herein, shall be incorporated into the FRT for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of the Commission's regulations. The fixed base return on equity of 9.6% set forth in the Members' FRT will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act. The asset depreciation rates set forth in the Members' FRT filing will not be changed absent a filing pursuant to Section 205 or Section 206 of the Federal Power Act.

**Section VI. Informational Filings**

By March 15 of each year, each Member shall submit to FERC an informational filing

("Informational Filing") of its FRT for the Rate Year. Each Member shall submit each year's Informational Filing in the same docket assigned to its initial informational filing,[1] subject to the determination of the FERC's Secretary. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that the Member has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. The transmittal letter accompanying the Informational Filing shall inform the Commission that the Informational Filing is not intended to be subject to the Commission's notice requirements, and that it is not being submitted for the purpose of having the Commission assign a docket number to the filing nor for the purpose of obtaining Commission acceptance, approval or other review of the filing. Each Member shall provide notification of each Informational Filing through notification on the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

[1] In 2016, MPS submitted its Informational filing in ER16-1182, OCMU in ER16-1183, PMU in ER16-1184, SCMU in ER16-1185, and WMUD in in ER16-1186.

# ADDENDUM 34 TO ATTACHMENT H

## Watertown Municipal Utility Department

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Index

13 Months Ended December 31, 2XXX

| Schedule/Workpaper | Description | Updated? |
|---|---|---|
| Attachment H | Uses EIA Form 412 Data to Calculate ATRR | Yes |
| Schedule 1 | SPP Directed Projects ATRR | Yes |
| Schedule 1a | SPP Directed Projects | Yes |
| Schedule 2 | Electric Balance Sheet | Yes |
| Schedule 3 | Electric Income Statement | Yes |
| Schedule 4 | Electric Plant | Yes |
| Schedule 5 | Taxes Other than Income Taxes | Yes |
| Schedule 6 | Depreciation Rates | Yes |
| Schedule 7 | O&M Expense | Yes |
| Schedule 8 | Supplemental Wage Data | Yes |

**Watertown (SD) Municipal Utilities Department**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| 1 | GROSS REVENUE REQUIREMENT | page 3, line 21 | | | #DIV/0! |
| | REVENUE CREDITS (Note I) | | | | |
| 2 | Account No. 454 (Note H) | EIA Form 412 | - | TP 0.000% | - |
| 3a | Transmission charges for all transmission transactions | EIA Form 412 | - | TP 0.000% | - |
| 3b | Transmission charges for all transmission transactions included in Native Load | EIA Form 412 | - | TP 0.000% | - |
| 3c | Account No. 456.1 | (line 3a less line 3b) | - | TP 0.000% | - |
| 4 | Revenues from Grandfathered Interzonal Transactions | EIA Form 412 | - | TP 0.000% | - |
| 5 | Revenues from service provided by the ISO at a discount | EIA Form 412 | - | TP 0.000 | - |

| | | | | % | |
|---|---|---|---|---|---|
| 6 | TOTAL REVENUE CREDITS | (sum lines 2, 3c, 4, 5) | | | - |
| 7 | ATRR for SPP Directed Projects | Schedule 1, line 2, col 9 | | | #DIV/0! |
| 8 | NET REVENUE REQUIREMENT | (line 1 minus lines 6 and 7) | | | #DIV/0! |



**Watertown (SD) Municipal Utilities Department**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) |
|---|---|---|---|---|---|
| | **RATE BASE** | | | | |
| | GROSS PLANT IN SERVICE (Note L) | | | | |
| 1 | Production | Schedule 4, Column G, Line 6 | - | NA 0.000% | - |
| 2 | Transmission | Schedule 4, Column G, Line 7 | - | TP 0.000% | - |
| 3 | Distribution | Schedule 4, Column G, Line 8 | - | NA 0.000% | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| 4 | General & Intangible | Schedule 4, Column G, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Common | Schedule 4, Column G, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 6 | TOTAL GROSS PLANT | (sum lines 1-5) | - | **GP=** | **#DIV/0!** | #DIV/0! |
| | ACCUMULATED DEPRECIATION (Note L) | | | | | |
| 7 | Production | Schedule 4, Column N, Line 6 | - | NA | 0.00% | - |
| 8 | Transmission | Schedule 4, Column N, Line 7 | - | TP | 0.00% | - |
| 9 | Distribution | Schedule 4, Column N, Line 8 | - | NA | 0.00% | - |
| 10 | General & Intangible | Schedule 4, Column N, Line 1 + Line 9 | - | W/S | #DIV/0! | #DIV/0! |
| 11 | Common | Schedule 4, Column N, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL ACCUM. DEPRECIATION | (sum lines 7-11) | - | | | #DIV/0! |
| | NET PLANT IN SERVICE | | | | | |
| 13 | Production | (line 1 - line 7) | - | | | - |
| 14 | Transmission | (line 2 - line 8) | - | | | - |
| 15 | Distribution | (line 3 - line 9) | - | | | - |
| 16 | General & Intangible | (line 4 - line 10) | - | | | #DIV/0! |
| 17 | Common | (line 5 - line 11) | - | | | #DIV/0! |
| 1 | TOTAL NET PLANT | (sum lines | | **N** | # | #DI |

| | | | | | | |
|---|---|---|---|---|---|---|
| 8 | | 13-17) | - | **P =** | **DIV/0!** | V/0! |
| 19 | LAND HELD FOR FUTURE USE (Note A) | EIA Form 412 | - | TP | 0.000% | - |
| | WORKING CAPITAL (Note B) | | | | | |
| 20 | CWC | (1/8 * page 3, line 8) | - | | | #DIV/0! |
| 21 | Materials & Supplies (Note A) | EIA Form 412 | | TE | 0.000% | - |
| 22 | Prepayments | Schedule 2, Column B, Line 20 | - | GP | #DIV/0! | #DIV/0! |
| 23 | TOTAL WORKING CAPITAL | (sum lines 20-22) | - | | | #DIV/0! |
| 24 | RATE BASE | (sum lines 18, 19, and 23) | - | | | #DIV/0! |



**Watertown (SD) Municipal Utilities Department**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Total Company Amount ($)** | **Allocator** | **Transmission Amount ($)** |
| | O&M (Note M) | | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1 | Transmission | Schedule 7, Column E, Line 8 | - | TE | 0.000% | - |
| 1a | Less LSE Expenses included in Transmission O&M Accounts | EIA Form 412 | - | TE | 100.000% | - |
| 2 | Less Account 565 | Schedule 7, Column C, Line 8 | - | TE | 0.000% | - |
| 3 | A&G | Schedule 7, Column E, Line 13 | - | W/S | #DIV/0! | #DIV/0! |
| 4 | Less FERC Annual Fees | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5 | Less EPRI & Reg. Comm. Exp. & Non-safety Ad (Note C) | EIA Form 412 | - | W/S | #DIV/0! | #DIV/0! |
| 5a | Plus Transmission Related Reg. Comm. Exp. (Note C) | EIA Form 412 | - | TE | 0.000% | - |
| 6 | Common | Schedule 7, Column E, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 7 | Transmission Lease Payments | EIA Form 412 | - | TE | 0.000% | - |
| 8 | TOTAL O&M | (sum lines 1, 3, 5a, 6, 7 less lines 1a, 2, 4, 5) | - | | | #DIV/0! |
| | DEPRECIATION AND AMORTIZATION EXPENSE (Note L) | | | | | |
| 9 | Transmission | Schedule 4, Column O, Line 7 | - | TP | 0.000% | - |
| 10 | General & Intangible | Schedule 4, Column | - | W/ | #DI | #DIV/0! |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | O, Line 1 and Line 9 | | S | V/0! | |
| 11 | Common | Schedule 4, Column O, Line 17 | - | CE | #DIV/0! | #DIV/0! |
| 12 | TOTAL DEPRECIATION | (Sum lines 9 - 11) | - | | | #DIV/0! |
| | TAXES OTHER THAN INCOME TAXES (Note D) | | | | | |
| | LABOR RELATED | | | | | |
| 13 | Payroll | Schedule 5, Column B, Lines 1 + 2 | - | W/S | #DIV/0! | #DIV/0! |
| 14 | Highway and vehicle | Schedule 5, Column B, Line 3 | - | W/S | #DIV/0! | #DIV/0! |
| | PLANT RELATED | | | | | |
| 15 | Property | Schedule 5, Column B, Line 4 | - | GP | #DIV/0! | #DIV/0! |
| 16 | Gross Receipts | Schedule 5, Column B, Line 5 | - | NA | 0.00% | - |
| 17 | Other | Not Used | | NA | 0.00% | - |
| 18 | Payments in lieu of taxes | Schedule 3, Column B, Line 6 | - | GP | #DIV/0! | #DIV/0! |
| 19 | TOTAL OTHER TAXES | (sum lines 13-14 and 15-18) | - | | | #DIV/0! |
| 20 | RETURN | (page 2, line 24 * R) | #DIV/0! | | | #DIV/0! |
| 21 | GROSS REVENUE REQUIREMENT | (sum lines 8, 12, 19, and 20) | #DIV/0! | | | #DIV/0! |

**Watertown (SD) Municipal Utilities Department**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

| Line No. | 1<br>Description | 2<br>Source Reference | 3<br>Total Company Amount ($) | 4<br>Allocator | 5<br>Transmission Amount ($) | |
|---|---|---|---|---|---|---|
| | TRANSMISSION PLANT INCLUDED IN ISO RATES | | | | | |
| 1 | Total transmission plant | page 2, line 2, column 5 | | | - | |
| 2 | Less transmission plant excluded from ISO rates (Note F) | EIA Form 412 | | | - | |
| 3 | Less transmission plant included in OATT Ancillary Services (Note G ) | EIA Form 412 | | | - | |
| 4 | Transmission plant included in ISO rates | (line 1 less lines 2 & 3) | | | - | |
| 5 | Percentage of transmission plant included in ISO Rates | (line 4 divided by line 1) | | | **0.00 %** | **= TP** |
| | TRANSMISSION EXPENSES | | | | | |
| 6 | Total transmission expenses | page 3, line 1, column 3 | | | - | |
| 7 | Less transmission expenses included in OATT Ancillary Services (Note E) | EIA Form 412 | | | - | |
| 8 | Included transmission expenses | (line 6 less line 7) | | | - | |
| 9 | Percentage of transmission expenses after adjustment | (line 8 divided by line 6) | | | 0.00 % | |
| 10 | Percentage of transmission expenses included in ISO Rates | (line 9 times line | | | **0.00 %** | **= TE** |

5)

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | WAGES & SALARIES | | | | | | |
| 11 | Production | Schedule 8, Column E, Line 4 | - | NA | 0.000% | - | |
| 12 | Transmission | Schedule 8, Column E, Line 11 | - | TP | 0.000% | - | |
| 13 | Distribution | Schedule 8, Column E, Line 19 | - | NA | 0.000% | - | |
| 14 | Other | Schedule 8, Column E, Line 24 | - | NA | 0.000% | - | |
| 15 | Total | (sum lines 11-14) | - | | | - | |
| 16 | Administrative & General Salaries | Schedule 8, Column E, Line 14 | - | | | | |
| 17 | Wages & Salaries Allocator (Note N) | (line 15, col 5 divided by col 3) | | | | **#DIV/0!** | **= W/S** |
| | COMMON PLANT | | | | | | |
| 18 | Electric | Schedule 4, Column F, Line 10 | | | | 0 | |
| 19 | Gas | EIA Form 412 | | | | 0 | |
| 20 | Water | EIA Form 412 | | | | 37,400,049 | |
| 21 | Total | (sum lines 18-20) | | | | 37,400,049 | |
| 22 | Percentage of Electric Common Plant | (line 17 divided by line 21) | | | | 0.00% | |
| 23 | Common Plant Allocator (CE) | (line 22 times line 17) | | | | **#DIV/0!** | **= CE** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | RETURN (R) | | | | | | | |
| 24 | Long Term Interest (Note J) | Schedule 3, Column B, Line 16 | - | | | | | |
| | | | $ Amount | % | Cost (Note O) | Weighted | | |
| 25 | Long Term Debt | Schedule 2, Column D, Line 37 | - | #DIV/0! | 0.00% | #DIV/0! | | |
| 26 | Proprietary Capital | Schedule 2, Column D, Line 32 | - | 100.00% | 10.10% | 10.10% | | |
| 27 | Total | (sum lines 25, 26) | - | #DIV/0! | | #DIV/0! | = | R |



**Watertown (SD) Municipal Utilities Department**
Formula Rate Template for SPP Zone 19 Transmission
Attachment H (Utilizing EIA Form 412 - Nonlevelized)
12 Months Ended December 31, 2XXX

Notes:

A Transmission related only.

B Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 8, column 5.
Prepayments are the electric related prepayments booked to Account No. 165.

C Line 5 - EPRI Annual Membership Dues, all Regulatory Commission Expenses, and non-safety

related advertising.

Line 5a - Regulatory Commission Expenses directly related to transmission service, ISO filings or transmission siting.

D Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.

Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template,

since they are recovered elsewhere.

E Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1, 561.2, 561.3, and 561.BA.

F Removes transmission plant determined to be state-jurisdictional by Commission order according to the seven-factor test (until account

balances are adjusted to reflect application of seven-factor test).

G Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation

step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up

facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

H Includes income related only to transmission facilities, such as pole attachments, rentals and special use.

I The revenues credited on page 1 lines 2-5 shall include only the amounts received directly (in the case of grandfathered agreements)

or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include

revenues associated with FERC annual charges, gross receipts taxes, ancillary services, facilities not included in this template (e.g., direct

assignment facilities and GSUs) which are not recovered under this Rate Formula Template.

J Include only the amount from Accounts 427, 428, 429 and 430.

K Account Nos. 561.4 and 561.8 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.

L Plant in Service, Accumulated Depreciation, and

| | |
|---|---|
| | Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC. |
| M | Schedules 1a and 12-FERC charges should not be included in O&M recovered under this formula rate. |
| N | If the utility has more employees assigned to A&G than to all other functions combined, set the W&S allocator equal to the amount of transmission plant includable in ISO rates divided by the sum of the total gross production, transmission, and distribution plant. |
| O | The cost of proprietary capital is fixed and cannot be changed absent a 205 or 206 filing with FERC. The cost of long-term debt is calculated by dividing long-term interest (line 24) by the amount of long-term debt (line 25, col 3). The cost of proprietary capital included an incentive adder of 50 basis points approved in Docket No. ER15-2324. |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 |
|---|---|---|---|
| **Line No.** | **Description** | **Source Reference** | **Transmission Amount ($)** |
| 1 | Gross Transmission Plant - SPP (Note A) | Attach H, page 2, line 2 col 5 | - |
| 2 | SPP Transmission Plant Accumulated Depreciation | Attach H, page 2, line 8 col 5 | - |
| 3 | Net Transmission Plant - SPP (Note B) | (line 1 less line 2) | - |
| | O&M EXPENSE | | |
| 4 | Total O&M Allocated to SPP Transmission | Attach H, page 3, line 8 col 5 | #DIV/0! |
| **5** | **Annual Allocation Factor for O&M** | **(line 3 divided by line 1)** | **#DIV/0!** |
| | TAXES OTHER THAN INCOME TAXES | | |
| 6 | Total Other Taxes Allocated to SPP Transmission | Attach H, page 3, line 19 col 5 | #DIV/0! |
| **7** | **Annual Allocation Factor for Other Taxes** | **(line 6 divided by line 1)** | **#DIV/0!** |
| **8** | **Annual Allocation Factor for Expense** | **Sum of lines 5 and 7** | **#DIV/0!** |
| | DEPRECIATION PLUS RETURN ALLOCATED TO SPP | | |
| 9 | Depreciation | Attach H, p 3, line 12 | #DIV/ |

| | | | |
|---|---|---|---|
| | | col 5 | 0! |
| 1 0 | Return | Attach H, p 3, line 20 col 5 | #DIV/ 0! |
| 1 1 | Depreciation plus return | (line 9 plus line 10) | #DIV/ 0! |
| **1 2** | **Annual Allocation Factor for Depreciation and Return** | **(line 12 divided by line 3)** | **#DIV/ 0!** |



**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1: SPP Directed Projects ATRR

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Upgrade Name** | **Upgrade ID** | **Upgrade Gross Plant** | **Annual Allocation Factor for Expense** | **Annual Expense Charge** | **Upgrade Net Plant** | **Annual Allocation Factor for Depreciation & Return** | **Annual Charge for Depreciation & Return** | **Net Annual Revenue Requirement** |
| | | | (Note C) | (Page 1 line 7) | (Col. 3 * Col. 4) | Note D | (Page 1 line 12) | (Col. 6 * Col. 7) | (Sum Col. 5 & 8) |
| 1a | Project 1 | Project 1 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1b | Project 2 | Project 2 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1c | Project 3 | Project 3 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1d | Project 4 | Project 4 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |
| 1e | Project 5 | Project 5 | $ - | #DIV/0! | #DIV/0! | $ - | #DIV/0! | #DIV/0! | #DIV/0! |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 1<br>f | Project 6 | Project 6 | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| … | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
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| | | | $<br>- | #DIV/0! | #DIV/0! | $<br>- | #DIV/0! | #DIV/0! | #DIV/0! |
| | | | | | | | | | |
| 2 | Annual Totals | | | | | | | | #DIV/0! |

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H and is inclusive of all CWIP.

B Net Transmission Plant is that identified on page 2 line 14 of Attachment H and is inclusive of all CWIP.

C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 and includes all CWIP This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Plant values are from Schedule 4- Line 14.

D Net Plant is derived from Schedule 4- Line 42 and includes all CWIP

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 1a: SPP Directed Projects

13 Months Ended December 31, 2XXX

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Line No.** | **Project ID** | **Description** | **December** | **January** | **February** | **March** | **April** | **May** | **June** | **July** | **August** | **September** | **October** | **November** | **December** | **13 Month Average ($)** |
| | **Gross Plant in Service** | | | | | | | | | | | | | | | |
| 1a | Project 1 | | | | | | | | | | | | | | | - |
| 1b | Project 2 | | | | | | | | | | | | | | | - |
| 1c | Project 3 | | | | | | | | | | | | | | | - |
| 1d | Project 4 | | | | | | | | | | | | | | | - |
| 1e | Project 5 | | | | | | | | | | | | | | | - |
| 1f | Project 6 | | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | | |
| **2** | **Total Gross Plant in Service** | | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** | **-** |
| | **Accumulated Depreciation** | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3a | Project 1 | | | | | | | | | | | | | | - |
| 3b | Project 2 | | | | | | | | | | | | | | - |
| 3c | Project 3 | | | | | | | | | | | | | | - |
| 3d | Project 4 | | | | | | | | | | | | | | - |
| 3e | Project 5 | | | | | | | | | | | | | | - |
| 3f | Project 6 | | | | | | | | | | | | | | - |
| … | | | | | | | | | | | | | | | - |
| | | | | | | | | | | | | | | | |
| 4 | **Total Accumulated Depreciation** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | **Net Plant in Service** | | | | | | | | | | | | | | |
| 5a | Project 1 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5b | Project 2 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5c | Project 3 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5d | Project 4 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5e | Project 5 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 5f | Project 6 | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| … | | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | | | | | | | | | | | | | | | |
| 6 | **Total Net Plant in Service** | - | - | - | - | - | - | - | - | - | - | - | - | - | - |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 2: Electric Balance Sheet (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | | C | E |
|---|---|---|---|---|---|
| Line No. | ASSETS and OTHER DEBITS | AMOUNT (Dollars) | Line No. | LIABILITIES and OTHER CREDITS | AMOUNT (Dollars) |
| 1 | **ELECTRIC PLANT** Electric Plant & Adjustments (101-106,114,116) | | 29 | **PROPIETARY CAPITAL** Investment of Municipality (208) | $ - |
| 2 | Construction Work In Progress (107) | | 30 | Miscellaneous Capital (211, 219, 219.1) | $ - |
| 3 | (Less) Accumulated Provision for Depreciation, Amortization and Depletion (108,111,115) | | 31 | Retained Earnings (215, 215.1, 216) | |
| 4 | **Net Electric Plant** | **$ -** | 32 | **TOTAL PROPRIETARY CAPITAL** | **$ -** |
| 5 | Nuclear Fuel (120.1-120.4, 120.6) | $ - | | **LONG TERM DEBT** | |
| 6 | (Less) Accumulated Provision for Amortization of Nuclear Fuel Assemblies (120.5) | $ - | 33 | Bonds (221, 222) | $ - |
| 7 | **Net Electric Plant including Nuclear Fuel** | **$ -** | 34 | Advances from Municipality and Other Long Term Debt (223, 224) | $ - |
| 8 | **OTHER PROPERTY & INVESTMENTS** Non-Electric Plant Property (121) | $ - | 35 | Unamortized Premium on Long Term Debt (225) | $ - |
| 9 | (Less) Accumulated Provision for Depreciation and Amortization (122) | $ - | 36 | (Less) Unamortized Discount on Long Term Debt (226) | $ - |
| 10 | Investment in Associated | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Enterprises (123-123.1) | $ - | 37 | **Total Long Term Debt** | **$ -** |
| 11 | Investments & Special Funds (124-129) | $ - | | | |
| 12 | **Total Other Property and Investments** | **$ -** | | **OTHER NONCURRENT LIABILITIES** | |
| 13 | **CURRENT & ACCRUED ASSETS** Cash, Working Funds & Investments (131-136) | | 38 | Accumulated Operating Provisions (228.1-.4) | $ - |
| | | | 39 | Accumulated Provisions for Rate Refunds | $ - |
| | | | 40 | **Total Other Non Current Liabilities** | **$ -** |
| 14 | Notes & Other Receivables (141, 143, 145, 146, 172) | | | **CURRENT AND ACCRUED LIABILITIES** | |
| 15 | Customer Accounts Recevable (142) | | 41 | Notes Payable (231) | $ - |
| 16 | (Less) Accumulated Provision for Uncollectible Accounts (144) | | 42 | Accounts Payable (232) | |
| 17 | Fuel Stock & Expenses Undistributed (151-152) | | 43 | Notes and Accounts Payable to Associated Enterprises (233, 234) | |
| 18 | Plant Materials & Operating Supplies (154) | | 44 | Customer Deposits (235) | |
| 19 | Other Supplies & Misc (153, 155-163) | | 45 | Accrued taxes (236) | |
| 20 | Prepayments (165) | | 46 | Accrued Interest payable (237) | |
| 21 | Accrued revenues (173) | | 47 | Misc Curr & Accr Liabilities (239-245) | |
| 22 | Misc Current & Accrued Assets (171, 174) | | 48 | **Total Current & Accrued Liabilities** | **$ -** |
| 23 | **Total Current & Accrued Assets** | **$ -** | | **DEFERRED CREDITS** | |
| | **DEFERRED DEBITS** | | 49 | Customer Advances for Construction (252) | $ - |
| 24 | Unamortized Debt Expense (181) | $ - | | | |
| 25 | Extraordinary Property Losses, Study Costs, and Charges (182.1, 182.2, 182.3, 183) | $ - | 50 | Other Deferred Credits (253, 256, 281-283) | $ - |
| 26 | Miscellaneous Debt, Research and | | | | |

| | | | | | |
|---|---|---|---|---|---|
| | Development Expenses & Unamortized Losses (184-191) | $ - | 51 | Unamortized gain on Reacquired Debt (257) | $ - |
| 27 | **Total Deferred Debits** | **$ -** | 52 | **Total Deferred Credits** | **$ -** |
| 28 | **TOTAL ASSETS & OTHER DEBITS** | **$ -** | 53 | **TOTAL LIABILITIES & OTHER CREDITS** | **$ -** |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 3: Electric Income Statement (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B |
|---|---|---|
| Line No. | | Amount (Dollars) |
| 1 | Electric Operating Revenues (400) | |
| 2 | Operation Expenses (401) | |
| 3 | Maintenance Expenses (402) | |
| 4 | Depreciation Expenses (403) | |
| 5 | Amortization of Electric Plant, Property Losses, and Regulatory Study Costs (404-407) | |
| 6 | Taxes and Tax Equivalents (408.1, 409.1) | |
| 7 | TOTAL ELECTRIC OPERATING EXPENSES | $ - |
| 8 | **NET ELECTRIC OPERATING INCOME** | $ - |
| 9 | Income from Electric Plant Leased to Others (412, 413) | $ - |
| 10 | Electric Operating Income | $ - |
| 11 | Other Electric Income (415, 417, 418, 419, 421, 421.1) | |
| 12 | Other Electric Deductions (416, 417, 421.2) | |
| 13 | Allowance for Other Funds Used During Construction (419.1) | |
| 14 | Taxes Applicable to Other Income and Deductions (408.2, 409.2) | $ - |
| 15 | Electric Income | $ - |
| 16 | Income Deductions from Interest on Long Term Debt (427) | $ - |
| 17 | Other Income Deductions (428-431) | $ - |
| 18 | Allowance for Borrowed Funds Used During Constructions (432) | $ - |
| 19 | Total Income Deductions | $ - |

| | | |
|---|---|---|
| 20 | Income Before Extraordinary Items | **$ -** |
| 21 | Extraordinary Items (434) | $ - |
| 22 | Extraordinary Deductions (435) | $ - |
| 23 | **NET INCOME** | **$ -** |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended December 31, 2XXX

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 4: Electric Plant (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | | A | B | C | D | E | F | G | H | I | J | K | L | M | N | O |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **ELECTRIC PLANT** | | | | | | | **ACCUMULATED DEPRECIATION** | | | | | | | |
| Line No. | | Beginning Balance | Additions | Retirements | Transfers | Ending Balance | Adjusted BOY | BOY and EOY Average | Beginning Balance | Additions | Retirements | Transfers | Accumulated Depreciation | Adjusted BOY | BOY and EOY Average | Depreciation Expense |
| 1 | Intangible Plant (301-303) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | $ - |
| | | | | | | | | | | | | | | | | |
| 2 | Steam Production (310-316) | | | | | $ - | $ - | **$ -** | | | | | $ - | $ - | **$ -** | $ - |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3 | Nuclear Production (320-325) | | | | | $ - | $ - | **$ -** | | | | | | $ - | $ - | **$ -** | | $ - |
| 4 | Hydraulic Production (330-336) | | | | | $ - | $ - | **$ -** | | | | | | $ - | $ - | **$ -** | | $ - |
| 5 | Other Production (340-346) | | | | | $ - | $ - | **$ -** | $ - | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 6 | **Total Production Plant** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |
| | | | | | | | | | | | | | | | | | | |
| 7 | Transmission Plant (350-359) | | | | | $ - | $ - | **$ -** | | | | | | $ - | $ - | **$ -** | | |
| 8 | Distribution Plant (360-373) | | | | | $ - | $ - | **$ -** | | | | | | $ - | $ - | **$ -** | | |
| 9 | General Plant (389-399) | | | | | $ - | $ - | **$ -** | | | | | | $ - | $ - | **$ -** | | |
| 10 | **Total Electric Plant In Service** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |

| | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11 | Electric Plant Leased to Others | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 12 | Electric Plant Held for Future Use | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 13 | Electric Plant Miscellaneous | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 14 | **Electric Plant & Adjustments** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |
| | | | | | | | | | | | | | | | | | | |
| 15 | Construction Work in Progress | | | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |
| 16 | **Total Electric Plant & Adj's** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | **$ -** | | **$ -** |
| 17 | Common Plant | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - | $ - | $ - | $ - | $ - | $ - | **$ -** | | $ - |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 5: Taxes other than Income Taxes (EIA Form 412)

12 Months Ended December 31, 2XXX

| Line No. | A Description | B Amount ($) | C Notes/Comments |
|---|---|---|---|
| | **Taxes other than Income Taxes, Operating Income** | | |
| | **Payroll Taxes:** | | |
| 1 | FICA Taxes | | |
| 2 | Unemployment Taxes | | |
| | **Plant Related Taxes:** | | |
| 3 | Highway Taxes | | |
| 4 | Property Taxes | 0 | |
| 5 | Gross Receipts Taxes | | |
| 6 | Payment In Lieu of Taxes (Transfer) | | |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 6: Depreciation Rates

12 Months Ended December 31, 2XXX

| Column | A | B | C | D |
|---|---|---|---|---|
| Line No. | | | | |
| 1 | **FERC Account** | **Transmission Plant** | **Average Service Life In Years** | **Calculated Annual Depreciation Rate** |
| 2 | 350 | Land and Land Rights* | N/A | 0.0% |
| 3 | 351 | Energy Storage Equipment - Transmission | N/A | 0.0% |
| 4 | 352 | Structures & Improvements | 40 | 2.5% |
| 5 | 353 | Station Equipment | N/A | 0.0% |
| 6 | 354 | Towers & Fixtures | N/A | 0.0% |
| 7 | 355 | Poles & Fixtures | 33.3 | 3.0% |
| 8 | 356 | Overhead Conductors and Devices | 33.3 | 3.0% |
| 9 | 357 | Underground Conduit | N/A | 0.0% |
| 10 | 358 | Underground Conductors and Devices | N/A | 0.0% |
| 11 | 359 | Roads and Trails | N/A | 0.0% |
| 12 | | **General Plant** | | |
| 13 | 390 | Structures & Improvements | 40 | 2.5% |
| 14 | 391 | Office Furniture and Equipment | 8.33 | 12.0% |
| 15 | 392 | Transportation Equipment | 8.33 | 12.0% |
| 16 | 393 | Stores Equipment | 25 | 4.0% |
| 17 | 394 | Tools, Shop and Garage Equipment | 8.33 | 12.0% |
| 18 | 395 | Laboratory Equipment | 8.33 | 12.0% |
| 19 | 396 | Power Operated Equipment | N/A | 0.0% |
| 20 | 397 | Communication Equipment | 5 | 20.0% |
| 21 | 398 | Miscellaneous Equipment | N/A | 0.0% |

| | | | | | |
|---|---|---|---|---|---|
| 22 | | **Intangible Plant** | | | |
| 23 | | 301 | Organization | 5 | 20.0% |
| 24 | | 302 | Franchises and consents | N/A | 0.0% |
| 25 | | 303 | Miscellaneous intangible plant | N/A | 0.0% |

*** Land is not depreciable.**

**Note: These depreciation rates will not be changed absent a FERC order.**

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 7: O&M Expense (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | Fuel Cost | Operation | Maintenance | Total |
| 1 | Steam Power Generation (500-507, 510-514) Fuel Cost (501) | $ - | $ - | $ - | $ - |
| 2 | Nuclear Power Generation | $ - | $ - | $ - | $ - |
| 3 | Hydraulic Power Generation (535-540, 541-545) | $ - | $ - | $ - | $ - |
| 4 | Other Power Generation (546-550, 551-554) Fuel cost (547) | $ - | $ - | $ - | $ - |
| 5 | Purchased Power (555) | $ - | | $ - | $ - |
| 6 | Other Production Expenses (556-557) | $ - | | $ - | $ - |
| 7 | Total Production Expenses | **$ -** | **$ -** | **$ -** | **$ -** |
| 8 | Transmission Expenses (560-567, 568-573) | XXXXXXXXXXXXX | | | $ - |
| 9 | Distribution Expenses (580-589, 590-598) | XXXXXXXXXXXXX | | | $ - |
| 10 | Customer Account Expenses (901-905) | XXXXXXXXXXXXX | | | $ - |

| | | | | | |
|---|---|---|---|---|---|
| 11 | Customer Service & Information Expenses (907-910) | XXXXXXXXXXXXX | | | $ - |
| 12 | Sales Expenses (911-916) | XXXXXXXXXXXXX | | | $ - |
| 13 | Admin & General exp (920-935) | XXXXXXXXXXXXX | | | $ - |
| 14 | Total Electric Operation and Maintenance Expenses | **$ -** | **$ -** | **$ -** | **$ -** |

| | | |
|---|---|---|
| 15 | Total Number of Full Time Employees | |
| 16 | Total Number of Part Time Employees | |

| | | | | | |
|---|---|---|---|---|---|
| 17 | Common O&M Expense | $ - | $ - | $ - | $ - |

**Watertown (SD) Municipal Utilities Department**

Formula Rate Template for SPP Zone 19 Transmission

Schedule 8: Supplemental Wage Data (EIA Form 412)

12 Months Ended December 31, 2XXX

| Column | A | B | C | D | E |
|---|---|---|---|---|---|
| Line No. | | | Accounts | Salaries | |
| 1 | | | Production / Generation | | |
| 2 | | | Operating Supervisor | $ - | |
| 3 | | | Maintanence | $ - | |
| 4 | | | Employee Benefits | $ - | $ - |
| 5 | | | Transmission: | | |
| 6 | | | Maintenance Supervision | | |
| 7 | | | Load Dispatching | | |
| 8 | | | Maintenance of Lines | | |
| 9 | | | Station Expense | | |
| 10 | | | Equipment Maintenance | | |
| 11 | | | Employee Benefits | | $ - |
| 12 | | | Distribution: | | |
| 13 | | | Maintenance Supervision | | |
| 14 | | | Meter Expense | | |
| 15 | | | Maintenance/Installation of Lines | | |
| 16 | | | Transformers | | |
| 17 | | | Equipment Maintenance | | |
| 18 | | | Training | | |
| 19 | | | Employee Benefits | | $ - |
| 20 | | | Customer Service & Information | | |
| 21 | | | Customer Records & Collection Salaries | | |
| 22 | | | Meter Reading Salaries | | |
| 23 | | | Customer Installation Expense Salaries | | |
| 24 | | | Employee Benefits | | $ - |

| | | | |
|---|---|---|---|
| 25 | Administrative & General | | |
| 26 | Salaries of Executives | | |
| 27 | General Office Salaries | | |
| 28 | Employee Benefits | | $ - |
| 29 | Total | | $ - |

# MRES MEMBER UTILITIES

# ANNUAL UPDATE PROTOCOLS

# UNDER ATTACHMENT H OF SPP OPEN ACCESS TRANSMISSION TARIFF

## Section I. Applicability

The following procedures shall apply to Moorhead Public Service ("MPS"), Orange City Municipal Utilities ("OCMU"), Pierre Municipal Utilities ("PMU"), Sioux Center Municipal Utilities ("SCMU") and Watertown Municipal Utility District ("WMUD") calculation of its annual transmission revenue requirement ("ATRR") pursuant to its Formula Rate Template ("FRT"). These utilities will be referred to as the "Members" in these protocols. The transmission formula rate template and protocols together comprise the filed rate ("Formula Rate"), and any modifications to the Formula Rate shall require a filing under Section 205 or 206 of the Federal Power Act.

## Section II. Annual ATRR Update

1. Beginning on or before May 1, 2016, and on or before each subsequent May 1, the Members shall determine their ATRRs to be effective on June 1, 2016 and each subsequent June 1.
2. On or before May 1, 2016, and on or before each subsequent May 1, the Members shall request SPP to post their FRTs and supporting documentation on the SPP OASIS, and shall notify Interested Parties of the website address where such information is posted via the SPP email exploder list titled "Formula Rate Posting Information Notification."
    A. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the SPP Open Access Transmission Tariff ("OATT"), state utility regulatory commissions, consumer advocacy agencies, and state

attorneys general ("Interested Parties"). Interested Parties can contact MRES to be included as an Interested Party.

B. MRES Members shall provide electronic notice of Annual ATRR Update postings to all Interested Parties within 10 days of such posting through an email to the Formula Rate Posting Information Notification exploder maintained by SPP.

C. As used in these Protocols, "Formula Rate Posting Information Notification" exploder shall mean the list of email addresses maintained by SPP of Interested Parties, provided that such Interested Parties request to be added to the Formula Rate Posting Information Notification exploder through the link on the SPP website. The exploder list is titled "Formula Rate Posting Information Notification" and can be accessed at http://www.spp.org/stakeholder-center/exploder-lists/. Interested Parties may include, but are not limited to, (i) SPP Tariff Transmission Customers; (ii) any state regulatory agency with rate jurisdiction over a public utility located within the SPP footprint; and (iii) any consumer advocate agency authorized by state law to review and contest the rates for any such public utility.

3. If the date for posting the FRT falls on a weekend or a holiday recognized by the Federal Energy Regulatory Commission ("FERC" or "Commission"), then the posting shall be due on the next business day. The date on which posting of the FRT shall be that year's "Publication Date." Any delay in the Publication Date or in the posting of the FRT will result in an equivalent extension of time for the submission of Information Requests discussed in Section III of these protocols.

4. The Annual Update shall:

   A. Include a workable data-populated FRT and underlying work papers in native format with all formulas intact;

   B. Be based on the Member's audited financial statements for the either the prior fiscal or calendar year, as applicable. MPS, PMU and WMUD base their audited financial statements on a calendar year from January 1 to December 31. OCMU

and SCMU base their audited financial statements on a fiscal year from July 1 to June 30.

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the FRT that are not otherwise available in audited financial statements, such that Interested Parties may replicate the calculation of the results;

D. Identify all material adjustments made to the audited financial statements data in determining formula inputs (including page and line numbers);

E. With respect to any change in accounting that materially affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

i. Identify any Accounting Changes, including:

1. The initial implementation of an accounting standard or policy;

2. The initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

3. Correction of errors and prior period adjustments that affect the

4. ATRR calculation;

5. The implementation of new estimation methods or policies that change prior estimates; and

6. changes to income tax elections (if applicable);

ii. Identify items included in the FRT at an amount other than on a historic cost basis (e.g., fair value adjustments);

iii. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the FRT;

iv. Provide, for each item identified pursuant to items II.4.e.i - II.4.e.iii of these protocols, a narrative explanation of the individual impact of such changes on the FRT.

5. Each of the Members shall hold an open meeting among Interested Parties ("Formula Rate Update Meeting") between the Publication Date and May 31 of each year. No less than seven (7) days prior to such Formula Rate Update Meeting, each Member shall provide notice on the Member Related Posting section of the SPP OASIS of the time, date, and location of its Formula Rate Update Meeting. The Formula Rate Update Meeting shall (i) permit the Member to explain and clarify its FRT and (ii) provide Interested Parties an opportunity to seek information and clarifications from the Member about the FRT. Each Member shall provide remote access for participation of Interested Parties at such meetings.

6. If a Member constructs any transmission project that utilizes a regional cost sharing mechanism, it shall participate in a joint informational meeting with other transmission owners to establish revenue requirements for recovery of costs of projects subject to the same regional cost allocation. Notice of Joint informational meetings shall be posted on the SPP website and distributed to Interested Parties via email no less than 7 days prior to such meeting.

**Section III. Information Exchange Procedures**

Each Member's FRT shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until July 1 following the Publication Date (unless such period is extended with the written consent of the applicable Member or by FERC order) to serve reasonable information and document requests on the applicable Member ("Information Exchange Period"). If July 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

a. The extent or effect of an Accounting Change;

b. Whether the FRT fails to include data properly recorded in accordance with these protocols;

c. The proper application of the formula rate and procedures in these protocols;

d. The accuracy of data and consistency with the formula rate of the calculations shown in the FRT;

e. The prudence of actual costs and expenditures;

f. The effect of any change to the underlying Uniform System of Accounts; or

g. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. The Members shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. The Members shall respond to all information and document requests received on or before July 1 by no later than August 10 following the Publication Date, unless the Information Exchange Period is extended by the Members or FERC.

3. Each Member will cause to be posted on the Member Related Postings section of the SPP OASIS all information requests regarding the Member's FRT in SPP from Interested Parties and the Member's response(s) to such requests; except, however, if responses to information and document requests include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the applicable Member and the requesting party.

4. Members shall not claim that non-confidential responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent FERC proceeding addressing the applicable Member's FRT. However, each Member may require that Interested Parties execute a non-disclosure agreement to

obtain access to material that the Member deems commercially sensitive or that contains Critical Energy Infrastructure Information as that term is defined in 18 CFR§ 388.113(c)(1).

**Section IV. Challenge Procedures for the FRT Update**

1. No later than July 5 of each year, any Interested Party may notify a Member in writing of any specific challenge(s) to any component of the most recently posted FRT ("Preliminary Challenge"). A party submitting a Challenge to a Member must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Within five (5) business days of receiving notice of such challenge(s), any Member so notified shall provide written notice to all Interested Parties of such challenge(s) and post notice of such challenge(s) on the Member Related Posting section of the SPP OASIS. The Member and the Interested Party shall make good faith efforts to resolve the Preliminary Challenge through informal negotiations, and shall allow any Interested Party to participate in such negotiations.
2. Each Member shall provide and post a written response within fourteen (14) calendar days of receiving a Preliminary Challenge. Its written response shall notify all Interested Parties of the extent to which the Member agrees or disagrees with the position raised by the Interested Party(ies), and what, if any, modifications to the FRT will result. If the Member disagrees with the issue(s) raised in the Preliminary Challenge, it shall provide supporting documentation with its response.
3. If the Member and the Interested Parties have not resolved all identified issues within thirty (30) calendar days after receipt of the Member's response to the issue(s), senior management representatives of the Member and the Interested Parties shall meet to try to resolve the issue(s). Each challenged Member shall appoint a senior representative to work with the party that submitted the Challenge (or its representative) toward a resolution of the challenge. If the Member disagrees with such challenge, the Member

will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. Any modification to the FRT that results from such negotiations and that is agreed upon no later than November 15 shall be incorporated into the FRT for the next Rate Year and incorporated into the Member's Informational Filing. However, to the extent such negotiations lead to agreed-upon changes to the ATRR, such changes shall be incorporated into the FRT for the next rate year.

4. If these senior management representatives are not able to resolve the issue(s) within thirty (30) calendar days, any Interested Party that has not resolved any Preliminary Challenge to the Formula Rate Update may then file with FERC a Formal Challenge to a Formula Rate Update pursuant to these Implementation Procedures ("Formal Challenge").

    a. A Formal Challenge shall:

        i. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;
        ii. Explain how the action or inaction violates the filed rate formula or protocols;
        iii. Set forth the business, commercial, economic, or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

            1. The extent or effect of an Accounting Change;
            2. Whether the FRT fails to include data properly recorded in accordance with these protocols;
            3. The proper application of the formula rate and procedures in these protocols;
            4. The accuracy of data and consistency with the formula rate of the charges shown in the FRT;
            5. The prudence of actual costs and expenditures;

6. The effect of any change to the underlying Uniform System of Accounts; or

7. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

iv. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

v. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

vi. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

vii. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

viii. State whether the filing party utilized the Informal Challenge procedures described in these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

b. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on the applicable Member. Service to a Member must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on a Member's Informational Filing required under Section VI of these protocols.

5. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the FRT fails to include data properly recorded in accordance with these protocols; (3) the proper

application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the FRT; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

6. Each Member will cause to be posted all Informal Challenges from Interested Parties and the Member's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by the Member to be confidential information, such information will not be publicly posted but will be made available to requesting parties pursuant to a confidentiality agreement to be executed by the Member and the requesting party.

7. Any changes or adjustments to the FRT resulting from the Information Exchange and Informal Challenge processes that are agreed to by a MRES Member will be reported in the Informational Filing required pursuant to Section VI of these protocols.

8. An Interested Party shall have until April 15 following the Review Period (unless such date is extended with the written consent of the Member to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on the Member on the date of such filing as specified in Section IV.C(2) above. A Formal Challenge shall be filed in the same docket as the Member's Informational Filing discussed in Section VI of these protocols. The Member shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge on any issue during the applicable Review Period.

9. In any proceeding initiated by FERC concerning the FRT or in response to a Formal Challenge, the Member shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the FRT consistent with these protocols, and that it followed the applicable requirements and procedures in these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of a MRES Member to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the FRT under the Challenge Procedures set forth in these protocols and the FRT shall not be subject to challenge by anyone for the purpose of modifying the FRT. Any modifications to the FRT will require, as applicable, a Federal Power Act section 205 or section 206 filing.

    Any Interested Party seeking changes to the application of the FRT due to a change in the Uniform System of Accounts, shall first raise the matter with MRES in accordance with this Section IV before pursuing a Formal Challenge.

**Section V. Changes to the ATRR**

Any changes to the data inputs, the result of any FERC proceeding to consider the FRT, or a result of the procedures set forth herein, shall be incorporated into the FRT for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with 18 C.F.R. §35.19a of the Commission's regulations. The fixed base return on equity of 9.6% set forth in the Members' FRT will remain fixed in that Template and will not be changed absent a filing pursuant to section 205 of the Federal Power Act. The asset depreciation rates set forth in the Members' FRT filing will not be changed absent a filing pursuant to Section 205 or Section 206 of the Federal Power Act.

**Section VI. Informational Filings**

By March 15 of each year, each Member shall submit to FERC an informational filing

("Informational Filing") of its FRT for the Rate Year. Each Member shall submit each year's Informational Filing in the same docket assigned to its initial informational filing,[1] subject to the determination of the FERC's Secretary. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying work papers; (2) that the Member has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the Transmission Revenue Requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of costs. The Informational Filing must also describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge procedures. The transmittal letter accompanying the Informational Filing shall inform the Commission that the Informational Filing is not intended to be subject to the Commission's notice requirements, and that it is not being submitted for the purpose of having the Commission assign a docket number to the filing nor for the purpose of obtaining Commission acceptance, approval or other review of the filing. Each Member shall provide notification of each Informational Filing through notification on the Formula Rate Posting Information Notification exploder maintained by SPP, and shall request the docket or sub-docket number assigned to each Informational Filing to be posted on the SPP OASIS within 5 days of the Commission assigning such a number.

[1] In 2016, MPS submitted its Informational filing in ER16-1182, OCMU in ER16-1183, PMU in ER16-1184, SCMU in ER16-1185, and WMUD in in ER16-1186.

# ATTACHMENT I

## Reserved for Future Use

# ATTACHMENT J
# RECOVERY OF COSTS ASSOCIATED WITH NEW FACILITIES

## I. Direct Assignment Facilities

Where a System Impact and/or Facilities Study indicates the need to construct Direct Assignment Facilities to accommodate a request for Transmission Service, the Transmission Customer shall be charged the full cost of such Direct Assignment Facilities. Such costs shall be specified in a Service Agreement.

## II. Network Upgrades

Where applicable the costs of completed Network Upgrades shall be allocated as specified in Sections III, IV, V and VI of this Attachment. The revenue requirements of Base Plan Upgrades, approved Balanced Portfolios, and approved Interregional Projects will be recovered through Schedule 11, subject to filing such rate or revenue requirements with the Commission, and where applicable Directly Assigned Upgrade Costs. These costs may be recovered in whole or in part through the Base Plan Zonal Charge, Base Plan Region-wide Charge, and/or a direct assignment charge. The cost allocable to each of these charges shall be determined in accordance with Section III of this Attachment. The revenue requirements for other Network Upgrades may be recovered by Transmission Owners through Schedules 7, 8, and 9 subject to their filing such rate or revenue requirements with the Commission.

## III. Base Plan Upgrades

A single Base Plan Upgrade is comprised of any upgrade or group of upgrades required to be made to a single transmission circuit, where a transmission circuit is comprised of all load carrying elements between circuit breakers or the comparable switching devices. A load carrying element within a Base Plan Upgrade that is connected at two different voltage levels (e.g. a 345kV/138kV transformer) shall, for the purposes of this Attachment J, be considered to have a nominal operating voltage of its lower voltage level (excluding any tertiary windings) and its costs shall be allocated in accordance with the rules governing the lower voltage level in this Attachment J. A waiver may be requested to use a transformer's higher voltage level instead of the lower voltage level for the purposes of cost allocation under this Attachment J based on the anticipated utilization of the transformer. Such request must be made in writing with supporting analysis and submitted to the Transmission Provider not later than one hundred eighty (180) days following the inclusion of the transformer in an approved SPP Transmission Expansion Plan. Any waiver request submitted shall be evaluated based upon the following general factors, including but not limited to: (i) whether the power flows through the transformer predominately are from the lower voltage to the higher voltage; (ii) whether the transformer is not necessary for the support of, or does not substantially benefit, the lower voltage system in the host zone to which it is connected. The Transmission Provider shall make a recommendation to accept or deny the waiver, on a non-discriminatory basis, to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee will consider the waiver request and the Transmission Provider's recommendation, and will provide its own recommendation (along with the Transmission Provider's recommendation) regarding such waiver to the SPP Board of Directors. Barring unusual circumstances, the recommendation to approve or reject such waiver request will be submitted to the SPP Board of Directors within one hundred twenty (120) days following the receipt of the waiver request.

### A. Allocation of Base Plan Upgrade Costs Eligible for Cost Allocation

1. If the cost of a Base Plan Upgrade is less than or equal to $100,000, the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of the Zone in which the Base Plan Upgrade is located.

2. Other than Base Plan Upgrades allocable under Section III.A.1, if a) the Base Plan Upgrade is included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System; b) is included in Schedule 2 of this Attachment J; c) is an approved high priority upgrade; d) is a Network Upgrade required pursuant to Attachment AB to this Tariff; or e) is a Base Plan Upgrade cost eligible for cost allocation under Section III.B.1 and is not associated with a new or changed Designated Resource for a wind generation plant, then:

   i. X% of the annual transmission revenue requirement associated with such Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Region-wide Charge, where X shall be set as follows:

      a. For all Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010 or whose nominal operating voltage level is less than 300 kV but greater than 100 kV, X shall be 33%, except for Base Plan Upgrades that are granted a waiver under Section III.E of Attachment J.

      b. For all other Base Plan Upgrades whose nominal operating voltage level is greater than or equal to 300 kV, X shall be 100%.

      c. For all other Base Plan Upgrades whose nominal operating voltage level is less than or equal to 100 kV, X shall be 0%.

   ii. (100-X)% of the annual transmission revenue requirement associated with such Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones' share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment S to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10 MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000.

b. For all other Base Plan Upgrades, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated solely to the Base Plan Zonal Annual Transmission Revenue Requirement of the Zone in which the Base Plan Upgrade is located.

3. If the Base Plan Upgrade cost eligible for cost allocation under Section III.B.1 of Attachment J is a) associated with a new or changed Designated Resource that is a wind generation plant and b) the Base Plan Upgrade is located within the same zone as the Transmission Customer's Point of Delivery, then:

i. X% of the annual transmission revenue requirement associated with the portion of the Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Region-wide Annual

Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge, where X shall be set as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010 or whose nominal operating voltage level is less than 300 kV and greater than 100 kV, X shall be 33%, except for Base Plan Upgrades that are granted a waiver under Section III.E of Attachment J.

b. For all other Base Plan Upgrades whose nominal operating voltage level is greater than or equal to 300 kV, X shall be 100%.

c. For all other Base Plan Upgrades whose nominal operating voltage level is less than or equal to 100 kV, X shall be 0%.

ii. (100-X)% of the annual transmission revenue requirement associated with the portion of the Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones' share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment S to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10

MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000.

b. For all other Base Plan Upgrades, this portion of the annual transmission revenue requirement for Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of the Zone in which the Base Plan Upgrade is located.

4. If the Base Plan Upgrade cost eligible for cost allocation under Section III.B.1 of Attachment J is a) associated with a new or changed Designated Resource that is a wind generation plant and b) the Base Plan Upgrade is located within a zone(s) other than the Transmission Customer's Point of Delivery, then:

i. Y% of the annual transmission revenue requirement associated with the Base Plan Upgrade costs eligible for cost allocation shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge, where Y shall be set as follows:

a. For Base Plan Upgrades issued a Notification to Construct prior to June 19, 2010 or whose nominal operating voltage level is less than 300 kV, Y shall be 67%.

b. For all other Base Plan Upgrades Y shall be 100%.

ii. (100-Y)% of the annual transmission revenue requirement associated with the Base Plan Upgrade costs eligible for cost allocation shall be directly assigned to the Transmission Customer.

**B. Conditions for Classifying Service Upgrade Costs Associated with Designated Resources As Base Plan Upgrade Costs Eligible for Cost Allocation**

1. Except as provided in Section III.A.1 and subject to the limits and rules set forth in Subsections d and f below, the costs of Service Upgrades associated with new or changed Designated Resources shall be classified

as Base Plan Upgrade costs eligible for cost allocation if the conditions in the following Subsections a and b are met, and if the condition in Subsection c is met as applicable.

a. The Transmission Customer's commitment to the Designated Resource has a duration of at least five years.

b. In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer's existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer's projected system peak responsibility determined pursuant to SPP Criteria.

c. If the Designated Resource is a wind generation plant, then the sum of: (1) the requested capacity and (2) the transmission capacity reserved for the Transmission Customer's existing Designated Resources that are wind generation plants shall not exceed 20% of the Transmission Customer's projected system peak responsibility as determined pursuant to SPP Criteria in the first year the Designated Resource is planned to be used by the Transmission Customer.

d. Safe Harbor Cost Limit for Eligibility of the Costs of Base Plan Upgrade for Cost Allocation

    i. For Base Plan Upgrades that cost over $100,000, the aggregate cost of such upgrades assigned to each individual transmission service request that is less than or equal to the Safe Harbor Cost Limit of $180,000 / MW times the requested capacity is eligible for cost allocation in accordance with:

        1) Section III.A.2 for a new or changed Designated Resource other than a wind generation plant; or

2) Sections III.A.3 and 4 for a new or changed Designated Resource that is a wind generation plant.

ii. Unless a waiver of the Safe Harbor Cost Limit is granted pursuant to Section III.C, any costs that exceed the Safe Harbor Cost Limit for a transmission service request shall be directly assigned to the Transmission Customer and allocated among the upgrades affected by the transmission service request in accordance with Section V.c of Attachment Z1 of this Tariff.

e. Base Plan Upgrade costs eligible for allocation as a result of the granting of a waiver shall be allocated in accordance with Sections III.A.2, III.A.3, or III.A.4, as applicable.

f. For each transmission service request, the amount of Base Plan Upgrade costs eligible for cost allocation shall be allocated among all Upgrades required to grant the transmission service request based upon the remaining cost after allocation of any Directly Assigned Upgrade Costs in accordance with Section III.B.1(d)(ii) of this Attachment J.

2. The Transmission Customer must provide the Transmission Provider the information that the Transmission Provider deems necessary to verify that the new or changed Designated Resource meets conditions in Section III.B.1.a, b and c above.

3. If an upgrade for a new or changed Designated Resource meets the requirements set forth in Section III.B.1.a, b, and c above, the costs up to the $180,000/MW Safe Harbor Cost Limit will be classified as Base Plan Upgrade costs eligible for cost allocation.

4. If the conditions set forth in Section III.B.1.a, b, and c above are not met, and the Transmission Customer does not secure a waiver of the relevant condition(s), the costs of the upgrades will be directly assigned to the Transmission Customer. If the costs of upgrades associated with a new or

changed Designated Resource exceeds the Safe Harbor Cost Limit and the Transmission Customer does not secure a waiver of that limit, the costs of the upgrades in excess of the limit will be directly assigned to the Transmission Customer. The Transmission Customer shall receive compensation in accordance with Attachment Z2 to this Tariff for any such directly assigned costs.

**C. Waiver of Conditions for Classifying Service Upgrade Costs Associated with Designated Resources As Base Plan Upgrade Costs Eligible for Cost Allocation**

**1. Waiver Process**

If one or more of the conditions in Section III.B.1.a, b, c are not met or if the Base Plan Upgrade cost exceeds the Safe Harbor Cost Limit, the Transmission Customer may seek a waiver from the Transmission Provider in order that the costs of any Service Upgrade(s) that otherwise would be directly assigned to the Transmission Customer may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation.

To obtain a waiver for the conditions set forth in Section III.B.1.a, b, c, the Transmission Customer must submit a request for a waiver to the Transmission Provider simultaneous with its request for long-term transmission service for the new or changed Designated Resource. The request for such waiver must be submitted sufficiently in advance of a regularly-scheduled meeting of the SPP Board of Directors that occurs prior to the close of the open season for the Aggregate Facilities Study to allow for review by the Transmission Provider. Timing for the submittal of a waiver shall be specified in the Transmission Provider's business practices.

Aggregate Facilities Studies performed by the Transmission Provider as part of the Aggregate Transmission Service Study procedure, which is described in Attachment Z1, will determine whether the costs for Service Upgrades associated with a new or changed Designated Resource might exceed the Safe Harbor Cost Limit. If the Transmission Provider determines that the costs for Service Upgrades associated with a new or changed Designated Resource might

exceed the Safe Harbor Cost Limit, the Transmission Provider shall notify the affected Transmission Customer when the Transmission Provider posts the first iteration of the associated Facilities Study. The affected Transmission Customer may request a waiver regarding the costs in excess of the Safe Harbor Cost Limit in accordance with Section III.C.2 of Attachment Z1 of this Tariff.

Following the receipt of a request for a waiver, the Transmission Provider will review the request and make a determination on a non-discriminatory basis of whether a waiver should be granted based upon consideration of the factors described in Section III.C.2. of this Attachment. The Transmission Customer requesting the waiver shall be responsible for the reasonable costs of any studies that the Transmission Provider performs in making its determination. The Transmission Provider will provide a report and recommendation to the Markets and Operations Policy Committee for each requested waiver. The Markets and Operations Policy Committee will consider the waiver request and the Transmission Provider's report and recommendation, and will provide its own recommendation (along with the Transmission Provider's report and recommendation) regarding each requested waiver to the SPP Board of Directors.

**2. Factors to be Considered in Evaluating Waiver Requests**

Any waiver request submitted by a Transmission Customer pursuant to Section III.C.1. of this Attachment shall be evaluated based upon the following general factors, including but not limited to:

i. There are insufficient competitive resource alternatives for one or more Transmission Customers.

ii. In the event that the aggregate costs of a Service Upgrade associated with a new or changed Designated Resource exceed the Safe Harbor Cost Limit, (i) those costs up to the level of the Safe Harbor Cost Limit shall be classified as Base Plan Upgrade costs eligible for cost allocation, and (ii) those costs that exceed the Safe Harbor Cost Limit may be classified in whole or in part as Base Plan Upgrade costs eligible for cost allocation taking into account the extent to which the duration of the Transmission Customer's commitment to the new or changed Designated Resource

exceeds the five-year commitment period set forth in paragraph III.B.1. above.

iii. The five-year commitment period for the new or changed Designated Resource may be waived if: (i) the associated Service Upgrade costs are significantly less than the Safe Harbor Cost Limit; or (ii) the associated Service Upgrades provide benefits to other Transmission Customers that would offset in less than five years any costs allocated to them as a result of the upgrade being classified as a Base Plan Upgrade.

iv. If a request for a waiver is received by the Transmission Provider based upon other circumstances, such waiver request shall also be considered pursuant to the waiver process described in Section III.C.1. of this Attachment.

If the costs of the Service Upgrade(s) required for a new or changed Designated Resource are not eligible for classification as Base Plan Upgrade costs, the Transmission Customer may nevertheless request the construction of such upgrades. In such event, the costs of such upgrades shall be allocated in accordance with Attachment Z1 to this Tariff.

**D. Review of Base Plan Allocation Methodology**

1. The Transmission Provider shall review the reasonableness of the regional allocation methodology and factors (X% and Y%) and the zonal allocation methodology at least once every six years in accordance with this Section III.D. The Transmission Provider and/or the Regional State Committee may initiate such review at any time. Any change in the regional allocation methodology and factors or the zonal allocation methodology shall be filed with the Commission.

2. For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of Base Plan Upgrades approved for construction after June 19, 2010 to each pricing Zone within the SPP Region as identified in the methodology in Section III.D.4. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts

utilizing the analysis specified in Section III.7.d of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J.

3. The Transmission Provider shall review the results of the cost allocation analysis with SPP's Regional Tariff Working Group, Markets and Operations Policy Committee, and the Regional State Committee. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website.

4. The Transmission Provider shall request the Regional State Committee provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.

   i) One year prior to the cost allocation impact analysis the Markets and Operations Policy Committee and Regional State Committee will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the Regional State Committee and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint; and

   ii) Starting in 2015 and at any time thereafter, any member company that feels that it has an imbalanced cost allocation may request relief through the Markets and Operations Policy Committee. The Markets and Operations Policy Committee recommendation, if any, will be forwarded with the request for relief to the Regional State Committee and Board of Directors for review.

5. In accordance with the SPP Bylaws, the SPP Board of Directors will initiate the appropriate actions, including any necessary filings with the Commission, consistent with the Regional State Committee recommendations.

**E. Waiver of Base Plan Allocation Methodology**

1. For a Base Plan Upgrade between 100 kV and 300 kV with cost allocable to any Base Plan Zonal Annual Transmission Revenue Requirement

specified in Column (5) of Table 1 in Section I of Attachment H, a waiver of such cost allocation methodology may be requested based on the utilization or anticipated utilization of the Base Plan Upgrade. If the SPP Board of Directors grants the requested waiver, one hundred percent (100%) of the annual transmission revenue requirement associated with that Base Plan Upgrade's cost eligible for cost allocation shall be allocated prospectively in the same manner as annual transmission revenue requirements allocated in accordance with Section III.A.2.i.b of Attachment J. No Directly Assigned Upgrade Costs shall be eligible for waiver and revised cost allocation under this Section III.E.

2. For a Base Plan Upgrade to be eligible for waiver under this Section III.E, the Base Plan Upgrade must satisfy each of the following three criteria:

   a. Capacity Criterion – The total nameplate capacity of generating resources that are physically connected in the Zone where the Base Plan Upgrade is located and not affiliated with load in that Zone exceeds one hundred percent (100%) of the prior calendar year's average twelve-coincident peak Resident Load utilized in calculating the Base Plan Zonal Load Ratio Share for the Zone. For the purpose of this Section III.E.2, a generating resource shall be deemed affiliated with load in a Zone if:

      i. the load serving entities with load in the Zone have either ownership of, or contractual rights to, the generating resource; or

      ii. the generating resource is owned by a Federal Power Marketing Agency that has a commitment to serve load in the Zone where the resource is located.

   b. Flow Criterion – Energy flow on each Base Plan Upgrade attributed to generating resources that are physically connected in the Zone where the Base Plan Upgrade is located and not affiliated with load in that Zone exceeds seventy percent (70%) of the sum of flows on the Base Plan Upgrade attributed to:

i. Generating resources affiliated with the load in the Zone where the Base Plan Upgrade is located; and

ii. Generating resources that are physically connected in the Zone and not affiliated with load in the Zone. Affiliation of each generating resource will be determined in accordance with sections III.E.2.a.i and ii.

c. Benefit Criterion – The set of Base Plan Upgrades included in each waiver request must result in benefit to load outside the Zone where the Base Plan Upgrades are connected. The benefit may be quantified in terms of adjusted production cost and/or savings through the Integrated Marketplace and is to be assessed on a present value basis over the remaining lives of the Base Plan Upgrades for which the waiver is requested. Sufficient benefit to load outside the Zone where the Base Plan Upgrades are connected is demonstrated if such benefit exceeds either:

i. Fifty percent (50%) of the upgrades' projected total benefit to load in the SPP Region; or

ii. The portion of the upgrades' annual revenue requirement projected to be borne by load outside the upgrade's Zone under region-wide cost allocation.

3. Any request for waiver under this Section III.E shall be submitted to the Transmission Provider in writing and accompanied by supporting information and analysis.

a. For a facility with a Notification to Construct issued on or before August 1, 2022, such request for waiver shall be submitted no later than one hundred eighty (180) days after August 1, 2022.

b. For a facility with a Notification to Construct issued after August 1, 2022, such request for waiver shall be submitted no later than one hundred eighty (180) days after the issuance of the facility's Notification To Construct.

4. The request for waiver and supporting information and analysis submitted to the Transmission Provider must satisfy the criteria contained in Section III.E.2.

5. The process for evaluation of any request for waiver under Section III.E shall be as follows:

    a. Upon receipt of a requesting entity's application and justification for the waiver, Transmission Provider shall post to the Transmission Provider website a copy of the requesting entity's application and justification for the waiver subject to any necessary protections of Critical Energy Infrastructure Information.

    b. The Transmission Provider shall evaluate the waiver request and develop its recommendation.

    c. Within ninety (90) days of receipt of the waiver request, Transmission Provider shall provide a written recommendation and rationale regarding the approval or denial of the waiver request to the SPP Cost Allocation Working Group ("CAWG"), Regional State Committee, Members Committee, and SPP Board of Directors.

    d. Within thirty (30) days of Transmission Provider's written recommendation to the CAWG, Regional State Committee, Members Committee, and SPP Board of Directors, any interested party may submit comments to the CAWG, Regional State Committee, Members Committee, and SPP Board of Directors with its recommendation and rationale regarding the approval or denial of the waiver request.

    e. The CAWG shall vote to recommend approval or denial of the waiver request at its next monthly scheduled meeting at least thirty (30) days after the deadline for any interested party to submit comments regarding the approval or denial of the waiver request.

        i. The CAWG may elect to delay its vote to recommend approval or denial of the waiver request until its next scheduled meeting.

f. The CAWG shall provide its recommendation regarding approval or denial of the waiver request to the Regional State Committee at the Regional State Committee's next quarterly scheduled meeting after the CAWG has voted to recommend approval or denial of the waiver request.

g. At the Regional State Committee's quarterly scheduled meeting when the CAWG provides its recommendation regarding approval or denial of the waiver request, the Regional State Committee shall vote to recommend approval or denial of the waiver request to the Members Committee and SPP Board of Directors.

    i. The Regional State Committee may elect to delay its vote to recommend approval or denial of the waiver request until its next scheduled meeting.

h. At the first SPP Board of Directors and Members Committee meeting following the Regional State Committee's vote to recommend approval or denial of the waiver request, the Regional State Committee will present its recommendation regarding the approval or denial of the waiver request to the SPP Board of Directors and Members Committee.

    i. At this same SPP Board of Directors and Members Committee meeting, any party that submitted comments to the CAWG, Regional State Committee, Members Committee, and SPP Board of Directors with its recommendation and rationale regarding the approval or denial of the waiver request may present its recommendation and rationale to the SPP Board of Directors and Members Committee.

i. Pursuant to Sec. 5.1(a) of the SPP Bylaws, the Members Committee will provide input to the SPP Board of Directors regarding approval or denial of the waiver request.

j. The SPP Board of Directors shall vote to approve or deny the waiver request at the first SPP Board of Directors and Members Committee

meeting following the Regional State Committee's vote to recommend approval or denial of the waiver request.

i. The SPP Board of Directors may elect to delay its vote to approve or deny the waiver request until its next scheduled meeting.

6. For a Base Plan Upgrade with an annual transmission revenue requirement included in Attachment H at the time of approval of its cost allocation waiver under this Section III.E, the revised cost allocation will become effective on the first day of the calendar month following approval of the waiver by the SPP Board of Directors.

## IV. Approved Balanced Portfolios

One hundred percent (100%) of the annual transmission revenue requirement for an approved Balanced Portfolio shall be recovered through the Region-wide Charge.

### A. Reallocation of Zonal Revenue Requirements for Deficient Zone(s)

For an approved Balanced Portfolio, the balance may have been achieved by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual Transmission Revenue Requirement ("Reallocated Revenue Requirements") from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement in accordance with Section IV.4.c of Attachment O to this Tariff.

#### 1. Implementation of Reallocated Revenue Requirements

The initial reallocation of the Reallocated Revenue Requirements from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement shall occur when at least 10% of the estimated levelized annual transmission revenue requirements for the approved Balanced Portfolio has been included in rates under the Tariff (the "Trigger Date").

On the Trigger Date and on the anniversary of the Trigger Date in each of the subsequent four years, 20% of the Reallocated Revenue Requirements required to balance the portfolio for the deficient Zone(s), as estimated in accordance with Section IV.4.c of Attachment O to this Tariff, shall be reallocated to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement. However, if all the upgrades in the approved Balanced Portfolio are completed and included in rates under the Tariff and the actual costs of any third party impacts identified under Section IV.3.c of Attachment O are determined prior to the fourth anniversary of the Trigger Date, the remaining Reallocated

Revenue Requirements shall be reallocated and the true-up specified in Section IV.A.2 of this Attachment shall be performed.

The reallocation of the Reallocated Revenue Requirements shall be from the Base Plan Zonal Annual Transmission Revenue Requirement of the deficient Zone(s) first, then, if necessary, from the Zonal Annual Transmission Revenue Requirement of the deficient Zone(s).

**2. Final Reallocation of Reallocated Revenue Requirements and True-up**

Upon the completion and inclusion in rates under the Tariff of all of the upgrades that are part of the approved Balanced Portfolio and the determination of the actual cost of any third party impacts attributable to the Balanced Portfolio under Section IV.3.c of Attachment O, the final amount of costs to be reallocated from the Reallocated Revenue Requirements for the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement to balance the approved Balanced Portfolio shall be trued-up based on the applicable fixed charge rate and actual costs. This true-up shall result in Reallocated Revenue Requirements for the deficient Zone(s) that are sufficient to achieve balance over the ten-year period analyzed in accordance with Section IV.4.c of Attachment O. For each deficient Zone, this shall include annual reallocation amounts in the remaining years that are increased to a level adequate to offset, on a present value basis, the lower amount of reallocation resulting from implementation of the Reallocated Revenue Requirements in 20% annual increments as described in Section IV.A.1 of this Attachment such that the present value of the total amount of the reallocation for each Zone is consistent with Section IV.4.c of Attachment O. The final reallocation shall be performed using the same benefits estimated at the time the Balanced Portfolio was approved.

Notwithstanding the foregoing, if the ten-year net present value of levelized annual transmission revenue requirements based on actual costs and third party impact costs under Section IV.3.c of Attachment O exceeds the ten-year net present value of estimated benefits for the entire approved Balanced Portfolio, then the reallocation for each Zone shall be set at a level that equates the benefit to cost ratio in each Zone to the trued-up benefit to cost ratio for the approved Balanced Portfolio over the ten-year period analyzed.

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**B. Reconfiguration of an Approved Balanced Portfolio**

**1. Conditions Under Which an Approved Balanced Portfolio may be Reconfigured**

Under certain conditions, the Transmission Provider shall review an approved Balanced Portfolio for unintended consequences and may recommend reconfiguring a previously approved Balanced Portfolio. Conditions that would initiate such review include but are not limited to:

i. Cancellation of an upgrade that is part of an approved Balanced Portfolio;

ii. Unanticipated decreases in benefits or increases in the costs of upgrades that are part of an approved Balanced Portfolio or increases in the costs of third party impacts under Section IV.3.c of Attachment O; and

iii. Significant unanticipated changes in the transmission system.

**2. Factors to be Considered in Determining Whether a Balanced Portfolio Should be Reconfigured**

Reconfiguration of a Balanced Portfolio shall be evaluated based upon the following general factors, including but not limited to, the impact of the reconfiguration on:

i. Meeting the conditions for a Balanced Portfolio specified in Section IV.3.e of Attachment O to this Tariff;

ii. The number of deficient Zones as defined in Section IV.4.a of Attachment O to this Tariff;

iii. The amount of Reallocated Revenue Requirements that needs to be transferred from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement in order to balance the reconfigured portfolio; and

iv. The increase in the overall cost of the reconfigured Balanced Portfolio, if upgrades are added to the portfolio.

**3. Reallocation of Reallocated Revenue Requirements**

If a reconfigured portfolio is to be balanced by transferring a portion of the Reallocated Revenue Requirements from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement, the reallocation of the revenue requirements specified in Section IV.A of this Attachment shall be adjusted based on the costs and benefits of the proposed reconfigured Balanced Portfolio as approved.

**4. Recommendation and Approval of a Reconfigured Balanced Portfolio**

Based on the analysis performed in accordance with Sections IV.B.1 through IV.B.3 of this Attachment, the Transmission Provider shall provide a report and make a recommendation in regard to reconfiguration of the Balanced Portfolio to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee shall consider the Transmission Provider's report and recommendation, and shall provide its own recommendation (along with the Transmission Provider's report and recommendation) to the SPP Board of Directors. Based upon these recommendations, the SPP Board of

Directors shall take action regarding reconfiguration of the Balanced Portfolio.

## V. Other Network Upgrades

### A. Sponsored Upgrades

The Directly Assigned Upgrade Cost of a Sponsored Upgrade shall be borne voluntarily by the Project Sponsor. The Project Sponsor shall execute an Agreement for Sponsored Upgrade in which it agrees to bear these Directly Assigned Upgrade Costs. In the Agreement, the Project Sponsor shall elect to pay for the Sponsored Upgrade by (1) a lump sum payment or (2) periodic charges calculated in accordance with Commission policy (both hereafter referred to as "Project Sponsor's Payment"). The lump sum payment option is the only eligible option for a Sponsored Upgrade to be constructed by Western-UGP. Such periodic charges shall be paid on a monthly basis over a twenty year period unless a different frequency and/or shorter term is established in the Agreement for Sponsored Upgrade. The present value of the Project Sponsor's Payment shall equal the present value of the annual revenue requirements of the Sponsored Upgrade over a twenty year plant life. The annual revenue requirements of the Sponsored Upgrade shall be calculated by multiplying the levelized fixed charge rate of the Transmission Owner, based on full depreciation over a 20 year plant life and including operating and maintenance expenses and any applicable tax consequences, by the nondepreciated actual cost of the Sponsored Upgrade.

The Transmission Provider shall file the Agreement initially utilizing good faith estimates of the construction costs for the assigned upgrade. Upon completion of the Sponsored Upgrade, the Transmission Provider shall true up the Directly Assigned Upgrade Costs to the actual construction costs as appropriate and calculate the Project Sponsor's Payment.

In addition, the Directly Assigned Upgrade Cost of the Sponsored Upgrade shall be reduced as provided in Section VII of this Attachment J and by any revenue credits granted to a Transmission Owner for the use of the Sponsored Upgrade.

For the Directly Assigned Upgrade Costs assigned to the Project Sponsor for the Sponsored Upgrade, the Project Sponsor shall be eligible for compensation through candidate ILTCRs in accordance with Attachment Z2 of this Tariff. If the Project Sponsor is to receive candidate ILTCRs pursuant to Section IV of Attachment Z2 of this Tariff, then the candidate ILTCR MW and source to sink paths related to the candidate ILTCRs shall be included in the Sponsored Upgrade Agreement described under Schedule 1 of this Attachment J. The term of such ILTCR shall be specified in the agreement and shall be at least ten years and not more than twenty years. In addition, if the Project Sponsor is to receive candidate ILTCRs, the Project Sponsor must also execute Attachment AH of this Tariff if the Project Sponsor is not already a Market Participant.

**B. Service Upgrades**

The cost of a Service Upgrade shall be allocated in accordance with Attachment Z1 to this Tariff. For any Directly Assigned Upgrade Costs assigned to a Transmission Customer for a Creditable Upgrade, the Transmission Customer shall be eligible to receive transmission revenue credits in accordance with Attachment Z2 of this Tariff unless the Transmission Customer qualifies for, and elects to receive, candidate ILTCRs in accordance with Attachment Z2 of this Tariff. If the Transmission Customer receives revenue credits pursuant to Sections I and II of Attachment Z2 of this Tariff then the Transmission Customer shall not be eligible for candidate ILTCRs for the Directly Assigned Upgrade Costs. For any Directly Assigned Upgrade Costs assigned to a Transmission Customer for a Service Upgrade that is not a Creditable Upgrade, the Transmission Customer shall be eligible for compensation through candidate ILTCRs in accordance with Attachment Z2 of this Tariff. If the Transmission Customer is to receive candidate ILTCRs pursuant to Section IV of Attachment Z2 of this Tariff, then the candidate ILTCR MW and source to sink paths related to the candidate ILTCRs

shall be included in the Transmission Service Agreement or Network Integration Transmission Service agreement. The term of such ILTCR shall be specified in the agreement and shall be at least ten years and not more than twenty years.

**C. Generation Interconnection Related Network Upgrades**

The cost of a generation interconnection related Network Upgrade shall be allocated in accordance with Attachment V to this Tariff. For any Directly Assigned Upgrade Costs assigned to an Interconnection Customer for a Network Upgrade required in its Generator Interconnection Agreement, the Interconnection Customer shall be eligible for compensation through candidate ILTCRs in accordance with Attachment Z2 of this Tariff . If the Interconnection Customer is to receive candidate ILTCRs in accordance with Section IV of Attachment Z2 of this Tariff, then the candidate ILTCR MW and source to sink paths related to the candidate ILTCRs shall be included in the Interconnection Customer's Generator Interconnection Agreement. The term of such ILTCR shall be specified in the agreement and shall be at least ten years and not more than twenty years.

**D. Zonal Reliability Upgrades**

1. The cost of Zonal Reliability Upgrades (i) included in the 2005 SPP Transmission Expansion Plan and (ii) placed in service prior to January 1, 2008 shall be allocated in accordance with Section III to this Attachment.
2. The cost of all other Zonal Reliability Upgrades shall be includable in the applicable Zonal Annual Transmission Revenue Requirement.

## VI. Interregional Projects as Network Upgrades

The annual transmission revenue requirements associated with the costs allocated to the SPP Region for the approved Interregional Projects shall be included in the Region-wide Annual Transmission Revenue Requirement and recovered through the Region-wide Charge.

## VII. Treatment of Upgrades that Permit Deferral or Displacement of Network Upgrades

### A. Deferred Upgrade

In the case of a Base Plan Upgrade, an upgrade that is part of an approved Balanced Portfolio, a Zonal Reliability Upgrade, or a Service Upgrade that may be deferred ("Deferred Upgrade") as a result of a proposed Network Upgrade, the achievable Accredited Revenue Requirements shall be equal to the time value of the affected Transmission Owner's(s') revenue requirement(s) for the Deferred Upgrade over the period of the deferral, calculated as follows:

1. A Transmission Owner's annual revenue requirement for a Deferred Upgrade shall be determined using the same method as is used by the Transmission Owner to calculate its revenue requirement for transmission facilities for other purposes, but applying that method to the projected incremental investment in the Deferred Upgrade.
2. The time value of the deferral shall be calculated by discounting to present value the accredited annual revenue requirements for each individual year in the deferral period and summing the resulting values. For each individual year in the deferral period, the time value of the deferral will be determined by discounting the annual revenue requirement for that year first from January 1 of that year and then from December 31 of that year, summing the two resulting values, and dividing by two. For any partial year encompassed by the deferral period, the time value of the deferral shall be calculated in the same manner as indicated in the immediately preceding sentence, except that the resulting value will be pro-rated based on the number of months in the partial year divided by 12.

### B. Displaced Upgrade

In the case of a Base Plan Upgrade, an upgrade that is part of an approved Balanced Portfolio, a Zonal Reliability Upgrade, or a Service Upgrade that may be displaced ("Displaced Upgrade") as a result of a proposed Network Upgrade,

the achievable Accredited Revenue Requirements shall be equal to the time value of the affected Transmission Owner's(s') revenue requirement(s) for the Displaced Upgrade over the expected service life of the facility that is displaced. The methodology for calculating the Accredited Revenue Requirements shall be the same as set forth in Section VII.A. of this Attachment, except that the expected service life of the facility shall be substituted for the deferral period in all instances.

**C. Application of Accredited Revenue Requirements**

The Transmission Provider shall calculate the Accredited Revenue Requirements that are achievable due to a Deferred Upgrade or Displaced Upgrade. The Accredited Revenue Requirements shall be based on the estimated project costs for the approved upgrade which is deferred or displaced.

1. If a proposed Network Upgrade defers or displaces the need for a Base Plan Upgrade associated with a new or changed Designated Resources for which there are Directly Assigned Upgrade Costs, the Accredited Revenue Requirements related to Base Plan Upgrade charges shall only include the costs that are allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and the Base Plan Region-wide Annual Transmission Revenue Requirement.
2. If a proposed Network Upgrade defers or displaces the need for an upgrade that is part of an approved Balanced Portfolio, the Accredited Revenue Requirements related to Balanced Portfolio charges shall only include the costs that are allocated to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement.
3. If a proposed Network Upgrade defers or displaces the need for a Zonal Reliability Upgrade, the Accredited Revenue Requirements related to Zonal Reliability Upgrade charges shall only include the costs that are assigned to the Zonal Annual Transmission Revenue Requirement.

4. If a proposed Network Upgrade defers or displaces the need for a Service Upgrade required to provide Long-Term Firm Point-to-Point Transmission Service, the Accredited Revenue Requirements related to the transmission service charges shall only include the expected increase in revenue that can be distributed through Section II.C of Attachment L to this Tariff, for service under Schedule 7, as a result of displacement or deferral of the Service Upgrade.

**D. Assignment and Recovery of Accredited Revenue Requirements**

1. For a proposed Network Upgrade, other than an upgrade included in a Balanced Portfolio, that results in a Deferred Upgrade or Displaced Upgrade:

   i. The entity responsible for paying the cost of the Network Upgrade shall be responsible for any positive difference between the present value of the total costs for its upgrade and the present value of the Accredited Revenue Requirements.

   ii. The Accredited Revenue Requirements of the deferred or displaced upgrades shall be recovered through charges specified in:

      a. Section III.A of this Attachment for deferred or displaced Base Plan Upgrades;

      b. Section IV of this Attachment for deferred or displaced upgrades associated with a Balanced Portfolio;

      c. Section V.D of this Attachment for deferred or displaced Zonal Reliability Upgrades; and

      d. Section V.B. of this Attachment for deferred or displaced Service Upgrades.

   iii. The calculations for determining the Accredited Revenue Requirements shall be filed with the Commission by the Transmission Provider prior to the imposition of any charges or credits hereunder.

2. The costs of the upgrades included in an approved Balanced Portfolio that result in a Deferred Upgrade or Displaced Upgrade shall be included in the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement and shall be recovered through the Region-wide Charge.

   i. The costs of a Network Upgrade that is deferred or displaced by the upgrades included in an approved Balanced Portfolio shall not be recovered through the original recovery mechanism for such upgrade.

   ii. In the evaluation of the benefits of the Balanced Portfolio as specified in Section IV.3.d of Attachment O to this Tariff, the Accredited Revenue Requirements associated with the deferred or displaced Base Plan Upgrade(s), Zonal Reliability Upgrade(s) and Service Upgrade(s) shall be treated as benefits to the Zones to which those Accredited Revenue Requirements are distributed or would have been otherwise assigned or recovered as specified in:

      a. Section III.A of this Attachment for deferred or displaced Base Plan Upgrades;

      b. Section V.D of this Attachment for deferred or displaced Zonal Reliability Upgrades; and

      c. Section II.C of Attachment L for service under Schedule 7 for deferred or displaced Service Upgrades.

## VIII. Uncompleted Network Upgrades

The costs of Network Upgrades that are not completed through no fault of the Transmission Owner charged with construction of the upgrades shall be handled as follows:

If a proposed Network Upgrade was accepted and approved by the Transmission Provider, the Transmission Provider shall develop a mechanism to recover such costs and distribute such revenue on a case by case basis. Such recovery and distribution mechanism shall be filed with the Commission. The Transmission Owner(s) that incurred the costs shall be reimbursed for those costs by the Transmission Provider. These costs shall include, but are not limited to: the costs associated with attempting to obtain all necessary approvals for the project, study costs, and any construction costs.

## Schedule 1 to Attachment J

## Agreement For Sponsored Upgrade

This Agreement For Sponsored Upgrade ("Agreement") is entered into this _____ day of _____, _____, by and between _____ ("Project Sponsor"), and Southwest Power Pool, Inc. ("Transmission Provider") on behalf of itself and the designated Transmission Owner(s). The Project Sponsor and Transmission Provider shall be referred to as "Parties."

WHEREAS, the Transmission Provider administers an Open Access Transmission Tariff ("Tariff") to provide Transmission Service within the Southwest Power Pool and acts as agent for the Transmission Owners in providing service under the Tariff; and

WHEREAS, the Sponsored Upgrade identified in the Appendix attached hereto has been endorsed by the Markets and Operations Policy Committee and the Board of Directors of the Transmission Provider; and

WHEREAS, the Project Sponsor has agreed to bear the cost of the Sponsored Upgrade; and

WHEREAS, the Parties intend that capitalized terms used herein shall have the same meaning as in the Tariff;

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein, the Parties agree as follows:

1.0 This Agreement shall become effective on the later of (l) the date of the execution of this Agreement by both Parties or (2) such other date as it is permitted to become effective by the Commission. ("Effective Date")

2.0 This Agreement shall terminate on the later of the following events: (1) the Project Sponsor has fulfilled its obligation to make Project Sponsor's Payment pursuant to Section 3.0; (2) the Transmission Provider has fulfilled its obligation to pay the Project Sponsor all compensation pursuant to Section 5.0, recognizing that no obligation to pay compensation will remain after the Sponsored Upgrade has been permanently removed from service; or (3) the end of the candidate ILTCR term.

3.0 Project Sponsor agrees to pay the Directly Assigned Upgrade Costs of the Sponsored Upgrade pursuant to Attachment J of the Tariff. Project Sponsor has elected to pay for the Sponsored Upgrade in one of the following manners, as indicated in the Appendix attached hereto: (1) by a lump sum payment or (2) a periodic charge, both hereinafter referred to as "Project Sponsor's Payment." The Parties recognize that the initial Project Sponsor's Payment will be based on an estimate of the Directly Assigned Upgrade Costs. While Transmission Provider represents that the Project Sponsor's Payment is based on a good faith estimate of the Directly Assigned Upgrade Costs, such estimate shall not be binding, and the Project Sponsor shall compensate the Transmission Provider and designated Transmission Owner(s) for all costs

incurred pursuant to the provisions of the Tariff. Promptly after the Sponsored Upgrade is placed in service, Transmission Provider shall adjust the Project Sponsor's Payment to reflect all such costs incurred, as appropriate.

4.0 Project Sponsor shall maintain a Letter of Credit in the amount specified in this Agreement or such other form of security acceptable to Transmission Provider pursuant to Attachment X of the Tariff until such time as the Project Sponsor has fulfilled its obligation to make Project Sponsor's Payment pursuant to Section 3.0. The Transmission Provider may waive the requirement for a Letter of Credit or such other form of security if the Project Sponsor and the designated Transmission Owner are one and the same entity.

5.0 Transmission Provider agrees to provide Project Sponsor with candidate ILTCRs in the amounts on a specific source-to-sink path in accordance with Section IV of Attachment Z2 of the Tariff. Candidate ILTCRs shall be the exclusive compensation of the Project Sponsor under this Agreement. Candidate ILTCR parameters shall be documented in the Appendix attached hereto.

6.0 Transmission Provider agrees to arrange for the construction of the Sponsored Upgrade in accordance with the Tariff, the SPP Membership Agreement and the construction timeline specified herein.

7.0 Any notice or request made to or by either Party regarding this Agreement shall be made to the representative of the other Party as indicated below.

Southwest Power Pool, Inc.:

_____

201 Worthen Drive

Little Rock, AR 72223-4936

Project Sponsor:

_____

_____

_____

8.0 The Tariff is incorporated herein and made a part hereof for all purposes.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

Southwest Power Pool, Inc.:

By:_____ _____ _____

Name Title Date

Project Sponsor:

By:_____ _____ _____

Name Title Date

## Appendix

## Specifications

1.0 Designated Transmission Owner(s): _____

2.0 Description of Sponsored Upgrade: _____

_____

_____

_____

_____

_____

3.0 Project Sponsor's Payment:* The Project Sponsor shall elect to pay the Directly Assigned Upgrade Grade Costs of the Sponsored Upgrade by (1) a lump sum payment or (2) a periodic charge as indicated below:

_____ Lump Sum Payment:_____

Payment Due Date:_____

_____Periodic Charge:_____

_____

_____

* The Project Sponsor's Payment specified herein shall initially be based on a good faith estimate of Directly Assigned Upgrade Costs. The Project Sponsor's Payment shall be subject to adjustment and true up after the Sponsored Upgrade is placed in service.

4.0 Compensation to Project Sponsor: The Project Sponsor shall receive candidate ILTCRs where the MW amount of such candidate ILTCRs have been determined using the process described under Section IV of Attachment Z2 of the Tariff. The term for the

candidate ILTCRs will be mutually agreed to by the parties such that the specified candidate ILTCR has a life of at least ten (10) years and no more than twenty (20) years from the date that the facility is placed in service.

Candidate Incremental LTCRs

* Source _____
* Sink _____
* Candidate Incremental LTCR MW _____
* Term (years from in-service date of Sponsored Upgrade) _____

5.0 Project Timeline (Milestones): _____

_____

_____

_____

_____

_____

6.0 Letter of Credit:_____

# Schedule 2 to Attachment J

## Base Plan Upgrades Specifically Designated for Cost Allocation under Attachment J, Section III.A.2

| Project | | Owner | Date Needed | Voltage |
|---|---|---|---|---|
| 345 kV Line - AVS to Charlie Creek #2 | ZONE 19 | BEPC | 12/1/2017 | 345 |
| AVS Switchyard [345 kV] | ZONE 19 | BEPC | 12/1/2017 | 345 |
| Charlie Creek Substation [345 kV] | ZONE 19 | BEPC | 12/1/2017 | 345 |
| 230/115 kV Line (DC) - Judson Sub to Williston Sub [230 kV portion] | ZONE 19 | BEPC | 12/1/2017 | 230 |
| 345/230 kV Judson Substation | ZONE 19 | BEPC | 12/1/2017 | 230 |
| 345 kV Line - Charlie Creek Sub to Indian Hills to Judson | ZONE 19 | BEPC | 12/1/2017 | 345 |
| 230 kV Line - Tande Sub to Neset Sub | ZONE 19 | BEPC | 12/1/2017 | 230 |
| 345/230 kV Tande Substation | ZONE 19 | BEPC | 12/1/2017 | 230 |
| 345 kV Line - Judson Sub to Tande Sub | ZONE 19 | BEPC | 12/1/2017 | 345 |
| Neset Substation [230 kV] | ZONE 19 | BEPC | 12/1/2017 | 230 |

# ATTACHMENT K
# REDISPATCH PROCEDURES AND REDISPATCH COSTS

## I. Redispatch to Accommodate a Request for Firm Transmission Service

### A. Purpose

This Procedure shall apply only to entities that, when applying for Firm Point-To-Point or Network Integration Transmission Service, were told that the service could be provided only if redispatch occurs. If an entity in these circumstances does not agree to the limited Auction Revenue Rights or Long-Term Congestion Rights as provided in Section 13.5 of this Tariff, then its request for Firm Point-to-Point Transmission Service will be denied in whole or in part. To the extent the Transmission Provider can relieve any system constraint for Firm Point-To-Point or Network Integration Transmission Service through operation of the Energy and Operating Reserve Markets described in Attachment AE of this Tariff, it shall do so, provided that the Eligible Customer agrees to the limitations on Auction Revenue Rights and Long-Term Congestion Rights pursuant to the terms of Section 13.5 of this Tariff and this procedure. The procedure under this Section I is not for the purpose of sustaining non-firm service.

### B. Assessment Process

Upon receipt of an Application for Firm Point-to-Point or Network Integration Transmission Service, the Transmission Provider shall make a determination of the availability of the requested Firm Transmission Service. The Transmission Provider will identify transmission constraints utilizing generally accepted power system analysis techniques. Where the requested Firm Transmission Service is determined to be not fully available because of transmission constraints, then the Transmission Provider will assess the need for redispatch of generation.

The procedure to be implemented is as follows:

1. Determine the available transmission capacity for the requested Firm Transmission Service utilizing a load flow computer simulation of the transmission system recognizing all firm uses of the system.
2. Determine the owned generation resources of the Transmission Owners or others that will relieve the transmission constraint and the amount of transmission capacity available through redispatch.
3. The Transmission Provider shall inform the Eligible Customer if the Transmission Provider concludes that redispatch can sustain the requested Firm Transmission Service.

4. Any disputes as to compensation for service under this Tariff shall go to dispute resolution in accord with the provisions of this Tariff.

**C. Redispatch Costs**

If redispatch services are provided pursuant to this Attachment K, the Transmission Provider will in good faith attempt to relieve the constraint through operation of the Energy and Operating Reserve Markets described in Attachment AE of this Tariff. Costs associated with redispatch services shall be collected and paid in accordance with the Energy and Operating Reserve Markets settlement procedures described in Attachment AE of this Tariff.

[Reserved for Future Use]

[Reserved for Future Use]

[Reserved for Future Use]

# ATTACHMENT L
# TREATMENT OF REVENUES

## I. Payments And Distribution Of Revenues

Payments received by the Transmission Provider under Part I, Section 7 of this Tariff will be distributed to the Transmission Owners, to the providers of ancillary services, and to any Upgrade Sponsor(s) due revenue credits pursuant to Attachment Z2 of this Tariff in accordance with the provisions of this Attachment L. Payments and distribution of revenues associated with the Integrated Marketplace will be made in accordance with Section 8 of Attachment AE.

## II. Distribution Of Transmission Service Revenues Associated With The Zonal Annual Transmission Revenue Requirement

Transmission service revenues associated with the Zonal Annual Transmission Revenue Requirement shall be distributed in accordance with the following:

### A. Grandfathered Agreements

Except by mutual agreement of the Parties to Grandfathered Agreements, the Transmission Provider shall have no claim to the revenues collected under such agreements, and shall not collect or allocate any revenues for transmission service related to such transactions. The Transmission Owner providing the transmission service under the Grandfathered Agreements, therefore, will continue to receive payment directly from the customer under the Grandfathered Agreement. Nothing herein is intended to supersede or otherwise affect rights that any party to a Grandfathered Agreement may have with respect to termination of the Grandfathered Agreement. In the event that a Grandfathered Agreement remains in effect between or among two or more Transmission Owners in a multi-owner Zone other than Zone 1, the associated charges and revenues will be treated as set forth in Section II.B.2(b) below for purposes of determining the appropriate distribution of revenues among the Transmission Owners in that Zone.

### B. Revenue Distribution – Network Integration Transmission Service

1. Single-Owner Zones

Where there is only one Transmission Owner in a Zone, revenues associated with facilities with a Zonal Annual Transmission Revenue Requirement shall be distributed as follows:

(a) Except to the extent required under paragraph II.B.1(b) of this Attachment L, revenues collected by the Transmission Provider under Schedule 9 in connection with the provision of Network Integration Transmission Service shall be distributed to the Transmission Owner in the Zone where the Network Load is located.

(b) When a Network Customer has designated Network Load not physically interconnected with the Transmission System under Section 31.4 of the Tariff, revenues collected by the Transmission Provider for Network Integration Transmission Service for that portion of the Network Customer's Network Load shall be distributed to the

Transmission Owner of the transmission Zone from which the Schedule 9 rate was derived and where the Network Load not physically connected with the Transmission System is included in the denominator when calculating Load Ratio Shares for that Zone in accordance with Section 34.4 of this Tariff. If the Network Load outside the Transmission Provider's Transmission System is not included in the calculation of the transmission Zone's load ratio share allocation then the revenue shall be distributed among Transmission Owners on the same basis as the revenues collected in connection with the provision of Point-To-Point Transmission Service.

2. Multi-Owner Zones

When more than one Transmission Owner within a single Zone has established its owner-specific zonal annual revenue requirement ("OZRR"), the Transmission Provider shall distribute revenues owed to the Transmission Owners in the Zone as described below.

(a) Except to the extent required under paragraph II.B.2(e) of this Attachment L, the Transmission Provider shall distribute revenues it collects under Schedule 9 to each Transmission Owner in the Zone where the load is located in proportion to its respective share of the Zonal Annual Transmission Revenue Requirements ("ZRR") shown in Attachment H for that Zone, as adjusted in accordance with paragraph II.B.2(b) below. The resulting adjusted OZRRs of the Transmission Owners in the Zone as calculated in paragraph II.B.2(b) below will be combined to provide the basis for distribution of revenues from Schedule 9 charges.

(b) For any year in which a Transmission Owner is a seller of transmission service to another Transmission Owner within the same Zone under one or more Grandfathered Agreements, the selling Transmission Owner's OZRR used to allocate revenue from Schedule 9 charges shall be reduced by the revenues associated with these Grandfathered Agreements in that year, but only to the extent that such costs have not already been credited against the selling Transmission Owner's OZRR. For any year in which a Transmission Owner is a purchaser of transmission service from a Transmission Owner within the same Zone under one or more Grandfathered Agreements, the purchasing Transmission Owner's OZRR shall be increased by the charges payable under these Grandfathered Agreements in that year, but only to the extent those charges are not already included in the purchasing Transmission Owner's OZRR.

(c) For each Transmission Owner in the Zone that has elected not to take Network Integration Transmission Service for its Native Load Customers or that has elected not to make payments to the Transmission Provider for its OZRR in taking Network Integration Transmission Service for its Native Load Customers and/or that provides long term transmission service under Grandfathered Agreements (other than those addressed in paragraph II.B.2(b) above), the Transmission Provider shall compute hypothetical NITS payments equal to the cost to serve its Native Load Customers and to serve long-term customers served under Grandfathered Agreements (other than those addressed in paragraph II.B.2(b) above) as if those customers were paying for service under Schedule 9.

(d) For each Transmission Owner, the Transmission Provider shall calculate an amount equal to the sum of hypothetical NITS payments determined in accordance with paragraph II.B.2(c) above, if any, plus distributed Schedule 9 charges in accordance with paragraph II.B.2(a) above, less its OZRR as adjusted pursuant to paragraph II.B.2(b) above. If the resulting amount is positive, the Transmission Owner shall pay the Transmission Provider this amount. If the resulting amount is negative, the Transmission Provider shall pay the Transmission Owner this amount.

(e) The treatment described in paragraphs II.B.2(b)-(d) above is premised on the assumption that the annual transmission revenue requirement of the Transmission Owner that is the seller under a Grandfathered Agreement has not been reduced by the amount of the charges associated with the Grandfathered Agreement. In such circumstances, the parties to the Grandfathered Agreement will attempt to reach agreement on a treatment of the Grandfathered Agreement that results in appropriate compensation to the Transmission Owners in the Zone while preventing the imposition of excessive costs on others. If the Transmission Owners in the Zone are unable to reach agreement, either Transmission Owner may invoke the dispute resolution procedures of the Tariff or seek a determination from FERC as to the appropriate treatment of the Grandfathered Agreement charges.

(f) When a Network Customer has designated Network Load outside the Transmission Provider's Transmission System under Section 31.4 of the Tariff, revenues collected by the Transmission Provider for Network Integration Transmission Service for that portion of the Network Customer's Network Load shall be distributed to the Transmission Owners of the transmission Zone from which the Schedule 9 rate was derived and where the

Network Load not physically connected with the Transmission System is included in the denominator when calculating Load Ratio Shares for that Zone in accordance with Section 34.4 of this Tariff. If the Network Load not physically connected with the Transmission System is not included in the calculation of the transmission Zone's load ratio share allocation, then the revenue shall be distributed among Transmission Owners on the same basis as the revenues collected in connection with the provision of Point-To-Point Transmission Service.

(g) Sections II.B.2(a) through II.B.2.(e) above do not apply to Zone 1. In the event a Transmission Owner within Zone 1 other than American Electric Power establishes its owner-specific zonal annual revenue requirement ("OZRR") as stated in Attachment H, that subsequent Transmission Owner will be entitled to receive revenue, collected by the Transmission Provider from other Transmission Customers within Zone 1 including any Transmission Owner within Zone 1 taking service under Section 39, in an amount equal to one minus that Transmission Owner's Load Ratio Share of the Zone 1 total Network Load multiplied by that Transmission Owner's OZRR.

(h) Section II.B.2(f) above does not apply to revenues from a Network Customer having Network Load in Zone 19 which has designated Network Load outside the Transmission Provider's Transmission System under Section 31.4 of this Tariff designated prior to October 1, 2015. For such load, revenues collected by the Transmission Provider for Network Integration Transmission Service for such portion of the Network Customer's Network Load shall be distributed among Transmission Owners of Zone 19.

(i) Nothing herein is intended to supersede or otherwise affect rights that any Transmission Owner in a multi-owner Zone may have to seek designation of its facilities as a separate Zone under the Tariff.

3. Revenue Credits – Tariff Attachment Z2

Network Integration Transmission Service revenue collected by the Transmission Provider attributed to the use of Creditable Upgrades pursuant to the provisions of Attachment Z2 of this Tariff shall be paid to Upgrade Sponsors in accordance with Attachment Z2.

**C. Revenue Distribution -- Point-To-Point Transmission Service**

Irrespective of the number of Transmission Owners in a Zone, and except to the extent required under Section IV of this Attachment L, revenues collected by the Transmission Provider

under Schedules 7 and 8 and revenues allocated pursuant to paragraphs II.B.1(b) and II.B 2(f). shall be distributed as follows:

1. If a Point-To-Point Transmission Service reservation could not be granted but for the use of one or more Creditable Upgrades, pursuant to the provisions of Attachment Z2, the revenue from that reservation will first be distributed to the Upgrade Sponsors of such Creditable Upgrades in accordance with the provisions of Attachment Z2. Any remaining revenue shall be distributed in accordance with all other provisions of this Section C.

2. If the generation source(s) and load(s) are located within a single Zone, 50% of the revenues shall be distributed to the Transmission Owner(s) in that Zone in proportion to their respective OZRR(s), as adjusted in accordance with Section 34.1(2) of this Tariff; and 50% of the revenues shall be distributed to the Transmission Owner(s) in that Zone in proportion to the MW-mile impacts incurred by each such Transmission Owner.

3. In all instances other than that described in the preceding paragraph: 50% of the revenues shall be distributed to all Transmission Owners in proportion to their respective OZRRs, as adjusted in accordance with Section 34.1(2) of this Tariff; and 50% of the revenues shall be distributed to the Transmission Owners whose facilities incur MW-mile impacts due to the transaction, in proportion to the MW-mile impacts incurred by each such Transmission Owner. A Transmission Owner's OZRR used for this purpose shall be that stated in Attachment H and where applicable, such OZRR shall be adjusted in accordance with Section 34.1(2) of this Tariff. The MW-mile impacts shall be determined by use of the procedures in Attachment S.

## III. Distribution of Revenues From Base Plan Zonal Charges and Region-wide Charges and Interregional Projects

### A. Distribution of Revenues Based on Annual Transmission Revenue Requirements

Revenues associated with the Base Plan Zonal Annual Transmission Revenue Requirements and with the Region-wide Annual Transmission Revenue Requirement, specified in Attachment H and collected by the Transmission Provider under Schedule 11 of the Tariff but excluding revenues collected pursuant to Sections III.B and III.C of this Attachment L, shall be distributed to Transmission Owners owning Base Plan Upgrades, upgrades within approved Balanced Portfolios, an approved Interregional Project and to Transmission Owners with facilities in Zones from which any amount has been reallocated from the Zonal Annual Transmission Revenue Requirements in accordance with Section IV.A of Attachment J. Such revenue distribution shall be in proportion to the Transmission Owners' respective (i) annual transmission revenue requirements for Base Plan Upgrades as reduced for Schedule 11 point-to-point revenue and revenue distributed and allocated under Attachment AU in accordance with Section II.A of Schedule 11 under this Tariff, (ii) annual transmission revenue requirements for upgrades within approved Balanced Portfolios as reduced for Schedule 11 point-to-point revenue and revenue distributed and allocated under Attachment AU in accordance with Section II.A of Schedule 11 under this Tariff, (iii) annual transmission revenue requirements for approved Interregional Projects as reduced for Schedule 11 point-to-point revenue and revenue distributed and allocated under Attachment AU in accordance with Section II.A of Schedule 11 under this Tariff, and (iv) amounts reallocated from the Zonal Annual Transmission Revenue Requirements in accordance with Section IV.A of Attachment J.

### B. Distribution of Point-To-Point Revenues under Zonal ATRR Reallocation

Revenues derived from the component of the Region-wide Charge for Point-To-Point Transmission Service that is associated with any amount reallocated from the Zonal Annual Transmission Revenue Requirements, in accordance with Section IV.A of Attachment J, shall be distributed to Transmission Owners proportionately to the distribution of revenues collected under Schedules 7 and 8 as provided in Section II.C of this Attachment L.

### C. Distribution of Revenues for Creditable Upgrades Included in Schedule 11 Rates

Revenue collected by the Transmission Provider under Schedule 11 attributed to use of Creditable Upgrades shall be distributed to the Upgrade Sponsors to which such revenues are due in accordance with Section II.D and III.C.2 of Attachment Z2.

**D. Distribution of Revenues to Interregional Planning Region**

Revenues associated with approved Interregional Projects collected by the Transmission Provider under Schedule 11 of the Tariff to compensate an Interregional Planning Region in accordance with the interregional cost allocation pursuant to the Addendum(s) to Attachment O will be distributed by the Transmission Provider to the applicable Interregional Planning Region.

**E. Distribution of Revenues to Other Transmission Providers**

Revenues associated with transmission upgrades approved pursuant to the coordination agreements under Addendum 1 to Attachment O and approved to be collected by the Transmission Provider under Schedule 11 of the Tariff to compensate other transmission providers will be distributed by the Transmission Provider to the applicable other transmission provider.

## IV. Distribution Of Other Revenues

1. Revenues associated with redispatch service will be paid to the Resource owner providing the service for the Transmission Provider in accordance with the settlement procedures specified in Attachment AE.
2. Revenues associated with Reactive Supply and Voltage Control from Generation Sources Services under Schedule 2 of the Tariff will be paid to the generation owner providing the service for the Transmission Provider consistent with the development of the charges under Schedule 2.
3. Energy or revenues received as compensation for transmission losses shall be distributed consistent with Attachment M to the Tariff.
4. Revenues associated with Scheduling, System Control and Dispatch Service under Schedule 1 shall be allocated to the Transmission Owners within the transmission system that provide such service as follows:
    a. For Firm or Non-Firm Point-To-Point Transmission Service, for through and out transactions, Schedule 1 charge revenues shall be allocated to Transmission Owners in proportion to the respective scheduling revenue requirement of each such Transmission Owner associated with the provision of this service.
    b. For Customers taking Firm or Non-Firm Point-To-Point Transmission Service, for transactions into and within the Transmission System, Schedule 1 charge revenues shall be allocated to Transmission Owner whose Zone is the Point of Delivery.
    c. For Customers taking Network Integration Transmission Service, Schedule 1 charge revenues shall be allocated to Transmission Owner in whose Zone the load is located.
5. Revenues associated with Tariff Administration Service under Schedule 1-A1 will remain with the Transmission Provider to pay for the costs of providing that service.
6. Payments associated with penalties imposed under this Tariff will be used to reduce the Transmission Provider's Scheduling and Tariff Administration Service

costs (though the non-penalty portion of the charge will go back to the Transmission Owner(s) that actually provided the service).

7. Transmission Owner costs associated with System Impact and Facilities Studies compensated by the Transmission Customer shall go to the appropriate Transmission Owner(s).
8. The revenues associated with Direct Assignment Facilities shall go directly to the Transmission Owner(s) owning the facilities.
9. The revenues associated with Network Upgrades, not otherwise provided for in Section III of this Attachment L, shall be first assigned to the Transmission Owner building the Network Upgrades to meet the annual revenue requirements of such facilities. If multiple Transmission Owners construct the facilities, the revenues shall be shared in accordance with each Transmission Owner's respective revenue requirement for such facilities or as otherwise agreed by the Transmission Owners. The remaining revenues shall be allocated in accordance with Section II of this Attachment L.
10. The revenues associated with Wholesale Distribution Service shall go directly to the Transmission Owner(s) owning the facilities consistent with Schedule 10.
11. Any additional revenues received under Section 22.1 of the Tariff shall be treated in the same manner as revenues under Section II.B.2 for single-owner Zones, and Section II.C.2 for multi-owner Zones, of this Attachment L.
12. All revenues received by the Transmission Provider to compensate a Transmission Owner(s) not party to a generation interconnection agreement for the construction of Network Upgrades and Distribution Upgrades (as defined in Attachment V to the Tariff) associated with such generation interconnection agreement will be distributed by the Transmission Provider to the applicable Transmission Owner(s).

## V. Adjustments To Revenue Allocations in the Event of Customer Non-Payments

If the amounts collected by the Transmission Provider for Transmission Services and Market Services are insufficient to fully pay the Transmission Owners and providers of Market Services, then the following procedures apply:

### A. Definitions

The following definitions apply in this Section V of Attachment L. Capitalized terms used in this Attachment L and not defined herein shall be given the meaning assigned to them under the Tariff.

**1. Credit Support Documents:** Any agreement or instrument in any way guaranteeing or securing any or all of a Market Participant's obligations under the Tariff (including, without limitation, the Credit Policy), any agreement entered into under, pursuant to, or in connection with the Tariff or any agreement entered into under, pursuant to, or in connection with the Tariff or the Credit Policy, and/or any other agreement to which the Transmission Provider and Market Participant are parties, including, without limitation, any Guaranty, Letter of Credit, Credit and Security Agreement (Attachment B to the Credit Policy) or agreement granting a security interest.

**2. Default:** Any default under Article Eight or otherwise under the Credit Policy.

**3. Defaulting Market Participant:** A Market Participant that defaults under section 8.1 of the Credit Policy.

**4. FERC:** The Federal Energy Regulatory Commission.

**5. Market Services:** Services taken and/or provided pursuant to the Tariff, excluding Transmission Services and interconnection obligations.

**6. Non-Defaulting Market Participants:** Market Participants, other than the Defaulting Market Participant, who conducted business in the market during the time covered by the invoice(s) containing the Unpaid Obligation.

**7. Unpaid Obligation:** An unpaid past due amount of an invoice pursuant to Section 7 of the Tariff or for Market Services for which SPP does not reasonably expect payment in full and which SPP has declared to be an Unpaid Obligation.

**8. Uncollectible Obligation:** An Unpaid Obligation that has not been paid within ninety (90) days after SPP declared an invoice an Unpaid Obligation, or sooner, should by any means the Market Participant's Service Agreement be terminated.

**B. General**

SPP shall only be required to remit to the Transmission Owners, providers of Market Services, and Upgrade Sponsors, the revenues that it has collected, without dispute, under the SPP Tariff for Market Services or Transmission Services, as applicable.

**C. Procedures for Non-Payment of Amounts Invoiced for Market Services**

**1.** The following procedures apply to defaults in payment of amounts invoiced for Market Services. (With respect to defaults of amounts invoiced pursuant to Section 7 of the Tariff, see Section V.D. of this Attachment L.) At such time as SPP concludes that SPP does not reasonably expect payment in full of an unpaid past due amount, which SPP may conclude as early as within 1 day after the due date, then SPP shall declare such unpaid past due amount to be an Unpaid Obligation. SPP will notify Market Participants of the declaration of an Unpaid Obligation by posting a notice to the OASIS. Such notification will identify the Defaulting Market Participant, the amount of the Unpaid Obligation, the applicable week(s) of service for which the Defaulting Market Participant was initially invoiced the Unpaid Obligation, and the future billing week(s) in which SPP will, because of the Unpaid Obligation, reduce the revenues to be paid to all Non-Defaulting Market Participants who conducted business in the market during the time covered by the invoice applicable to the Unpaid Obligation.

SPP will then make reduced payments on the corresponding payout date to the Non-Defaulting Market Participants receiving revenues for Market Services associated with the Unpaid Obligation. A payment to a Non-Defaulting Market Participant will be reduced in amount equal to such Non-Defaulting Market Participant's pro rata share of the Unpaid Obligation.

Upon the earliest feasible date after declaring an Unpaid Obligation, SPP will take the following additional steps: (i) identify and segregate all funds held by SPP with respect to the Defaulting Market Participant; (ii) recover the Unpaid Obligation by drawing upon the entire amount of collateral provided by the Defaulting Market Participant, provided that any amount of the Unpaid Obligation not paid by such draw shall continue to be an Unpaid Obligation; (iii) seek to recover the Unpaid Obligation from any guarantor of the Defaulting Market Participant's obligations; (iv) seek to exercise other remedies under the Credit Support Documents provided by the Defaulting Market Participant; and (v) pursue other available remedies for Defaults, including, without limitation, initiating a filing with FERC to terminate the Service Agreement

of the Defaulting Market Participant. SPP may deviate from steps (i) through (v), including omission of steps and use of other measures as SPP may determine, in its discretion, are appropriate to maximize collection, minimize collection costs, and produce cost effective collection efforts relative to, for example, the likelihood of collection of the Unpaid Obligation.

Any amounts received by SPP pursuant to this Section V.C.1. of this Attachment L shall be applied to reduce the amount of the Unpaid Obligation if those amounts are received prior to the issuance of a notice to cure the Default. After the notice to cure is issued, Section V.C.2. of this Attachment L will apply.

**2. Payments by Defaulting Market Participants of Unpaid Obligations.** This Section V.C.2 applies to amounts invoiced to Market Participants for Market Services only.

After SPP has declared an Unpaid Obligation, SPP will send the Defaulting Market Participant a notice to cure the Default as specified in Section 8.3 of the SPP Credit Policy. The Defaulting Market Participant must take the following steps to cure its Default: (i) pay all unpaid obligations to SPP, including, without limitation, the amount of the Unpaid Obligation, interest, and enforcement and collection costs; and (ii) meet the creditworthiness requirements of SPP, including, without limitation, any additional financial assurances that may be required by SPP given the Defaulting Market Participant's prior Default.

In the event the Defaulting Market Participant attempts to cure its Default by making partial payment of the Unpaid Obligation, the partial payment shall not be applied to reduce the Unpaid Obligation but shall instead be segregated from other SPP funds. Such segregated partial payments shall accumulate until the full amount of the Unpaid Obligation is cured by a series of two or more partial payments. In the event SPP determines that the Unpaid Obligation is uncollectible pursuant to Section V.C.2. of this Attachment L and is an Uncollectible Obligation, the segregated partial payments along with any interest shall be applied using the formula set forth in Section V.C.3.b. of this Attachment L, and the funds will be distributed as described in Section V.C.3.c. of this Attachment L. Section V.E. of this Attachment L applies if a Market Participant provides partial payments for Unpaid Obligations of both Market Services and Transmission Services.

In the event the full amount of the Unpaid Obligation is paid by the Defaulting Market Participant prior to SPP declaring the Uncollectible Obligation, those revenues will be

distributed to Market Participants in the same percentages as the previous reduction of revenues associated with the Unpaid Obligation.

**3. Uplift.** This Section V.C.3 of Attachment L applies to amounts invoiced to Market Participants for Market Services only. Ninety (90) days after declaring an invoice an Unpaid Obligation or sooner, should by any means the Market Participant's Service Agreement be terminated, SPP will declare that Unpaid Obligation an Uncollectible Obligation. SPP shall proceed to recover the Uncollectible Obligation from all Market Participants who conducted business in the market during the period covered by the invoice(s) associated with the Uncollectible Obligation(s) on a pro rata basis, with the amount of the Uncollectible Obligation adjusted by the amount of the Unpaid Obligation recovered pursuant to Section V.C.1. of this Attachment L and partial payments pursuant to Sections V.C.2. and V.E. of this Attachment L.

**a. Eligibility for Share of Uncollectible Obligation.**

The Uncollectible Obligation shall be allocated by SPP to all Non-Defaulting Market Participants that had been invoiced by SPP during the same period of time as the unpaid invoice(s) of the Market Participant whose Unpaid Obligation has been declared an Uncollectible Obligation.

**b. Uncollectible Obligation Allocation Methodology.**

The formula below is the basis for allocating the Uncollectible Obligation to all Non-Defaulting Market Participants who conducted business in the market during the time covered by the invoice(s) containing the Uncollectible Obligation(s).

% Loss for $MP_A$ =

$MP_A$ Market Charges +
Market Credits in weekly invoicing cycle/
$MP_{ALL}$ (Market Charges + Market Credits) in weekly invoicing cycle.

Loss Obligation of $MP_A$ = ((% Loss for $MP_A$) x $ Amt of Uncollectible Obligation) minus (-) (Reduction of Payments + Pro rata share of partial payment(s))

Where:

MP = Market Participant

Market Charges = The absolute value of all charge amounts associated with invoices for Market Services.

Market Credits = The absolute value of all credit amounts associated with invoices for Market Services.

$MP_{ALL}$ = All Market Participants other than Market Participants with Uncollectible Obligations.
Reduction of Payment = The amount of the Unpaid Obligation originally assessed to Market Participant as described in Section V.C.1. above.

Pro rata share of partial payment(s) = Any partial payments received during cure period as described in Section V.C.2.

All individual charge amounts and all individual credit amounts invoiced for Market Services shall be included in the calculation of Market Charges and Market Credits. The Market Charges and Market Credits of Market Participants with Uncollectible Obligations will not be included in the calculation of the percentage of the loss to be allocated to all Non-Defaulting Market Participants that had been invoiced by SPP during the same period of time as the unpaid invoice(s) of the Defaulting Market Participant whose Unpaid Obligation has been declared an Uncollectible Obligation.

**c. Application of Recovered Uncollectible Obligation.**

Any funds that are attributable to an Uncollectible Obligation that are recovered by SPP (other than amounts recovered by the uplift of the Uncollectible Obligations) after the Uncollectible Obligation has been uplifted pursuant to Section V.C.3.b. of this Attachment L, shall first be applied to satisfy outstanding costs of enforcement and collection of the Unpaid Obligation or Uncollectible Obligation, and any other amount due to SPP under the Tariff or any other agreements. Any remaining funds attributable to an uplifted Uncollectible Obligation, together with any remaining interest and late charges collected with respect to the uplifted Uncollectible Obligation, shall be distributed pro rata to the Non-Defaulting Market Participants, using the same formula specified under Section V.C.3.b. of this Attachment L to whom the Uncollectible Obligation was uplifted and who satisfied their obligation to pay the uplifted Uncollectible Obligation.

**D. Procedures for Non-Payment of Amounts Invoiced Pursuant to Section 7 of the Tariff**

**1.** The following procedures apply to a Defaulting Market Participant with respect to defaults of amounts invoiced pursuant to Section 7 of the Tariff. (With respect to defaults of amounts invoiced for Market Services, see Section V.C. of this Attachment L.) Transmission Owners and Upgrade Sponsors due revenue credits will receive revenues in accordance with Sections I and V.A. of this Attachment L.

At such time as SPP concludes that SPP does not reasonably expect payment in full of an unpaid past due amount, which SPP may conclude as early as within 1 day of the due date, then SPP shall declare such unpaid past due amount to be an Unpaid Obligation. SPP will notify Market Participants of the declaration of an Unpaid Obligation by posting a notice to the OASIS. Such notification will identify the Defaulting Market Participant, the amount of the Unpaid Obligation, the applicable month of service for which the Defaulting Market Participant was initially invoiced the Unpaid Obligation, and the future billing month in which SPP will, because of the Unpaid Obligation, reduce the revenues to be paid to all Transmission Owners and Upgrade Sponsors due revenue credits who received payments during the time covered by the invoice containing the Unpaid Obligation.

SPP will then make reduced payments on the corresponding payout date to the Transmission Owners and Upgrade Sponsors due revenue credits receiving revenues for invoices associated with the Unpaid Obligation. A payment to a Transmission Owner or Upgrade Sponsor due revenue credits will be reduced in amount equal to such entity's pro rata share of the Unpaid Obligation.

Upon the earliest feasible date after declaring an Unpaid Obligation, SPP will take the following steps: (i) identify and segregate all funds held by SPP with respect to the Defaulting Market Participant; (ii) recover the Unpaid Obligation by drawing upon the entire amount of collateral provided by the Defaulting Market Participant, provided that any amount of the Unpaid Obligation not paid by such draw shall continue to be an Unpaid Obligation; (iii) seek to recover the Unpaid Obligation from any guarantor of the Defaulting Market Participant's obligations; (iv) seek to exercise other remedies under the Credit Support Documents provided by the Defaulting Market Participants; and (v) pursue other available remedies for Defaults, including, without limitation, initiating a filing with FERC to terminate the Service Agreement of the Defaulting Market Participant. SPP may deviate from steps (i) through (v), including omission of steps and use of other measures as SPP may determine, in its discretion, are appropriate to

maximize collection, minimize collection costs, and produce cost effective collection efforts relative to, for example, the likelihood of collection of the Unpaid Obligation. Any amounts received by SPP pursuant to this Section V.D.1. of this Attachment L shall be applied to reduce the amount of the Unpaid Obligation if those amounts are received prior to the issuance of a notice to cure the Default. After the notice to cure is issued, Section V.D.2. of this Attachment L will apply.

**2. Payments by Defaulting Market Participants of Unpaid Obligations.** This Section V.D.2 applies to amounts invoiced to Market Participants pursuant to Section 7 of the Tariff only.

After SPP has declared an Unpaid Obligation, SPP will send the Defaulting Market Participant a notice to cure their Default as specified in Section 8.3 of the SPP Credit Policy. The Defaulting Market Participant must take the following steps to cure its Default: (i) pay all Unpaid Obligations to SPP, including, without limitation, the amount of the Uncollectible Obligation, interest, and enforcement and collection costs; and (ii) meet the creditworthiness requirements of SPP, including, without limitation, any additional financial assurances that may be required by SPP given the Defaulting Market Participant's prior Default.

In the event the Defaulting Market Participant attempts to cure its Default by making partial payments, rather than apply a partial payment to the Unpaid Obligation, SPP shall segregate such partial payments from other funds. Such segregated partial payments shall accumulate until the full amount of the Unpaid Obligation is cured by a series of two or more partial payments. In the event that the Defaulting Market Participant does not satisfy the entire Unpaid Obligation in full within 90 days of Default, SPP shall remit to the Transmission Owners the segregated partial payments in the same percentage as the amount each Transmission Owner was originally owed of the original unpaid invoice. This remittance will occur 90 days after the date of Default or sooner should by any means the Defaulting Market Participant's Service Agreement be terminated.

In the event the full amount of the Unpaid Obligation is paid by the Market Participant within 90 days of Default, those revenues will be distributed in the same percentages as the previous reduction of revenues associated with the Unpaid Obligation.

**3. Application of Additional Recovered Unpaid Obligation**

Any funds that are attributable to an Unpaid Obligation that are recovered by SPP subsequent to the ninety (90) day period after SPP declares the Unpaid Obligation pursuant to Section V.D.1 of this Attachment L, shall first be applied to satisfy outstanding costs of enforcement and collection of the Unpaid Obligation, and any other amount due to SPP under the Tariff or any other agreements. Any remaining funds attributable to such an Unpaid Obligation, together with any remaining interest and late charges collected with respect to the Unpaid Obligation, shall be distributed pro rata to the Transmission Providers and Upgrade Sponsors, using the same procedure specified under Section V.D.2 of this Attachment L.

**E. Default of Both Market Service and Tariff Section 7 Invoices**

In the event a Market Participant simultaneously Defaults on invoices for Market Services and Tariff Section 7 charges, and notices to cure have been sent as specified in Section 8.3 of the SPP Credit Policy and if the Defaulting Market Participant has attempted to cure its Defaults by making partial payments to the Unpaid Obligations, SPP shall segregate such partial payment(s) from other funds. Such segregated partial payments shall accumulate until the full amount for all Unpaid Obligations is cured by a series of two or more partial payments. In the event that the Defaulting Market Participant does not satisfy the entire Unpaid Obligation in full within 90 days of the Default, SPP shall remit to the Transmission Owners impacted by Section V.D. of this Attachment L and to Market Participants impacted by Section V.C. of this Attachment L the segregated amount pursuant to Sections V.D. and V.C., respectively. To the extent the Defaulting Market Participant has identified the invoice(s) with which such partial payments were associated or to the extent SPP reasonably identifies such invoice(s), such partial payments shall be distributed in accordance with the provisions for the type of service identified for the associated invoice(s). In the event the Defaulting Market Participant has not indicated the invoice(s) that partial payments are directed to and SPP does not reasonably determine which invoice(s) are associated with such partial payments, SPP shall remit to all Market Participants the percentage of such partial payments as the amount they were originally owed of the combined unpaid invoices. This remittance will occur 90 days after the date of Default or sooner should by any means the Market Participant's Service Agreement be terminated.

# ATTACHMENT M
# LOSS COMPENSATION PROCEDURE

## I. PURPOSE

This loss compensation procedure will be used to quantify real power losses for which the Transmission Customer or Network Customer is responsible when taking service under this Tariff. The Transmission Provider shall maintain a schedule showing the real power loss factors for the provision of transmission service across each Zone on the Transmission System. The injection loss factor ("ILF") and delivery loss factor ("DLF") for each Zone are stated in Appendix 1 to this Attachment M.

## II. TRANSMISSION LOSS DETERMINATION - NETWORK INTEGRATION TRANSMISSION SERVICE

(a) The Network Customer shall be responsible for real power losses associated with Network Integration Transmission Service to its Network Load for each Zone in which its Network Load is located for the purposes of determining charges under Schedule 9 and Schedule 11 to this Tariff. The Network Customer's loss responsibility is the product of the Zone DLF, shown in Column D of Appendix 1 to this Attachment M and the hourly metered Network Load for the hour that is coincident with the applicable Zone monthly peak load hour and such loss responsibility shall be included when calculating that Network Customer's Load Ratio Share, Base Plan Zonal Load Ratio Share and Region-wide Load Ratio Share.

(b) Loss energy associated with hourly energy settlement under the Integrated Marketplace shall be accounted for under the settlement procedures for the Energy and Operating Reserve Markets specified in Attachment AE. Loss energy associated with the transmission of Federal Power-Western-UGP to the Statutory Load Obligations served by Western-UGP shall be the product of the amount of Federal Power-Western-UGP delivered to the Statutory Load Obligations and the Zone 19 DLF, shown in Column D of Appendix 1 to this Attachment M in accordance with Section 39.3(e)(ii) of this Tariff.

## III. TRANSMISSION LOSS DETERMINATION - POINT-TO-POINT TRANSMISSION SERVICE

The Transmission Customer shall be responsible for real power losses associated with Transmission Service under Schedule 7 and Schedule 8 to this Tariff. For purposes of

calculating a Transmission Customer's loss responsibility, such Transmission Customer's Transmission Service reservation capacity shall not be adjusted by the demand zonal loss factors stated in Appendix 1 to this Attachment M. Real power losses associated with settlement of Transmission Service schedules in the Integrated Marketplace shall be accounted for under the settlement procedures for the Energy and Operating Reserve Markets specified in Attachment AE.

## IV. OTHER LOSSES

Additional compensation will be required for real power losses when the meter used to measure the energy taken at a delivery point is located on facilities not on the Transmission System. The Transmission Customer shall be responsible for any real power losses incurred on facilities not on the Transmission System.

# APPENDIX 1 TO ATTACHMENT M
# DEMAND ZONAL LOSS FACTORS

| (A) ZONE | (B) NAME | (C) INJECTION LOSS FACTOR ("ILF") | (D) DELIVERY LOSS FACTOR ("DLF") |
|---|---|---|---|
| 1 | American Electric Power | 2.90% | 2.9866% |
| 2 | Kansas City Board of Public Utilities | 0.32% | 0.32% |
| 3 | City Utilities of Springfield | 2.00% | 2.0408% |
| 4 | Empire District Electric Company | 2.71% | 2.7855% |
| 5 | Grand River Dam Authority | 3.3816% | 3.5% |
| 6 | Evergy Metro, Inc. | 1.8646% | 1.90% |
| 7 | Oklahoma Gas and Electric Company | 3.00% | 3.0928% |
| 8 | Midwest Energy, Inc. | 4.26% | 4.4496% |
| 9 | Evergy Missouri West, Inc. | 1.92% | 1.9576% |
| 10 | Southwestern Power Administration | 4.00% | 4.1667% |
| 11 | Southwestern Public Service | 2.738606% | 2.8115717% |
| 12 | Sunflower Electric Power Corporation | 4.87% | 5.12% |
| 13 | Western Farmers Electric Cooperative | 3.00% | 3.0928% |
| 14 | Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc. ) | 2.9786% | 3.07% |
| 15 | Reserved for Future Use | | |
| 16 | Lincoln Electric System | 1.07% | 1.0816% |
| 17 | Nebraska Public Power District | 2.4% | 2.4590% |
| 18 | Omaha Public Power District | 1.1858% | 1.20% |
| 19 | Upper Missouri Zone | 3.8462% | 4.00% |

[Reserved for Future Use]

[Reserved for Future Use]

# ATTACHMENT N

[Reserved for Future Use]

# ATTACHMENT O
# TRANSMISSION PLANNING PROCESS

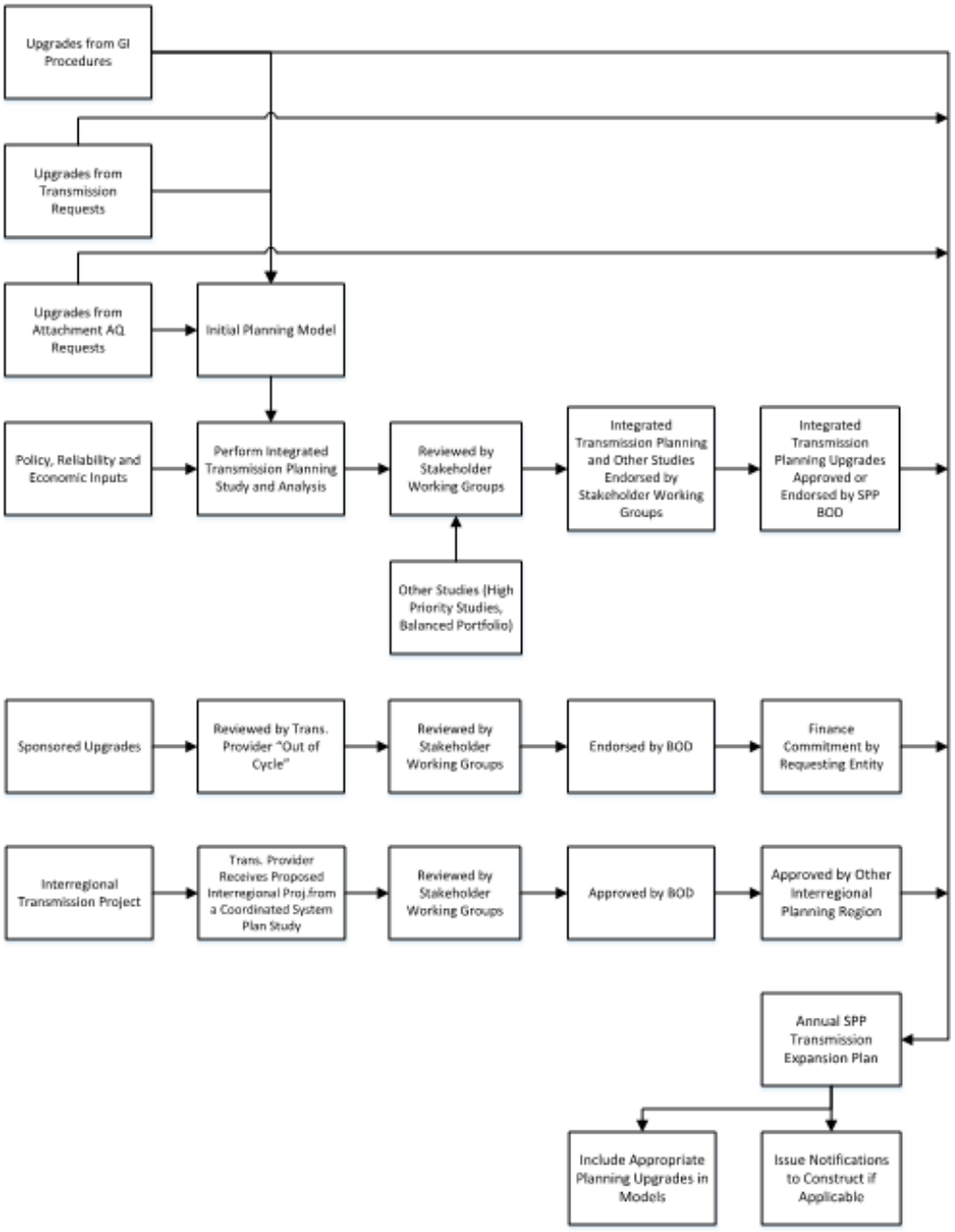
## I. Overview of Planning Process

The Transmission Provider's transmission planning process is an open process. New and proposed transmission facilities can come from the following processes in this Tariff: 1) transmission service requests; 2) Generator Interconnection Requests; 3) requests pursuant to Attachment AQ of this Tariff; 4) the Integrated Transmission Planning Assessment; 5) the Balanced Portfolio process; 6) the high priority study process; 7) requests for Sponsored Upgrades; 8) the 20-Year Assessment; 9) the evaluation of proposed Interregional Projects; and 10) the Generator Retirement Process. Figure 1 illustrates the planning processes within SPP and how these processes result in a comprehensive regional plan called the SPP Transmission Expansion Plan (STEP).

Each of these sources of potential upgrades has its own evaluation and approval process. Transmission service requests are evaluated in accordance with Attachment Z1 of this Tariff. Generator Interconnection Requests are assessed under the provisions of Attachment V of this Tariff. In addition, the process for making changes in delivery point facilities to upgrade, retire, replace, or establish delivery points is described in Attachment AQ of this Tariff. The study processes for the Integrated Transmission Planning Assessment, Sponsored Upgrades, Balanced Portfolios, high priority upgrades, 20-Year Assessment, and proposed Interregional Projects are described in this Attachment O of this Tariff.

The results from all these sources are collected and reported in the annual SPP Transmission Expansion Plan which gives a projection of transmission changes in the SPP Region in accordance with this Attachment O.

## Figure 1 – SPP Transmission Planning Process



## II. Roles and Responsibilities

References to the "stakeholder working group" is a generic term that references those working group(s) as defined in the SPP Bylaws, Sections 3 through 6 that are charged with the transmission planning process. The current names of all the working groups shall be posted on the SPP website.

1) Division of Responsibilities

a) The rights, powers and obligations for planning are set forth in the SPP Membership Agreement in (i) Article 2.0 for the Transmission Provider and (ii) Article 3.0 for the Members. The division of responsibility between the Transmission Provider and the Members is set forth in the SPP Criteria and in this Attachment O. The SPP Membership Agreement, the SPP Criteria and the Tariff shall be posted on the SPP website.

b) The Transmission Provider shall be responsible for developing the list of projects in accordance with the stakeholder process set forth in Sections II, III and V of this Attachment O, and including interregional coordination set forth in Section VIII of this Attachment O.

c) The Transmission Provider shall perform transmission planning studies to assess the reliability and economic operation of the Transmission System in accordance with Section III of this Attachment O.

d) As inputs to the planning process, the Transmission Provider shall include and maintain requirements to serve existing commitments for long-term transmission service and Generator Interconnection Service in accordance with Section III.5 of this Attachment O and any applicable roll-over rights as set out in Section 2.2 of this Tariff. The Transmission Provider shall also take into account all previously approved projects in accordance with Section III of this Attachment O.

e) In accordance with Section II.5 of this Attachment O, the Transmission Provider shall review, and include as appropriate, all Zonal Reliability Upgrades as proposed by the Transmission Owners to meet Zonal Planning Criteria, including such plans developed by Transmission Owners that have their own FERC approved local planning process, to ensure coordination of the projects set forth in such plans with the potential solutions developed in the regional planning process.

f) The Transmission Provider shall review and include, as appropriate, all reasonably expected demand resource, transmission, or generation options identified by stakeholders in accordance with Section III of this Attachment O.

g) The Transmission Provider shall describe the details regarding expansion planning methodology, criteria, assumptions and data in the Integrated Transmission Planning Manual, which shall be developed by the Transmission Provider, in consultation with stakeholders, and approved by the Markets and Operations Policy Committee. The Transmission Provider shall post the Integrated Transmission Planning Manual on its website.

h) The Transmission Provider shall conduct an annual survey of stakeholders to identify Public Policy Requirements in accordance with Section III of this Attachment O.

i) In accordance with its NERC reporting requirements, the Transmission Provider shall publish an annual reliability report that shall include a list of the following:

i) Regional upgrades required to maintain reliability in accordance with the NERC Reliability Standards and SPP Criteria;

ii) Zonal Reliability Upgrades required to maintain reliability in accordance with more stringent Zonal Planning Criteria; and

iii) Upgrades developed with neighboring Transmission Providers, including results from the coordinated system plans.

j) Using the data provided in Section VII of this Attachment O, the Transmission Provider shall develop the planning model(s) in accordance with the Integrated Transmission Planning Manual to be used for the transmission planning processes in this Attachment O. The schedule for the model development will be posted on the SPP website.

2) Stakeholder Working Groups

a) The purpose of the stakeholder working groups is to provide technical advice, assistance and oversight to the Transmission Provider in all aspects of the regional and local planning process, including but not limited to:

i) Review and development of coordinated planning among the Transmission Provider and the Transmission Owners including accepted Network Upgrades developed by those Transmission Owners that have their own FERC approved local planning process, or Zonal Reliability Upgrades identified to meet Zonal Planning Criteria;

ii) Review and development of regional planning criteria;

iii) Review and development of Available Transfer Capability related calculation criteria as specified in Attachment C of this Tariff;

iv) Review and development of transmission rating criteria;

v) Compliance with NERC Reliability Standards concerning transmission assessment, transfer capability and ratings of transmission facilities;

vi) Review and development of the list of transmission needs driven in whole or in part by Public Policy Requirements for which transmission solutions will be evaluated; and

vii) Review of Interregional Projects in accordance with Section IV.7 of this Attachment O.

b) All the stakeholder working group representation shall be appointed and chaired in accordance with Article 3.0 of the SPP Bylaws. All meetings of the stakeholder working groups are open to all entities.

c) Voting in the various stakeholder working groups shall conform to Article 3.9 of the SPP Bylaws.

d) The data, information, and technical support necessary for the Transmission Provider to perform studies as required by the planning process and to develop the regional reliability projects are provided by the Transmission Owners, Transmission Customers and Generator Interconnection Customers and other entities in accordance with Section VII of this Attachment O.

e) Stakeholder working groups that work with the Transmission Provider on transmission planning shall meet at least quarterly and additional meetings, web conferences and teleconferences shall be scheduled as needed. Teleconference capability will be made available for stakeholder working group meetings. Notice of meetings of the stakeholder working groups shall be posted on the SPP website and distributed via email distribution lists. Meeting agendas and minutes shall be posted on the SPP website.

3) Participation by State Regulators

In accordance with the SPP Bylaws, any regulatory agency having utility rates or services jurisdiction over a Member may participate fully in all SPP planning activities.

4) Adherence to Regional Planning Criteria

i) The regional planning criteria are comprised of the NERC Reliability Standards and SPP Criteria.

ii) The regional planning criteria may change from time to time based upon the then current process for changing reliability criteria.

iii) The individual Transmission Owners shall be obligated under the NERC Reliability Standards and SPP Criteria to resolve reliability violations and compliance needs identified by the Transmission Provider or by the individual Transmission Owners themselves in accordance with these standards and criteria.

5) Use of Zonal Planning Criteria

a) Each Zone within the SPP Region may develop Zonal Planning Criteria that, at a minimum, conform to the NERC Reliability Standards and SPP Criteria. There shall be only one set of Zonal Planning Criteria per Zone. The Facilitating Transmission Owner within the Zone shall hold open meeting(s) to discuss the development of the Zonal Planning Criteria and shall invite all other Transmission Owners and Transmission Customers that receive Long-Term Service to serve load within that Zone. Any initial development of and subsequent modification(s) to the Zonal Planning Criteria of a Zone shall be discussed in open meeting(s). Zonal Planning Criteria for Zone 10 shall be subject to Attachment AD of the Tariff.

i) Transmission Owners and Transmission Customers that receive Long-Term Service to serve load within that Zone may submit proposed Zonal Planning Criteria to the Facilitating Transmission Owner by May 1st.

ii) By June 1st, the Facilitating Transmission Owner will post a proposed draft Zonal Planning Criteria and all proposed Zonal Planning Criteria received to the Facilitating Transmission Owner's OASIS linked from the Transmission Provider's website for review and input by any interested party within that Zone.

iii) Any interested parties within that Zone will be have thirty (30) days from the time any proposed draft Zonal Planning Criteria is posted to the Facilitating Transmission Owner's OASIS to provide written comments to the Facilitating Transmission Owner. Any written comments provided in this timeframe, will be posted to the Facilitating

Transmission Owner's OASIS linked from the Transmission Provider's website within one week from receipt of such written comment(s).

iv) After consideration of all proposed draft Zonal Planning Criteria and written comments related to any proposed draft Zonal Planning Criteria, the Facilitating Transmission Owner shall post a final draft Zonal Planning Criteria to the Facilitating Transmission Owner's OASIS linked from the Transmission Provider's website no later than August 1st.

v) After the final draft Zonal Planning Criteria has been posted, interested parties within that Zone will have thirty (30) days to provide written comments to the Facilitating Transmission Owner that will be posted to the Facilitating Transmission Owner's OASIS linked from the Transmission Provider's website within one week from receipt of such written comment(s).

vi) By October 1st, the Facilitating Transmission Owner shall coordinate with Transmission Owners and Transmission Customers that receive Long-Term Service to serve load in that Zone to determine a date and time for the open meeting and shall post a notice of the open meeting, where development or revision of Zonal Planning Criteria shall be discussed, on the Facilitating Transmission Owner's OASIS linked from the Transmission Provider's website.

b) To ensure that the Transmission Owners and Transmission Customers that receive Long-Term Service to serve load within that Zone have input in the development of the Zonal Planning Criteria and that all input is considered during the review of the

proposed Zonal Planning Criteria, each Transmission Owner and Transmission Customer that receives Long-Term Service to serve load within that Zone shall be eligible to participate in a two-step voting process to approve or not approve the latest version of the final draft Zonal Planning Criteria. The Zonal Planning Criteria shall be approved if both steps of the two-step process receive the required votes for approval.

i) The first step of the two-step voting process is a load-weighed vote of all Transmission Customers receiving Long-Term Service to serve load in that Zone based on the prior calendar year's 12 month peak load in that Zone. Approval of Step 1 is accomplished with a percentage of vote to approve greater than or equal to the largest load in the Zone plus one-half of the remainder of the load in the Zone. If the proposed Zonal Planning Criteria is approved in the first step of the two-step process, the proposed Zonal Planning Criteria would proceed to the second voting step of the two-step process.

ii) The second step of the two-step process would require a vote of approval of more than 50% of the Transmission Owners and Transmission Customers that receive Long-Term Service to serve load within that Zone. If an entity is both a Transmission Owner and a Transmission Customer in that Zone, the entity will be allowed one vote for the second step of the two-step process. If there is an Affiliate relationship, either through ownership or through contract, between any Transmission Owner or Transmission Customer that receives Long-Term Service to serve load within that Zone and another Transmission Owner or Transmission Customer that receives Long-Term Service to

serve load within that Zone, those Affiliated entities are only allowed one vote in step 2 of the two-step process.

iii) Zone 19 is exempt from using the two-step voting process described in Section II.5.b of Attachment O of the Tariff. Zone 19 will utilize its pre-existing consensus voting process as described below that ensures that the Transmission Owners and Transmission Customers that receive Long-Term Service to serve load within Zone 19 have input in the development of the Zonal Planning Criteria for Zone 19 and that all input is considered during the review of the proposed Zonal Planning Criteria for Zone 19. In the event that Zone 19 no longer uses the pre-existing consensus voting process, Zone 19 will no longer be exempt from using the two-step voting process described in Section II.5.b.

1) The Zone 19 Zonal Planning Criteria shall be developed, approved, and revised, as necessary, under the pre-existing Zone 19 voting process, which utilizes a similar approach to the two-step voting process described in Section II.5.b.i & ii of Attachment O of the Tariff. The pre-existing Zone 19 voting process includes the same voting parties as the two-step voting process. Instead of a two-step process with sequential votes, the pre-existing Zone 19 voting process includes two similar components in an averaged single vote that requires a 75% consensus vote for approval: a) a first vote component by the same eligible Transmission Customers as the two-step voting process based upon weighted load in the Zone, and b) a second

vote component by Transmission Owners in the Zone based upon gross Zonal Annual Transmission Revenue Requirement. The design of the pre-existing Zone 19 voting process was implemented to ensure consensus within the Zone. No single entity can account for over 33% of the weighted vote relating to either vote component (i.e. load or gross Zonal ATRR in Zone 19).

c) By March 1st, the Facilitating Transmission Owner shall send the Transmission Provider minutes and a report from the Zonal Planning Criteria meeting(s). The Facilitating Transmission Owner will provide to the Transmission Provider, the Transmission Owners, and Transmission Customers that receive Long-Term Service to serve load within that Zone the approved Zonal Planning Criteria by April 1st of each year for incorporation into the Transmission Provider's transmission planning process.

d) By March 15th, if a Transmission Owner or Transmission Customer that receives Long-Term Service to serve load within that Zone wishes to challenge the results of the Zonal Planning Criteria vote, the Transmission Owner or Transmission Customer that receives Long-Term Service to serve load within that Zone may submit to the Transmission Provider a dispute of the voting tabulation that approved the Zonal Planning Criteria.

i) Any dispute of the voting tabulation submitted by a Transmission Owner or Transmission Customer that receives Long-Term Service to serve load within that Zone shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the

Facilitating Transmission Owner for resolution on an informal basis as promptly as practicable.

ii) If the Transmission Provider and the Facilitating Transmission Owner find that the disputed voting tabulation was in error and would have resulted in the voting process failing instead of passing, the Zonal Planning Criteria would revert to the most recently approved Zonal Planning Criteria or if no Zonal Planning Criteria has been approved, then the Transmission Provider's Planning Criteria shall be used. If the Transmission Provider and the Facilitating Transmission Owner find that the disputed voting tabulation was in error and would have resulted in the voting process passing instead of failing, the Zonal Planning Criteria voted on shall be used. Nothing in this section shall restrict the rights of any party to file a Complaint with FERC under relevant provisions of the Federal Power Act.

e) The Facilitating Transmission Owner in each Zone must provide to the Transmission Provider, the Transmission Owners, and the Transmission Customers who receive Long-Term service to serve load in that Zone at least once a year, by April 1st, the Zonal Planning Criteria for that Zone, if a set of Zonal Planning Criteria has been developed in accordance with Section II.5 of this Attachment O. This is necessary for the Transmission Provider to assess the need for Zonal Reliability Upgrades to be included in the SPP Transmission Expansion Plan. If no set of approved Zonal Planning Criteria is provided by the Facilitating Transmission Owner by April 1$^{st}$, then the Transmission Provider would use the most recently approved Zonal Planning Criteria provided to it for that Zone, or, if no

Zonal Planning Criteria has been approved, then only the SPP Criteria shall be used.

f) The Zonal Planning Criteria and assumptions shall be reviewed and modifications proposed on a yearly basis following the timeline set forth Section II.5 of this Attachment O, provided that if the Zonal Planning Criteria are made more stringent, the increased requirements will not apply retroactively to studies previously completed or studies already underway by the Transmission Provider. Access to the Zone-specific Zonal Planning Criteria shall be made available via an electronic link on the SPP website.

g) The Zonal Planning Criteria of each Zone shall be the basis for determining whether a reliability violation exists for which a need for a new Zonal Reliability Upgrade should be considered.

h) All Transmission Owners within the Zone shall apply the Zonal Planning Criteria comparably to all load in the applicable Zone.

i) Zonal Planning Criteria and Transmission Owners' local planning processes must provide for: (a) the identification of transmission needs driven in whole or in part by Public Policy Requirements; and (b) the evaluation of potential solutions to meet those needs.

j) Transmission Owners may continue to utilize their own company-specific local planning process or their own FERC-approved local planning process to identify system upgrades (i.e., outside of SPP's regional planning process). Any cost associated with a system upgrade exclusively identified as needed through a Transmission Owner's local planning process or FERC-approved local planning process, and not identified through the Transmission Provider's regional planning process using the

SPP Planning Criteria or the Zonal Planning Criteria, shall not be included in rates as a Base Plan Upgrade or a Zonal Reliability Upgrade and shall be direct assigned to the identifying Transmission Owner.

6) Planning Summits

i) The Transmission Provider shall conduct, at a minimum, a planning summit once a year.

ii) The purpose of a planning summit is for the Transmission Provider and the stakeholders to share current SPP transmission network issues, provide solution alternatives and review study findings. Summits also provide an open forum where all stakeholders have an opportunity to provide advice and recommendations to the Transmission Provider to aid in the development of the SPP Transmission Expansion Plan.

iii) Each planning summit shall be open to all entities.

iv) The Transmission Provider shall chair and facilitate the planning summits.

v) Teleconference capability will be made available for planning summits. Planning summit web conferences shall be held as needed.

vi) Notice of an upcoming planning summit and web conferences shall be posted on the SPP website and distributed via email distribution lists.

## III. The Integrated Transmission Planning Assessment

The Integrated Transmission Planning Assessment evaluates the system upgrades, at all applicable voltage levels, identified in the ten-year planning horizon.

1) Commencement of the Process

Upon the commencement of the process, the Transmission Provider shall: (i) post the study schedule and information relating to the study process on the SPP website; and (ii) provide notice of the posting via email distribution lists. The schedule shall include a timeline and process for stakeholder submission of transmission needs, including transmission needs driven by Public Policy Requirements, and solutions to such needs as described in this Section III of this Attachment O.

2) Preparation of the Integrated Transmission Planning Assessment

a) The Integrated Transmission Planning Assessment shall review the system for a ten-year planning horizon. This assessment is not intended to review each consecutive year in the planning horizon.

b) The Integrated Transmission Planning Assessment shall identify solutions required to meet the criteria defined in Section III.3 of this Attachment O and assess the cost effectiveness of proposed solutions over a forty-year time horizon.

c) The Transmission Provider shall develop the Integrated Transmission Planning Assessment study scope with input from the stakeholders, in accordance with the parameters in the Integrated Transmission Planning Manual. The study scope and the Integrated Transmission Planning Manual shall specify the methodology, criteria, assumptions, and data to be used, including how transmission needs will be identified, and how the

input requirements described in Section III.3 of this Attachment O will be incorporated. The study scope shall include an explanation of which Public Policy Requirements will be evaluated for potential solutions in the Integrated Transmission Planning Assessment. The final Integrated Transmission Planning Assessment study scope shall be posted on the SPP website.

d) Notice of the transmission needs being evaluated in the Integrated Transmission Planning Assessment will be provided pursuant to Section III.6 of this Attachment O. In accordance with the study scope and the Integrated Transmission Planning Manual, the Transmission Provider shall analyze potential solutions pursuant to Section III.7 of this Attachment O.

3) Policy, Reliability, and Economic Input Requirements to the Integrated Transmission Planning Assessment

In accordance with the Integrated Transmission Planning Manual, the Transmission Provider shall incorporate, as appropriate, the following as part of its planning studies:

a) NERC Reliability Standards;

b) SPP Criteria;

c) Zonal Planning Criteria as set forth in Section II;

d) Previously identified and approved transmission projects;

e) Zonal Reliability Upgrades developed by Transmission Owners, including those that have their own FERC-approved local planning process, to meet Zonal Planning Criteria;

f) Long-term firm transmission service;

g) Load forecasts, including the impact on load of existing and planned demand management programs, exclusive of demand response resources;

h) Capacity forecasts, including generation additions and retirements;

i) Existing and planned demand response resources;

j) Congestion within SPP and between the SPP Region and other regions and balancing areas;

k) Renewable energy standards;

l) Fuel price forecasts;

m) Energy efficiency requirements;

n) Other relevant environmental or government mandates;

o) Public Policy Requirements identified through the annual survey of stakeholders and additional Public Policy Requirements as determined by the Transmission Provider and stakeholders;

p) Operational experience gained from markets operated by the Transmission Provider;

q) Other input requirements identified during the stakeholder process and included in the Integrated Transmission Planning Assessment scope; and

r) Identified persistent operational issues.

4) Inclusion of Generation and Demand Response Resources in the Integrated Transmission Planning Assessment

In developing the long term capacity forecasts, the Integrated Transmission Planning Assessment will include generation and demand response resources capable of providing any of the functions assessed in the SPP planning process, and that can be relied upon on a long-term basis. Such generation and demand response resources shall be permitted to participate in the planning process on a comparable basis. Stakeholders may also propose any combination of demand resources, transmission, or generation as alternate solutions to identified needs.

5) Additional Information to be Included in the Integrated Transmission Planning Assessment

a) The studies performed under this Section III of Attachment O shall accommodate and model the specific long-term firm transmission service of Transmission Customers upon the completion of the associated Aggregate Facilities Study in accordance with Attachment Z1 of this Tariff and specific interconnections of Generation Interconnection Customers in accordance with the schedule for Generator Interconnection Agreements and Generation Interconnection Service upgrades in the Integrated Transmission Planning Manual.

b) Transmission upgrades related to requests for transmission service that are described in Sections 19 and 32 of this Tariff and Attachment Z1 of this Tariff. Upgrades associated with the accepted long-term firm transmission service are included in the Transmission System planning model upon the completion of the associated Aggregate Facilities Study in accordance with Attachment Z1 of this Tariff. Transmission upgrades related to an

approved request for transmission service may be deferred or supplemented by other upgrades based upon the results of subsequent studies. Changes in planned upgrades do not remove the obligation of the Transmission Provider to have adequate transmission facilities available to start or continue the approved transmission service.

c) Interconnection facilities and other transmission upgrades related to requests for Generator Interconnection Service are described in Attachment V of this Tariff. Upgrades associated with the modeled Generator Interconnection Service are included in the Transmission System planning model upon the execution of a Generator Interconnection Agreement with the Generator Interconnection Customers or filing of an un-executed Generator Interconnection Agreement with the Commission. Transmission upgrades related to an approved interconnection agreement may be deferred or supplemented by other upgrades based upon the results of subsequent studies. Changes in planned upgrades do not remove the obligation of the Transmission Provider to have adequate transmission facilities available to start or continue the approved interconnection service.

d) A Sponsored Upgrade will be included in the Transmission System planning model upon execution of the Agreement for Sponsored Upgrade in Schedule 1 to Attachment J of this Tariff.

e) Projects approved in accordance with Section IV of this Attachment O will be included in the Transmission System planning model upon approval for construction.

6) Identification of Needs and Detailed Project Proposals

After the study scope has been finalized, the Transmission Provider shall identify potential transmission needs, including any needs driven by Public Policy Requirements, in accordance with the Integrated Transmission Planning Assessment scope and the Integrated Transmission Planning Manual. The Transmission Provider shall notify stakeholders of identified transmission needs and provide a transmission planning response window of thirty (30) days during which any stakeholder may propose a detailed project proposal (DPP). The Transmission Provider shall track each DPP and retain the information submitted pursuant to Section III.6(a) of this Attachment O. If the project described in a DPP is approved by the SPP Board of Directors as an ITP upgrade, the submitting stakeholder may qualify for incentive points as described in Section III of Attachment Y of this Tariff.

a) The information supplied by the stakeholder must be sufficient to allow the Transmission Provider to evaluate the project described in the DPP. At a minimum, the DPP must include the following information:

i) description of the project including one-line diagrams and configuration(s), if available;

ii) the specific need(s) identified in the Integrated Transmission Planning Assessment to be addressed;

iii) engineering and modeling data required by the Transmission Provider including identification and justification of any changes in modeling assumptions from those used in the current Integrated Transmission Planning Assessment;

iv) results of transmission project economic or reliability analysis, if available; and

v) any other information available to support the evaluation or cost estimation of the project.

b) Any stakeholder providing a DPP that meets the requirements set forth in Section III.6(a) of this Attachment O will be recorded by the Transmission Provider for the Integrated Transmission Planning Assessment for which the DPP was submitted, including the contact information of the stakeholder that submitted the DPP.

c) If the Transmission Provider, in its sole discretion, determines that the information provided in a DPP is incomplete, the Transmission Provider shall provide written notice to the stakeholder that submitted the DPP. The stakeholder shall be permitted to cure such deficiency by the later of the end of the transmission planning response window or 10 days after the Transmission Provider issues such notice. Failure to cure the deficiency shall result in the submission being disqualified as a DPP.

d) The Transmission Provider shall hold all DPPs in confidence until the thirty (30) day transmission planning response window has closed. Subsequent to the close of the transmission planning response window, information contained in a DPP shall be disclosed to stakeholders only as the Transmission Provider determines it is necessary for the review of the DPP during the planning process and for documentation of the reason(s) why the DPP was or was not chosen in the current Integrated Transmission Planning Assessment. The remaining information in the DPP will remain confidential.

e) A stakeholder that submits a DPP is eligible for incentive points, in accordance with Section III of Attachment Y of this Tariff, for the current Integrated Transmission Planning Assessment.

7) Process to Analyze Transmission Solutions and Alternatives for the Integrated Transmission Planning Assessment

a) The Transmission Provider shall perform the required studies to analyze the potential solutions for improvements to the Transmission System, provided by the Transmission Provider and by the stakeholders, in order to address the final Integrated Transmission Planning Assessment study scope which shall consider the current and anticipated future needs of the SPP Region within the parameters of the Integrated Transmission Planning Manual. The analysis shall also consider the value brought to the SPP Region by incremental changes to the proposed solutions.

b) For all potential solutions provided by the stakeholders, including reliability upgrades that Transmission Owners (which includes those Transmission Owners that have their own FERC-approved local planning process), propose to address violations of Zonal Planning Criteria pursuant to Section II.5 of this Attachment O, and upgrades to address transmission needs driven in whole or in part by identified Public Policy Requirements, the Transmission Provider shall determine if there is a more comprehensive regional solution to address the reliability needs, economic needs, and needs driven by Public Policy Requirements identified in the assessment.

c) The Transmission Provider will consider, on a comparable basis, any alternative proposals which could include, but would not be limited to, generation options, demand response programs, “smart grid” technologies, and energy efficiency programs. Solutions will be evaluated against each other based on a comparison of their relative effectiveness of performance and economics.

d) The Transmission Provider shall assess the cost effectiveness of proposed solutions. Such assessments shall be performed in accordance with the Integrated Transmission Planning Manual. This analysis shall take into consideration the following:

i) The financial modeling time frame for the analysis shall be 40 years (with the last 20 years provided by a terminal value).

ii) The analysis shall include quantifying the benefits resulting from dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics as appropriate, in accordance with this Attachment O and the Integrated Transmission Planning Manual.

iii) The analysis shall identify and quantify, if possible, the benefits related to any proposed transmission upgrade that is required to meet any regional reliability criteria.

iv) The analysis scope shall include different scenarios to analyze sensitivities to load forecasts, wind generation levels, fuel prices, environmental costs, and other relevant factors. The Transmission Provider shall consult the stakeholders to guide the development of these scenarios.

v) The results of the analysis shall be reported on a regional, zonal, and state-specific basis.

vi) The analysis shall assess the net impact of the transmission plan, developed in accordance with this Attachment O, on a typical residential customer within the SPP Region and on a $/kWh basis.

e) The Transmission Provider shall make a comprehensive presentation of the preferred solutions, including the results of the analysis above, to the stakeholder working groups and at a planning summit meeting or web conference. The presentation shall include a discussion of all the Transmission Provider and stakeholder alternatives considered and reasons for choosing the particular preferred solutions.

f) The Transmission Provider shall solicit feedback on the solutions from the stakeholder working groups and through the stakeholders attending the various planning summits. The Transmission Provider will also include feedback from stakeholders through other meetings, teleconferences, web conferences, and via email or secure web-based workspace.

g) Upon consideration of the results of the cost effectiveness analysis and feedback received in the subsequent review process, the Transmission Provider shall prepare the annual Integrated Transmission Planning Assessment report, which shall include a draft list of projects for review and approval in accordance with Section V of this Attachment O. The report shall also include an explanation of which transmission needs driven by Public Policy Requirements were evaluated for potential solutions in the Integrated Transmission Planning Assessment, as well as an explanation of why other transmission needs driven by Public Policy Requirements were not evaluated.

## IV. Other Planning Studies

1) Sponsored Upgrade Studies

Any entity may request that a Sponsored Upgrade be built. SPP will evaluate the impact of any proposed Sponsored Upgrade on Transmission System reliability and identify any necessary mitigation of these impacts. The proposed Sponsored Upgrade shall not be approved as a Sponsored Upgrade if it has been previously identified and included in the current SPP Transmission Expansion Plan as either 1) an upgrade required to satisfy requests for transmission service; 2) an upgrade required to satisfy a Generator Interconnection Request; 3) an approved ITP Upgrade; 4) an upgrade within approved Balanced Portfolios; or 5) an approved high priority upgrade. Such entity must be willing to assume the cost of such Sponsored Upgrade, study costs, and any cost associated with such necessary mitigation. The proposed Sponsored Upgrade will be submitted to the proper stakeholder working group for their review as a part of the transmission planning process.

2) 20-Year Assessments

a) The Transmission Provider shall perform a 20-Year Assessment at least once every five years, or more frequently if approved by the SPP Board of Directors. The purpose of the 20-Year Assessment is to produce an informational report of possible transmission upgrades that may be used in future planning studies by looking at a longer planning horizon. No project may be authorized for construction as the result of a 20-Year Assessment.

b) The 20-Year Assessment shall review the system for a twenty-year planning horizon and address, at a minimum, facilities 300 kV and above needed in year 20. This assessment is not intended to review each consecutive year in the planning horizon.

c) The Transmission Provider, in consultation with the stakeholders, shall develop the scope for each 20-Year Assessment and post the scope on the SPP website.

d) For each 20-Year Assessment the Transmission Provider shall publish a report summarizing the findings. The report and related studies and the criteria, assumptions and data underlying the report shall be posted on the SPP website.

3) High Priority Studies

a) The Transmission Provider shall perform high priority studies in accordance with Attachment O of this Tariff and the Integrated Transmission Planning Manual which shall be maintained on the SPP website.

b) Potential Balanced Portfolios, as developed through the process specified in Section IV.4 of this Attachment O, shall be considered to be high priority studies.

c) The stakeholders may request high priority studies, including a request for the Transmission Provider to study potential upgrades or other investments necessary to integrate any combination of resources, whether demand resources, transmission, or generation, identified by the stakeholders. Annually, the costs of up to three high priority studies requested by the stakeholders and performed by the Transmission Provider shall be recovered pursuant to Schedule 1-A1 of this Tariff. A high priority study of a potential Balanced Portfolio initiated by the Transmission Provider will not be considered a stakeholder request pursuant to this Section IV.3.c of this Attachment O.

d) The Transmission Provider, in consultation with the stakeholders, shall develop the scope for each high priority study and post the scope(s) on the SPP website.

e) Each study shall include:

i) Quantification of benefits and costs in accordance with this Attachment O and the Integrated Transmission Planning Manual; and

ii) An analysis of the sensitivity of the economics of the upgrades included in the high priority study to changes in assumptions.

f) The Transmission Provider shall solicit input from the stakeholders and the Regional State Committee regarding the appropriate sensitivity analyses to be performed.

g) For each high priority study the Transmission Provider shall publish a report, including but not limited to, the study input assumptions, the estimated cost of the upgrades, any third party impacts, the expected economic benefits of the upgrades, and identify reliability impacts, if any, of the upgrades. The report and related studies and the criteria, assumptions and data underlying the report shall be posted on the SPP website, with password protected access if required to preserve the confidentiality of information in accordance with the provisions of the Tariff and the SPP Membership Agreement and to address Critical Energy Infrastructure Information (CEII) requirements. The CEII compliant redacted version of the report shall be posted on the SPP website. The redacted version shall include instructions for acquiring the complete version of the report.

h) The Transmission Provider may recommend, based on the results of a high priority study, a high priority upgrade for inclusion in the SPP Transmission Expansion Plan in accordance with the approval process set forth in Section V of this Attachment O.

4) Evaluation of Potential Balanced Portfolios

a) The Transmission Provider shall solicit input from stakeholders on combinations of potential economic upgrades to be evaluated as potential Balanced Portfolios.

b) Each economic upgrade to be included in a potential Balanced Portfolio:

i) Must include a 345 kV or higher voltage facility;

ii) May include lower voltage transmission facilities needed to integrate the 345 kV or higher facilities and achieve the benefits; however, the cost of the lower voltage transmission facilities cannot exceed the cost of the 345 kV or higher facilities included in the economic upgrade; and

iii) An economic upgrade that includes lower voltage transmission facilities for which the cost of such facilities exceeds the cost of the 345 kV or higher facilities constituting the economic upgrade may be included in the evaluation of a potential Balanced Portfolio, if a Project Sponsor agrees to bear the portion of the cost of the lower voltage facilities that is in excess of the cost of the 345 kV or higher facilities.

iv) Will include an evaluation of the costs of the upgrades, including any cost impacts potentially allocable to the Transmission Provider

or a Zone(s) from a third party upgrade(s) required to relieve congestion on a neighboring system due to the construction of the potential Balanced Portfolio.

c) The Transmission Provider shall determine for each Zone the net present value of the revenue requirements of each potential Balanced Portfolio as follows:

i) The revenue requirements for each potential Balanced Portfolio shall be calculated as if all of the upgrades associated with the potential Balanced Portfolio are simultaneously available to the power system. This requirement is for evaluation purposes only and shall not restrict the timing of the construction of individual upgrades within a Balanced Portfolio approved by the SPP Board of Directors.

ii) Based on input from the Transmission Owners and other pertinent information, the Transmission Provider shall estimate the construction costs of each upgrade in the potential Balanced Portfolio.

iii) For each upgrade in the potential Balanced Portfolio, the Transmission Provider shall use the transmission fixed charge rate(s) for the appropriate Transmission Owner(s) to estimate the revenue requirements. In each annual planning cycle, the Transmission Owner shall supply its fixed charge rate to the Transmission Provider.

iv) The fixed charge rate(s) shall take account of all costs necessary to support the upgrade in the potential Balanced Portfolio, including but not limited to, operation and maintenance expenses,

depreciation, property and payroll taxes, income taxes, if applicable, return on investment and any other factors affecting the revenue requirement associated with the upgrade.

v) The revenue requirements also shall include any specific costs that are projected to be incurred by the Transmission Provider or a Zone(s) as a result of third-party impacts due to one or more upgrades within a proposed Balanced Portfolio.

vi) The revenue requirements for the potential Balanced Portfolio shall equal the sum of the revenue requirements of the upgrades that comprise the potential Balanced Portfolio.

vii) The Transmission Provider shall estimate the cost for each Zone by allocating the revenue requirements for the potential Balanced Portfolio to each Zone based on its Region-wide Load Ratio Share forecasted over the ten year period analyzed.

viii) If any costs of an upgrade in the potential Balanced Portfolio will be borne by other funding mechanisms, such costs shall not be included in the determination of the net present value of the revenue requirements for the potential Balanced Portfolio.

d) The Transmission Provider shall determine for each Zone the net present value of the benefits of each potential Balanced Portfolio as follows:

i) The benefits from each potential Balanced Portfolio shall be calculated as if all of the upgrades associated with the potential Balanced Portfolio are simultaneously available to the power system.

ii) The Transmission Provider shall use an adjusted production cost metric to analyze the benefits of the potential Balanced Portfolio, where adjusted production cost is the production cost minus revenues from sales plus cost of purchases. As described in Section IV.6 of this Attachment O, the Transmission Provider shall continue to evaluate and explore with the stakeholders any additional metrics and criteria which have quantifiable economic effects.

iii) The adjusted production cost benefit for each Zone shall equal the difference between the adjusted production cost with the potential Balanced Portfolio modeled and without the potential Balanced Portfolio modeled.

iv) The Transmission Provider shall estimate the annual benefits for each Zone over the same ten-year period as used to determine the costs by calculating the annual benefits for at least three specific years in the ten-year time period and interpolating the annual benefits for the remaining years.

e) A potential Balanced Portfolio shall meet the following conditions:

i) Cost Beneficial: The sum of the benefits of the potential Balanced Portfolio determined in Section IV.4.d of this Attachment O must equal or exceed the sum of the costs determined in Section IV.4.c of this Attachment O; and

ii) Balanced: For each Zone, the sum of the benefits of the potential Balanced Portfolio determined in Section IV.4.d of this Attachment O must equal or exceed the sum of the costs determined in Section IV.4.c of this Attachment O. Additionally,

the balance may be achieved through the provisions set forth in Section IV.5 of this Attachment O.

f) In developing a potential Balanced Portfolio, the Transmission Provider shall timely publish a report, including but not limited to, the study input assumptions, the estimated costs included in the potential Balanced Portfolio, and the expected economic benefits of the potential Balanced Portfolio. With regard to such report, the Transmission Provider shall comply with the information sharing and reporting requirements in Part VII (Information Exchange) and Section IV.3 (High Priority Studies) of this Attachment O, including the requirements for treatment of confidential information.

5) Options for Achieving a Balanced Portfolio

a) Section IV.4 of this Attachment O sets forth provisions to achieve a Balanced Portfolio when there are deficient Zones. A deficient Zone is a Zone where the costs allocated to the Zone in Section IV.4.c of this Attachment O exceed the benefits allocated to the Zone in Section IV.4.d of this Attachment O, including any additional costs or benefits derived from the application of the provisions in this Section IV.5 of this Attachment O.

b) In order to achieve a Balanced Portfolio, the Transmission Provider may include transmission upgrades that do not adhere to the voltage requirements of Sections IV.4.b.i and ii of this Attachment O.

c) If including the lower voltage transmission facilities does not achieve a Balanced Portfolio, the Transmission Provider may balance the portfolio by transferring a portion of the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual Transmission Revenue

Requirement from the deficient Zone(s) to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement. Transmission Provider shall include the following constraints in this assessment:

i) Limit the amount to be transferred from the Base Plan Zonal Annual Transmission Revenue Requirement and/or the Zonal Annual Transmission Revenue Requirement to the Balanced Portfolio Region-wide Annual Transmission Revenue Requirement to the minimum amount that will balance the portfolio over the ten-year period analyzed;

ii) Transfer from the Base Plan Zonal Annual Transmission Revenue Requirement first, then, if necessary, transfer from the Zonal Annual Transmission Revenue Requirement; and

iii) For each Zone, meet the conditions specified in Section IV.4.e.ii of this Attachment O.

6) Development of Additional Benefit Metrics for Balanced Portfolios

a) The Transmission Provider shall continue to evaluate and explore with the stakeholders via the transmission planning process any additional metrics and criteria which have quantifiable economic effects, such as:

i) Reduction in system losses;

ii) Differing environmental impacts;

iii) Improvement to capacity margin and operating reserve requirements;

iv) Energy, capacity and ancillary service market facilitation;

v) Increased competition in wholesale markets;

vi) Reliability enhancement, including storm hardening and black start capability; and

vii) Critical infrastructure and homeland security.

b) Any subsequent adjustment to the metrics and criteria for evaluating potential Balanced Portfolios developed by the Transmission Provider, with input from the stakeholders, shall be proposed through Tariff amendments.

7) Evaluation of Proposed Interregional Projects

a) Proposed Interregional Projects shall be developed through the Transmission Provider's participation in an Interregional Planning Process with one or more Interregional Planning Regions in accordance with the provisions of Section VIII of this Attachment O.

b) The Transmission Provider shall facilitate a regional review of the proposed Interregional Projects identified in the Coordinated System Plan (CSP) report developed and issued pursuant to the applicable Interregional Planning Process. The regional review will be subject to the timelines identified in the respective Interregional Planning Region procedures in accordance with the applicable Addendum(s) to this Attachment O.

c) The Transmission Provider shall, in consultation with stakeholders, develop the Regional Review Methodology which shall be posted on the

Transmission Provider's website. The methodology will contain, at a minimum, the specific procedures to:

i) Determine the assumptions and criteria necessary to complete the regional review of proposed Interregional Projects.

ii) Determine the regional models to be used in the evaluation of proposed Interregional Projects.

iii) Determine the appropriate updates to the regional models to be used in the evaluation of proposed Interregional Projects.

iv) Quantify the benefits of each proposed Interregional Project using the Transmission Provider's regional benefit metrics consistent with Section III.7 of this Attachment O.

d) For an Interregional Project that is reviewed pursuant to the Regional Review Methodology, the Transmission Provider shall perform the following types of transmission planning studies:

i) Projects Addressing Reliability Issues Description of Analyses: The study scope will determine what types of analyses will be performed. These analyses will be based on the issue that is being addressed by the interregional transmission project. At a minimum, a steady state N-1 analysis will be performed. If needed, the scope will also include directives to perform stability and/or dynamic analyses. Additional analyses can be performed if determined to be needed by the Transmission Provider, in consultation with the stakeholder working group assigned to analyze transmission reliability issues.

ii) Projects Addressing Economic Issues Description of Analyses: The analyses that will be performed will be based on the benefit metrics that will be used as determined by the Transmission Provider, in consultation with the stakeholder working group assigned to analyze economic issues. At a minimum, a security constrained unit commitment/security constrained economic dispatch analysis will be utilized for the calculation of adjusted production cost. Additional analyses will be included in the scope as determined by the Transmission Provider, in consultation with the stakeholder working groups, on what metrics to utilize.

iii) Projects Addressing Public Policy Issues Description of Analyses: Public policy projects will be evaluated to determine whether or not the transmission project will aid in meeting the applicable public policy requirement, and if so, is it more efficient or cost effective than regional solutions. The analysis will use a security constrained economic dispatch and unit commitment model to perform a curtailment and dispatch study. Additional analyses performed in the latest ITP may also be utilized as determined by the Transmission Provider, in consultation with the applicable stakeholder working groups.

e) For each regional review of a proposed Interregional Project, the Transmission Provider shall publish a report which includes, but is not limited to, the following:

i) The results of the regional review analysis and a comparison to the results contained in the CSP report;

ii) The study input assumptions and criteria used to assess the proposed Interregional Project;

iii) The proposed Interregional Project's reliability impacts on the Transmission Provider's system and impacts on third parties not participating in the applicable Interregional Planning Process;

iv) Any expected benefits of the proposed Interregional Project; and

v) The Transmission Provider shall make a recommendation whether to approve the proposed Interregional Project and the allocation of proposed Interregional Project costs between the Interregional Planning Regions.

f) The Transmission Provider's report shall be posted on the Transmission Provider's website. If the Transmission Provider's report contains confidential information in accordance with the provisions of the Tariff, the SPP Membership Agreement, or CEII requirements, the report will be password protected to preserve the confidentiality of information and a redacted version of the report shall be posted on the Transmission Provider's website. The redacted version shall include instructions for acquiring the complete version of the report.

g) The Transmission Provider's report shall be reviewed by the appropriate stakeholder group(s) in accordance with the provisions of Section II of this Attachment O. The stakeholder group(s) and the Transmission Provider will each provide a recommendation to the Markets and Operations Policy Committee. The Markets and Operations Policy Committee shall make a recommendation to the SPP Board of Directors regarding the approval of a proposed Interregional Project.

h) The SPP Board of Directors shall review all reports and recommendations related to the regional review of the proposed Interregional Project.

i) The SPP Board of Directors may approve a proposed Interregional Project only where the benefits equal or exceed the costs for the SPP Region.

ii) The Transmission Provider shall notify the applicable interregional joint planning committee whether a proposed Interregional Project has been approved by the SPP Board of Directors.

i) To qualify as an approved Interregional Project, the proposed Interregional Project must be approved by the SPP Board of Directors and the corresponding Interregional Planning Region in accordance with the applicable Interregional Planning Process.

j) Upon approval by the corresponding Interregional Planning Region and the SPP Board of Directors, the Transmission Provider's portion of the approved Interregional Project will be constructed in accordance with Section VI of this Attachment O.

## V. The SPP Transmission Expansion Plan Report

The SPP Transmission Expansion Plan shall be a comprehensive listing of all transmission projects in the SPP for the planning horizon. Projects included in the SPP Transmission Expansion Plan are: 1) upgrades required to satisfy requests for transmission service; 2) upgrades required to satisfy requests for generator interconnection; 3) Network Upgrades required pursuant to the study results under Attachment AQ of this Tariff; 4) approved projects from the Integrated Transmission Planning Assessment; 5) upgrades within approved Balanced Portfolios; 6) approved high priority upgrades; 7) endorsed Sponsored Upgrades; 8) approved Interregional Projects; 9) approved projects from the 20-Year Assessment; and 10) approved projects from the Generator Retirement Process. To be included in the SPP Transmission Expansion Plan, each project must have been endorsed or approved through its proper process. This Section V describes the process used to approve or endorse the specific upgrades identified in the Integrated Transmission Planning Assessment, the 20-Year Assessment, high priority upgrades, and Balanced Portfolios. The SPP Transmission Expansion Plan shall also identify whether any approved Competitive Upgrades, as that term is defined in Attachment Y of this Tariff, cause reliability violations on an adjacent neighboring transmission system, in Section V.7 of this Attachment O.

1) Development of the Recommended Set of Upgrades from Planning Studies

a) Upon completion of the analysis, studies and stakeholder review and comment on the results in accordance with Sections III and IV of this Attachment O, the Transmission Provider shall prepare a draft list of all projects for review by the stakeholders. The Transmission Provider shall post the draft project list on the SPP website and shall identify the assessment process with which they are associated.

b) Upon posting of the draft project list, the Transmission Provider shall invite written comments to be submitted to the Transmission Provider.

c) The Transmission Provider shall review the draft project list with the stakeholder working groups and the Regional State Committee.

d) Considering the input from the stakeholders through this review process, the Transmission Provider shall prepare a recommended list of proposed ITP Upgrades based upon the analysis as described in Section III, upgrades within proposed Balanced Portfolios, proposed high priority upgrades, and proposed 20-Year Assessment upgrades for review and approval.

2) Disclosure of the Recommended Set of Upgrades and Supporting Information from Planning Studies

a) The Transmission Provider shall disclose planning information, which includes the recommended list of proposed upgrades and the underlying studies, by providing:

i) All stakeholders equal access, notice and opportunity to participate in planning summits, the stakeholder working group meetings and the sub-regional planning meetings as well as any associated web conferences or teleconferences as set forth in Section II of this Attachment O; and

ii) For the contemporaneous availability of such meeting handouts on the SPP website.

b) The related study results, criteria, assumptions, analysis results, and data underlying the studies used to develop the proposed ITP Upgrades, the list of upgrades within proposed Balanced Portfolios, proposed high priority upgrades, and proposed 20-Year Assessment upgrades shall be posted on the SPP website, with password protected access if required to preserve

the confidentiality of information in accordance with the provisions of the Tariff and the SPP Membership Agreement and to address CEII requirements. Additionally, Transmission Owner specific local plans and criteria shall be accessible via an electronic link on the SPP website in accordance with Section VII of this Attachment O. The CEII compliant redacted version of the SPP Transmission Expansion Plan and individual Transmission Owner specific local plans shall be posted on the SPP website. Redacted versions shall include instructions for acquiring the complete version of the SPP Transmission Expansion Plan and individual Transmission Owner specific local plans. An electronic link shall be provided on the SPP website by which stakeholders may send written comments on the SPP Transmission Expansion Plan and Transmission Owner specific local plans and criteria.

3) Approval and Endorsement Process

a) The Markets and Operations Policy Committee shall make a recommendation regarding the approval of ITP Upgrades. Approval by the SPP Board of Directors is required for the inclusion of ITP Upgrades in the SPP Transmission Expansion Plan.

b) The Markets and Operations Policy Committee shall make a recommendation regarding the inclusion of a proposed Balanced Portfolio in the SPP Transmission Expansion Plan. Approval by the SPP Board of Directors is required for inclusion of a Balanced Portfolio in the SPP Transmission Expansion Plan. SPP is not required to have a Balanced Portfolio each year.

c) If the SPP Board of Directors approves a list of ITP Upgrades, upgrades within Balanced Portfolios, or high priority upgrades other than those recommended by the Markets and Operations Policy Committee, the

explanation for the deviation shall be included in the SPP Transmission Expansion Plan.

d) The Markets and Operations Policy Committee shall make a recommendation regarding the approval of a high priority upgrade recommended by the Transmission Provider. Approval by the SPP Board of Directors is required for the inclusion of a high priority upgrade in the SPP Transmission Expansion Plan.

e) The Markets and Operations Policy Committee shall make a recommendation regarding the approval of a 20-Year Assessment upgrade recommended by the Transmission Provider. Approval by the SPP Board of Directors is required for the inclusion of a 20-Year Assessment upgrade in the SPP Transmission Expansion Plan.

f) The Markets and Operations Policy Committee shall make a recommendation regarding endorsement of a proposed Sponsored Upgrade. Endorsement by the SPP Board of Directors is required for the inclusion of a Sponsored Upgrade in the SPP Transmission Expansion Plan.

g) The Transmission Provider shall post the list of projects the SPP Board of Directors is expected to take action on to the SPP website. The Transmission Provider shall, in addition to the posting, e-mail notice of such posting to the stakeholders at least ten days prior to a meeting at which the SPP Board of Directors is expected to take action on accepting or modifying the list.

h) The list of approved ITP Upgrades, upgrades within approved Balanced Portfolios, approved high priority upgrades, and endorsed Sponsored Upgrades may be modified throughout the year by the SPP Board of

Directors provided that such action shall be posted and noticed pursuant to this section.

i) The list of upgrades for transmission service are approved in accordance with the provisions of Attachment Z1 of this Tariff and included in the STEP accordingly.

j) The list of interconnection facilities and other transmission upgrades related to requests for Generator Interconnection Service are approved in accordance with the provisions of Attachment V of this Tariff and included in the STEP accordingly.

k) The list of Interregional Projects is approved in accordance with Section IV.7 of this Attachment O and included in the STEP accordingly.

l) Any recommendation for approval of a Generator Retirement Upgrade shall be made by the Transmission Provider in accordance with Attachment AB of this Tariff. Approval by the SPP Board of Directors is required for the inclusion of a Generator Retirement Upgrade in the SPP Transmission Expansion Plan.

m) The SPP Transmission Expansion Plan shall be presented to the SPP Board of Directors at least once a year. Approval of the ITP Upgrades, Balanced Portfolios, and high priority upgrades, and the endorsement of the other projects contained in the SPP Transmission Expansion Plan by the SPP Board of Directors shall certify a regional plan for meeting the transmission needs of the SPP Region.

4) Updates to the SPP Transmission Expansion Plan

a) Modifications to the SPP Transmission Expansion Plan may be made between the annual approvals as required to maintain system reliability and to meet new business opportunities as they are identified.

b) The Transmission Provider shall work with the stakeholders on an on-going basis throughout the year analyzing any newly identified issues and incorporating any necessary adjustments to the SPP Transmission Expansion Plan on an out-of-cycle basis.

c) On a quarterly basis, the Transmission Provider shall post any modifications to the SPP Transmission Expansion Plan on the SPP website.

d) The modifications shall be reviewed by the stakeholders and the Regional State Committee, endorsed by the stakeholder working groups, and approved or endorsed by the SPP Board of Directors, in accordance with Section V of this Attachment O.

5) Removal of an Upgrade from the SPP Transmission Expansion Plan

The Transmission Provider, in consultation with the stakeholders in accordance with Section V of this Attachment O, may remove an upgrade from an approved SPP Transmission Expansion Plan. A Transmission Owner that has incurred costs related to the removed upgrade shall be reimbursed for any expenditure pursuant to Section VIII of Attachment J to the Tariff.

6) Status of Upgrades Identified in the SPP Transmission Expansion Plan

a) The Transmission Provider shall track the status of planned system upgrades to ensure that the projects are built in time or that acceptable mitigation plans are in place to meet customer and system needs.

b) On a quarterly basis, at a minimum, the Transmission Provider shall:

i) Report to the Markets and Operations Policy Committee, the Regional State Committee and the SPP Board of Directors on the status of the upgrades identified in the SPP Transmission Expansion Plan; and

ii) Post the status of the upgrades on the SPP website.

7) Impacts on Adjacent Systems

As part of the evaluation of any Competitive Upgrade, the Transmission Provider will determine, based on its planning model, whether a proposed Competitive Upgrade causes any reliability violations on the transmission system of an adjacent transmission planning region. The Transmission Provider shall identify any such violations as part of the transmission planning process that identified the Competitive Upgrade. Except as otherwise provided in this Tariff or as otherwise provided in an agreement between the Transmission Provider and an adjacent transmission system, the Transmission Provider shall not pay any cost for any upgrade or system modification necessary to mitigate or resolve any such violation on an adjacent transmission system, and listing of such violations in the SPP Transmission Expansion Plan does not constitute any agreement on the part of the Transmission Provider or its stakeholders to pay any such cost.

## VI. Construction of Transmission Facilities

1) The Transmission Provider shall not build or own transmission facilities. In accordance with Section VI of this Attachment O and Attachment Y of this Tariff, the Transmission Provider shall designate one or more entities to assume the responsibilities of a Transmission Owner for all Network Upgrades approved for construction under this Tariff.

2) Any owner of Transmission Facilities, as defined in Attachment AI of this Tariff, which are, or are capable of being used by the Transmission Provider to provide transmission service pursuant to Part II and Part III of this Tariff, shall have the right to sign the SPP Membership Agreement as a Transmission Owner and thereby acquire all of the rights and obligations of a Transmission Owner described therein, including all of the rights and obligations of a Transmission Owner described in this Tariff and specifically Section VI of this Attachment O.

3) Each Transmission Owner and DTO shall use due diligence to construct transmission facilities as directed by the SPP Board of Directors subject to such siting, permitting, and environmental constraints as may be imposed by state, local and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals. Such construction shall be performed in accordance with Good Utility Practice, applicable SPP Criteria, industry standards, the applicable Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements), and in accordance with all applicable requirements of federal or state regulatory authorities. Each Transmission Owner shall be fully compensated to the greatest extent permitted by the Commission for the costs of construction undertaken by such Transmission Owner in accordance with this Tariff.

4) A specific endorsed Sponsored Upgrade in the SPP Transmission Expansion Plan will be deemed approved for construction upon execution of a contract that

financially commits a Project Sponsor to such upgrade. The Transmission Owner responsible for the Sponsored Upgrade shall be determined as follows:

a) If the Sponsored Upgrade is a rebuild of an existing facility or utilizes rights-of-way where facilities exist, the Sponsored Upgrade will be assigned to the Transmission Owner of the existing facility;

b) If the Sponsored Upgrade is a new transmission facility, the entity sponsoring the Sponsored Upgrade may become the Transmission Owner of the facility if it meets the qualifications to become a Transmission Owner set forth in Section III.1(b) of Attachment Y of this Tariff, including executing an SPP Membership Agreement as a Transmission Owner; or

c) If the Transmission Owner is not determined under subsections (a) and (b) above, the Transmission Provider will follow the process contained in Section IV of Attachment Y of this Tariff.

5) Network Upgrade(s) and Distribution Upgrades (as defined in Attachment V to the Tariff) identified in a Generator Interconnection Agreement will be constructed pursuant to the Generation Interconnection Agreement or pursuant to Attachment Y of this Tariff. Network Upgrades and Distribution Upgrades (as defined in Attachment V to the Tariff) identified in a Generator Interconnection Agreement required to be constructed by the Transmission Owner who is a party to the Generator Interconnection Agreement shall be constructed pursuant to the Generator Interconnection Agreement. All other Network Upgrades and Distribution Upgrades (as defined in Attachment V to the Tariff) identified in a Generator Interconnection Agreement to be constructed by Transmission Owners not a party to the Generator Interconnection Agreement shall be constructed pursuant to Section IV of Attachment Y of this Tariff.

## VII. Information Exchange

1) Data Requirements

a) Any entity that is subject to the NERC Reliability Standards is required to provide data to the Transmission Provider in accordance with the NERC Reliability Standards for Modeling, Data and Analysis (the "NERC MOD Standards").

b) When an entity has developed a preliminary engineering concept for new facilities that impact the interconnected operation of the Transmission System, it shall contact the Transmission Provider so that the optimal integration of any new facilities and potentially benefiting parties can be identified.

c) In preparation for the annual update of transmission planning models for each annual planning cycle, Members, Transmission Customers, Transmission Owners, Generator Interconnection Customers and all other stakeholders must provide to the Transmission Provider the data specified in this Section VII of this Attachment O in accordance with the study schedule posted on the SPP website.

d) During the course of the annual planning cycle, if material changes to the data occur, the data owners must provide timely written notice to the Transmission Provider.

e) The format required to submit modeling data shall be posted on the SPP website.

f) The modeling data shall be posted on the SPP website with password protected access.

2) Owners of transmission facilities shall provide to the Transmission Provider:

a) Modeling data for power flow, short-circuit and stability analysis;

b) Detailed power system models of their transmission systems and provide updates to their models via a password protected web based application;

c) Data regarding the design and operation of their transmission facilities;

d) Their FERC Form 715;

e) Their individual company-specific planning criteria;

f) Planning grade cost estimates and schedules for upgrades in the SPP Transmission Expansion Plan in a timely manner;

g) Their five-year transmission construction plans; and

h) Their transmission fixed charge rate.

3) Generator owners shall provide to the Transmission Provider:

a) Modeling data for power flow, short-circuit and stability analysis;

b) Data for planned additions or upgrades, including status and expected in-service dates, planned retirements and environmental restrictions; and

c) Modeling data to perform economic planning studies in accordance with Sections III and IV of this Attachment O. Data required to model generating units for the economic planning studies is documented in the

Integrated Transmission Planning Manual which shall be posted on the SPP website.

4) Transmission Customers

a) Network Customers shall provide the Transmission Provider an update of the information on its Network Integration Transmission Service application with a ten year forecast of summer and winter load at each delivery point and ten year projection of network resources and with any other information that has changed from the original application.

b) Point-to-point Transmission Customers shall provide to the Transmission Provider their good faith projections on their need for service including transmission capacity, duration and points of delivery and receipt over the ten year planning horizon.

c) Transmission Customers with existing and planned demand response resources, shall provide information on such resources.

5) Neighboring Transmission Providers and RTOs

In accordance with applicable agreements and Section VIII of this Attachment O, the Transmission Provider shall exchange with neighboring Transmission Providers and RTOs the data required for the development of power flow cases, short-circuit cases and stability cases over the ten year planning horizon.

6) Stakeholder Access to Transmission Planning Information

a) The planning information, data, and models provided pursuant to this Section VII shall be sufficient to allow parties to replicate results of the planning studies.

b) The Transmission Provider shall provide a secure web-based workspace for hosting and sharing planning information, data, and models.

c) The secure web-based workspace shall be password protected and require CEII clearance in accordance with Section VII.8 of this Attachment O.

d) Instructions to obtain access to the Transmission Provider's power flow models shall be posted on the SPP website.

e) Instructions to obtain copies of the Transmission Provider's transmission planning maps shall be posted on the SPP website.

7) Confidentiality Requirements

a) The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information in accordance with the provisions of the Tariff and the SPP Membership Agreement.

b) For those entities that have executed a confidentiality agreement, the Transmission Provider shall provide password protected access to confidential information related to the SPP Transmission Expansion Plan and the underlying studies and models via the SPP website.

c) The form of confidentiality agreement shall be posted on the SPP website.

d) The confidentiality agreement shall allow access to applicable system design software results needed to participate in the SPP Transmission Expansion Plan process, to replicate the results of specified transmission planning studies, or to confirm assumptions used in creating adjusted production cost-benefit metrics used to analyze a specified Balanced

Portfolio; provided however, if the results include resource-specific data (including input data), access will be limited to individuals that are not Competitive Duty Personnel. For the purposes of this section:

i) "Competitive Duty Personnel" are any individuals directly engaged in Competitive Duties.

ii) "Competitive Duties" include: (1) the marketing, purchase, or sale of electric power at wholesale, or (2) the direct supervision of any employee with responsibilities for the marketing, purchase, or sale of electric power at wholesale.

e) Other transmission planning information shall be posted on the SPP website and may be password protected, as appropriate.

f) Confidentiality agreements shall be required for Members and Market Participants to receive data where the owner of the data has given permission to the Transmission Provider to release the data.

8) Critical Energy Infrastructure Information (CEII) Requirements

a) The Transmission Provider shall take appropriate steps to protect CEII information.

b) The Transmission Provider shall screen Members and Market Participants prior to providing access to CEII information. Individuals that do not belong to a confirmed pre-screened Member or Market Participant shall make application for approval to obtain CEII used in the transmission planning process in accordance with the procedures posted on the SPP website.

c) For those entities that have met the CEII requirements in Section VII.8.b of this Attachment O, the Transmission Provider shall provide password protected access to CEII information related to the SPP Transmission Expansion Plan and the underlying studies and models via the SPP website.

d) The Transmission Provider shall follow the guidelines set forth by the Commission to flag data which shall be treated as CEII sensitive.

## VIII. Interregional Planning

1) The Transmission Provider shall participate in interregional planning with the following Interregional Planning Regions listed in the respective Addendums to this Attachment O:

Addendum 3- The Midcontinent Independent System Operator, Inc. ("MISO")

Addendum 4- Southeastern Regional Transmission Planning (SERTP)

2) The portion of an approved Interregional Project to be constructed by each Interregional Planning Region shall be determined in accordance with the applicable Addendum to this Attachment O.

3) The costs of an approved Interregional Project shall be allocated to each Interregional Planning Region in accordance with the applicable Addendum to this Attachment O.

4) The Transmission Provider's obligation to construct an approved Interregional Project within the SPP Region shall be determined in accordance with Section IV.7 of this Attachment O.

## IX. Recovering Costs Associated with the Planning Process

1) The Transmission Provider's costs associated with the planning process and associated studies set forth in this Attachment O shall be recovered pursuant to Schedule 1-A1 of the Tariff.

2) The Transmission Provider's costs associated with studies for potential Sponsored Upgrades, shall be the responsibility of the entities requesting such studies.

3) The Transmission Provider's costs for studies associated with requests for long-term firm transmission service shall be recovered pursuant to Sections 19 and 32 of the Tariff.

4) The Transmission Provider's costs for studies associated with requests for interconnection service shall be recovered pursuant to Attachment V of the Tariff.

## X. Cost Allocation

The costs associated with new or upgraded transmission facilities shall be allocated in accordance with Attachment J to the Tariff.

## XI. Dispute Resolution

Any dispute regarding the planning process shall be resolved utilizing the procedures identical to those set forth in Section 12 of the Tariff.

## ADDENDUM 1 TO ATTACHMENT O

## INTERREGIONAL COORDINATION AGREEMENTS

1) In addition to interregional planning pursuant to Section VIII of Attachment O, the Transmission Provider shall undertake to coordinate any studies with other transmission providers primarily through participation in the agreements, as may be amended from time to time, listed below:

a) The Joint Operating Agreement between Southwest Power Pool, Inc. and Associated Electric Cooperative, Inc. (Rate Schedule FERC No. 10);
b) The Joint Operating Agreement between Southwest Power Pool, Inc. and Saskatchewan Power Corporation (dated October 1, 2015); and
c) All other agreements between the Transmission Provider and transmission systems to which the SPP Region is interconnected and which are not identified in Section VIII of this Attachment O.

2) On an annual basis, the Transmission Provider shall review the ongoing planning activities under the coordination agreements specified in this Addendum 1 to determine any need for additional interregional studies. The Transmission Provider shall share this review with the stakeholders at a planning summit and solicit input regarding any additional interregional studies that should be initiated by the Transmission Provider.

3) Any Network Upgrade approved pursuant to the coordination agreements under this Addendum 1 shall not be considered an approved Interregional Project pursuant to the Interregional Planning Process identified in Section VIII of Attachment O.

## ADDENDUM 2 TO ATTACHMENT O

## ENROLLMENT IN THE SPP TRANSMISSION PLANNING REGION

The following entities have elected to become part of the SPP transmission planning region:

AEP Oklahoma Transmission Company, Inc.
AEP Southwestern Transmission Company, Inc.
Arkansas Electric Cooperative Corporation
Basin Electric Power Cooperative
Central Nebraska Public Power and Irrigation District
Central Power Electric Cooperative, Inc.
City of Coffeyville
City of Independence, MO
City Utilities of Springfield, Missouri
Corn Belt Power Cooperative
East River Electric Power Cooperative, Inc.
East Texas Electric Cooperative, Inc.
Empire District Electric Company
Evergy Kansas Central, Inc.
Evergy Kansas South, Inc.
Evergy Metro, Inc.
Evergy Missouri West, Inc.
Grand River Dam Authority
Harlan Municipal Utilities
Heartland Consumers Power District
ITC Great Plains, LLC
Kansas City Board of Public Utilities
Kansas Power Pool
L and O Power Cooperative
Lea County Electric Cooperative, Inc.
Lincoln Electric System
Midwest Energy, Inc.
Missouri Joint Municipal Electric Utility Commission
Missouri River Energy Services
Mor-Gran-Sou Electric Cooperative, Inc.
Mountrail-Williams Electric Cooperative
Nebraska Public Power District
Northwest Iowa Power Cooperative
NorthWestern Corporation (South Dakota)
Oklahoma Gas and Electric Company
Oklahoma Municipal Power Authority
Omaha Public Power District
People’s Electric Cooperative
Prairie Wind Transmission, LLC
Public Service Company of Oklahoma
Roughrider Electric Cooperative, Inc.

South Central MCN LLC
Southwestern Electric Power Company
Southwestern Power Administration*
Southwestern Public Service Company
Sunflower Electric Power Corporation
Transource Missouri, LLC
Transource Oklahoma, LLC
Tri-State Generation and Transmission Association, Inc.
Western Area Power Administration-Upper Great Plains Region
Western Farmers Electric Cooperative

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* Participates in SPP regional planning through Attachment AD of this Tariff.

# ADDENDUM 3 TO ATTACHMENT O

## COORDINATED INTERREGIONAL TRANSMISSION PLANNING WITH THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

Pursuant to Section VIII of Attachment O, the Transmission Provider and the Midcontinent Independent System Operator, Inc. ("MISO") shall undertake coordinated interregional transmission planning in accordance with the provisions of Article IX of the Joint Operating Agreement between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc. ("JOA"). The agreement can be found on the SPP website.

The objective of coordinated interregional transmission planning with MISO is to identify potential Interregional Projects, calculate the benefits to each region and present that information to the Transmission Provider and MISO. The process for coordinated interregional transmission planning between the Transmission Provider and MISO provides for joint identification and analysis of proposed Interregional Projects which may benefit the regions served by the Transmission Provider and MISO. The process includes, but is not limited to:

i. Establishment of a joint planning committee and stakeholder committee;

ii. Voting procedures whereby proposed Interregional Projects may be approved for construction by both parties;

iii. Data exchange requirements;

iv. Coordinated system planning between the parties to identify and evaluate proposed Interregional Projects;

v. Determination of costs and benefits for each party; and

vi. Construction and ownership of approved Interregional Projects.

Any proposed Interregional Projects shall be reviewed by the Transmission Provider in accordance with Section IV.7 of Attachment O. The Transmission Provider will construct its part of any approved Interregional Projects in accordance with Section VI of Attachment O. Any cost obligation of the SPP Region related to Interregional Projects shall be allocated in accordance with Section VI of Attachment J.

# ADDENDUM 4 TO ATTACHMENT O

## INTERREGIONAL TRANSMISSION COORDINATION BETWEEN THE TRANSMISSION PROVIDER AND THE SOUTHEASTERN REGIONAL TRANSMISSION PLANNING PROCESS

Pursuant to Section VIII of Attachment O, the Transmission Provider and the public utility transmission providers in the Southeastern Regional Transmission Planning Process ("SERTP") region shall undertake coordinated interregional transmission planning in accordance with the provisions of this Addendum 4. All terms not otherwise defined herein shall have the definitions assigned in the Tariff.

For purposes of this Addendum 4, the Transmission Provider's regional transmission planning process is the process described in Attachment O of this Tariff; the SERTP is the process described in the respective Attachment Ks (or comparable tariff sections) of the public utility transmission providers in the SERTP. References to the respective regional transmission planning processes in this Addendum 4 are intended to identify the activities described in those tariff provisions. Unless noted otherwise, Section references in this Addendum 4 refer to Sections within this Addendum 4.

## INTERREGIONAL TRANSMISSION PLANNING

### 1. Coordination

**1.1 Annual Coordination:** Representatives of the Transmission Provider and the SERTP will meet no less than once per year to facilitate the interregional coordination procedures described below (as applicable). Representatives of the Transmission Provider and the SERTP may meet more frequently to coordinate the evaluation of interregional transmission project(s).

**1.2. Data Exchange**

**1.2.1 Annual Data Exchange:** At least annually, the Transmission Provider and the public utility transmission providers in the SERTP shall exchange power-flow models and associated data used in the regional transmission planning processes to develop their respective then-current regional transmission plan(s). The Transmission Provider shall designate a representative for its region and the SERTP sponsors shall designate a representative for the SERTP region to facilitate the annual data exchange. The data exchange will occur when such data is available in each of the regional transmission planning processes, typically during the first calendar quarter. Additional transmission-based models and data used in the development of the respective regional transmission plans will be exchanged between the Transmission Provider and the public utility transmission providers in the SERTP if requested. Data exchanged between the Transmission Provider and the public utility transmission providers in the SERTP under this Section 1.2.1 shall be posted on the

pertinent regional transmission planning websites consistent with the posting requirements of the respective regional transmission planning processes and is generally considered CEII.

**1.2.2 Exchange of Regional Transmission Plans:** The Transmission Provider's regional transmission plan(s) will be posted on the SPP website pursuant to the Transmission Provider's regional transmission planning process. The Transmission Provider will also notify the SERTP representative of such posting so they may retrieve the transmission plan(s). The public utility transmission providers in the SERTP will exchange the then-current SERTP regional transmission plan(s) in a similar manner according to its regional transmission planning process.

**1.2.3 Confidentiality:** Any CEII and Confidential data disclosed by the Transmission Provider pursuant to this Addendum 4 shall be subject to the provisions of Section VII of Attachment O of this Tariff.

**1.3. Joint Evaluation**

**1.3.1 Identification of Interregional Transmission Projects:** At least biennially, the Transmission Provider will review the then-current regional transmission plan of the SERTP, and the public utility transmission providers in the SERTP will review the Transmission Provider's then-current regional transmission plan. Such plans include the transmission needs of each region as prescribed by each region's planning process. This review shall occur on a mutually agreeable schedule, taking into account each region's regional transmission planning processes timetable.

If through this review, the Transmission Provider and the public utility transmission providers, as applicable, in the SERTP identify a potential interregional transmission project that could be more efficient or cost effective than transmission projects included in the respective regional transmission plans, the Transmission Provider and the public utility transmission providers in the SERTP will jointly evaluate the potential transmission project pursuant to Section 1.3.4.

**1.3.2 Identification of Interregional Transmission Projects by Stakeholders:** Stakeholders may also propose transmission projects that may be more efficient or cost-effective than transmission projects included in the Transmission Provider's and/or the SERTP's regional transmission plans pursuant to the procedures in each region's regional transmission planning processes. The Transmission Provider and the public utility transmission providers in the SERTP will evaluate interregional transmission projects proposed by stakeholders pursuant to Section 1.3.4.

**1.3.3** Interregional transmission projects proposed for potential interregional cost allocation must be submitted in both the SERTP and Transmission Provider's regional transmission planning processes and satisfy the requirements of Section 2.1. The submittal must identify the potential transmission project as interregional in scope and identify that such project will interconnect between the SERTP region and the Transmission Provider. The Transmission Provider will verify whether the submittal for the potential interregional transmission project satisfies all applicable

requirements. Upon finding that the proposed interregional transmission project satisfies all such applicable requirements, the Transmission Provider will notify SERTP. Once the potential interregional transmission project has been proposed through the regional transmission planning processes in both regions, and upon both regions so notifying one another that the project is eligible for consideration pursuant to their respective regional transmission planning processes, the Transmission Provider and SERTP will jointly evaluate the proposed interregional transmission projects pursuant to Sections 1.3.4.

**1.3.4 Evaluation of Interregional Transmission Projects:**

**1.3.4.1 Joint Evaluation of Interregional Transmission Projects:** The Transmission Provider and the public utility transmission providers in the SERTP shall act through their respective regional transmission planning processes to evaluate potential interregional transmission projects and to determine whether the inclusion of any potential interregional transmission projects in each region's regional transmission plan would be more efficient or cost-effective than transmission projects included in the respective then-current regional transmission plans. Initial coordination activities to facilitate such analysis will typically begin during the third calendar quarter. Such analysis shall be consistent with accepted planning practices of the respective regions and the methods utilized to produce each region's respective regional transmission plan(s). The Transmission Provider will evaluate potential interregional transmission projects in

accordance with Section IV.7 of Attachment O of this Tariff. To the extent possible, and as needed, information will be coordinated between the Transmission Provider and the public utility transmission providers in the SERTP, including, but not limited to:

- Planning horizons;
- Expected timelines/milestones associated with the joint evaluation;
- Study assumptions and data;
- Models; and
- Criteria

The Transmission Provider and the public utility transmission providers in the SERTP will exchange status updates for new interregional transmission project proposals or proposals currently under consideration as needed. These status updates will generally include, if applicable: (i) an update of the region's evaluation of the proposal; (ii) the anticipated timeline for future assessments; and (iii) reevaluations related to the proposal.

**1.3.4.2 Determination of Regional Benefit(s) for Interregional Cost Allocation Purposes:** The Transmission Provider and the SERTP shall evaluate the proposed interregional transmission project that meets the criteria of Section 2 for interregional cost allocation within the respective regions as follows:

A. Each region, acting through its regional transmission planning process, will evaluate proposals to determine whether the proposed

interregional transmission project(s) provides Regional Benefits to its respective region. For purposes of this Addendum 4, "Regional Benefit" shall mean the calculation described in Section 1.3.4.2.B.

B. Based upon the evaluation made pursuant to 1.3.4.2.A, each region will quantify a Regional Benefit based upon (i) for the Transmission Provider, the Transmission Provider shall calculate the total avoided costs of regional transmission projects that would be displaced if the proposed interregional transmission project was included; and (ii) for the SERTP, the SERTP sponsors shall calculate the total avoided costs of transmission projects included in the then-current regional transmission plan that would be displaced if the proposed interregional transmission project was included.

C. Updated Regional Benefits calculations will be exchanged in a similar manner to the status updates described in Section 1.3.4.1. In any regional benefit to cost ("BTC") ratio calculation(s) performed pursuant to the respective regional transmission planning processes, the anticipated allocation of costs of the interregional transmission project to each region shall be based upon the ratio of the region's Regional Benefit to the sum of the Regional Benefits identified for both SPP and the SERTP.

**2. Cost Allocation**

**2.1 Interregional Transmission Projects Proposed for Interregional Cost Allocation Purposes:** For a transmission project to be considered for purposes of interregional cost allocation between the Transmission Provider and the SERTP, the following criteria must be met:

A. The transmission project must interconnect to transmission facilities in both the Transmission Provider's and SERTP regions, and must meet the qualification criteria for transmission projects potentially eligible to be included in the regional transmission plans for purposes of regional cost allocation in accordance with the respective regional transmission planning processes of both the Transmission Provider and the SERTP. The facilities to which the project is proposed to interconnect may be either existing facilities or transmission projects included in the regional transmission plan that are currently under development.

B. The transmission project must be proposed in the Transmission Provider and the SERTP regional planning processes for purposes of cost allocation, as well as any other regions to which the proposed transmission project would interconnect, in accordance with the procedures of the applicable regional transmission planning processes. If the proposed transmission project is being proposed by a transmission developer, the transmission developer must also satisfy all qualification criteria specified in the respective regional transmission planning processes, as applicable.

**2.2 Inclusion in Regional Transmission Plans for Purposes of Cost Allocation:** An interregional transmission project proposed for interregional cost allocation purposes in each region will be included in the respective regional transmission plans for purposes of cost allocation after each region has performed all evaluations and the transmission project has obtained all approvals, as prescribed in the respective regional transmission planning processes, necessary for it to be included in each regional transmission plan for purposes of cost allocation.

**2.3 Allocation of Costs Between the Transmission Provider and the SERTP:** The cost of an interregional transmission project selected for purposes of cost allocation in the regional transmission plans of both the Transmission Provider and the SERTP will be allocated between the regions as follows:

A. Each region will be allocated a portion of the interregional transmission project's costs in proportion to such region's Regional Benefit to the sum of the Regional Benefits identified for both the Transmission Provider and the SERTP.

- The Regional Benefits used for this determination shall be based upon the last Regional Benefit calculation performed – pursuant to the method described in Section 1.3.4.2 – before each region included the transmission project in its regional transmission plan for purposes of cost allocation and as approved by each region.
- Should one region be willing to bear more costs of the interregional transmission project than the costs identified pursuant to the methodology described in this Section 2.3.A, the regions may

voluntarily agree, subject to applicable regional approvals, to an alternative cost sharing arrangement.

**2.4 Milestones of Required Steps Necessary to Maintain Status as Being Selected for Interregional Cost Allocation Purposes:** Once selected in the respective regional transmission plans for purposes of cost allocation, the Transmission Provider and the SERTP sponsor(s) that will be allocated costs of the transmission project ("beneficiaries") and the transmission developer must mutually agree upon an acceptable development schedule including milestones by which the necessary steps to develop and construct the transmission project must occur. These milestones may include (to the extent not already accomplished) obtaining all necessary rights-of-way and requisite environmental, state, and other governmental approvals and executing a mutually-agreed upon contract(s) between the transmission developer and the beneficiaries. If the specified milestones are not met, then the Transmission Provider and the SERTP sponsor(s) may remove the transmission project from the selected category in the regional transmission plan for purposes of cost allocation.

**2.5 Interregional Project Contractual Arrangements:** The contracts referenced in Section 2.4 will address terms and conditions associated with the development of the proposed transmission project included in the regional transmission plans for purposes of cost allocation, including but not limited to:

a) Engineering, procurement, construction, maintenance, and operation of the proposed transmission project, including coordination responsibilities of the parties;

b) Emergency restoration and repair;

c) The specific financial terms/specific total amounts to be charged by the transmission developer of the transmission project to each beneficiary, as agreed to by the parties;

d) Creditworthiness/project security requirements;

e) Milestone reporting, including schedule of projected expenditures;

f) Reevaluation of the transmission project; and

g) Non-performance or abandonment.

**2.6 Removal from Regional Transmission Plans for Purposes of Cost Allocation:** An interregional transmission project may be removed from the Transmission Provider's or the SERTP's regional transmission plan for purposes of cost allocation (1) if the project is removed from either regions', regional transmission plans pursuant to the requirements of its regional transmission planning process or (2) if the developer fails to meet the developmental milestones established pursuant to Section 2.4.

**2.6.1:** The Transmission Provider and/or the public utility transmission providers in the SERTP will notify the other party if an interregional transmission project or a portion thereof is likely to be removed from its regional transmission plan.

## 3. Transparency

**3.1** The Transmission Provider and the public utility transmission providers in the SERTP shall host their respective regional websites for communication of information related to coordinated interregional transmission planning procedures. The regions shall coordinate on the documents and information that is posted on

their respective websites to ensure consistency of information. Each regional website shall contain, at a minimum, the following information:

i. Link to this Addendum;

ii. Information related to joint meetings, such as links to materials for joint meetings;

iii. Documents relating to joint evaluations; and

iv. Procedures for coordination and joint evaluation

**3.2** Access to the data utilized will be made available through the pertinent regional planning websites subject to the requirements in Section 1.2.3. The Transmission Provider will make available, on the SPP website, links to where stakeholders can register (if applicable/available) for SERTP stakeholder committees and distribution lists.

**3.3** The Transmission Provider shall report back to its stakeholders on the status of any interregional activities done under this Addendum 4 including:

- Facilities to be evaluated
- Analysis performed
- Determinations/results

**3.4** Stakeholders will have an opportunity to provide input and feedback related to interregional facilities identified, analysis performed, and any determination/results within the respective regional transmission planning processes. Stakeholders may participate in either or both regions' regional transmission planning processes to provide their input and feedback regarding the interregional coordination activities described in this Addendum 4.

## ADDENDUM 5 TO ATTACHMENT O

## MERCHANT TRANSMISSION DEVELOPER INTERCONNECTION

Other than for generation interconnections addressed by Attachment V of this Tariff, this Addendum 5 is applicable to Merchant Transmission Developers that request an interconnection to the Transmission System. For purposes of this Addendum 5, a Merchant Transmission Developer is an entity that assumes all financial responsibility for the development, construction and operation of the transmission facilities it seeks to interconnect to the Transmission System and does not seek regional cost allocation or cost recovery for such facilities under this Tariff. Merchant Transmission Developers must comply with all requirements set forth in the SPP Criteria, including but not limited to providing the following information to the Transmission Provider, as required in the SPP Criteria:

Transmission Interconnection Review Data Checklist

1. Primary contact and all affected parties' contact information.
2. Overview of the proposed interconnection and its need.
3. Estimated or proposed in-service date.
4. List of all studies run by season.
    a. Power flow studies minimum requirements met.
    b. Short circuit studies minimum requirements met.
    c. Dynamics studies minimum requirements met.
5. Affected parties planning criteria, if applicable.
6. A detailed description of the proposed interconnection.
    a. In-service date
    b. Design information
    c. Ratings of the interconnection
    d. A geographic map of the interconnection area
    e. Electrical one-line diagrams of the facilities being connected.
7. Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
8. Details of any required mitigation plans including identification of the affected parties responsible for mitigation.

a. In-service date
b. Design information
c. Ratings of the facilities
d. A geographic map of the facility area
e. Electrical one-line diagrams of the facilities being connected.

9. Comments of affected parties covering agreement or points of disagreement of the proposed interconnection, if any.
10. Additional studies may be required for DC interconnections.

Compliance with the data submission requirements specified in this Addendum does not constitute approval of the physical interconnection of the facility by the Transmission Provider.

# ATTACHMENT P

## TRANSMISSION SERVICE TIMING REQUIREMENTS

| Transmission Service Type | Term | Transmission Requests 2/ No Later Than | Transmission Requests 2/ No Earlier Than 8/ | Transmission Provider Response to Application | Aggregate Transmission Service Study | Customer Response 1/ | Energy Scheduling 2/ No Later Than | Energy Scheduling 2/ Changes No Later Than |
|---|---|---|---|---|---|---|---|---|
| Long Term Firm | 1 Year or More | In accordance with the open season specified in Section II of Attachment Z1 | | At the close of the open season specified in Section II of Attachment Z1 | Aggregate Transmission Service Study performed following close of open season as specified in Attachment Z1 in accordance with schedule specified in Sections 19.4 or 32.4 as appropriate | In accordance with the schedule specified in Sections 19.4 or 32.4 as appropriate | 12:00 day prior | 20 mins prior to start of schedule |

| Transmission Service Type | Term | Transmission Requests 2/ No Later Than | Transmission Requests 2/ No Earlier Than 8/ | Transmission Provider Response to Application | Determine Capacity Available or System Impact Study (From Date of Customer Commitment) | | Customer Response 1/ | Energy Scheduling 2/ No Later Than | Energy Scheduling 2/ Changes No Later Than |
|---|---|---|---|---|---|---|---|---|---|
| Short-Term Firm | More than 1 month (monthly) | 31 days prior | 120 days prior | 24 hrs | 30 days | 60 days | 4 days | 12:00 day prior | 20 mins prior to start of schedule |
| Short-Term Firm | 1 mo (monthly) | 8 days prior | 90 days prior | 24 hrs | 30 days | 60 days | 4 days | 12:00 day prior | 20 mins prior to start of schedule |

| **Transmission Service Type** | **Term** | **Transmission Requests 2/** | | **Transmission Provider Response to Application** | **Aggregate Transmission Service Study** | | **Customer Response** [1/] | **Energy Scheduling 2/** | |
|---|---|---|---|---|---|---|---|---|---|
| | | **No Later Than** | **No Earlier Than 8/** | | | | | **No Later Than** | **Changes No Later Than** |
| Short-Term Firm | More than 1 wk up to 1 month (weekly) | 8 days prior | 60 days prior | 24 hrs | 30 days | 60 days | 48 hrs | 12:00 day prior | 20 mins prior to start of schedule |

| **Transmission Service Type** | **Term** | **Transmission Requests 2/** | | **Transmission Provider Response to Application** | **Determine Capacity Available or System Impact Study (From Date of Customer Commitment)** | | **Customer Response [1/]** | **Energy Scheduling 2/** | |
|---|---|---|---|---|---|---|---|---|---|
| | | **No Later Than** | **No Earlier Than 8/** | | | | | **No Later Than** | **Changes No Later Than** |
| Short-Term Firm | 1 wk (weekly) | 2 days prior | 30 days prior | 24 hrs | 30 days | 60 days | 48 hrs | 12:00 day prior | 20 mins prior to start of schedule |
| Short-Term Firm | More than 1 day up to 1 wk (daily) | 2 days prior | 14 days prior | 24 hrs | 30 days | 60 days | 24 hrs | 12:00 day prior | 20 mins prior to start of schedule |
| Short-Term Firm | 1 Day (daily) | 10:00 day prior | 3 days prior 4/ | 24 hrs | queued > 24 hrs to start: 30 days<br>queued < 24 hrs to start: best effort | 60 days | queued > 24 hrs to start: 24 hrs<br>queued < 24 hrs to start: 2 hrs | 12:00 day prior | 20 mins prior to start of schedule |
| Non-Firm | 1 month or greater (monthly) | 3 days prior | 60 days prior | N/A | 2 days | N/A | 24 hrs | 15:00 day prior | 20 mins prior to start of schedule |

| Transmission Service Type | Term | Transmission Requests 2/ | | Transmission Provider Response to Application | Determine Capacity Available or System Impact Study (From Date of Customer Commitment) | | Customer Response [1/] | Energy Scheduling 2/ | |
|---|---|---|---|---|---|---|---|---|---|
| | | No Later Than 8/ | No Earlier Than | | | | | No Changes Later Than | No Later Than |
| Non-Firm | 1 wk up to 1 mo (weekly) | 2 days prior | 14 days prior | N/A | 4 hrs | N/A | 24 hrs | 15:00 day prior | 20 mins prior to start of schedule |

| **Transmission Service Type** | **Term** | **Transmission Requests 2/** | | **Transmission Provider Response to Application** | **Determine Capacity Available or System Impact Study (From Date of Customer Commitment)** | | **Customer Response 1/** | **Energy Scheduling 2/** | |
|---|---|---|---|---|---|---|---|---|---|
| | | **No Later Than 8/** | **No Earlier Than** | | | | | **No Later Than** | **Changes No Later Than** |
| Non-Firm | 1 day up to 1 wk (daily) | 10:00 day prior | 2 days prior 4/ | N/A | 30 mins | N/A | 2 hrs | 15:00 day prior | 20 mins prior to start of schedule |
| Non-Firm On-Peak Hours 9/ | 16 hours (06:00 – 22:00) (daily) | 10:00 day prior | 2 days prior 4/ | N/A | 30 mins | N/A | 30 mins | 20 mins prior to hour | 20 mins prior to start of schedule |
| Non-Firm Off-Peak Hours 9/ | 8 hours (00:00 – 06:00 & 22:00 – 24:00) (daily) | 10:00 day prior | 2 days prior 4/ | N/A | 30 mins | N/A | 30 mins | 20 mins prior to hour | 20 mins prior to start of schedule |
| Non-Firm 7/ | 1 hour up to 1 day (hourly) | 30 mins. prior | 10:00 day prior | N/A | Queued > 1 hr prior to start: 30 mins | N/A | Queued day prior: 30 mins | 20 mins prior to hour | 20 mins prior to start of schedule |
| | | | | | Queued < 1 hr prior to start best effort | | Queued current day: 5 min 5/ | | |
| Next Hour Market | next-hour (hourly) | 20 mins prior 3/ | 1 hour prior 3/ | N/A | Best Effort | N/A | N/A 3/ | 20 mins prior to hour 3/ | 20 mins. prior to hour 3/ |

1/ For transactions not covered by an umbrella service agreement, the customer response must be execution of a service agreement or a request that an unexecuted service agreement be filed with the Commission pursuant to Section 15.3 of the Tariff. For transactions under an umbrella service agreement, the above times are the deadlines by which time the customer must notify the Transmission Provider of its acceptance of the offer to provide transmission.

2/ The Transmission Provider, in its discretion exercised on a non-discriminatory basis, may waive any of these requirements.

3/ All Next-Hour Market requests are submitted on schedule request and are deemed to be pre-confirmed.

4/ Excluding Sundays and NERC Holidays.

5/ Or 23:00 of previous day if for first hour of day.

6/ Non-firm schedules will be accepted after 15:00 day prior if there are no new reliability risks identified since the reservation was accepted. This includes but is not limited to NERC TLR in effect.

7/ With regard to non-firm hourly for next day transmission involving the DC ties under this Tariff, the following rule applies to limit abuse of the Transmission Provider's scheduling process: If more than three (3) requests are submitted by the same Transmission Customer or group of affiliated Transmission Customers per DC tie, per direction between 09:55:00 a.m. and 10:05:00 a.m. CPT, then all such requests shall be considered invalid.

8/ All transmission service requests received within the first five minutes after the specified deadline shall be deemed as having been received simultaneously. Transmission Provider shall not make such requests publicly available via the OASIS or otherwise until the close of the five minute period. Subject to the preceding sentences, a lottery system conducted by the Transmission Provider shall be used to assign priorities for reservation requests received simultaneously. Allocations of capacity shall be based on the priority established by such lottery in conjunction with the duration of transmission service requested consistent with the principles set forth in Sections 13.2 and 14.2 of the SPP OATT.

9/ For displaced and superseded purposes, Daily Non-Firm On-Peak hours and Daily Non-Firm Off-Peak hours services will have a NERC priority (3-ND) greater than Hourly Non-Firm (2-NH) service. A Daily Non-Firm request that is 24 hours in duration will have priority over a Daily Non-Firm request for either the On-Peak hours only or the Off-Peak hours only. For curtailment purposes, a tagged transaction utilizing Daily Non-Firm On-Peak hours or Daily Non-Firm Off-Peak hours transmission service will be assigned a priority of 3-ND to be curtailed with other transactions with a priority of 3-ND on a pro rata basis. The Customer taking Daily Non-Firm On-Peak hours or Daily

Non-Firm Off-Peak hours transmission service will be charged the applicable Attachment T rate for daily service determined by the day for which the service is being reserved. Unless otherwise explicitly stated in Attachment T, Off-Peak days are defined as Saturdays, Sundays, and NERC Holidays. All other days are considered On-Peak for the purposes of transmission service charges.

**Transmission Service Increments Offered Under the Tariff**

Point-To-Point Transmission Service and Network Integration Transmission Service are further characterized by service increments and windows, consistent with the version of NAESB Wholesale Electric Quadrant (WEQ-001) Business Practice Standards incorporated pursuant to Attachment R-1 of this Tariff. The Transmission Provider offers only the following service increment and window combinations:

**Fixed Hourly** – The service starts at the beginning of a clock hour and stops at the end of a clock hour.

**Fixed Daily** – The service starts at 00:00 and stops exactly 24:00 of the same calendar day (same as 00:00 of the next consecutive calendar date).

**Extended Weekly** – The service starts at 00:00 of any date and stops at 00:00 more than one week later, but less than four weeks later.

**Extended Monthly** – The service starts at 00:00 of any date and stops at 00:00 more than one month later, but less than twelve months later.

**Extended Yearly** – The service starts at 00:00 of any date and stops at 00:00 more than one year later.

Transmission service products are offered and processed only in Central Prevailing Time, as defined in Attachment X of the Tariff. Transmission Provider utilizes the 24-hour clock convention of time keeping.

# ATTACHMENT Q
# FORM OF APPLICATION FOR SHORT-TERM FIRM AND NON-FIRM TRANSMISSION SERVICE

| | | | | |
|---|---|---|---|---|
| Email Address: | | | Submit | Reset |
| Customer Information | | | Seller Information | |
| Name | | Company | Company | |
| Comments | | | DUNS | |
| Paths and POR/POD Information | | | Transmission Information | |
| POR | | POD | Capacity Type | |
| Path Name | | | Capacity | Price |
| [1] Source | | [2] Sink | Pre-confirmed | |
| Dates and Times | | | Reference Numbers | |
| Begin Date | Time | Time Zone | Deal | |
| | | | Request | |
| End Date | Time | Time Zone | Sale | |

[1] Delivering Member [2] Receiving Member

# ATTACHMENT R
# NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL TRANSMISSION LOADING RELIEF ("TLR") PROCEDURE

The North American Electric Reliability Corporation's ("NERC")'s TLR Procedures originally filed March 18, 1998, which are now the mandatory Reliability Standards that address TLR, and any amendments thereto, on file and accepted by the Commission, are hereby incorporated and made part of this Tariff. See www.nerc.com for the current version of the NERC's TLR Procedures.

# ATTACHMENT R-1

## North American Energy Standards Board Business Practices

The current versions of the NAESB WEQ Business Practice Standards incorporated by reference into the Commission's regulations as specified in Part 38 of the Commission's regulations (18 CFR Part 38) are incorporated by reference into this tariff.

# ATTACHMENT S
# PROCEDURE FOR CALCULATION OF MW-MILE IMPACTS FOR USE IN ASSIGNMENT OF REVENUE REQUIREMENTS, REVENUE ALLOCATION AND DETERMINATION OF LOSSES

## 1. Introduction

The purpose of this Attachment S is to set forth the procedures for calculation of MW-mile impacts for use in assignment of revenue requirements, revenue allocation and determination of losses as implemented by the Transmission Provider. The MW-mile technique is a distance based impact method of assessing transmission use and topology recognizing that power will, to some extent, flow over all available paths from the generating source to the load. Definitions of the models and parameters used in the calculations are presented, as well as a description of the calculations performed. Details of the application of MW-mile impacts to the assignment of revenue requirements, allocation of revenues and the determination of losses are discussed in Attachments J, L and M respectively.

## 2. Definitions, Models and Parameters Used

2.1 Composition of the Network Model - The network models used in the MW-mile calculations are derived from loadflow models of the Transmission System assembled annually by the Transmission Provider. Prior to April 1 each year, data are submitted, models assembled, modifications required for using the models in the MW-mile impact calculations are made, and the impact tables for the upcoming year is computed.

2.1.1 The model used in the calculations is the Summer Peak Load Operating Model, as modified for use in the MW-mile analysis.

2.1.2 Transmission Elements Included in the MW-mile Analysis - The intent in constructing the network model(s) is to include and accurately represent all facilities that are expected to exhibit a material response to changes on the Transmission System. This set of facilities may not include all facilities that are included in a Transmission Owner's revenue requirement.

2.1.3 Transmission Facility Rating Assumptions - The ratings used are the most limiting rating reported in the then-current Transmission Provider's operating model for the normal continuous MVA capacity of each transmission facility for the applicable season. For transmission lines, these ratings are normally the lesser of the conductor thermal rating and the rating of terminal equipment such as switches, wavetraps, etc. For transformers, these ratings are normally the continuous rating of the transformers. The corresponding ratings from the applicable Transmission Provider's planning model are used in estimating MW-mile impacts for future years.

2.1.4 Modeling Phase Shifters - Phase shifting transformers within the SPP Region are represented based on typical operations.

2.2 Transmission Facility Ownership Representation - Transmission Owners are required to update their transmission facility ownership representation annually. This update shall reflect all new transmission facility additions and retirements for

the prior calendar year including any new network facilities constructed pursuant to any regional transmission planning process.

2.2.1 Transmission Lines and Terminals - Each transmission line which is to be included in the calculation of the MW-mile impacts has a record in a branch ownership file. The ownership file contains two types of records for every transmission line: one record contains the total line mileage; the other record reflects the percent of each Transmission Owner's "ownership" (i.e., for collecting rents) of the line. If ownership percentages for a given branch are not provided, the ownership will be divided equally to the AREA numbers in which the buses on either end of the branch reside in the loadflow model. If a transmission line does not have a mileage entry in the ownership file, it will not be included in the calculation since the line mileage is not known.

2.2.2 Transformers - The transformer ownership file is similar to the branch ownership file, except that there is no mileage record associated with the transformer. The records for transformers serve the same function as for transmission lines. If ownership percentages for a given branch are not provided, the ownership will be divided equally to the AREA numbers in which the buses on either end of the branch reside in the loadflow model.

2.2.3 Generation and Load - The ownership representation for generation and load is maintained in generation and load ownership files. These files are required in order to model transactions. For each bus that has either generation or load, a record in the ownership file is used to allocate to the AREAs their percent ownership. If no record is entered for a load bus or generator bus, the ownership is allocated to the AREA in which the bus resides in the loadflow model.

2.2.4 Representation of Utilities Outside of the SPP Region - Utilities outside of the SPP Region are to be represented in the model as needed to result in accurate impact calculations. Minimum representation for a non-Member involved in a sale to a Member is ownership of a generator bus in the non-Member's system or a generator bus judged to be electrically close to the

non-Member's system. Similarly, minimum representation for a non-Member involved in a purchase from a Member is ownership of a load bus in the non-Member's system or a load bus judged to be electrically close to the non-Member's system.

## 3. Calculating Impacts for Revenue Allocation and Determination of Losses

3.1 Explanation of the Impact Calculation - The distribution of flows over each and every facility due to transactions between each combination of potential parties is calculated. A commercially available power systems analysis software package is used to perform the necessary network flow calculations

3.2 The "MW-Mile" Method

(a) The MW-mile technique starts from a solved loadflow model of the Transmission System. Transactions are modeled between each combination of potential parties by changing generation on the sending, or selling end, and changing the load on the receiving, or buying end. The amount by which the generation and load are changed is small. A linear analysis technique is then used to determine the distribution of flows on each branch in the network. This value is used in subsequent calculations.

(b) Individual branch impacts are calculated given the flow on the branch due to the transaction and the line mileage (for transmission lines) as described in Section 2.2. The individual branch impacts for transmission lines are determined as follows:

Transmission Line Impacts = P * L [MW-miles]

where

P = calculated flow due to the transaction

L = line length in miles

(c) Similarly, the individual branch impacts for transformers are determined as follows:

Transformer Impacts = P * one mile [MW-miles]

where

P = calculated flow due to the transaction.

(d) The sum of all the individual branch impacts for each Transmission Owner is calculated in units MW-miles. These impacts can be summarized, by Transmission Owner, for all combinations of power transfers between Transmission Owner systems.

*MW-mile Impacts = $\varphi$ MW-miles [MW-miles]*

3.3 Application to Determination of Losses - Transmission service MW-mile impacts using this MW-mile methodology shall be set forth in matrices developed by the Transmission Provider and posted on the Transmission Provider's OASIS. The matrices shall be changed once per year or as deemed necessary by the Transmission Provider.

3.4 Generator and Load Dispatch - All capacity transactions are simulated as coming from all of a seller's on-line generation, except for that generation which is already fully loaded, in proportion to unit MVA base (nameplate rating). The transaction is simulated as delivered to all of the buyer's load.

Energy transactions are simulated as coming from all of the seller's on-line generation, except for that generation which is already fully loaded, in proportion to the unit MVA base (nameplate rating) and delivered to all of the buyer's load.

Each load on a bus at which the buyer represents load ownership will be allocated a proportionate amount of the transaction. The portion of the transaction allocated to at any given bus is the amount of load owned by the buyer on that bus divided by the total load owned by the buyer.

## 4. Calculating the Impact for Base Plan Zonal Annual Transmission Revenue Requirement Assignment

The zonal portion of the revenue requirements associated with Base Plan Upgrades shall be assigned to Zones using the Incremental MW-mile Benefit Determination. The Transmission Provider shall develop a Summer season model of the Transmission System, as specified in this Attachment S, using the most recent information available, that includes all of the transmission enhancements included in the approved SPP Transmission Expansion Plan. For this benefit determination, a comparison is made between this model with all upgrades in service and with each approved upgrade removed. The difference in MW-mile impacts for each Zone provides the information necessary for the determination of the magnitude of benefit for each Zone.

4.1 Explanation of the Incremental MW-mile Benefit Determination Calculation – The incremental MW-mile is determined by building the base case with all Base Plan Upgrades in service. A MW-mile calculation is performed by measuring the flows on each line multiplied by the distance as described in Section 3.2. The sum of the positive MW-mile impacts is used for this calculation. Then a benefit determination calculation is made with each new transmission upgrade removed individually. The reduction in MW-mile impact due to each new transmission upgrade is the measure of its zonal benefit.

4.2 The results of this MW-mile analysis shall be posted on the Transmission Provider's website.

# ATTACHMENT T
# RATE SHEETS FOR POINT-TO-POINT TRANSMISSION SERVICE

## American Electric Power - West

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the American Electric Power – West ("AEPW") rate zone are set forth in the "AEP-West PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website. Transmission Owners that have Commission approved rate(s) in the AEPW rate zone are: American Electric Power ("AEP"); East Texas Electric Cooperative, Inc. and Deep East Electric Cooperative, Inc., (hereinafter referred to collectively as "Texas Electric Cooperatives"); Oklahoma Municipal Power Authority ("OMPA"); AEP West Transmission Companies ("AEP-West Transco"); Coffeyville Municipal Light and Power ("CMLP"); Arkansas Electric Cooperative Corporation ("AECC"); and Transource Oklahoma ("TROK").

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges based upon the rates set forth in the RRR File, calculated pursuant to the AEP rate formula and protocols ("AEP Formula Rate"); the AEP-West Transco rate formula and protocols ("AEP-West Transco Formula Rate"); the AECC rate

formula and protocols ("AECC Formula Rate"); and the Transource Oklahoma rate formula and protocols ("TROK Formula Rate") set forth in Attachment H, Addendums 4, 12, 38, and 48 respectively, of the Tariff, and as described below:

1. Yearly delivery: the sum of (a) $2,053.993/MW for the Texas Electric Cooperatives, (b) $91.51/MW for OMPA, (c) $47.32/MW for CMLP and (d) the sum of the firm yearly delivery rates set forth in the AEP Formula Rate, the AEP-West Transco Formula Rate, the AECC Formula Rate, and the TROK Formula Rate.
2. Monthly delivery: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK yearly delivery rates divided by 12 months.
3. Weekly delivery: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK yearly delivery rates divided by 52 weeks.
4. Daily delivery:

   On-Peak: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK yearly delivery rates divided by 260 days.

   Off-Peak: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK yearly delivery rates divided by 365 days .

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges based upon the rates set forth in the RRR File, calculated pursuant to the AEP Formula Rate, the AEP-West Transco Formula Rate, the AECC formula rate, and the TROK formula rate and as described below:

1. Monthly delivery: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK firm yearly delivery rates divided by 12 months.

2. Weekly delivery: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK firm yearly delivery rates divided by 52 weeks.

3. Daily delivery:

   On-Peak: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK firm yearly delivery rates divided by 260 days.

   Off-Peak the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK firm yearly delivery rates divided by 365 days.

4. Hourly delivery:

   On-Peak: the sum of the AEP, Texas Electric Cooperatives, OMPA, CMLP, AEP-West Transco, AECC, and TROK firm yearly delivery rates divided by 4,160 hours.

   Off-Peak: the sum of the AEP, Texas Electric Cooperatives OMPA, CMLP, AEP-West Transco, AECC, and TROK firm yearly delivery rates divided by 8,760 hours.

For the purpose of the rate specified for Daily delivery the Off-Peak Period shall be Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day and the On-Peak Period shall be all days that are not in the Off-Peak Period.

For the purpose of the rate specified for Hourly delivery On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. Off-Peak is all hours not designated as On-Peak.

Discounts for Certain Through and Out Service Transactions via AEP Pricing Zone:

For the purpose of this Section, the following definitions shall apply:

**AEP:** American Electric Power, Inc. including its operating company affiliates located in the SPP region (Public Service Company of Oklahoma and Southwestern Electric Power Company).

**AEP Operating Companies' Tariff:** The open access transmission service tariff on file with the Commission under which the AEP Operating Companies offer, among other services, ERCOT Regional Transmission Service.

**ERCOT:** The Electric Reliability Council of Texas.

**ERCOT Power Supplier**: An electric utility that sells electricity for resale into ERCOT and takes transmission service under Part IV of the AEP Operating Companies' Tariff for such sales.

**Load Serving Entity**: Any electric utility operating in ERCOT that serves Native Load Customers within ERCOT.

**Native Load Customer**: The wholesale and/or retail power customers of TCC and TNC on whose behalf TCC and TNC, by statute, franchise, regulatory requirement, or contract, have undertaken an obligation to construct and operate the TCC and TNC systems to meet the reliable electric needs of such customers or the wholesale and retail power customers of a Load Serving Entity who, by statute, franchise, regulatory requirement, or contract has undertaken an obligation to plan, construct and operate the Load Serving Entity's system to meet the reliable electric needs of such customers. Native Load Customers do not include load served outside of ERCOT.

**Planned Resource:** Any generation resource owned, controlled, or purchased by an ERCOT Power Supplier or Load Serving Entity and designated as a Planned Resource for the purpose of serving load located in ERCOT.

**TCC:** AEP Texas Central Company.

**TNC:** AEP Texas North Company.

**Unplanned Resource:** Any generation resource owned or purchased by an ERCOT Power Supplier or Load Serving Entity, used to serve loads within ERCOT and not designated as a Planned Resource.

**Discount Provision:** A Load Serving Entity that takes ERCOT Regional Transmission Service under Part IV of the AEP Operating Companies' Tariff and also takes transmission service under Part II of this Tariff to import into ERCOT Planned Resources or Unplanned Resources to serve its Native Load Customers in ERCOT shall have its zonal rates under Schedules 7 and 8 reduced by 45.27% in instances when AEP is the applicable pricing zone under the SPP Tariff. This discount applies only to charges under Schedules 7 and 8 of the SPP Tariff.

## City Utilities of Springfield, Missouri

## Rate Sheet for Point-To-Point Transmission Service

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the City Utilities of Springfield, MO formula rate shown in Attachment H, Addendum 17, and described below:

1. Annual Deliveries: one-twelfth of the rate per kW of Reserved Capacity per year.
2. Monthly delivery: rate per kW of Reserved Capacity per month.
3. Weekly delivery: rate per kW of Reserved Capacity per week.
4. Daily delivery: rate per kW of Reserved Capacity per day.

### Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: rate per kW of Reserved Capacity per month.
2. Weekly delivery: rate per kW of Reserved Capacity per week.
3. Daily delivery: rate per kW of Reserved Capacity per day.

4. Hourly Deliveries: rate per kW of Reserved Capacity per day divided by 16.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the on-peak rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

## The Empire District Electric Company

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in The Empire District Electric Company Zone are set forth in the "Empire PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

**Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates**

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

**Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates**

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to The Empire District Electric Company formula rate shown in Attachment H, Addendum 18, and described below:

1. Yearly delivery: one-twelfth of the rate per MW of Reserved Capacity per year.
2. Monthly delivery: rate per MW of Reserved Capacity per month.
3. Weekly Delivery: rate per MW of Reserved Capacity per week.
4. Daily delivery:

    On-Peak: rate per MW of Reserved Capacity per day.

Off-Peak: rate per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to The Empire District Electric Company formula rate shown in Attachment H, Addendum 18, and described below:

1. For Monthly delivery: rate per MW of Reserved Capacity per month.
2. For Weekly delivery: rate per MW of Reserved Capacity per week.
3. For Daily delivery:
   - On-Peak: rate per MW of Reserved Capacity per day.
   - Off-Peak: rate per MW of Reserved Capacity per day.
4. Hourly delivery:
   - On-Peak: rate per MWh of Reserved Capacity per hour.
   - Off-Peak: rate per MWh of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

## Evergy Kansas Central, Inc. (Evergy Kansas South, Inc. and Evergy Kansas Central, Inc.)

## Rate Sheet for Point-To-Point Transmission Service

These Point-To-Point charges shall be calculated using the Existing Zonal Annual Transmission Revenue Requirement ("Zonal ATRR") for the Evergy Kansas Central, Inc. rate zone as specified in Attachment H, Section I, Table 1, Line 14, Column (3), which is the sum of Existing Zonal ATRRs referenced in Attachment H, Section I, Table 1, Column (3) as being in the Evergy Kansas Central, Inc. rate zone. As a result of the rate formula and associated protocols set forth in Attachment H, Addendum 3 of this Tariff ("Evergy Kansas Central, Inc. Formula Rate"), the Existing Zonal ATRR referenced in Attachment H, Section I, Table 1, Line 14a, Column (3) shall be posted on the SPP website by October 15 of each calendar year and shall be effective on January 1 of the following year. The Prairie Wind Transmission LLC rate formula and associated protocols ("Prairie Wind Formula Rate") set forth in Attachment H, Addendum 15 of this Tariff, the Existing Zonal ATRR is referenced in Attachment H, Section I, Table 1, Line 14b, Column (3) shall be posted on the SPP website by September 1 of each calendar year and shall be effective on January 1 of the following year. The South Central MCN LLC rate formula and associated protocols ("South Central MCN Formula Rate") set forth in Attachment H, Addendum 43 of this Tariff, the Existing Zonal ATRR is referenced in Attachment H, Section I, Table 1, Line 14d, Column (3) shall be posted on the SPP website by October 1 of each calendar year and shall be effective on January 1 of the following year. The Kansas Power Pool rate formula and associated protocols ("Kansas Power Pool Formula Rate") set forth in Attachment H, Addendum 16 of this Tariff, the Existing Zonal ATRR is referenced in Attachment H, Section I, Table 1, Line 14c, Column (3) shall be posted on the SPP website by October 1 of each calendar year and shall be effective on January 1 of the following year. The results for the Point-To-Point rates described herein shall be specifically set forth in the "Evergy Kansas Central, Inc. PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue

Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

**Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates**

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Evergy Kansas Central, Inc. Formula Rate, Prairie Wind Formula Rate, Kansas Power Pool Formula Rate and the South Central MCN Formula Rate set forth in Attachment H, Addendums 3, 15, 16, and 43 respectively, of the Tariff, and as described below:

1. Yearly delivery charge: the sum of the firm yearly delivery rates set forth in the Evergy Kansas Central, Inc. Formula Rate, the Prairie Wind Formula Rate, Kansas Power Pool Formula Rate and the South Central MCN Formula Rate.
2. Monthly delivery charge: the yearly delivery charge divided by 12 months ($/kW/Mo).
3. Weekly delivery charge: the yearly delivery charge divided by 52 weeks ($/kW/Wk).
4. Daily delivery charge: Peak: the weekly delivery charge divided by 5 days ($/kW/Day).
   Off Peak: the weekly delivery charge divided by 7 days ($/kW/Day).

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the Peak Rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Evergy Kansas Central, Inc. Formula Rate, the Prairie Wind Formula Rate, Kansas Power Pool Formula Rate and the South Central MCN Formula Rate set forth in Attachment H, Addendums 3, 15, 16, and 43 respectively, of the Tariff, and as described below:

1. Monthly delivery charge: the yearly delivery charge for Firm Point-To-Point service specified divided by 12 months ($/kW/Mo).
2. Weekly delivery charge: the yearly delivery charge for Firm Point-To-Point service specified divided by 52 weeks ($/kW/Week).
3. Daily delivery charge: Peak: the weekly delivery charge divided by 5 days ($/kW/Day).

   Off Peak: the weekly delivery charge divided by 7 days ($/kW/Day).
4. Hourly delivery charge: Peak: the daily delivery charge divided by 16 hours ($/kW/Hr).

   Off Peak: the daily delivery charge divided by 24 hours ($/kW/Hr).

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

## Evergy Metro, Inc.

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Evergy Metro, Inc. Zone are set forth in the "EMe PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website. Transmission Owners that have Commission approved rate(s) in the Evergy Metro, Inc. Zone are: Evergy Metro, Inc. ("EMe") and City of Independence, Missouri ("INDP").

**Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates**

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

**Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates**

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the EMe formula rate shown in Attachment H, Addendum 10, Parts 1 and 2, and as described below:

1. Yearly delivery: one-twelfth of the sum of (a) the rate per MW of Reserved Capacity per year as set forth in the EMe formula rate and (b) $2,442.048 for INDP.
2. Monthly delivery: the sum of the EMe and INDP yearly rates divided by 12 per MW of Reserved Capacity per month.

3. Weekly delivery: the sum of the EMe and INDP yearly rates divided by 52 per MW of Reserved Capacity per week.

4. Daily on-peak delivery: the sum of the EMe and INDP yearly delivery rates divided by 260 per MW of Reserved Capacity per day.

5. Daily off-peak delivery: the sum of the EMe and INDP yearly delivery rates divided by 365 per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the EMe formula rate shown in Attachment H, Addendum 10, Parts 1 and 2, and as described below:

1. Monthly delivery: the sum of the EMe and INDP yearly rates divided by 12 per MW of Reserved Capacity per month.

2. Weekly delivery: the sum of the EMe and INDP yearly rates divided by 52 per MW of Reserved Capacity per week.

3. Daily on-peak delivery: the sum of the EMe and INDP yearly delivery rates divided by 260 per MW of Reserved Capacity per day.

4. Daily off-peak delivery: the sum of the EMe and INDP yearly delivery rates divided by 365 per MW of Reserved Capacity per day.

5. Hourly on-peak delivery: the sum of the EMe and INDP yearly delivery rates divided by 4,160 per MW of Reserved Capacity per hour.

6. Hourly off-peak delivery: the sum of the EMe and INDP yearly delivery rates divided by 8,760 per MW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily on-peak delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the

rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

## Evergy Missouri West, Inc.

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Evergy Missouri West, Inc. Zone are set forth in the "EMW PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website. Transmission Owners that have Commission approved rate(s) in the Evergy Missouri West, Inc. rate zone are: Evergy Missouri West, Inc. and Transource Missouri, LLC.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Evergy Missouri West, Inc. formula rate shown in Attachment H, Addendum 11, Parts 1 and 2, and Transource Missouri, LLC rate formula and protocols shown in Attachment H, Addendum 21 of this Tariff and as described below:

1. Yearly delivery: one-twelfth of the rate per MW of Reserved Capacity per year.
2. Monthly delivery: rate per MW of Reserved Capacity per month.
3. Weekly delivery: rate per MW of Reserved Capacity per week.

4. Daily on-peak delivery: rate per MW of Reserved Capacity per day.

5. Daily off-peak delivery: rate per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Evergy Missouri West, Inc. formula rate shown in Attachment H, Addendum 11, Parts 1 and 2, and Transource Missouri, LLC rate formula and protocols shown in Attachment H, Addendum 21 of this Tariff and as described below:

1. Monthly delivery: rate per MW of Reserved Capacity per month.

2. Weekly delivery: rate per MW of Reserved Capacity per week.

3. Daily on-peak delivery: rate per MW of Reserved Capacity per day.

4. Daily off-peak delivery: rate per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

5. Hourly delivery: The rate per MW of Reserved Capacity per hour for on-peak service and the rate per MW of Reserved Capacity per hour for off-peak service are stated in the RRR File. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily on-peak delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

## Grand River Dam Authority

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Grand River Dam Authority Zone are set forth in the "GRDA PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

**Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates**

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

**Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates**

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Grand River Dam Authority formula rate shown in Attachment H, Addendum 13, and described below:

1. Yearly delivery: one-twelfth of the rate per kW of Reserved Capacity per year.
2. Monthly delivery: rate per kW of Reserved Capacity per month.
3. Weekly Delivery: rate per kW of Reserved Capacity per week.
4. Daily delivery:
   - On-Peak: rate per kW of Reserved Capacity per day.
   - Off-Peak: rate per kW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Grand River Dam Authority formula rate shown in Attachment H, Addendum 13, and described below:

1. For Monthly delivery: rate per kW of Reserved Capacity per month.
2. For Weekly delivery: rate per kW of Reserved Capacity per week.
3. For Daily delivery:
   - On-Peak: rate per kW of Reserved Capacity per day.
   - Off-Peak: rate per kW of Reserved Capacity per day.
4. Hourly delivery:
   - On-Peak: rate per kWh of Reserved Capacity per hour.
   - Off-Peak: rate per kWh of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

## Kansas City Board of Public Utilities

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Kansas Board of Public Utilities rate Zone are set forth in the "BPU PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Kansas City Board of Public Utilities formula rate shown in Attachment H, Addendum 46 and described below:

1. Yearly delivery: one-twelfth of the rate per MW of Reserved Capacity per year.
2. Monthly delivery: rate per MW of Reserved Capacity per month.
3. Weekly delivery: rate per MW of Reserved Capacity per week.
4. Daily on-peak delivery: rate per MW of Reserved Capacity per day.
5. Daily off-peak delivery: rate per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Kansas City, Kansas Board of Public Utilities formula rate shown in Attachment H, Addendum 46 and described below:

1. Monthly delivery: rate per MW of Reserved Capacity per month.
2. Weekly delivery: rate per MW of Reserved Capacity per week.
3. Daily on-peak delivery: rate per MW of Reserved Capacity per day.
4. Daily off-peak delivery: rate per MW of Reserved Capacity per day.
5. Hourly on-peak delivery: rate per MW of Reserved Capacity per hour.
6. Hourly off-peak delivery: rate per MW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily on-peak delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

## Lincoln Electric System

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Lincoln Electric System Zone are set forth in the "LES PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

**Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates**

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

**Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates**

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Lincoln Electric System formula rate shown in Attachment H, Addendum 6, and described below:

1. Yearly delivery: one-twelfth of the rate per MW of Reserved Capacity per year.
2. Monthly delivery: rate per MW of Reserved Capacity per month.
3. Weekly delivery: rate per MW of Reserved Capacity per week.
4. Daily delivery:

    On-Peak: rate per MW of Reserved Capacity per day.

Off-Peak: rate per MW of Reserved Capacity per day.

On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Off-Peak is all hours not designated as On-Peak.

The total demand charged in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Lincoln Electric System formula rate shown in Attachment H, Addendum 6, and described below:

1. Monthly delivery: rate per MW of Reserved Capacity per month.
2. Weekly delivery: rate per MW of Reserved Capacity per week.
3. Daily delivery:
   - On-Peak: rate per MW of Reserved Capacity per day.
   - Off-Peak: rate per /MW of Reserved Capacity per day.
4. Hourly delivery:
   - On-Peak: rate per MWh of Reserved Capacity per hour.
   - Off-Peak: rate per MWh of Reserved Capacity per week.

On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Off-Peak is all hours not designated as On-Peak.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified

for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

# Reserved for Future Use

## Rate Sheet for Point-To-Point Transmission Service

## Midwest Energy, Inc.

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Midwest Energy, Inc. Zone are set forth in the "Midwest PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Midwest Energy, Inc. formula rate shown in Attachment H, Addendum 14, and described below:

1. Yearly delivery: one-twelfth of the rate per kW of Reserved Capacity per year.
2. Monthly delivery: rate per kW of Reserved Capacity per month.
3. Weekly delivery: rate per kW of Reserved Capacity per week.
4. Daily delivery: rate per kW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Midwest Energy, Inc. formula rate shown in Attachment H, Addendum 14, and described below:

1. Monthly delivery: rate per kW of Reserved Capacity per month.
2. Weekly delivery: rate per kW of Reserved Capacity per week.
3. Daily delivery: rate per kW of Reserved Capacity per day.
4. Hourly delivery: rate per MWh of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

## Nebraska Public Power District ("NPPD")

## Rate Sheet for Point-To-Point Transmission Service

These Point-To-Point charges in the Nebraska Public Power District rate zone ("NPPD Zone") shall be calculated using the rate formula set forth in Addendum 7 of Attachment H of the SPP Tariff ("NPPD Formula Rate"), the formula rate set forth in Addendum 36 of Attachment H of the SPP Tariff ("Tri-State Formula Rate") plus the Point-to-Point Transmission Service rate for The Central Nebraska Public Power and Irrigation District ("CNPPID") set forth below. The results of the NPPD formula calculation shall be posted on the SPP website and in an accessible location on the NPPD website by December 15 of each calendar year and shall be effective on January 1 of the following year. The results of the Tri-State formula calculation shall be posted on the SPP website and in an accessible location on the Tri-State website by June 15 of each calendar year and shall be effective on July 1 of that year. The results for the Point-To-Point rates described herein shall be specifically set forth in the "NPPD PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Firm Point-To-Point Transmission Service at the sum of the applicable charges set forth in the

RRR File, calculated pursuant to the NPPD Formula Rate shown in Attachment H, Addendum 7, to the Tri-State Formula Rate shown in Attachment H, Addendum 36 plus the Point-to-Point Transmission Service rate for CNPPID and described below:

1. Annual delivery: Shall be the rate for Reserved Capacity per year specified in line 13 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus revenue requirement per year in the Tri-State Formula Rate divided by the applicable average of the 12 coincident system peaks (the rate per MW of Reserved Capacity) plus an annual Point-to-Point Transmission Service rate of $128.961 per MW for CNPPID.

2. Monthly delivery: Shall be the rate for Reserved Capacity per month specified in line 14 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 12 months in the Tri-State Formula Rate plus a monthly Point-to-Point Transmission Service rate of $10.747 per MW for CNPPID.

3. Weekly delivery: Shall be the rate for Reserved Capacity per week specified in line 15 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 52 weeks in the Tri-State Formula Rate plus a weekly Point-to-Point Transmission Service rate of $2.480 per MW for CNPPID.

4. Daily delivery:

   On-Peak: Shall be the rate for Reserved Capacity per day specified in line 16 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 260 days in the Tri-State Formula Rate plus a daily on-

peak Point-to-Point Transmission Service rate of $0.496 per MW for CNPPID.

Off-Peak: Shall be the rate for Reserved Capacity per day specified in line 17 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 365 days in the Tri-State Formula Rate plus a daily off-peak Point-to-Point Transmission Service rate of $0.353 per MW for CNPPID.

Service in the opposite direction of the original schedule shall be considered a new and separate service under this Tariff requiring payment of a separate charge.

On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Saturdays, Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Off-Peak is all hours not designated On-Peak.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the NPPD Formula Rate shown in Attachment H, Addendum 7 plus the Point-to-Point Transmission Service rate for CNPPID, and described below. Service in the opposite direction of the original schedule shall be considered a new and separate service under this Tariff requiring payment of a separate charge.

1. Monthly delivery: Shall be the rate for Reserved Capacity per month specified in line 14 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 12 months in the Tri-State Formula Rate plus a monthly

Point-to-Point Transmission Service rate of $10.747 per MW for CNPPID.

2. Weekly delivery: Shall be the rate for Reserved Capacity per week specified in line 15 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 52 weeks in the Tri-State Formula Rate plus a weekly Point-to-Point Transmission Service rate of $2.480 per MW for CNPPID.

3. Daily delivery:

On-Peak: Shall be the rate for Reserved Capacity per day specified in line 16 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 260 days in the Tri-State Formula Rate plus a daily on-peak Point-to-Point Transmission Service rate of $0.496 per MW for CNPPID.

Off-Peak: Shall be the rate for Reserved Capacity per day specified in line 17 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 365 days in the Tri-State Formula Rate plus a daily off-peak Point-to-Point Transmission Service rate of $0.353 per MW for CNPPID.

4. Hourly delivery:

On-Peak: Shall be the rate for Reserved Capacity per hour specified in line 18 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 4160 hours in the Tri-State Formula Rate plus an hourly

on-peak Point-to-Point Transmission Service rate of $0.031 per MW for CNPPID.

Off-Peak: Shall be the rate for Reserved Capacity per hour specified in line 19 of Page 1 of the Formula Rate Template for NPPD set forth in Addendum 7 of Attachment H of this Tariff plus annual rate divided by 8760 hours in the Tri-State Formula Rate plus an hourly off-peak Point-to-Point Transmission Service rate of $0.015 per MW for CNPPID.

On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Saturdays, Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Off-Peak is all hours not designated as On-Peak.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the On-peak rate specified for Daily delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

Capacity designations at the Point(s) of Receipt will be inclusive of losses.

## Oklahoma Gas and Electric Company

## Rate Sheet for Point-To-Point Transmission Service

These Point-To-Point charges shall be calculated using the Existing Zonal Annual Transmission Revenue Requirement ("Zonal ATRR") for the Oklahoma Gas and Electric Company rate zone as specified in Attachment H, Section I, Table 1, Line 7, Column (3), which is the sum of Existing Zonal ATRRs referenced in Attachment H, Section I, Table 1, Column (3) as being in the Oklahoma Gas and Electric Company rate zone total. As a result of the rate formula set forth in Attachment H, Addendum 2-A of this Tariff ("OG&E Formula Rate") and the OG&E Formula Rate Implementation Protocols set forth in Attachment H, Addendum 2-B of the Tariff, the Existing Zonal ATRR referenced in Attachment H, Section I, Table 1, Line 7a, Column (3) shall be posted on the SPP website by September 1 of each calendar year and shall be effective on January 1 of the following year. The Arkansas Electric Cooperative Corporation rate formula ("AECC Formula Rate") and the associated protocols set forth in Attachment H, Addendum 38 of this Tariff, the Existing Zonal ATRR is referenced in Attachment H, Section I, Table 1, Line 7c, Column (3). The People's Electric Cooperative rate formula ("PEC Formula Rate") and the associated protocols set forth in Attachment H, Addendum 51 of this Tariff, the Existing Zonal ATRR is referenced in Attachment H, Section I, Table 1, Line 7d, Column (3). The results for the Point-To-Point rates described herein shall be specifically set forth in the "OGE PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under

Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the OG&E Formula Rate shown in Attachment H, Addendum 2-A and Addendum 2-B, and described below:

1. Yearly delivery: the Existing Zonal ATRR referenced in Attachment H, Section I, Table 1, Line 7a, 7c and 7d, Column (3) divided by the 12-CP divisor identified on page 1, line 5 of the OG&E Formula Rate $/kW of Reserved Capacity per year, plus $0.0752/kW for Oklahoma Municipal Power Authority.

2. Monthly delivery: the yearly charge divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063/kW for Oklahoma Municipal Power Authority.

3. Weekly delivery: the yearly charge divided by 52 for the $/kW Reserved Capacity per week plus $0.0014/kW for Oklahoma Municipal Power Authority.

4. Weekday delivery: the weekly charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003/kW for Oklahoma Municipal Power Authority.

5. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002/kW for Oklahoma Municipal Power Authority.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the OG&E Formula Rate shown in Attachment H, Addendum 2-A and Addendum 2-B, and described below:

1. Monthly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 12 for the $/kW of Reserved Capacity per month plus $0.0063/kW for Oklahoma Municipal Power Authority.

2. Weekly delivery: the yearly delivery charge for Firm Point-to-Point service specified above divided by 52 for the $/kW of Reserved Capacity per week plus $0.0014/kW for Oklahoma Municipal Power Authority.

3. Weekday delivery: the weekly delivery charge divided by 5 for the $/kW of Reserved Capacity per day plus $0.0003/kW for Oklahoma Municipal Power Authority.

4. Weekend and Holiday delivery: the weekly delivery charge divided by 7 for the $/kW of Reserved Capacity per day plus $0.0002/kW for Oklahoma Municipal Power Authority.

5. Hourly delivery: the weekend and holiday delivery charge divided by 24 for the $/MW of Reserved Capacity per hour plus $0.0086/MWh for Oklahoma Municipal Power Authority.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Weekend and Holiday Delivery rate specified for Weekday delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

## Omaha Public Power District ("OPPD")

## Rate Sheet for Point-To-Point Transmission Service

These Point-To-Point charges shall be calculated using OPPD's Formula-based Rate Template as set forth in Addendum 8 of Attachment H of the SPP Tariff ("OPPD Formula Rate"). The results of the formula calculation shall be posted on the SPP website by July 20 of each calendar year and shall be effective on August 1 of such year. The results for the Point-To-Point rates shall be specifically set forth in the "OPPD PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the OPPD Formula Rate shown in Attachment H, Addendum 8, and described below:

Monthly delivery: The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 13 ($/kW/Mo).

Weekly delivery: The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 14 ($/kW/Week).

Daily delivery:

On-Peak The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 15 ($/kW/Day)

Off-Peak The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 16 ($/kW/Day)

For the purposes of the Daily delivery charge, the On-Peak days are Monday through Friday, excluding the NERC defined holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, and Off-Peak days are all other days. The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the OPPD Formula Rate shown in Attachment H, Addendum 8, and described below:

Monthly delivery: The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 13 ($/kW/Mo).

Weekly delivery: The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 14 ($/kW/Week).

Daily delivery:

On-Peak The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 17 ($/kW/Day)

Off-Peak The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 17a ($/kW/Day)

Hourly delivery

On-Peak The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 18

Off-Peak The rate as shown on the Formula-based Rate Template for OPPD, page 1, line 18a

For the purposes of the Daily delivery charge, the On-Peak days are Monday through Friday, excluding the NERC defined holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, and the Off-Peak days are all other days. For the purposes of the Hourly delivery charge, On-Peak hours are all hours between HE 0700 and continuing through HE 2200, excluding Saturdays, Sundays, and the NERC defined holidays of New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day, and Off-Peak hours shall be all other hours.

The total demand charge in any week, pursuant to a reservation for Daily or Hourly delivery shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week. In addition, the total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day.

## Southwestern Power Administration

## Rate Sheet for Point-To-Point Transmission Service

These Point-To-Point charges in the Southwestern Power Administration rate zone ("Southwestern Zone") shall be calculated using the Point-to-Point Transmission Service rate for Southwestern Power Administration ("Southwestern") set forth below, plus South Central MCN LLC's ("South Central MCN") rate formula set forth in Addendum 43 to Attachment H of this Tariff ("South Central MCN Formula Rate"), plus Missouri Joint Municipal Electric Utility Commission ("MEUC)" rate formula set forth in addendum 50 to Attachment H of this Tariff ("MEUC Formula Rate"), plus People's Electric Cooperative ("PEC") rate formula set forth in Addendum 51 to Attachment H of this Tariff ("PEC Formula Rate"). The results for the Point-To-Point rates described herein shall be specifically set forth in the "SPA PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Firm Point-To-Point Transmission Service at the sum of the applicable charges set forth in the RRR File, Southwestern's Point-to-Point Transmission Service rate, plus the Point-to-Point Transmission Service rate calculated pursuant to the South Central MCN Formula Rate shown in Attachment H, Addendum 43, plus the Point-to Point Transmission Service rate calculated pursuant to the MEUC Formula Rate shown in Attachment H, Addendum 50, plus the Point-to-Point Transmission Service rate calculated pursuant to the PEC Formula Rate shown in Attachment H, Addendum 51 as described below:

Yearly: the Southwestern yearly per kilowatt of transmission capacity reserved for annual service or invoiced in accordance with a longer term agreement as set forth in the RRR File, plus the South Central MCN Zonal Annual Transmission Revenue Requirement, as referenced in Attachment H, Section I, Table 1, Line 10b, Column (3), plus the MEUC Zonal Annual Transmission Revenue Requirement, as referenced in Attachment H, Section I, Table 1, Line 10c, Column (3), plus the PEC Zonal Annual Transmission Revenue Requirement, as referenced in Attachment H, Section I, Table 1, Line 10d, Column (3) of the Southwestern Zone divided by the applicable average of the 12 coincident system peaks.

Monthly: Southwestern's $1.48 per kilowatt of transmission capacity reserved in increments of one month of service or invoiced in accordance with a longer term agreement, plus South Central MCN's yearly delivery charge divided by 12 months, plus MEUC's yearly delivery charge divided by 12 months, plus PEC's yearly delivery charge divided by 12 months.

Weekly: Southwestern's $0.370 per kilowatt of transmission capacity reserved in increments of one week of service, plus South Central MCN's yearly delivery charge divided by 52 weeks, plus MEUC's yearly delivery charge divided by 52 weeks, plus PEC's yearly delivery charge divided by 52 weeks.

Daily: Southwestern's $0.0673 per kilowatt of transmission capacity reserved in increments of one day of service, plus South Central MCN's weekly delivery charge divided by 5 days, plus MEUC's weekly delivery charge divided by 5 days, plus PEC's weekly delivery charge divided by 5 days.

Transmission Customers whose loads are directly connected to Southwestern's system and are not within Southwestern's control area will be charged on the greatest of (1) the peak demand at any particular point of delivery during a particular month, rounded up to the nearest whole megawatt, or (2) the highest peak demand recorded at such point of delivery during any of the previous 11 months, rounded up to the nearest whole megawatt, or (3) the capacity reserved by contract, which amount shall be considered such transmission customer's reserved capacity.

Secondary Transmission Service for such Transmission Customers shall be limited during any month to the most recent peak demand on which a particular Transmission Customer is billed or to the capacity reserved by contract, whichever is greater.

**Non-Firm Point-To-Point Transmission Service** The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1. Monthly delivery: Southwestern's $1.184/KW of Reserved Capacity per month, plus South Central MCN's yearly delivery charge divided by 12 months, plus MEUC's yearly delivery charge divided by 12 months, plus PEC's yearly delivery charge divided by 12 months.
2. Weekly delivery: Southwestern's $0.296/KW of Reserved Capacity per week, plus South Central MCN's yearly delivery charge divided by 52 weeks, plus MEUC's yearly delivery charge divided by 52 weeks, plus PEC's yearly delivery charge divided by 52 weeks.
3. Daily delivery: Southwestern's $0.0538/KW of Reserved Capacity per day, plus South Central MCN's weekly delivery charge divided by 5 days, plus MEUC's yearly weekly delivery charge divided by 5 days, plus PEC's yearly weekly delivery charge divided by 5 days.
4. Hourly delivery: Southwestern's $0.00336/KW of Reserved Capacity per hour, plus South Central MCN's daily delivery charge divided by 16 hours, plus MEUC's daily delivery charge divided by 16 hours, plus PEC's daily delivery charge divided by 16 hours.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

## Southwestern Public Service Company

## Rate Sheet for Point-To-Point Transmission Service

These Point-To-Point charges shall be calculated using the rate formula set forth in Attachment O - SPS of the Xcel Energy Operating Companies Joint Open Access Transmission Tariff ("Xcel Energy OATT"), plus South Central MCN LLC's ("South Central MCN") rate formula set forth in Addendum 43 to Attachment H of this Tariff ("South Central MCN Formula Rate"). The results of the formula calculation shall be posted on the SPP website and in an accessible location on the SPS OASIS website by October 1 of each calendar year and shall be effective on January 1 of the following calendar year. The results for the Point-To-Point rates described herein shall be specifically set forth in the "SPS PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Southwestern Public Service Company formula rate Attachment H, Addendum 5, the South Central MCN Formula Rate, and including an annual

Point-to-Point Transmission Service rate of $0.094 / kW per year for the Lea County Electric Cooperative, Inc. ("LCEC") described below:

1. Monthly delivery: Shall be the rate specified on line 11 of Page 1 of the Attachment O - SPS of the Xcel Energy OATT of Reserved Capacity per month, plus South Central MCN's yearly delivery charge divided by 12 months, plus $0.008 / kW for LCEC.
2. Weekly delivery: Shall be the rate specified on line 12 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per week, plus South Central MCN's yearly delivery charge divided by 52 weeks, plus $0.002 / kW for LCEC.
3. Daily delivery

   On-Peak: Shall be the rate specified on line 13, column 3 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per day, plus South Central MCN's weekly delivery charge divided by 6 days, plus $0.000 for LCEC.

   Off-Peak: Shall be the rate specified on line 13, column 5 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per day, plus South Central MCN's weekly delivery charge divided by 7 days, plus $0.00 for LCEC.

Service in the opposite direction of the original schedule shall be considered a new and separate service under this Tariff requiring payment of a separate charge.

On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Off-Peak is all hours not designated as On-Peak.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth

in the RRR File, calculated pursuant to the Southwestern Public Service Company formula rate in Attachment H, Addendum 5, the South Central formula rate in Attachment H, Addendum 43, and including an annual Point-to-Point Transmission Service rate of $0.094 / kW per year for the Lea County Electric Cooperative, Inc. ("LCEC") described below. Service in the opposite direction of the original schedule shall be considered a new and separate service under this Tariff requiring payment of a separate charge.

1. Monthly delivery: Shall be the rate specified on line 11 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per Month, plus South Central MCN's yearly delivery charge divided by 12 months, plus $0.008 / kW for LCEC.

2. Weekly delivery: Shall be the rate specified on line 12 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per week, plus South Central MCN's yearly delivery charge divided by 52 weeks, plus $0.002 / kW for LCEC.

3. Daily delivery

On-Peak: Shall be the rate specified on line 13, column 3 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per day, plus South Central MCN's weekly delivery charge divided by 6 days, plus $0.000 / kW for LCEC.

Off-Peak: Shall be the rate specified on line 13, column 5 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per day, plus South Central MCN's weekly delivery charge divided by 7 days, plus $0.000 / kW for LCEC.

4. Hourly delivery

On-Peak: Shall be the rate specified on line 14, column 3 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per hour, plus South Central MCN's daily delivery charge divided by 16 hours, plus $0.023 / kW for LCEC.

Off-Peak: Shall be the rate specified on line 14, column 5 of Page 1 of the Attachment O – SPS of the Xcel Energy OATT of Reserved Capacity per hour, plus South Central MCN's daily delivery charge divided by 24 hours, plus $0.011 / kW for LCEC.

On-Peak is all hours between HE 0700 and HE 2200, inclusive, Central Time Zone, excluding Sundays and holidays. Holidays shall be as defined by NERC, currently New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

**Off-Peak is all hours not designated as On-Peak.**

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in kilowatts of Reserved Capacity in any hour during such week.

Capacity designations at the Point(s) of Receipt will be inclusive of losses.

**Point-To-Point Transmission Service Across the Lamar Tie Line To/From the SPS Zone Transmission**

Customers taking Point-to-Point Transmission Service across the Lamar Tie Line to or from the Public Service Company of Colorado ("PSCo") transmission system and sourcing or sinking in the SPS Zone shall pay to SPP for such service a discounted rate of one-half the applicable rate under this Attachment T, Southwestern Public Service Company Rate Sheet for Point-To-Point Transmission Service.

## Sunflower Electric Power Corporation

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Sunflower Electric Power Corporation rate zone are set forth in the "SECC PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website.

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Sunflower Electric Power Corporation formula rate shown in Attachment H, Addendum 20, the ITC Great Plains, LLC formula rate shown in Attachment H, Addendum 9, and the Prairie Wind Transmission, LLC formula rate shown in Attachment H, Addendum 15, and described below:

1. Yearly delivery: one-twelfth of the rate per MW of Reserved Capacity per year.
2. Monthly delivery: rate per MW of Reserved Capacity per month.
3. Weekly delivery: rate per MW of Reserved Capacity per week.
4. Daily on-peak delivery: rate per MW of Reserved Capacity per day.

5. Daily off-peak delivery: rate per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the Sunflower Electric Power Corporation formula rate shown in Attachment H, Addendum 20, the ITC Great Plains, LLC formula rate shown in Attachment H, Addendum 9, and the Prairie Wind Transmission, LLC formula rate shown in Attachment H, Addendum 15, and described below:

1. Monthly delivery: rate per MW of Reserved Capacity per month.
2. Weekly delivery: rate per MW of Reserved Capacity per week.
3. Daily on-peak delivery: rate per MW of Reserved Capacity per day.
4. Daily off-peak delivery: rate per MW of Reserved Capacity per day.
5. Hourly on-peak delivery: rate per MW of Reserved Capacity per hour.
6. Hourly off-peak delivery: rate per MW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily on-peak delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

## Upper Missouri Zone

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Upper Missouri ("UMZ") rate zone are set forth in the "UMZ PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website. Transmission Owners that have Commission approved rate(s) in the UMZ rate zone are: Basin Electric Power Cooperative ("Basin Electric"); Heartland Consumers Power District ("Heartland"); Missouri River Energy Services ("MRES"); East River Electric Power Cooperative, Inc. ("East River"); Corn Belt Power Cooperative ("Corn Belt"); NorthWestern Corporation (South Dakota) ("NorthWestern"); Northwest Iowa Power Cooperative ("NIPCO"); Harlan Municipal Utilities ("HMU"); Western Area Power Administration, Upper Great Plains Region ("Western-UGP"); Central Electric Power Cooperative, Inc. ("Central Power"); Mountrail-Williams Electric Cooperative ("Mountrail-Williams"); Mor-Gran-Sou Electric Cooperative, Inc. ("Mor-Gran-Sou"); Roughrider Electric Cooperative, Inc. ("Roughrider"); and L and O Power Cooperative ("LOPC").

### Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

### Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

### Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges based upon the rates set forth in the RRR File, calculated pursuant to the formula rates of Basin Electric, Heartland, MRES, MRES Members (includes Moorhead Public Service; Orange City Municipal Utilities; City of Pierre, South Dakota; City of Sioux Center, Iowa; Watertown Municipal Utility Department*;* Denison Municipal Utilities; and Vermillion Light & Power), East River, Corn Belt, NorthWestern, NIPCO, HMU, Western-UGP, Central Power, Mountrail-Williams, Mor-Gran-Sou, Roughrider, and LOPC including any ATRR associated with facility credits provided in the UMZ rate zone, set forth in Attachment H, Addendums 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 37, 40, 41, 42, 45, 47, and 49 (list appropriate addendums, respectively) of the Tariff, and as described below:

1. Yearly delivery: the UMZ Monthly delivery rate multiplied by 12 months.
2. Monthly delivery: the sum of the Basin Electric, Heartland, MRES, MRES Members, East River, Corn Belt, NorthWestern, NIPCO, HMU, Western-UGP, Central Power, Mountrail-Williams, Mor-Gran-Sou, Roughrider, and LOPC Annual Transmission Revenue Requirements determined under these entities' formula rates, including any ATRR associated with facility credits provided in the UMZ rate zone, divided by the UMZ total load estimate and divided by 12 months.
3. Weekly delivery: the UMZ Yearly delivery rate divided by 52.
4. Daily delivery: the UMZ Weekly delivery rate divided by 7.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges based upon the rates set forth in the RRR File, calculated pursuant to the formula rates of Basin Electric, Heartland, MRES, MRES Members, East River, Corn Belt, NorthWestern, NIPCO, HMU, Western-UGP, Central Power, Mountrail-Williams, Mor-Gran-Sou, Roughrider, and LOPC including any ATRR associated with facility credits provided in the UMZ rate zone, and as described below:

1. Monthly delivery: the sum of the Basin Electric, Heartland, MRES, MRES Members, East River, Corn Belt, NorthWestern, NIPCO, HMU, Western-UGP, Central Power, Mountrail-Williams, Mor-Gran-Sou, Roughrider, and LOPC Annual Transmission Revenue Requirements determined under these entities' formula rates, including any ATRR associated with facility credits provided in the UMZ rate zone, divided by the UMZ total load estimate and divided by 12 months.
2. Weekly delivery: the UMZ Monthly delivery rate multiplied by 12 and divided by 52.
3. Daily delivery: the UMZ Weekly delivery rate divided by 7.
4. Hourly delivery: the UMZ Monthly delivery rate divided by 730 hours per month.

## Western Farmers Electric Cooperative

## Rate Sheet for Point-To-Point Transmission Service

The currently effective rates for Point-To-Point Transmission Service in the Western Farmers Electric Cooperative ("WFEC") rate Zone are set forth in the "WFEC PTP Rate Att T" tab of the Revenue Requirements and Rates File ("RRR File") posted on the SPP website. Transmission Owners that have Commission approved rate(s) in the WFEC rate Zone are: WFEC and People's Electric Cooperative ("PEC").

**Balanced Portfolio Reallocation Adjustment of Point-To-Point Rates**

Rates for Point-To-Point Transmission Service specified in this Attachment T shall be adjusted to reflect any amount reallocated from the Zonal Annual Transmission Revenue Requirement in accordance with Section IV.A of Attachment J. The rates, including any applicable reallocation adjustment, shall be set forth in the RRR File posted on the SPP website.

**Point-To-Point Transmission Service Revenue Crediting for Point-To-Point Rates**

Rates for Point-To-Point Transmission Service under this Attachment T shall reflect any adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, implemented in accordance with Section 34.1(2) of this Tariff. The rates, including any applicable adjustments for Schedule 7 and 8 revenues and revenues distributed and allocated under Attachment AU, shall be set forth in the RRR File.

**Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth in the RRR File, calculated pursuant to the WFEC formula rate and protocols ("WFEC Formula Rate") shown in Attachment H, Addendum 39, and the PEC formula rate and protocols ("PEC Formula Rate") shown in Attachment H, Addendum 51, and described below:

1. Yearly delivery: one-twelfth of the rate per MW of Reserved Capacity per year.
2. Monthly delivery: rate per MW of Reserved Capacity per month.
3. Weekly delivery: rate per MW of Reserved Capacity per week.

4. Daily on-peak delivery: rate per MW of Reserved Capacity per day.

5. Daily off-peak delivery: rate per MW of Reserved Capacity per day.

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any day during such week.

**Non-Firm Point-To-Point Transmission Service**

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth in the RRR File, calculated pursuant to the WFEC Formula Rate shown in Attachment H, Addendum 39, and the PEC Formula Rate shown in Attachment H, Addendum 51, and described below:

1. Monthly delivery: rate per MW of Reserved Capacity per month.

2. Weekly delivery: rate per MW of Reserved Capacity per week.

3. Daily on-peak delivery: rate per MW of Reserved Capacity per day.

4. Daily off-peak delivery: rate per MW of Reserved Capacity per day.

5. Hourly on-peak delivery: rate per MW of Reserved Capacity per hour.

6. Hourly off-peak delivery: rate per MW of Reserved Capacity per hour.

The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified for Daily on-peak delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified for Weekly delivery multiplied by the highest amount in megawatts of Reserved Capacity in any hour during such week.

# ATTACHMENT U
# RATE SCHEDULE FOR COMPENSATION FOR RESCHEDULED MAINTENANCE COSTS

## A. Introduction

This Attachment U provides for the payment by the Transmission Provider of compensation to Generator Owners for the costs of rescheduling a generator maintenance outage that qualifies per the criteria in Section B of this Attachment U ("Qualified" generator maintenance outage) and to Transmission Owners for the costs of rescheduling a transmission facility maintenance outage, when such maintenance outage is rescheduled pursuant to the Transmission Provider's or SPP Reliability Coordinator's direction, and for the recovery by the Transmission Provider of the costs of such payments.

## B. Compensation to Generator Owners

Owners of generating units within the SPP Region and owners of generating units pseudo-tied into the SPP Balancing Authority Area shall coordinate the scheduling of outages for the maintenance of generating units with the Transmission Provider. The Transmission Provider shall review the generating unit maintenance outage schedule requests submitted by Generator Owners. Any Generator Owner that reschedules a Qualified maintenance outage at the direction of the Transmission Provider or the SPP Reliability Coordinator is eligible to be reimbursed by the Transmission Provider for incremental costs incurred, in accordance with good utility practice, as a direct result of any such rescheduling. Generator Owners shall use best efforts to minimize incremental costs resulting from a rescheduled maintenance outage.

Criteria described herein must be met in order to consider the generator maintenance outage Qualified for the purposes of Attachment U cost recovery. To be considered Qualified, the maintenance outage for a generating unit within the SPP Region or a generating unit pseudo-tied into the SPP Balancing Authority Area must be submitted to the Transmission Provider at least sixty (60) calendar days prior to the start of the scheduled maintenance. The Transmission Provider then has fourteen (14) calendar days from the submission date to respond to the outage request. If the Transmission Provider denies the requested outage within the fourteen (14) calendar day response window, then the maintenance outage is not considered Qualified. Outage requests not acted upon by the Transmission Provider within the fourteen (14) calendar day response window will be considered Qualified. For maintenance outage requests submitted more than three hundred sixty-five (365) calendar days in advance, the Transmission Provider's fourteen (14) calendar day response window will start three hundred sixty-five (365) calendar days prior to the requested start date of the requested maintenance outage. Modification requests to a Qualified generator maintenance outage will not alter the Qualified status of the outage. If the Transmission Provider accepts a modification to a Qualified generator maintenance outage, the modified generator maintenance outage remains Qualified. If the Transmission Provider denies a modification to a Qualified generator maintenance outage, then the existing generator maintenance outage remains unchanged and maintains Qualified status.

All incremental costs for which compensation is sought or provided under this Section B are to be fully documented by the Generator Owner, supported by information such as invoices, receipts or contracts, and such documentation shall be made available to the Transmission

Provider. The Generator Owner shall provide the Transmission Provider with an attestation as to the prudence and validity of all incremental costs for which compensation is requested as well as information that the Transmission Provider determines is necessary to substantiate the incremental costs of rescheduling a Qualified generator maintenance outage. The Generator Owner shall forward to the Transmission Provider: (1) the initial statement and supporting documentation of the total incremental cost of rescheduling a Qualified generator maintenance outage within forty-five (45) calendar days of the end of the time period of the rescheduled Qualified generator maintenance outage; and (2) the final statement of such total incremental cost, accompanied by any additional documentation and the required attestation, within ninety (90) calendar days of the end of the time period of the rescheduled Qualified generator maintenance outage. Section D of this Attachment U describes the manner in which the Transmission Provider is to recover the costs of all reimbursements of incremental costs made to the Generator Owner pursuant to this Section B.

The following are the incremental costs resulting from a rescheduled Qualified generator maintenance outage that are eligible for recovery by the Generator Owner:

(1) Incremental labor costs: The labor costs eligible for recovery from the Transmission Provider shall be the actual out-of-pocket incremental labor costs incurred by the Generator Owner only because of the rescheduling of the Qualified generator maintenance outage. Incremental overhead costs associated with this labor also can be recovered if substantiating documentation is provided of such expenditures.

(2) Incremental materials costs: The materials costs eligible for recovery from the Transmission Provider shall be the actual out-of-pocket incremental materials costs incurred by the Generator Owner only because of the rescheduling of the Qualified generator maintenance outage.

## C. Compensation to Transmission Owners

Transmission Owners shall coordinate the scheduling of outages for the maintenance of transmission facilities with the Transmission Provider. Any Transmission Owner that reschedules a transmission facility maintenance outage at the direction of the Transmission Provider or the SPP Reliability Coordinator is eligible to be reimbursed by the Transmission Provider for incremental costs incurred as may be provided through its transmission formula rate or through approval of a request for such recovery by the Federal Energy Regulatory Commission. Transmission Owners shall use best efforts to minimize incremental costs resulting from a rescheduled transmission maintenance outage.

## D. Recovery of Generation Outage Costs Paid by the Transmission Provider

The Transmission Provider shall recover all costs resulting from the reimbursement of incremental costs made to Generator Owners, as specified in Section B of this Attachment U, through the Revenue Neutrality Uplift Distribution Amount described in Attachment AE of this Tariff. Costs will be recovered from Market Participants with market transactions subject to the Revenue Neutrality Uplift for the time period of the rescheduled Qualified generator maintenance outage, defined as the operating days from the originally scheduled maintenance outage start date to the actual maintenance outage start date, inclusive of both days, regardless of whether the actual Qualified generator maintenance outage start date is earlier or later than the originally scheduled outage start date. The Transmission Provider shall make available, upon request by Market Participants, data and information supporting the reimbursement of incremental costs to Generator Owners for rescheduled Qualified generator maintenance outages under this Attachment U for a period of thirty (30) calendar days after such amounts are billed to Market Participants, including any resettlement.

## E. Dispute Resolution

If a Generator Owner or Market Participant disagrees with the amounts reimbursed or charged, respectively, it may seek relief under the dispute resolution procedures pursuant to Part I, Section 12 of this Tariff or it may refer the dispute to the Commission for resolution.

# ATTACHMENT V
# GENERATOR INTERCONNECTION PROCEDURES (GIP)
# including
# GENERATOR
# INTERCONNECTION AGREEMENT (GIA)

# Generator
# Interconnection Procedures (GIP)

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## Section 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Breaching Party** shall mean a Party that is in Breach of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection Studies.

**Commercial Operation** shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

**Commercial Operation Date** of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Confidential Information** shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

**Contingent Facilities** shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. Contingent Facilities are identified in Appendix A of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by an Applicable Reliability Council.

**Decision Point One (DP1)** shall mean the period of time following the posting of the results of DISIS Phase One.

**Decision Point Two (DP2)** shall mean the period of time following the posting of the results of DISIS Phase Two.

**Default** shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable.

**Definitive Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures. The Definitive Interconnection System Impact Study is conducted in two phases.

**Definitive Interconnection System Impact Study Phase One (DISIS Phase One)** shall mean an initial phase of the Definitive Interconnection System Impact Study.

**Definitive Interconnection System Impact Study Phase Two (DISIS Phase Two)** shall mean the second phase of the Definitive Interconnection System Impact Study.

**Definitive Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

**Definitive Interconnection System Impact Study Queue Cluster Window (DISIS Queue Cluster Window)** shall mean the period during which the Transmission Provider shall accept Interconnection Requests for Definitive Interconnection System Impact Studies.

**Definitive Interconnection System Impact Study Review Period (DISIS Review Period)** shall mean the period following the close of the Definitive Interconnection System Impact Study Queue Cluster Window to resolve any deficiencies in the Interconnection Requests received during the Definitive Interconnection System Impact Study Queue Cluster Window.

**Dispute Resolution** shall mean the procedure in Section 13.5 of the Generator Interconnection Procedures for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

**Distribution System** shall mean the Transmission Owner's facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.

**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Electromagnetic Transient Study or EMT Study** shall mean an analysis to determine the electromagnetic transient response of the electric power system due to system disturbances.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall

be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interconnection Service (ERIS)** shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

**Environmental Review** shall mean a study conducted by Western-UGP, as the Transmission Owner, that contains a review of the proposed interconnection to Western-UGP's transmission facilities, pursuant to the National Environmental Policy Act ("NEPA"), 42 U.S.C. §4321, et seq., as amended, and setting forth Interconnection Customer's responsibilities in connection with such review of the interconnection.

**Existing Generating Facility** shall mean a Generating Facility that is currently interconnected to the Transmission System of the Transmission Provider.

**Fast Track Process** – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 14.1 and includes the section 14 screens, customer options meeting, and optional supplemental review.

**Federal Power Act** shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Financial Security** shall mean the security deposits required of the Interconnection Customer to enter Definitive Interconnection System Impact Study Phase One, Definitive Interconnection System Impact Study Phase Two, and Interconnection Facilities Study.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. A Generating Facility

consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generating Facility Modification** shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of the equipment at the Existing Generating Facility.

**Generating Facility Replacement** shall mean the process of replacing one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection as those being decommissioned and electrically disconnected.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in Appendix 6 to these Generator Interconnection Procedures or in Appendix 13 when Western-UGP is a Party, as the Transmission Owner, to the GIA.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Generator Interconnection Study Agreement** shall mean the study agreement for the Definitive Interconnection System Impact Study and the Interconnection Facilities Study in Appendix 3 of the Generator Interconnection Procedures.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or

words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Initial Queue Position** shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests. The Initial Queue Position is established based upon the date and time of receipt of the valid Interconnection Requests by Transmission Provider.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 3 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, to interconnect a Replacement Generating Facility, to increase the capacity of, or make a Material Modification to the operating characteristics of, an Existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Replacement Impact Study, the Reliability Assessment Study, the Definitive Interconnection System Impact Study, the Interim Availability Interconnection System Impact Study, and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements described in the Generator Interconnection Procedures: the Generator Interconnection Study Agreement or the Interim Availability Interconnection System Impact Study Agreement.

**Interim Availability Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System and, if applicable, an Affected System for the purpose of providing Interim Interconnection Service. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications on an interim basis.

**Interim Availability Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 5 of the Generator Interconnection Procedures for conducting the Interim Availability Interconnection System Impact Study.

**Interim Generator Interconnection Agreement (Interim GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility to allow interconnection to the Transmission System prior to the completion of the Interconnection Study process.

**Interim Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interim Generator Interconnection Agreement and, if applicable, the Tariff.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

**Network Resource Interconnection Service (NRIS)** shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interconnection Service in and of itself does not convey transmission service.

**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

**Notice of Dispute** shall mean a written notice of a dispute or claim that arises out of or in connection with the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, or its performance.

**Party or Parties** shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

**Permissible Technological Advancement** shall mean an advancement to turbines, inverters, plant supervisory controls or other technological advancements that do not increase the Interconnection Customer's requested Interconnection Service or cause any reliability concerns. A Permissible Technological Advancement does not degrade the electrical characteristics of the generating equipment (e.g., the ratings, impedances, efficiencies, capabilities, and performance of the equipment under steady-state and dynamic conditions), nor does it include changes in generation technology type or fuel type.

**Point of Change of Ownership** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

**Point of Interconnection** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, where the Interconnection Facilities connect to the Transmission System.

**Queue** shall mean the Definitive Interconnection System Impact Study Queue or the Interconnection Facilities Study Queue, as applicable.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Reliability Assessment Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of Transmission System during the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility.

**Replacement Generating Facility** shall mean a Generating Facility that replaces an Existing Generating Facility, or a portion thereof, at the same electrical Point of Interconnection pursuant to Section 3.9 of this Attachment V.

**Replacement Impact Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of the Transmission System.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers' Generating Facilities where such Interconnection Customers share the cost.

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility or Generating Facility's tie line; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

**Small Generating Facility** shall mean the Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request that meets the requirements of Section 14, but shall not include the Interconnection Customer's Interconnection Facilities.

**Stand Alone Network Upgrades** shall mean Network Upgrades that are not part of an Affected Systems that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable. If the Transmission Provider, Transmission Owner and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Owner must provide the Interconnection Customer a written technical explanation outlining why the Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within fifteen (15) days of its determination.

**Surplus Interconnection Service** shall mean any unneeded portion of Interconnection Service established in a Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection substation and at the same voltage level would remain the same.

**Surplus Interconnection Service Customer** shall mean either the Interconnection Customer to the original Generator Interconnection Agreement with unneeded Interconnection Service or the entity that wants to utilize Surplus Interconnection Service.

**Surplus Interconnection Service Facilities Queue Position** shall mean the position assigned by the Transmission Provider in accordance with Section 3.3.4.2 of the Generator Interconnection Procedures.

**Surplus Interconnection Service Facilities Study** shall mean the study performed in situations where additional Interconnection Facilities are identified by the Transmission Provider as being required to support the requested Surplus Interconnection Service.

**Surplus Interconnection Service Facilities Study Agreement** shall mean the form of agreement contained in Appendix 16 of the Generator Interconnection Procedures for conducting the Surplus Interconnection Service Facilities Study.

**Surplus Interconnection Service Impact Study** shall mean a study conducted by the Transmission Provider consisting of reactive power, short circuit/fault duty, stability analyses,

and any other appropriate studies necessary for the Transmission Provider to demonstrate reliable operation of the Surplus Interconnection Service on the Transmission System.

**Surplus Interconnection Service Impact Study Agreement** shall mean the form of agreement contained in Appendix 15 of the Generator Interconnection Procedures for conducting the Surplus Interconnection Service Impact Study.

**Surplus Interconnection Service Queue Position** shall mean the position assigned by the Transmission Provider upon receipt of a request for Surplus Interconnection Service based upon the date and time of receipt of the request.

**Surplus Interconnection Service Request** shall mean a request for Surplus Interconnection Service submitted by a Surplus Interconnection Service Customer.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled, or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Generator Interconnection Agreement or Interim Generator Interconnection Agreement, as applicable, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

**Western Area Power Administration-Upper Great Plains Region ("Western-UGP")** shall mean a division of the Western Area Power Administration, a Federal Power Marketing Agency, and Transmission Owner, that markets and transmits Federal power over Federal transmission facilities that have been transferred to the functional control of the Transmission Provider.

## Section 2. Scope and Application

### 2.1 Application of Generator Interconnection Procedures.

These Generator Interconnection Procedures apply, as specified in this Section 2, to the processing of Interconnection Requests for interconnections to the Transmission System that are subject to FERC jurisdiction.

2.1.1 Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Generating Facility except for Small Generating Facilities that meet the requirements of Section 14 of the GIP or Appendix 11. If the Interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under Sections 3 through 13.

2.1.2 Section 14 of the GIP applies to a request to interconnect a certified Small Generating Facility meeting the certification criteria in Appendix 9 and Appendix 10.

2.1.3 A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kW shall be evaluated under Appendix 11; except that Section 14 of the GIP shall instead apply to such request to interconnect a certified inverter-based Small Generating Facility no larger than 10kW if the Interconnection Request will result in an interconnection to, or modification to, the transmission facilities of Western-UGP, as the Transmission Owner, and such interconnection is subject to completion of the appropriate NEPA level of Environmental Review and issuance of the required NEPA decisional document.

2.1.4 A request for Generating Facility Replacement shall be evaluated pursuant to Section 3.9 of this GIP.

2.1.5 A request for Generating Facility Modification for an Existing Generating Facility must be submitted to and coordinated with the Transmission Provider to allow the Transmission Provider to determine whether the proposed modification would result in a substantive modification to the operating characteristics of such Existing Generating Facility. The Transmission Provider will notify the entity submitting the request within 30 days of making such determination whether additional action is required.

### 2.2 Pre-Application Process for Interconnection Requests Equal to or Less than 20 MW

2.2.1 The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name,

telephone number, and e-mail address of such contact employee or office shall be made available on the Transmission Provider's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Transmission Provider shall comply with reasonable requests for such information.

2.2.2 In addition to the information described in section 2.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission Provider shall provide the pre-application data described in section 2.2.3 to the Interconnection Customer within 20 Business Days of receipt of the completed request form and payment of the $300 fee. The pre-application report produced by the Transmission Provider is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider's system. The written pre-application report request form shall include the information in sections 2.2.2.1 through 2.2.2.8 below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

2.2.2.1 Project contact information, including name, address, phone number, and email address.

2.2.2.2 Project location (street address with nearby cross streets and town).

2.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

2.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.).

2.2.2.5 Size (alternating current kW).

2.2.2.6 Single or three phase generator configuration.

2.2.2.7 Stand-alone generator (no onsite load, not including station service – Yes or No?).

2.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads

in kW (if available) and specify if the load is expected to change.

2.2.3. Using the information provided in the pre-application report request form in section 2.2.2, the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Transmission Provider does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. Subject to section 2.2.4, the pre-application report will include the following information:

2.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

2.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

2.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

2.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

2.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

2.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

2.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

2.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 14.4.4.1.1 below and absolute minimum load, when available.

2.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the

substation/area. Identify whether the substation has a load tap changer.

2.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

2.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

2.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

2.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interrupting capacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

2.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on "available capacity" pursuant to section 2.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the Transmission Provider shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

**2.3 Comparability.**

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this GIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

**2.4 Base Case Data.**

Transmission Provider shall maintain current base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list on either its OASIS site or a password-protected website, subject to confidentiality provisions in Section 13.1 of the GIP, that the Transmission Provider is using to

perform Definitive Interconnection System Impact Studies. In addition, Transmission Provider shall maintain network models and underlying assumptions on either its OASIS site or a password-protected website. Such network models and underlying assumptions should reasonably represent those used during the most recent interconnection study and be representative of current system conditions. If Transmission Provider posts this information on a password-protected website, a link to the information must be provided on Transmission Provider's OASIS site. Transmission Provider is permitted to require that Interconnection Customer, OASIS site users and password-protected website users sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (2) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

**2.5 No Applicability to Transmission Service.**

Nothing in this GIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

**2.6 Participation by the United States Subject to Federal Laws and Regulations**

In the event that Western-UGP is the Transmission Owner under any of the provisions or agreements in this GIP, then in such case Section 39.3 of this Tariff is incorporated as if it were a part hereof.

## Section 3. Interconnection Requests

### 3.1 General.

An Interconnection Customer shall submit to Transmission Provider an Interconnection Request or a Generating Facility Replacement request by providing an executed Generator Interconnection Study Agreement in the form of Appendix 3 to this GIP and the deposit along with the other items in Section 8.2 of these Generator Interconnection Procedures. Transmission Provider shall apply the study deposit toward the cost of the applicable Interconnection Study. Interconnection Customer shall submit a separate Interconnection Request for each site and may submit multiple Interconnection Requests for a single site. Interconnection Customer must submit a deposit with each Interconnection Request even when more than one request is submitted for a single site. An Interconnection Request to evaluate one site at two different voltage levels shall be treated as two Interconnection Requests.

At Interconnection Customer's option, Transmission Provider and Interconnection Customer will identify alternative Point(s) of Interconnection and configurations at the Scoping Meeting to evaluate in this process and attempt to eliminate alternatives in a reasonable fashion given resources and information available. Interconnection Customer will select the definitive Point(s) of Interconnection to be studied no later than the end of the DISIS Review Period.

Interconnection Customers may request a level of Interconnection Service below the Generating Facility Capacity. These requests for Interconnection Service shall be studied at the level of Interconnection Service requested for purposes of Interconnection Facilities, and Network Upgrades, and associated costs, but may be subject to other studies at the full Generating Facility Capacity to ensure safety and reliability of the system, with the study costs borne by the Interconnection Customer. If after the additional studies are complete, Transmission Provider determines that additional Network Upgrades are necessary, then Transmission Provider must: (1) specify which additional Network Upgrade costs are based on which studies; and (2) provide a detailed explanation of why the additional Network Upgrades are necessary. Any Interconnection Facility and/or Network Upgrade costs required for safety and reliability also would be borne by the Interconnection Customer. Interconnection Customers may be subject to additional control technologies as well as testing and validation of those technologies consistent with Article 6 of the GIA or Interim GIA, as applicable. The necessary control technologies and protection systems shall be established in Appendix C of the executed, or requested to be filed unexecuted, GIA or Interim GIA, as applicable.

### 3.2 Identification of Types of Interconnection Services.

At the time the Interconnection Request is submitted, Interconnection Customer must request either Energy Resource Interconnection Service or Network Resource Interconnection Service, as described; all requests will be concurrently

studied for Energy Resource Interconnection Service, up to the end of DP1. Interconnection Customer may then elect to proceed with Network Resource Interconnection Service or to proceed under a lower level of interconnection service to the extent that only certain upgrades will be completed. A description of the modeling details used when studying a project as ERIS or NRIS can be found in Section 4 and Section 6 of the document "Guidelines for the SPP GIP Process and Business Practices" posted on the Transmission Provider's Generator Interconnection Study posting page on OASIS and in SPP Business Practice 7250.

### 3.2.1 Energy Resource Interconnection Service.

**3.2.1.1 The Product.** Energy Resource Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. Energy Resource Interconnection Service does not in and of itself convey any right to deliver electricity to any specific customer or Point of Delivery.

**3.2.1.2 The Study.** The study consists of short circuit/fault duty, steady state (thermal and voltage) and stability analyses. The short circuit/fault duty analysis would identify direct Interconnection Facilities required and the Network Upgrades necessary to address short circuit issues associated with the Interconnection Facilities. The stability and steady state studies would identify necessary upgrades to allow full output of the proposed Generating Facility and would also identify the maximum allowed output, at the time the study is performed, of the interconnecting Generating Facility without requiring additional Network Upgrades.

### 3.2.2 Network Resource Interconnection Service.

**3.2.2.1 The Product.** Transmission Provider must conduct the necessary studies and the Transmission Owner construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as Network Resources. Network Resource Interconnection Service allows Interconnection Customer's Generating Facility to be designated as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to Transmission Provider's Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur.

**3.2.2.2 The Study.** The Interconnection Study for Network Resource Interconnection Service shall assure that Interconnection Customer's Generating Facility meets the requirements for

Network Resource Interconnection Service and as a general matter, that such Generating Facility's interconnection is also studied with Transmission System at peak load, under a variety of severely stressed conditions, to determine whether, with the Generating Facility at full output, the aggregate of generation in the local area can be delivered to the aggregate of load on Transmission System, consistent with Applicable Reliability Standards. This approach assumes that some portion of existing Network Resources are displaced by the output of Interconnection Customer's Generating Facility. Network Resource Interconnection Service in and of itself does not convey any right to deliver electricity to any specific customer or Point of Delivery. The Transmission Provider may also study the Transmission System under non-peak load conditions. However, upon request by the Interconnection Customer, the Transmission Provider must explain in writing to the Interconnection Customer why the study of non-peak load conditions is required for reliability purposes.

**3.3 Utilization of Surplus Interconnection Service.**

An Interconnection Customer with an effective GIA may make Surplus Interconnection Service available at an existing Point of Interconnection substation utilizing the process outlined in this Section 3.3. The Interconnection Customer with an effective GIA or one of its affiliates shall have priority to utilize Surplus Interconnection Service. If an Interconnection Customer with an effective GIA or one of its affiliates does not exercise its priority, then an Interconnection Customer with an effective GIA may make the service available to other potential Interconnection Customers. Surplus Interconnection Service requested must be less than or equal to the amount of Surplus Interconnection Service made available by the Interconnection Customer with an effective GIA and cannot exceed the total Interconnection Service already provided by the Interconnection Customer’s GIA.

For the purposes of an Interconnection Customer making available or requesting Surplus Interconnection Service, references to the current Interconnection Customer or a currently effective GIA shall also include any generator which interconnected to the Transmission Provider’s system prior to when the transmission facilities where the generator is connected was included in this Tariff. The entity requesting Surplus Interconnection Service, or the entity making such Surplus Interconnection Service available, shall provide to the Transmission Provider the information necessary to verify the original interconnection service available in lieu of a GIA. This may be in the form of a currently-effective GIA, or if no currently-effective GIA exists, the original interconnection agreement, studies, Network Integration Transmission Service Agreement, or other technical information. The Transmission Provider may request any additional information necessary to evaluate the request for Surplus Interconnection Service in accordance with this Section 3.3.

Surplus Interconnection Service is only available up to the amount that can be accommodated without requiring additional Network Upgrades, unless (a) those additional Network Upgrades are either (1) located at the Point of Interconnection substation and at the same voltage level as the Generating Facility with an effective GIA, or (2) are System Protection Facilities; and (b) there are no material adverse impacts on the cost or timing of any Interconnection Requests pending at the time the Surplus Interconnection Service request is submitted.

### 3.3.1 Initiating a Request for Surplus Interconnection Service.

A request for Surplus Interconnection Service may be submitted by the Interconnection Customer with an effective GIA or the entity that wants to utilize Surplus Interconnection Service.

3.3.1.1 To initiate a request for Surplus Interconnection Service, the Interconnection Customer to the effective GIA shall notify the Transmission Provider and provide the following information in writing:

1. The Initial Queue Position number associated with the existing Interconnection Service.
2. The amount of Surplus Interconnection Service to be made available in megawatts.
3. The period(s) of time when Surplus Interconnection Service will be available.
4. The conditions under which Surplus Interconnection Service at the Point of Interconnection may be used.
5. Whether the Interconnection Customer intends to use the Surplus Interconnection Service for itself, for one of its affiliates, or to make it available to an un-affiliated Interconnection Customer.
6. Name, address, telephone number, and email address of Interconnection Customer's contact person.

3.3.1.2 The entity wishing to utilize Surplus Interconnection Service shall submit a request to the Transmission Provider and provide the following in writing:

1. The Point of Interconnection associated with the existing Interconnection Service and if known, the Initial Queue Position number.
2. The amount of Surplus Interconnection Service capacity requested in megawatts.
    a. Type of service requested: Energy Resource Interconnection Service or Network Resource Interconnection Service, if the existing service is also Network Resource Interconnection Service.
3. Preliminary one-line diagram of the proposed Generating Facility showing how it will connect to the existing Point of Interconnection substation.
4. Proposed Commercial Operation Date (day, month, and year).

5. Name, address, telephone number, and email address of Interconnection Customer's contact person.
6. Information demonstrating that the Interconnection Customer with an effective GIA agrees with allowing the surplus request to proceed.

**3.3.2 Surplus Interconnection Service Impact Study Agreement.**

Within five (5) Business Days following the request for Surplus Interconnection Service, Transmission Provider shall provide to the Surplus Interconnection Service Customer a non-binding good faith estimate of the cost and timeframe for completing the Surplus Interconnection Service Impact Study and tender a Surplus Interconnection Service Impact Study Agreement to the Surplus Interconnection Service Interconnection Customer. The Surplus Interconnection Service Impact Study Agreement shall provide that Surplus Interconnection Service Customer shall compensate Transmission Provider for the actual cost of the Surplus Interconnection Service Impact Study. The Surplus Interconnection Service Customer shall deliver the executed Surplus Interconnection Service Impact Study Agreement to Transmission Provider together with the required technical data along with a study deposit equal to $15,000. The initial $15,000 deposit will be applied towards the Surplus Interconnection Service Impact Study cost. If the Surplus Interconnection Service Customer's share of the Surplus Interconnection Service Impact Study costs exceed $15,000, then Surplus Interconnection Customer will be responsible for this excess cost. If the Surplus Interconnection Service Customer's share of the Surplus Interconnection Service Impact Study cost is less than $15,000, the difference shall be refunded to the Surplus Interconnection Service Customer.

**3.3.3 Surplus Interconnection Service Queue.**

The Transmission Provider shall assign a Surplus Interconnection Service Queue Position based upon the date and time of receipt from the Interconnection Customer of the completed and executed Surplus Interconnection Service Impact Study Agreement, study deposit, and all required technical data and models. The Surplus Interconnection Service Queue Position will be used to determine the order of performing the Surplus Interconnection Service Impact Study. A higher queued Surplus Interconnection Service Request is one that has been placed "earlier" in the queue in relation to another Surplus Interconnection Service Request that is lower queued.

**3.3.4 Surplus Interconnection Service Studies**

3.3.4.1 Surplus Interconnection Service Impact Study.

The Surplus Interconnection Service Impact Study shall consist of reactive power, short circuit/fault duty, stability analyses, and any other appropriate studies. Steady-state (thermal/voltage) analyses may be performed as necessary to ensure that all required

reliability conditions are studied. If the existing Interconnection Service was not studied under off-peak conditions, off-peak steady state analyses shall be performed to the required level necessary to demonstrate reliable operation of the Surplus Interconnection Service. If the original system impact study is not available for the Surplus Interconnection Service, both off-peak and peak analysis may need to be performed for the Existing Generating Facility associated with the request for Surplus Interconnection Service. The reactive power, short circuit/fault duty, stability, and steady-state analyses for Surplus Interconnection Service will identify any additional Interconnection Facilities and Network Upgrades necessary. The Transmission Provider may waive any or all of the additional studies if it determines that there is no reasonable expectation that the Surplus Interconnection Service will negatively impact the reliability of the Transmission System or that no additional Interconnection Facilities or Network Upgrades will be identified in the study.

The Transmission Provider will use reasonable efforts to complete the Surplus Interconnection Service Impact Study for a Surplus Interconnection Service Request within sixty (60) Calendar Days of receipt from the Interconnection Customer of a completed and executed Surplus Interconnection Service Impact Study Agreement, study deposit, and all required technical data and models. The Transmission Provider will notify the Surplus Interconnection Customer if it anticipates that the impact studies will not be completed within the required time and will provide an estimate of the expected date of completion.

3.3.4.2 Surplus Interconnection Service Facilities Study.

If additional Interconnection Facilities, Network Upgrades located at the Point of Interconnection substation and same voltage level as the Generating Facility with an effective GIA, or System Protection Facilities are identified as being required to support the requested Surplus Interconnection Service, the Transmission Provider will assign a Surplus Interconnection Facilities Queue Position and tender a Surplus Interconnection Service Facilities Study Agreement to the Surplus Interconnection Service Customer simultaneously with the delivery of the Surplus Interconnection System Impact Study to Interconnection Customer. The Surplus Interconnection Service Facilities Study Agreement shall provide that Surplus Interconnection Service Customer shall compensate Transmission Provider for the actual cost of the Surplus Interconnection Service Facilities Study. Within five (5) Business Days following the assignment of a Surplus Interconnection Service Facilities Queue Position, Transmission Provider shall provide to Surplus Interconnection Service Customer a non-

binding good faith estimate of the cost and timeframe for completing the Surplus Interconnection Service Facilities Study. Surplus Interconnection Service Customer shall within thirty (30) Calendar Days after receipt, execute and provide to the Transmission Provider the Surplus Interconnection Service Facilities Study Agreement, together with the required technical data along with a study deposit of $15,000. This study deposit is in addition to any amount provided in Section 3.3.2 of the GIP.

If the Surplus Interconnection Service Customer's share of the Surplus Interconnection Service Facilities Study costs exceed $15,000, then Surplus Interconnection Service Customer will be responsible for this excess cost. If the Surplus Interconnection Service Customer's share of the Surplus Interconnection Service Facilities Study cost is less than $15,000, the difference shall be refunded to the Surplus Interconnection Service Customer.

The Surplus Interconnection Service Facilities Study will be conducted in accordance with the requirements for an Interconnection Facilities Study specified in Section 8 of the GIP.

### 3.3.5 Surplus Interconnection Service Agreement.

If the Transmission Provider determines that (a) no additional impact studies are required, (b) determines that there are no impacts requiring additional Interconnection Facilities, System Protection Facilities or Network Upgrades or (c) posts a final Surplus Interconnection Service Facilities Study report, then the Transmission Provider will tender a draft agreement for Surplus Interconnection Service pursuant to the procedures in Section 11 of the GIP. The Interconnection Customer to the effective GIA that made the Surplus Interconnection Service available, Surplus Interconnection Service Customer, Transmission Owner and the Transmission Provider will be parties to the agreement for Surplus Interconnection Service.

## 3.4 Valid Interconnection Request.

### 3.4.1 Initiating an Interconnection Request.

To initiate an Interconnection Request, Interconnection Customer must satisfy the requirements in Section 8.2 of the GIP.

### 3.4.2 Acknowledgment of Interconnection Request.

Transmission Provider shall acknowledge receipt of the Interconnection Request within five (5) Business Days of receipt of the request.

### 3.4.3 Deficiencies in Interconnection Request.

An Interconnection Request will not be considered to be a valid request until all items in Section 8.2 of the GIP have been received by Transmission Provider.

**3.4.4 Scoping Meeting.**

After the receipt of a valid Interconnection Request, either the Interconnection Customer, Transmission Owner or the Transmission Provider may request to hold a Scoping Meeting, and such meeting shall be held on a date mutually agreed upon by the Parties.

The purpose of the Scoping Meeting shall be to discuss alternative interconnection options, to exchange information including any transmission data that would reasonably be expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection. Transmission Provider, Transmission Owner and Interconnection Customer shall provide such technical data, including, but not limited to: (i) general facility loadings, (ii) general instability issues, (iii) general short circuit issues, (iv) general voltage issues, and (v) general reliability issues as may be reasonably required to accomplish the purpose of the meeting. Transmission Provider, Transmission Owner and Interconnection Customer will also make available personnel and other resources as may be reasonably required to accomplish the purpose of the meeting in the time allocated for the meeting. On the basis of the meeting, Interconnection Customer shall designate its Point of Interconnection, pursuant to Section 8.2 of the GIP. The duration of the meeting shall be sufficient to accomplish its purpose.

**3.4.5 Environmental Review.**

In the event the Interconnection Request will result in an interconnection to, or modification to, the transmission facilities of Western-UGP, the Interconnection Request shall be subject to an Environmental Review as described in Section 8.6.1 of the GIP. The Interconnection Customer may request that the Environment Review begin any time after the Interconnection Request is accepted.

**3.5 OASIS Posting.**

**3.5.1** Transmission Provider will maintain on its OASIS a list of all Interconnection Requests. The list will identify, for each Interconnection Request: (i) the maximum summer and winter megawatt electrical output; (ii) the location by county and state; (iii) the station or transmission line or lines where the interconnection will be made; (iv) the projected In-Service Date; (v) the status of the Interconnection Request, including Initial Queue Position, and Interconnection Queue Position, as applicable; (vi) the type of Interconnection Service being requested; (vii) the availability of any studies related to the Interconnection Request; (viii) the date of the

Interconnection Request; (ix) the type of Generating Facility to be constructed (combined cycle, base load or combustion turbine and fuel type); (x) for Interconnection Requests that have not resulted in a completed interconnection, an explanation as to why it was not completed; and (xi) for a Generating Facility Replacement, the planned date of cessation of operation for the Existing Generating Facility or actual date if the Existing Generating Facility already has ceased commercial operations, the expected Commercial Operation Date of the replacement facility and requested Interconnection Service. The list will not disclose the identity of Interconnection Customer until Interconnection Customer executes a GIA or requests that Transmission Provider file an unexecuted GIA with FERC. Transmission Provider shall post to its OASIS site any deviations from the study timelines set forth herein. Interconnection Study reports and Re-Study reports shall be posted to Transmission Provider's OASIS site subsequent to the meeting between Interconnection Customer and Transmission Provider to discuss the applicable study results. Transmission Provider shall also post any known deviations in the Generating Facility's In-Service Date.

### 3.5.2 Requirement to Post Interconnection Study Metrics

Transmission Provider will maintain on its OASIS, or its website, summary statistics related to processing Interconnection Studies pursuant to Interconnection Requests, updated quarterly. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider’s OASIS site. For each calendar quarter, Transmission Providers must calculate and post the information detailed below in Sections 3.5.2.1 through 3.5.2.4.

#### 3.5.2.1 Definitive Interconnection System Impact Study Phase One processing time.

(A) Number of DISIS Phase One studies completed within Transmission Provider’s coordinated region during the reporting quarter,

(B) Number of DISIS Phase One studies completed within Transmission Provider’s coordinated region during the reporting quarter that were completed more than one-hundred twenty (120) Calendar Days after the close of the DISIS Queue Cluster Window as described in Section 8.5 of the GIP,

(C) At the end of the reporting quarter, the number of ongoing incomplete DISIS Phase One studies where such DISIS Phase One studies were still incomplete more than one-hundred twenty (120) Calendar Days after the close of the DISIS Queue Cluster Window

as described in Section 8.5 of the GIP before the reporting quarter end,

(D) Mean time (in days), each DISIS Phase One studies completed within Transmission Provider's coordinated region during the reporting quarter, from the date when Transmission Provider closed the DISIS Queue Cluster Window as described in Section 8.5 of the GIP to the date when Transmission Provider provided the completed DISIS Phase One studies,

(E) Percentage of DISIS Phase One studies exceeding one-hundred twenty (120) Calendar Days after the close of the DISIS Queue Cluster Window to complete this reporting quarter, calculated as the sum of Sections 3.5.2.1(B) and 3.5.2.1(C) divided by the sum of Sections 3.5.2.1(A) and 3.5.2.1(C).

**3.5.2.2 Definitive Interconnection System Impact Study Phase Two processing time.**

(A) Number of DISIS Phase Two studies completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of DISIS Phase Two studies completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than one hundred twenty (120) Calendar Days after the end of DP1 as described in Section 8.5 of the GIP,

(C) At the end of the reporting quarter, the number of ongoing incomplete DISIS Phase Two studies where such DISIS Phase Two studies were still incomplete more than one hundred twenty (120) Calendar Days after the end of DP1 as described in Section 8.5 of the GIP before the reporting quarter end,

(D) Mean time (in days), each DISIS Phase Two studies completed within Transmission Provider's coordinated region during the reporting quarter, from the date when Transmission Provider end of DP1 as described in Section 8.5 of the GIP to the date when Transmission Provider provided the completed Definitive Interconnection System Impact Study,

(E) Percentage of DISIS Phase Two studies exceeding one hundred twenty (120) Calendar Days after the end of DP1 to complete this reporting quarter, calculated as the sum of Sections 3.5.2.2(B) and 3.5.2.2(C) divided by the sum of Sections 3.5.2.2(A) and 3.5.2.2(C)).

**3.5.2.3 Interconnection Facilities Studies processing time.**

(A) Number of Interconnection Facilities Studies completed within Transmission Provider's coordinated region during the reporting quarter,

(B) Number of Interconnection Facilities Studies completed within Transmission Provider's coordinated region during the reporting quarter that were completed more than sixty (60) Calendar Days after the end of DP2,

(C) At the end of the reporting quarter, the number of ongoing incomplete Interconnection Facilities Studies where such Interconnection Facilities Studies were still incomplete more than sixty (60) Calendar Days after the close of DP2,

(D) Mean time (in days), each Interconnection Facilities Study completed within Transmission Provider's coordinated region during the reporting quarter, calculated from the end of DP2,

(E) Percentage of delayed Interconnection Facilities Studies this reporting quarter, calculated as the sum of Sections 3.5.2.3(B) and 3.5.2.3(C) divided by the sum of Sections 3.5.2.3(A) and 3.5.2.3(C).

**3.5.2.4 Interconnection Service Requests withdrawn from interconnection queue.**

(A) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter,

(B) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of any Interconnection Studies or execution of any Interconnection Study Agreements,

(C) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of a Definitive Interconnection System Impact Study,

(D) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue during the reporting quarter before completion of an Interconnection Facility Study,

(E) Number of Interconnection Service requests withdrawn from Transmission Provider's interconnection queue after execution of a GIA or Interconnection Customer requests the filing of an unexecuted, new GIA,

(F) Mean time (in days), for all withdrawn Interconnection Service requests, from the date when the request was determined to be valid to when Transmission Provider received the request to withdraw from the queue.

**3.5.3** Transmission Provider is required to post on OASIS or its website the measures in Sections 3.5.2.1(A) through 3.5.2.4(F) for each calendar quarter within thirty (30) days of the end of the calendar quarter. Transmission Provider will keep the quarterly measures posted on OASIS or its website for three calendar years with the first required report to be in the first quarter of 2020. If Transmission Provider retains this information on its website, a link to the information must be provided on Transmission Provider's OASIS site.

**3.5.4** In the event that any of the values calculated in Sections 3.5.2.1(E), 3.5.2.2(E) or 3.5.2.3(E) exceeds twenty-five (25) percent for two (2) consecutive calendar quarters, Transmission Provider will have to comply with the measures below for the next four consecutive calendar quarters and must continue reporting this information until Transmission Provider reports four consecutive calendar quarters without the values calculated in Sections 3.5.2.1(E), 3.5.2.2(E) or 3.5.2.3(E) exceeding twenty-five (25) percent for two consecutive calendar quarters:

(i) Transmission Provider must submit a report to the Commission describing the reason for each study or group of clustered studies pursuant to an Interconnection Request that exceeded its deadline (i.e., 120 or 60 Calendar Days) for completion (excluding any allowance for Reasonable Efforts). Transmission Provider must describe the reasons for each study delay and any steps taken to remedy these specific issues and, if applicable, prevent such delays in the future. The report must be filed at the Commission within forty-five (45) days of the end of the calendar quarter.

(ii) Transmission Provider shall aggregate the total number of employee-hours and third party consultant hours expended towards interconnection studies within its coordinated region that quarter and post on OASIS or its website. If Transmission Provider posts this information on its website, a link to the information must be provided on Transmission Provider's OASIS site. This information is to be posted within thirty (30) days of the end of the calendar quarter.

***3.5.5*** *The Transmission Provider will maintain on its OASIS a Transmission Owner's general non-binding indication as to whether the Transmission Owner intends to elect to fund the capital costs for Network Upgrades and System Protection Facilities.*

## 3.6 Coordination with Affected Systems.

Transmission Provider will coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System Operators and, if possible, include those results (if available) in its applicable Interconnection Study within the time frame specified in this GIP. Transmission Provider will include such Affected System Operators in all meetings held with Interconnection Customer as required by this GIP. Interconnection Customer will cooperate with Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

## 3.7 Withdrawal.

Interconnection Customer may withdraw its Interconnection Request at any time by written notice of such withdrawal to Transmission Provider. In addition, if Interconnection Customer fails to adhere to all requirements of this GIP, except as provided in Section 13.5 (Disputes), Transmission Provider shall deem the Interconnection Request to be withdrawn and shall provide written notice to Interconnection Customer of the deemed withdrawal and an explanation of the reasons for such deemed withdrawal. Upon receipt of such written notice, Interconnection Customer shall have fifteen (15) Business Days in which to either respond with information or actions that cures the deficiency or to notify Transmission Provider of its intent to pursue Dispute Resolution.

Withdrawal shall result in the loss of Interconnection Customer's Initial Queue Position or Interconnection Queue Position, as applicable, and may result in the forfeiture of Financial Security deposits provided in Sections 8.2, 8.5.1, and 8.5.2 of the GIP, as applicable, subject to the Financial Security provisions in Section 8.14 of the GIP. If an Interconnection Customer disputes the withdrawal and loss of its Initial Queue Position or Interconnection Queue Position, then during Dispute Resolution, Interconnection Customer's Interconnection Request is eliminated from the applicable Queue until such time that the outcome of Dispute Resolution would restore its Initial Queue Position or Interconnection Queue Position. An Interconnection Customer that withdraws or is deemed to have withdrawn its Interconnection Request shall pay to Transmission Provider all costs that Transmission Provider prudently incurs with respect to that Interconnection Request prior to Transmission Provider's receipt of notice described above. Interconnection Customer must pay all monies due to

Transmission Provider before it is allowed to obtain any Interconnection Study data or results.

Transmission Provider shall (i) update the OASIS list of Interconnection Requests and (ii) refund to Interconnection Customer any portion of Interconnection Customer's deposit or study payments that exceeds the costs that Transmission Provider has incurred, including interest earned in the interest-bearing account in which Transmission Provider shall have deposited such amount. In the event of such withdrawal, Transmission Provider, subject to the confidentiality provisions of Section 13.1 of the GIP, shall provide, at Interconnection Customer's request, all information that Transmission Provider developed for any completed study conducted up to the date of withdrawal of the Interconnection Request.

### 3.8 Identification of Contingent Facilities.

Contingent Facilities shall be identified at the conclusion of the Definitive Interconnection System Impact Study and again at the conclusion of the Interconnection Facilities Study and included in Interconnection Customer's GIA or Interim GIA, as applicable. Transmission Provider shall also provide, upon request of the Interconnection Customer, the estimated Interconnection Facility and/or Network Upgrade costs and estimated in-service completion time of each identified Contingent Facility when this information is readily available and not commercially sensitive.

Prior to assigning cost allocation for new upgrades pursuant to Section 4.2.2 of the GIP, the Transmission Provider will first mitigate constraints seen in the study process with Network Upgrades that are part of the current SPP Transmission Expansion Plan as well as with Network Upgrades that are not yet approved, but are currently assigned to active prior-queued Interconnection Requests.

For each Network Upgrade identified, the average incremental power flow impact of each Interconnection Request in the Cluster Study, as defined in Section 4.2.2 of the GIP, shall be determined using each seasonal model available for the Cluster Study period during which the generating facility associated with the Interconnection Request is most likely to be generating at nameplate capacity, after the Date Upgrade Needed, as defined in Section 4.2.2 of the GIP, of such upgraded facility. Each impact amount shall be determined by first establishing a set of initial seasonal Base Case power flow models that excludes flows associated with all requests included in the Cluster Study. Then each request will be added to the models and the change in flow across such Network Upgrades shall be determined for each request included in the Cluster Study. Dependence on a Network Upgrade shall be assigned to each request having a positive incremental impact on such Network Upgrade with a distribution factor that is greater than or equal to the amounts set forth in Sections 3.8.1 and 3.8.2 below. Dependence on each Network Upgrade shall be allocated to requests independently. Incremental flows having a negative impact (counter flow) on a Network Upgrade shall be ignored.

**3.8.1** The distribution factor for requests seeking ERIS shall be 20% for all outage-based thermal constraints and 3% for all other constraints.

**3.8.2** The distribution factor for requests seeking NRIS shall be 3% for all constraints.

## 3.9 Additional requirements for Generating Facility Replacement Requests.

### 3.9.1 Requirements for Replacement Generating Facility Requests.

i) Any Replacement Generating Facility must connect to the Transmission System at the same electrical Point of Interconnection (i.e. same voltage level at the interconnecting substation) as the Existing Generating Facility.

ii) The request for Generating Facility Replacement must be submitted to the Transmission Provider by the Interconnection Customer for its Existing Generating Facility at least one (1) year prior to the date that the Existing Generating Facility will cease operation or up to one year after a unit is determined to be in forced outage. The request shall include the planned or actual date of cessation of operation for the Existing Generating Facility and the expected Commercial Operation Date for the Replacement Generating Facility.

iii) The Interconnection Customer shall request only ERIS for the Replacement Generating Facility if the Existing Generating Facility has only ERIS or if the type of service is not specified in a GIA. The request for NRIS for the Replacement Generating Facility, when the Existing Generating Facility has only ERIS, shall be submitted as a separate Interconnection Request and shall proceed through the DISIS in the same manner as an Interconnection Request for a new Generating Facility. The Interconnection Customer may request either ERIS or NRIS for the Replacement Generating Facility if the Existing Generating Facility has NRIS. Requests for ERIS or NRIS that exceed the amount of Interconnection Service for the Existing Generating Facility shall be processed as a new Interconnection Request for the amount of such excess pursuant to Section 3.9.1.iv of this Attachment V to the Tariff.

iv) If the Replacement Generating Facility requires Interconnection Service (MW) in excess of that of the Existing Generating Facility that is being replaced, Interconnection Customer shall initiate a separate request for Interconnection Service in an amount (MW) equal to the excess. Such Interconnection Request shall be assigned a new Initial Queue Position, and proceed through the DISIS in the same manner as an Interconnection Request for a new Generating Facility.

v) If the request for Generating Facility Replacement requests less Interconnection Service (MW) than that of the Existing Generating Facility that is being replaced, the new Interconnection Service may be granted at the reduced amount.

vi) No request for Generating Facility Replacement may be made until twelve (12) months have elapsed from: (1) the date of any assignment of the Generator Interconnection Agreement applicable to the Existing Generating Facility, or (2) the date of sale or other transfer of such Existing Generating Facility. Upon submission of a request for Generating Facility Replacement, the Interconnection Customer shall not sell or otherwise transfer the Existing Generating Facility, the Replacement Generating Facility, nor assign the applicable Generator Interconnection Agreement until such time as the Transmission Provider completes evaluation of the request for Generating Facility replacement unless the Interconnection Customer first withdraws such request for Generating Facility Replacement in writing. In the event that the Transmission Provider notifies Interconnection Customer that the request for Generating Facility Replacement has been granted, the prohibition on sale, transfer, or assignment shall be extended in accordance with Section 3.9.5 of this Attachment V. For purposes of this Section 3.9.1 (vi), prohibited assignments include assignments to affiliates pursuant to Article 19.1 of the pro forma Generator Interconnection Agreement or any analogous provision in the applicable GIA. A transfer, sale, or assignment of the Existing Generating Facility, Replacement Generating Facility, or applicable GIA that violates this Section 3.9.1 (vi) of Attachment V shall void the request for Generating Facility Replacement.

#### 3.9.1.1 Requirements for modification of Replacement Generating Facility Requests.

The request for Replacement Generating Facility can be modified any time before the evaluation process is complete.

1) If the revised planned date of cessation of operation for the Existing Generating Facility is prior to the planned date of cessation of operation specified in original request, a new request for Replacement Generating Facility must be submitted at least one (1) year prior to the date that the Existing Generating Facility is planned to cease operation.

2) If the revised expected Commercial Operation Date for the Replacement Generating Facility is after the expected Commercial Operation Date for the Replacement Generating Facility in the original request, a new request for Replacement Generating Facility must be submitted at least one (1) year prior to the date that the Existing Generating Facility is planned to cease operation.

### 3.9.2 Evaluation Process for Generating Facility Replacement Requests.

The Transmission Provider will evaluate Generating Facility Replacement requests in the order in which they are submitted. The evaluation will consist of two studies: i) a Replacement Impact Study as set forth in

Section 3.9.2.1 of the GIP, and ii) a Reliability Assessment Study as set forth in Section 3.9.2.2 of the GIP.

Transmission Provider shall use Reasonable Efforts to complete the Replacement Impact Study and Reliability Assessment Study and share results with the Interconnection Customer within one hundred eighty (180) Calendar Days of the request.

**3.9.2.1 Generating Facility Replacement—Replacement Impact Study.**

The Replacement Impact Study will include analyses to determine if the Replacement Generating Facility has a material adverse impact on the Transmission System when compared to the Existing Generating Facility. The Replacement Impact Study may include steady-state (thermal/voltage), reactive power, short circuit/fault duty, and stability analyses, as necessary, to ensure that required reliability conditions are studied. If the Replacement Impact Study identifies any materially adverse impact from operating the Replacement Generating Facility when compared to the Existing Generating Facility, such impacts shall be deemed a Material Modification, and in order to move forward, the Interconnection Customer must submit all information and milestone payments necessary for a valid Interconnection Request for a new Generating Facility pursuant to Section 3.4 of this GIP, be assigned queue priority as of the date such information and milestones are provided, and proceed through the DISIS as an Interconnection Request for a new Generating Facility.

**3.9.2.2 Generating Facility Replacement—Reliability Assessment Study**

The Reliability Assessment Study for the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility shall evaluate the performance of the Transmission System to determine if thermal and/or voltage violations of applicable NERC Standards and applicable planning criteria are caused by removing the Existing Generating Facility from service prior to the Commercial Operation Date of the Replacement Generating Facility. This study shall compare the conditions on the Transmission System that would exist if the Existing Generating Facility is taken offline to the conditions on the Transmission System as they exist when the Existing Generating Facility is online. The scope of Reliability Assessment Study may include stability analysis as necessary. The Existing Generating Facility shall be responsible for mitigating any reliability violation identified in the Reliability Assessment Study and may not cease operations until all mitigations are implemented

or are in service. Mitigation for this interim period may, as applicable, include: (i) redispatch/reconfiguration through operator instruction; and (ii) remedial action scheme or any other operating steps depending upon the type of reliability violation identified.

### 3.9.3 Generating Facility Replacement—Notice to Proceed

Interconnection Customer requesting Generating Facility Replacement shall inform Transmission Provider within thirty (30) Calendar Days after having received results of the Replacement Impact Study and Reliability Assessment Study of its election to proceed and Transmission Provider will initiate an Interconnection Facilities Study or tender a draft GIA. Failure by the Interconnection Customer to provide an election to proceed within thirty (30) Calendar Days will result in withdrawal of the Interconnection Request pursuant to Section 3.7 of this GIP.

### 3.9.4 Scope of Interconnection Facilities Study

Interconnection Facilities Study focusing on the Interconnection Facilities for the Replacement Generating Facility will start, if the Transmission Provider determines such a study is necessary, upon Interconnection Customer's notice to proceed to the Transmission Provider after completion of the Replacement Impact Study and the Reliability Assessment Study. This Interconnection Facilities Study will identify estimates for cost and the time required to construct the Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to complete this portion of the Interconnection Facilities Study within ninety (90) Calendar Days.

### 3.9.5 GIA for Generating Facility Replacement.

Transmission Provider shall tender a draft GIA to the Interconnection Customer requesting Generating Facility Replacement within thirty (30) Calendar Days after the Interconnection Customer communicates its election to proceed with Generator Replacement if an Interconnection Facilities Study is not required or within thirty (30) Calendar Days after final Facility Study reports are provided to the Interconnection Customer. The draft GIA shall include appendices describing the timing of Generating Facility Replacement and a condition that the GIA cannot be assigned and the Replacement Generating Facility cannot be transferred to any other Party, including an affiliate of the Interconnection Customer, until such date as the Replacement Generating Facility achieves commercial operation. A transfer, sale, or assignment of the Existing Generating Facility, Replacement Generating Facility, or applicable GIA that violates this Section 3.9.5 shall be void and constitute a material breach of the GIA.

Upon issuance of the draft GIA, the procedures of Section 11 of this Attachment V shall apply. Upon execution of the GIA for the

Replacement Generating Facility, the Transmission Provider will file with FERC to terminate the GIA for the Existing Generating Facility.

## Section 4. Interconnection Request Evaluation Process

### 4.1 Queue Position.

**4.1.1** The Transmission Provider shall assign an Initial Queue Position to each Interconnection Request based on the date and time of receipt of the valid Interconnection Requests; provided that if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, and Interconnection Customer provides such information in accordance with Section 3.4.3 of the GIP, then Transmission Provider shall assign Interconnection Customer an Initial Queue Position based on the date the application form was originally submitted to the Transmission Provider. The Initial Queue Position of each Interconnection Request will be used solely as an identifier for the Interconnection Request.

All Interconnection Requests within the same DISIS Queue Cluster Window shall have equal priority.

**4.1.2** The Transmission Provider shall assign an Interconnection Queue Position for Interconnection Requests within the Interconnection Facilities Study Queue based upon the date and time the Interconnection Customer satisfies all of the requirements of Section 8.9 of the GIP to enter an Interconnection Facilities Study. The priority of the Interconnection Queue Position of each Interconnection Request as determined in Section 4.1.3 of the GIP will be used to determine the order of performing the Interconnection Facilities Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request.

**4.1.3** Once an Interconnection Customer has met all requirements for an Interconnection Facilities Study, its Interconnection Queue Position shall be deemed higher than those in the DISIS Queue. A higher queued Interconnection Request in the Interconnection Facilities Study Queue is one that has been placed "earlier" in the Interconnection Facilities Study Queue in relation to another Interconnection Request. Interconnection Requests in the Interconnection Facilities Study Queue shall be considered to be placed in the Interconnection Facilities Study Queue at the same time if the Interconnection Requests were studied in the same Definitive Interconnection System Impact Study and each meets the requirements of Section 8.9 of the GIP following the completion of that study. Moving a Point of Interconnection shall result in a lowering of Interconnection Queue Position if it is deemed a Material Modification under Section 4.4.3 of the GIP.

### 4.2 General Study Process.

#### 4.2.1 DISIS Queue Study Procedures.

The Transmission Provider shall accept Interconnection Requests for Definitive Interconnection System Impact Studies during the DISIS Queue Cluster Window. Following the transition period described in Section 5.1.3 of the GIP, each DISIS Queue Cluster Window will be eleven (11) calendar months in duration. Following the close of the DISIS Queue Cluster Window, there shall be a one (1) calendar month DISIS Review Period to resolve any deficiencies in the Interconnection Requests received during the DISIS Queue Cluster Window. Each subsequent DISIS Queue Cluster Window will begin on the first day of the next calendar month after the end of the previous DISIS Review Period. Following the DISIS Review Period, the Transmission Provider shall complete the study of valid Interconnection Requests within the DISIS Queue in accordance with the timeline specified in Section 8.5 of the GIP. The Transmission Provider shall simultaneously study two or more valid Interconnection Requests within the DISIS Queue on the basis of geographic location and proposed electrical interconnection as specified in the Interconnection Requests in a non-discriminatory manner without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service ("Cluster Study").

The Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Generating Facility. The Transmission Provider shall study individual Interconnection Requests within the DISIS Queue not included within a Cluster Study based upon Initial Queue Position without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service.

Cluster Studies performed within the Definitive Interconnection System Impact Study phase shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

### 4.2.2 Study Cost and Network Upgrade Cost Allocation.

The Transmission Provider shall determine each Interconnection Customer's share of each phase of the Definitive Interconnection System Impact Study cost by allocating 50% of the applicable study costs to Interconnection Customers pro-rata based on number of Interconnection Requests included in the applicable study phase and by allocating 50% of the applicable study costs to Interconnection Customers pro-rata based on requested MWs included in the applicable study phase. The full study costs for DISIS Phase 1 and DISIS Phase 2 will be shared by all Interconnection Requests which entered each respective study phase. If

Interconnection Customer withdraws its Interconnection Request before or during DP1 or DP2, Interconnection Customer will not be responsible for study costs for subsequent study phases except that any remaining non-refundable portions of the study deposit will be applied in accordance with Section 13.3 of this GIP.

For Network Upgrades identified in Cluster Studies, the Transmission Provider shall calculate each Interconnection Customer's share of Network Upgrade costs in the following manner:

a. All Network Upgrades that are required to provide Interconnection Service for all Interconnection Requests included in a Cluster Study shall be included in a cluster cost allocation assessment group ("CCAAG"). The cost of each Network Upgrade component will be allocated to each Interconnection Customer in the CCAAG on a pro-rata impact basis as provided for in paragraph b below. With regard to the cost allocation, the Transmission Provider shall review all Network Upgrades and determine the earliest date that each upgrade is required to be in-service in order to provide the requested Interconnection Service ("Date Upgrade Needed").

b. An allocation of the cost of each Network Upgrade to each Interconnection Customer shall be determined on a pro-rata basis for the positive incremental power flow impacts of the requested service on such Network Upgrade in proportion to the total of all positive incremental power flow impacts on such Network Upgrade. For each Network Upgrade identified, the average incremental power flow impact of each Interconnection Request in the Cluster Study shall be determined using each seasonal model available for the Cluster Study period during which the generating facility associated with the Interconnection Request is most likely to be generating at nameplate capacity, after the Date Upgrade Needed of such upgraded facility. Each impact amount shall be determined by first establishing a set of initial seasonal base cases that excludes flows associated with all requests included in the Cluster Study. Then each request will be added to the models and the change in flow across such Network Upgrades shall be determined for each request included in the Cluster Study. The cost of a Network Upgrade allocated to each request shall be proportional to the average positive incremental impact of each request on such Network Upgrade divided by the total average positive incremental impact of all requests included in the Cluster Study on such Network Upgrade. The cost of each Network Upgrade shall be allocated to requests independently. Incremental flows having a negative impact (counter flow) on a Network Upgrade shall be ignored.

### 4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Interconnection Queue Position or Initial Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

### 4.4 Modifications.

Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Interconnection Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2 or 4.4.5 of the GIP, or are determined not to be Material Modifications pursuant to Section 4.4.3 of the GIP.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 8.8 of the GIP and Section 8.13 of the GIP as applicable and Interconnection Customer shall retain its Interconnection Queue Position or Initial Queue Position.

**4.4.1** During DP1, modifications to the Interconnection Request permitted under this section shall include specifically: (a) a decrease of electrical output (MW) of the proposed project of up to fifty percent (50%) of original requested capacity, through either (1) a decrease in plant size or (2) a decrease in interconnection service level (consistent with the process described in Section 3.1 of the GIP) accomplished by applying Transmission Provider-approved injection-limiting equipment; (b) modifying the technical parameters associated with the Generating Facility technology or the Generating Facility step-up transformer impedance characteristics; (c) modifying the interconnection configuration; and (d) a change from Network Resource Interconnection Service to Energy Resource Interconnection Service; (e) a Permissible Technological Advancement for the Generating Facility after the submission of the Interconnection Request. Section 4.4.5 of the GIP specifies a separate technological change procedure including the requisite information and process that will be followed to assess whether the Interconnection Customer's proposed technological advancement under Section 4.4.1(e) of the GIP is a Material Modification.

During DP2, modifications to the Interconnection Request permitted under this section shall include specifically a decrease of electrical output (MW) of up to ten percent (10%) of the original requested capacity. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

**4.4.2** Prior to making any modification other than those specifically permitted by Sections 4.4.1, and 4.4.4 of the GIP, Interconnection Customer may first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform Interconnection Customer in writing of whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1and 8.2 of the GIP or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

**4.4.3** Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4 of the GIP, Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's cost. Transmission Provider shall describe for the Interconnection Customer any costs incurred to conduct any necessary additional studies, provide its costs to the Interconnection Customer, and either refund any overage or charge for any shortage for costs that exceed the deposit amount.

**4.4.4** Prior to the Effective Date of the GIA, extensions of less than three (3) cumulative years in the Commercial Operation Date of the Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing. Extensions of more than three (3) cumulative years of the Commercial Operation Date of the Generating Facility are deemed to be a Material Modification. Extensions of Commercial Operation Date due to circumstances in Section 8.7 of the GIP are applicable to this Section 4.4.4.

**4.4.5 Technological Change Procedure.**

If an Interconnection Customer seeks to incorporate a technological advancement into its Generating Facility, it should submit a technological advancement request to the Transmission Provider in writing prior to the end of DP2.

The technological advancement request must include a description of the proposed advancement and provide details necessary to evaluate whether the proposed advancement is material, including but not limited to, listing the specific parameters in Attachments A and B to Appendix 3 of the GIP that would change as a result of the proposed advancement.

If the proposed technological advancement is a Permissible Technological Advancement or would not change any of the parameters in Attachments A or B to Appendix 3 of the GIP, no study will be necessary and the proposed advancement will not be considered a Material Modification.

The Transmission Provider will notify the Interconnection Customer if a study is necessary to determine whether the change is considered a Material Modification. The Interconnection Customer will provide a study deposit of $10,000 within five (5) Business Days after notification that additional studies are required. Requiring such a deposit is just and reasonable because a deposit will reimburse the Transmission Provider for the time and effort needed to complete the technological advancement study as well as minimize the submission of frequent and/or frivolous technological advancement requests. Studies conducted under this Section 4.4.5 of the GIP will be completed in thirty (30) Calendar Days after the Interconnection Customer submits a formal technological advancement request to the transmission provider, provided that the Interconnection Customer has provided the required information and study deposit.

The Transmission Provider will determine whether a request is a Material Modification by conducting steady-state, reactive power, short-circuit/fault duty, and stability analyses. The Transmission Provider may waive any of these analyses if it determines that one or more is not necessary based on the nature of the requested change. The request shall be deemed a Material Modification if the results of the analyses show that the cost or timing of any Interconnection Request with a later Queue priority date would be adversely impacted as a result.

## Section 5. Procedures for Interconnection Requests Submitted Prior to Revision Date of Generator Interconnection Procedures

### 5.1 Transition Procedures.

**5.1.1** Any Interconnection Request for which the Transmission Provider has not started DISIS Phase One as of January 15, 2022 ("Revision Date") shall be subject to this GIP and shall meet the requirements of Section 8.2 of this GIP within twenty (20) Business Days of receipt of notice from Transmission Provider. This notice shall be provided to each Interconnection Customer no later than twenty (20) Business Days following the start of DISIS Phase One of the Cluster Study immediately higher in queue priority than its Interconnection Request, with the exception of the first Cluster Study to enter the DISIS following the Revision Date. Transmission Provider shall provide notice to the first Cluster Study entering the DISIS following the Revision Date within five (5) Business Days of the Revision Date. Study and security deposits required by Section 8.2 of the GIP will be reduced by any amounts previously provided by Interconnection Customer. Any Interconnection Customer that fails to meet these transition requirements shall have its Interconnection Request deemed withdrawn pursuant to Section 3.7 of this GIP.

**5.1.2** Any Interconnection Request for which either a GIA has been executed or a GIA has been filed unexecuted with FERC, as of the Revision Date, shall not be subject to this revised GIP. Any Interconnection Request for which the Transmission Provider has started DISIS Phase One as of the Revision Date shall proceed under the GIP in effect prior to the Revision Date.

**5.1.3 Transition Period.**

On the Revision Date, the then-open DISIS Queue Cluster Window will remain open until Transmission Provider completes DISIS Phase One for the most recently closed DISIS Queue Cluster Window or until the Transmission Provider determines that the DISIS Queue Cluster window should close due to the size (in megawatts) of Interconnection Requests submitted during the DISIS Queue Cluster Window (the "Open Season"). Transmission Provider may choose to extend subsequent DISIS Queue Cluster Windows and create additional Open Seasons until such time as it completes DISIS Phase One of the immediately preceding Cluster Study. The Transmission Provider shall provide at least ten (10) Business Days notice prior to the close of the Open Season. The period between the Revision Date and the date the last Open Season closes shall be known as the Backlog Mitigation Period. Each subsequent DISIS Queue Cluster Window will be eleven (11) calendar months in duration followed by a

one (1) calendar month DISIS Review Period. The DISIS Queue Cluster Window that is open at that time and each subsequent DISIS Queue Cluster Window shall have the duration specified in Section 4.2.1 of the GIP.

During the Backlog Mitigation Period, Transmission Provider will process DISIS Cluster Studies in parallel by (i) starting DISIS Phase One of each subsequent Cluster Study after the end of DP1 of the immediately preceding Cluster Study and (ii) starting DISIS Phase Two of each subsequent Cluster Study after the end of DP2 of the immediately preceding Cluster Study. Accordingly, for each DISIS Cluster Study processed during the Backlog Mitigation Period, Transmission Provider will calculate the DISIS Phase Two processing time set forth in Section 3.5.2.2 of this GIP from the end of DP2 of the immediately preceding Cluster Study.

Notwithstanding Section 4.1.1 of this GIP, Transmission Provider will process all Interconnection Requests submitted during DISIS Queue Cluster Windows 2018-002 and 2019-001 as one Cluster Study. All Interconnection Requests included in this combined Cluster Study will have equal queue priority.

## 5.2 New Transmission Provider.

If Transmission Provider transfers control of its Transmission System to a successor Transmission Provider during the period when an Interconnection Request is pending, the original Transmission Provider shall transfer to the successor Transmission Provider any amount of the deposit or payment with interest thereon that exceeds the cost that it incurred to evaluate the request for interconnection. Any difference between such net amount and the deposit or payment required by this GIP shall be paid by or refunded to the Interconnection Customer, as appropriate. The original Transmission Provider shall coordinate with the successor Transmission Provider to complete any Interconnection Study, as appropriate, that the original Transmission Provider has begun but has not completed. If Transmission Provider has tendered a draft GIA to Interconnection Customer but Interconnection Customer has not either executed the GIA or requested the filing of an unexecuted GIA with FERC, unless otherwise provided, Interconnection Customer must complete negotiations with the successor Transmission Provider.

For a generating facility on the original Transmission Provider's Transmission System with an effective generator interconnection agreement that requires an operating guide to implement operating restrictions, and if such operating guide has not been completed at the time the original Transmission Provider transfers control of its Transmission System to the successor Transmission Provider, the successor Transmission Provider shall perform a study to determine the operating restrictions of the generating facility.

### 5.3 Transitional Notice Requirements for Generating Facility Replacement.

All requests for Generating Facility Replacement that are submitted to the Transmission Provider within 365 Calendar Days after July 1, 2020 shall have a date of cessation of operation for the Existing Generating Facility that is not earlier than two years after July 1, 2020.

## Section 6. Reserved

## Section 7. Reserved

## Section 8. Definitive Planning Phase

### 8.1 Generator Interconnection Study Agreement.

The Generator Interconnection Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of each phase of the Definitive Interconnection System Impact Study.

### 8.2 Execution of Generator Interconnection Study Agreement.

Interconnection Customer shall execute and deliver the Generator Interconnection Study Agreement to the Transmission Provider prior to close of the DISIS Queue Cluster Window, along with each of the following:

a. Demonstration of Site Control;

1. Site Control for the Generating Facility:

Specifications for acceptable site size for the purpose of demonstrating Site Control for the Generating Facility are contained in the Guidelines for the SPP GIP Process and Business Practices posted on the Transmission Provider's Generator Interconnection Study posting page on OASIS; Interconnection Customer may propose an alternative site size for Transmission Provider approval. Transmission Provider shall approve a demonstration of Site Control for the Generating Facility with an alternative site size when the Interconnection Customer submits to Transmission Provider a final layout drawing of the Generating Facility that includes at a minimum: (i) the spacing and number of turbines; (ii) the cable requirements to interconnect the individual turbines to the collector substation and the cable requirements from the collector substation to the interconnection substation; (iii) the resistance and impedance measurements of the interconnecting cable and (iv) acknowledgment by Interconnection Customer that the layout drawing is intended to be final and not subsequently substantially changed. Interconnection Customer may modify the layout drawing of a project until it submits an Interconnection Request into the Definitive Interconnection System Impact Study Queue ("DISIS Queue"). Once an Interconnection Request has been submitted in the DISIS Queue, and Transmission Provider has approved the final layout drawing and demonstration of Site Control, any subsequent change to the design of the Generating Facility as depicted in the layout drawing will be subject to Section 4.4 of the GIP and will be evaluated to determine whether the change constitutes a Material Modification under Section 4.4 of the GIP.

2. Site Control for the Generating Facility's Tie Line:

Reasonable evidence of Site Control for at least fifty percent (50%) of the mileage of the Generating Facility's high voltage tie line to the Point of Interconnection, or in lieu of Site Control for the Generating Facility's high voltage tie line, additional financial security in the amount of $80,000 per line mile of right-of-way.

If Interconnection Customer elects to provide additional financial security in lieu of evidence of Site Control for the Generating Facility's high voltage tie line, the additional financial security will be considered at risk and subject to the provisions set forth in Section 8.14(b)-(c) of this GIP. If the Interconnection Customer subsequently satisfies the applicable Site Control requirement for the Generating Facility's high voltage tie line, the amount of additional in lieu of financial security will be refunded to the Interconnection Customer.

b. Study deposit, which shall be one of the following:

1. $25,000 deposit for requested capacity less than or equal to 2 MW;

2. $35,000 deposit for requested capacity greater than 2 MW and less than or equal to 20 MW;

3. $50,000 deposit for requested capacity of greater than 20 MW and less than 75 MW; or

4. $90,000 deposit for requested capacity greater than or equal to 75 MW.

An Interconnection Request for a Replacement Generating Facility shall be accompanied by a study deposit in the amount of $60,000.

Study deposits provided pursuant to this section shall be applied toward any Interconnection Studies applicable to the Interconnection Request. Twenty percent (20%) of the study deposit shall be non-refundable at the start of DISIS Phase One.

c. Definitive Point of Interconnection;

d. Maximum generator output capability (MW);

e. Technical information required in Appendix 7 of the GIP, if applicable; and

f. Security deposit equal to $4,000/MW of the requested Interconnection Service ("Financial Security One").

If the Definitive Interconnection System Impact Study uncovers any unexpected result(s) not contemplated during the Scoping Meeting, a substitute Point of Interconnection identified by Transmission Provider may be substituted for the designated Point of Interconnection specified above without loss of Initial Queue Position, and restudies shall be completed pursuant to Section 8.8 of the GIP as applicable.

The expected In-Service Date of the new Generating Facility or increase in capacity of the Existing Generating Facility shall be no later than the end of the process window for the regional expansion planning period not to exceed seven years from the date the Interconnection Request is received by Transmission Provider, unless Interconnection Customer demonstrates that engineering, permitting and construction of the new Generating Facility or increase in capacity of the Existing Generating Facility will take longer than the regional expansion planning period. The In-Service Date may succeed the date the Interconnection Request is received by Transmission Provider by a period up to ten years, or longer where Interconnection Customer and Transmission Provider agree, such agreement not to be unreasonably withheld.

The expected Commercial Operation Date of a Replacement Generating Facility shall be no more than three (3) years from the date of cessation of operation of the Existing Generating Facility or four (4) years from the date a unit is determined to be in forced outage. If the requested period of time between the cessation of operation of the Existing Generating Facility and expected Commercial Operation Date of the Replacement Generating Facility is more than three (3) years, the request shall be treated as Interconnection request for a new Generating Facility.

## 8.3 DISIS Review Period

During the DISIS Review Period, the Transmission Provider will validate Interconnection Requests. The Transmission Provider shall notify the Interconnection Customer of any deficiencies that would warrant removal from the DISIS Queue. Interconnection Customer shall have fifteen (15) Business Days from the date of the notice to cure any deficiencies, which may extend beyond the DISIS Review Period. If the Interconnection Customer does not cure the deficiencies within such time period, the Interconnection Request shall be deemed withdrawn. Transmission Provider may conduct additional Scoping Meetings during the DISIS Review Period.

## 8.4 Scope of Definitive Interconnection System Impact Study.

**8.4.1** The Definitive Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Definitive Interconnection System Impact Study will consider the Base Case, as well as all Interconnection Requests in the Definitive Interconnection System Impact Study Queue and all generating facilities (and with respect to (iii) below, any identified

Network Upgrades associated with such higher queued interconnection) that, on the date the Definitive Interconnection System Impact Study is commenced:

(i) are directly interconnected to the Transmission System;

(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;

(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and

(iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

**8.4.2** The Definitive Interconnection System Impact Study will be conducted in two phases. DISIS Phase One will consist of a power flow analysis and calculation of the short-circuit ratio. DISIS Phase Two will consist of a Short Circuit Ratio and Critical Clearing Time ("SCRCCT") screening, a short circuit analysis and a stability analysis, taking into account the impact on the power flow analysis of any requests withdrawn after the DISIS Phase One. When the SCRCCT screening indicates possible inverter instability due to an Interconnection Request, an EMT Study will be performed commencing not less than fifteen (15) months prior to the inverter-based resource Commercial Operation Date. Each phase of the Definitive Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. For purposes of determining necessary Interconnection Facilities and Network Upgrades, the Definitive Interconnection System Impact Study shall consider the level of Interconnection Service requested by the Interconnection Customer, unless otherwise required to study the full Generating Facility Capacity due to safety or reliability concerns. Each phase of the Definitive Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility (+/-30% accuracy) and a non-binding good faith estimated time to construct.

**8.4.3 Availability of Limited Operation.**

If the Definitive Interconnection System Impact Study determines that the full amount of interconnection capacity requested by the Interconnection Customer is not available by its requested Commercial Operation Date due to transmission constraints that may be remedied by an upgrade(s) with an

in-service date beyond the Commercial Operation Date proposed by the Interconnection Customer, the Transmission Provider shall quantify the amount of interconnection capacity available to the Interconnection Customer prior to the in-service date of such upgrade(s) ("Limited Operation"). The Interconnection Customer shall be notified of the amount of interconnection capacity available under the Limited Operation condition. The Interconnection Customer may choose to proceed with Limited Operation. The Interconnection Customer may also be subject to conditions in Section 8.7 of the GIP.

### 8.4.4 Facilities Analysis.

During the DISIS Phase One, the Transmission Provider shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed for transmission facilities at the Point of Interconnection to physically and electrically connect the Generating Facility to the Transmission System ("Facilities Analysis"). The Facilities Analysis shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Owner's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. The results of the Facilities Analysis shall be utilized as part of the Interconnection Facilities Study.

During DISIS Phase Two, the Transmission Provider shall work with the Transmission Owner to refine the estimates for cost and time required to construct the Transmission Owner's Interconnection Facilities and Network Upgrades at the Point of Interconnection which shall be determined with the same level of accuracy as the Transmission Owner's Interconnection Facilities Study described in Section 8.11(a) of this GIP. The results of the Facilities Analysis will be posted with the study results of DISIS Phase Two.

## 8.5 Definitive Interconnection System Impact Study Procedures.

a. The Transmission Provider shall coordinate the Definitive Interconnection System Impact Study with any Affected System that is affected by the Interconnection Request pursuant to Section 3.6 of the GIP above. The Transmission Provider shall utilize existing studies to the extent practicable when it performs the study. The Transmission Provider shall use Reasonable Efforts to complete DISIS Phase One no later than sixty (60) Calendar Days after the close of the DISIS Review Period.

The Transmission Provider shall use Reasonable Efforts to complete DISIS Phase Two no later than one hundred twenty (120) Calendar Days after the end of DP1 described in Section 8.5.1 of the GIP.

b. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Definitive Interconnection System Impact Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Definitive Interconnection System Impact Study. If Transmission Provider is unable to complete the Definitive Interconnection System Impact Study within the time period, it shall notify Interconnection Customer and provide an estimated completion date with an explanation of the reasons why additional time is required. Upon request, Transmission Provider shall provide Interconnection Customer all supporting documentation, workpapers and relevant pre-Interconnection Request and post-Interconnection Request power flow, short circuit and stability databases for the Definitive Interconnection System Impact Study, subject to confidentiality arrangements consistent with Section 13.1 of the GIP.

### 8.5.1 Decision Point One

DP1 will commence the next Business Day after the Transmission Provider posts the results of DISIS Phase One and shall be fifteen (15) Business Days in duration. During DP1, the Interconnection Customer shall have the opportunity to review the results of the DISIS Phase One analysis, ask questions, receive responses, decide whether to proceed to DISIS Phase Two and respond to the Transmission Provider. If the allocated costs reported in DISIS Phase One, including any cost of upgrades required to mitigate impacts to Affected Systems, are updated by the Transmission Provider at any point during DP1, DP1 will be extended by ten (10) Business Days.

During DP1, the Interconnection Customer may make modifications to the Interconnection Request in accordance with Section 4.4.1 of the GIP. All new technical data that is required as a result of the changes requested during DP1 including but not limited to generator impedances, dynamic response files, ratings, and performance information, must be supplied by the Interconnection Customer within ten (10) Business Days after the end of DP1.

Prior to the end of DP1, the Interconnection Customer shall provide all of the following to the Transmission Provider: (1) a written indication of their intent either to withdraw the request or to proceed to DISIS Phase Two; (2) a written indication of all changes to be made to the request as permitted under this Section 8.5.1; (3) reasonable evidence of continued Site Control of the Generating Facility; (4) reasonable evidence of

continued Site Control of fifty percent (50%) of the Generating Facility's high voltage tie line to the Point of Interconnection, unless additional financial security in lieu of Site Control was provided by Interconnection Customer with its Interconnection Request; and (5) an additional Financial Security deposit ("Financial Security Two") equal to the greater of:

a. Ten percent (10%) of the Financial Security Two Cost Factor, less the amount of Financial Security One that was provided to enter DISIS Phase One, or

b. $4,000 per MW of the requested capacity advancing to DISIS Phase Two,

Where:

Financial Security Two Cost Factor is calculated by first determining the cost allocation factor pursuant to Section 4.2.2 of the GIP applicable to an Interconnection Request for an upgrade assigned to that same Interconnection Request, and multiplying the cost allocation factor by itself and then by the total estimated cost of the upgrade; then summing the resulting products for every upgrade allocated to an Interconnection Request. The cost of upgrades required to mitigate impacts to Affected Systems is excluded from Financial Security Two.

If the Interconnection Customer does not respond with all required items prior to the end of DP1, its Interconnection Request will be deemed to have been withdrawn.

After the conclusion of DP1, fifty percent (50%) of the study deposit provided under Section 8.2(b) of this GIP shall be non-refundable for any Interconnection Request which proceeds to DISIS Phase Two.

### 8.5.2 Decision Point Two

DP2 will commence the next Business Day after the Transmission Provider posts the results of DISIS Phase Two and shall be fifteen (15) Business Days in duration. During DP2, the Interconnection Customer shall have the opportunity to review the results of the DISIS Phase Two analysis, ask questions, receive responses, decide whether to proceed to the Interconnection Facilities Study and respond to the Transmission Provider. If the allocated costs reported in DISIS Phase Two, including any cost of upgrades required to mitigate impacts to Affected Systems, are updated by the Transmission Provider at any point during DP2, DP2 will be extended by ten (10) Business Days.

During DP2, the Interconnection Customer may make modifications to the Interconnection Request in accordance with Section 4.4.1 of the GIP. All new technical data that is required as a result of the changes requested

during DP2 including but not limited to generator impedances, dynamic response files, ratings, performance information, must be supplied by the Interconnection Customer within five (5) Business Days after the end of DP2.

Prior to the end of DP2, the Interconnection Customer shall provide all of the following to the Transmission Provider: (1) a written indication of their intent either to withdraw the request or to proceed to the Interconnection Facilities Study; (2) a written indication of a reduction in the requested capacity as permitted under Section 4.4.1 of the GIP; (3) written indication that the requested Commercial Operation Date will be extended or that the Interconnection Customer seeks to proceed under Limited Operation, if necessary, pursuant to Section 8.7 of the GIP; (4) reasonable evidence of continued Site Control for the Generating Facility; (5) reasonable evidence of Site Control for at least seventy-five percent (75%) of the Generating Facility's high voltage tie line to the Point of Interconnection, unless additional financial security in lieu of Site Control was provided by Interconnection Customer with its Interconnection Request; (6) reasonable evidence of Site Control of one-hundred percent (100%) of any new substations identified as required at the Point of Interconnection; (7) reasonable evidence of having satisfied at least one development milestone described in Section 11.3 of the GIP; and (8) an additional financial security deposit ("Financial Security Three") equal to:

> Twenty percent (20%) of the total upgrade costs allocated to the Interconnection Request, less the amount of Financial Security One and Financial Security Two that was previously provided to enter DISIS Phase One and DISIS Phase Two.

The cost of any upgrades required to mitigate impacts to Affected Systems is excluded from Financial Security Three.

If the Interconnection Customer does not respond with all required items prior to the end of DP2, its Interconnection Request will be deemed to have been withdrawn.

After the conclusion of DP2, one-hundred percent (100%) of the study deposit provided under Section 8.2(b) of this GIP shall be non-refundable for any Interconnection Request which proceeds to Interconnection Facilities Study.

### 8.6 Meeting with Transmission Provider.

During DP1 and DP2, the Interconnection Customer may request that the Transmission Provider, Transmission Owner and Interconnection Customer meet to discuss the results of the applicable phase of the Definitive Interconnection System Impact Study. Such meeting shall be held on a date mutually agreed upon

by the Parties. Reasonable Efforts shall be made to hold the meeting prior to the end of DP1 or DP2, as applicable.

**8.6.1 Environmental Review.**

This Section 8.6.1 applies only in the event the Interconnection Request will result in an interconnection to, or modification to, the transmission facilities of Western-UGP. Unless previously requested, Western-UGP shall use Reasonable Efforts to tender to the Interconnection Customer, within fifteen (15) Calendar Days of the end of DP2, an Environmental Review agreement authorizing Western-UGP, at Interconnection Customer's expense, to perform environmental review of the proposed interconnection to Western-UGP's transmission facilities, including review under NEPA, 42 U.S.C. §4321, et seq., as amended, and setting forth Interconnection Customer's responsibilities in connection with such environmental review. The Environmental Review agreement shall contain a non-binding good faith estimate of the cost and timeframe for completing the Environmental Review. Interconnection Customer shall execute the environmental review agreement and return it, with the estimated funds set forth in the agreement based upon the level of Environmental Review required, to Western-UGP within thirty (30) Calendar Days after receipt by the Interconnection Customer. If an executed Environmental Review agreement and the required funds are not provided in the manner set forth above, the Interconnection Request shall be deemed withdrawn. Notwithstanding the provisions of Section 3.7 of the GIP, an Interconnection Customer shall have no right to cure the failure to deliver the executed Environmental Review agreement or the required funds in the timeframe identified above. If the costs incurred by Western-UGP are less than the deposit submitted by Interconnection Customer, Western-UGP shall refund the difference, without interest, as soon as the necessary vouchers are prepared. In addition, if at any time prior to the issuance of Western-UGP's final NEPA decisional document the Interconnection Customer fails to comply with the terms of the Environmental Review agreement, Western-UGP shall notify the Transmission Provider of the Interconnection Customer's failure. Upon such notification, Transmission Provider may deem the Interconnection Request withdrawn.

**8.6.1.1 Environmental Review Procedures.**

a. After receipt of an executed Environmental Review agreement, Western-UGP shall use Reasonable Efforts to complete the study and issue a draft study report to Interconnection Customer within eighteen (18) months, or the actual time required to complete the necessary level of Environmental Review.

b. At the request of Interconnection Customer or at any time Western-UGP determines that it will not meet the required time frame for completing the Environmental Review, Western-UGP shall notify Interconnection Customer as to the schedule status of the Environmental Review. If Western-UGP is unable to complete the Environmental Review within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

c. Western-UGP shall notify the Transmission Provider of the schedule status of the Environmental Review.

**8.7 Interconnection Requests That Require Previously Approved Network Upgrades.**

At the completion of DISIS Phase One and DISIS Phase Two, the Definitive Interconnection System Impact Study may identify one or more Network Upgrades previously approved for construction under Section VI of Attachment O of this Tariff ("Previously Approved Network Upgrade") and required to be in-service prior to an Interconnection Customer's Commercial Operation Date. If a Previously Approved Network Upgrade will not be in-service prior to the Interconnection Customer's Commercial Operation Date, Interconnection Customer's Commercial Operation Date may be extended for a maximum period of three (3) years pursuant to Section 4.4.5 of the GIP to accommodate the in-service date for a Previously Approved Network Upgrade. If the three (3) year extension is not sufficient for a Previously Approved Network Upgrade to be placed into service prior to the Interconnection Customer's Commercial Operation Date, the Interconnection Customer may either (1) withdraw the Interconnection Request, (2) request a reduction in the amount of interconnection capacity in Interconnection Customer's Interconnection Request in accordance with Section 8.5.1 or 8.5.2 of the GIP, as applicable, or (3) agree to the following conditions for moving into the Interconnection Facilities Study:

a. The Generating Facility will be allowed to operate under Limited Operation in accordance with Section 8.4.3 of the GIP before a Previously Approved Network Upgrade is placed into service;

b. The Interconnection Customer will meet all requirements of the GIP; and

c. The Interconnection Customer will provide financial security and authorize engineering, procurement, and construction of its cost assigned Network Upgrades and interconnection facilities no later than thirty (30) days after the effective date of the GIA.

**8.8 Re-Study.**

If Re-Study of the Definitive Interconnection System Impact Study is required due to a higher queued or equal priority queued project dropping out of the queue, or a modification of a higher queued project subject to Section 4.4 of the GIP, or re-designation of the Point of Interconnection pursuant to Section 8.2 of the GIP, the Transmission Provider shall notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study, as reduced by deposit amounts retained for other Interconnection Customer(s) under Section 13.3 of the GIP, shall be borne by the Interconnection Customer(s) being re-studied.

After the completion of the Restudy, an Interconnection Customer that is being restudied may elect to remain in the Interconnection Facilities Study Queue, or withdraw its Interconnection Request and receive a refund of its security deposit in accordance with Sections 8.14 and 13.3 of the GIP.

**8.9 Entry into Interconnection Facilities Study.**

To enter the Interconnection Facilities Study, the Interconnection Customer shall satisfy the requirements of Section 8.5.2 of the GIP, together with Financial Security Three, no later than the end of DP2. The Generator Interconnection Study Agreement shall provide that Interconnection Customer shall compensate Transmission Provider for the actual cost of the Interconnection Facilities Study.

**8.10 Scope of Interconnection Facilities Study.**

The Interconnection Facilities Study shall specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Definitive Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System. The Interconnection Facilities Study shall also identify the electrical switching configuration of the connection equipment, including, without limitation: the transformer, switchgear, meters, and other station equipment; the nature and estimated cost of any Transmission Owner's Interconnection Facilities and Network Upgrades necessary to accomplish the interconnection; and an estimate of the time required to complete the construction and installation of such facilities. DISIS Phase One and DISIS Phase Two analysis may be refreshed, at the discretion of the Transmission Provider, to account for the impact of any requests that withdrew after the end of DP2. The Interconnection Facilities Study will also identify any potential control equipment for requests for Interconnection Service that are lower than the Generating Facility Capacity.

The Interconnection Facilities Study shall utilize results of the Facility Analysis from the Definitive Interconnection System Impact Study performed in accordance with Section 8.4.4 of the GIP.

**8.11 Interconnection Facilities Study Procedures.**

a. Transmission Provider shall coordinate the Interconnection Facilities Study with any Affected System pursuant to Section 3.6 of the GIP above and with affected SPP Transmission Owners. Transmission Provider shall utilize existing studies to the extent practicable in performing the Interconnection Facilities Study. Within forty-five (45) Calendar Days of receiving a request from SPP, Transmission Owners shall provide all information necessary to complete the Interconnection Facilities Study in the format requested by SPP and to the required degree of accuracy. Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Interconnection Facilities Study report to Interconnection Customer no later than sixty (60) Calendar Days after the end of DP2, with a +/- 20 cost estimate contained in the report.

b. At the request of Interconnection Customer or at any time Transmission Provider determines that it will not meet the required time frame for completing the Interconnection Facilities Study, Transmission Provider shall notify Interconnection Customer as to the schedule status of the Interconnection Facilities Study. If Transmission Provider is unable to complete the Interconnection Facilities Study and issue a draft Interconnection Facilities Study report within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

c. After the Transmission Provider posts the results of Interconnection Facilities Study, the Interconnection Customer will have ten (10) Business Days to review the results of the Interconnection Facilities Study analysis, ask questions, receive responses, decide whether to proceed to the GIA and respond to the Transmission Provider. The Transmission Provider shall issue the final Interconnection Facilities Study report within five (5) Business Days of receiving Interconnection Customer's comments or promptly upon receiving Interconnection Customer's statement that it will not provide comments. The Transmission Provider may reasonably extend such five-day period upon notice to Interconnection Customer if Interconnection Customer's comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 13.1 of the GIP.

**8.12 Meeting with Transmission Provider.**

During the ten (10) Business Day review period provided in Section 8.11(c) of this GIP, the Interconnection Customer may request that the Transmission Provider, Transmission Owner and Interconnection Customer meet to discuss the results of the Interconnection Facilities Study. Such meeting shall be held on a date mutually agreed upon by the Parties. Reasonable Efforts shall be made to hold the meeting prior to the end of the review period.

**8.13 Re-Study.**

If Re-Study of the Interconnection Facilities Study is required due to a higher or equal priority queued project dropping out of the queue or a modification of a higher queued project pursuant to Section 4.4 of the GIP, Transmission Provider shall so notify Interconnection Customer in writing. Such Re-Study shall take no longer than sixty (60) Calendar Days from the date of notice. Any cost of Re-Study, as reduced by deposit amounts retained under Section 13.3 of the GIP, shall be borne by the Interconnection Customer(s) being re-studied.

**8.14 Financial Security Refund Eligibility.**

a. For the purposes of this Section 8.14, allocated costs includes the costs of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities, and any cost of upgrades required to mitigate impacts to Affected Systems that have been assigned to the Interconnection Request.

b. If an Interconnection Request is withdrawn after the beginning of DISIS Phase One, but prior to the end of DP1, twenty-five percent (25%) of Financial Security One and twenty-five (25%) of Financial Security provided in lieu of Site Control for the Generating Facility's tie line will be forfeited to the extent that equally-queued Interconnection Requests are subjected to increased total of Network Upgrades and Transmission Owner Interconnection Facilities upgrade costs as a result of the withdrawal. If the Transmission Provider determines that no equally-queued Interconnection Requests are subjected to increased total of Network Upgrades and Transmission Owner Interconnection Facilities upgrade costs as a result of the withdrawal, Financial Security One will be refunded with accrued interest, if any.

c. If an Interconnection Request is withdrawn after the end of DP1, but prior to the end of DP2, one-hundred percent (100%) of Financial Security One, one-hundred percent (100%) of Financial Security provided in lieu of Site Control for the Generating Facility's tie line, and twenty-five percent (25%) of Financial Security Two will be forfeited to the extent that equally-queued Interconnection Requests are subjected to increased total

of Network Upgrades and Transmission Owner Interconnection Facilities upgrade costs as a result of the withdrawal, unless both of the following conditions exist: 1) the total allocated costs for the withdrawn Interconnection Request, including those costs for upgrades to mitigate impacts to Affected Systems if known, increased by twenty-five percent (25%) or more from the end of DP1 to DISIS Phase Two, and 2) the allocated cost per MW of requested capacity, including costs for Affected Systems if known, increased by $10,000/MW or more from the end of DP1 to DISIS Phase Two. If the Transmission Provider determines that no equally-queued Interconnection Requests are subjected to increased total of Network Upgrades and Transmission Owner Interconnection Facilities upgrade costs as a result of the withdrawal, Financial Security One will be refunded with accrued interest, if any.

d. If an Interconnection Request is withdrawn after the end of DP2, Financial Security One, Financial Security Two, Financial Security Three, and Financial Security provided in lieu of Site Control for the Generating Facility's tie line will be forfeited to the extent that concurrently- or lower-queued Interconnection Requests are subjected to increased total of Network Upgrades and Transmission Owner Interconnection Facilities upgrade costs as a result of the withdrawal, unless both of the following conditions exist: 1) the total allocated costs for the withdrawn Interconnection Request, including those costs for upgrades to mitigate impacts to Affected Systems if known, increased by thirty-five percent (35%) or more from the end of DP2 to the Interconnection Facilities Study, and 2) the allocated cost per MW of requested capacity, including costs for Affected Systems if known, increased by $15,000/MW or more from the end of DP2 to the Interconnection Facilities Study. If the Transmission Provider determines that no concurrently- or lower-queued Interconnection Requests are subjected to increased upgrade costs as a result of the withdrawal, Financial Security One, Financial Security Two, Financial Security Three, and Financial Security provided in lieu of Site Control for the Generating Facility's tie line will be refunded with accrued interest, if any.

e. If the Interconnection Facilities Study is subsequently revised or a new or revised Affected System study is received resulting in a total allocated cost that meets the exception to forfeiture afforded under Section 8.14(d), the Interconnection Customer may withdraw the Interconnection Request within the next fifteen (15) Business Days after the posting of the revised study and receive a full refund of Financial Security One, Financial Security Two, Financial Security Three, and Financial Security provided in lieu of Site Control for the Generating Facility's tie line. The option to withdraw and receive a full refund without regard to the impact to concurrently- or lower-queued Interconnection Requests will expire fifteen (15) Business Days after the posting of the revised study. The total

allocated costs based on results of any revised studies will continue to be compared against the total allocated costs at the end of DP2.

f. If any portion of Financial Security One, Financial Security Two, Financial Security Three, or Financial Security provided in lieu of Site Control for the Generating Facility's tie line is retained by Transmission Provider due to harm caused to an equally- or lower-queued Interconnection Request, it shall be applied toward the increased cost of designing, procuring, and constructing any Network Upgrades assigned to an Interconnection Customer as a result of the withdrawal. Any remaining funds shall be refunded to the Interconnection Customer with accrued interest calculated from the date of the receipt of the Financial Security One, Financial Security Two, Financial Security Three, and Financial Security provided in lieu of Site Control for the Generating Facility's tie line to the date of the refund, if any. The refund will be made after the completion of the necessary Interconnection Studies to determine the adverse impact to other Interconnection Requests.

g. Following the execution of a GIA or the filing of an unexecuted GIA at the Commission, Financial Security One, Financial Security Two, Financial Security Three, and Financial Security provided in lieu of Site Control for the Generating Facility's tie line shall be applied in accordance with Article 11.6 of the GIA. Any remaining funds shall be refunded to the Interconnection Customer in accordance with the terms of the GIA.

## Section 9. Engineering & Procurement ('E&P') Agreement

Prior to executing a GIA, an Interconnection Customer may, in order to advance the implementation of its interconnection, request and Transmission Owner shall offer the Interconnection Customer, an E&P Agreement that authorizes Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection. However, Transmission Owner shall not be obligated to offer an E&P Agreement if Interconnection Customer is in Dispute Resolution as a result of an allegation that Interconnection Customer has failed to meet any milestones or comply with any prerequisites specified in other parts of the GIP. The E&P Agreement is an optional procedure and it will not alter the Interconnection Customer's Interconnection Queue Position or In-Service Date. The E&P Agreement shall provide for Interconnection Customer to pay the cost of all activities authorized by Interconnection Customer and to make advance payments or provide other satisfactory security for such costs. An E&P Agreement executed by Western-UGP, as the Transmission Owner, requires advance payments.

Interconnection Customer shall pay the cost of such authorized activities and any cancellation costs for equipment that is already ordered for its interconnection, which cannot be mitigated as hereafter described, whether or not such items or equipment later become unnecessary. If Interconnection Customer withdraws its application for interconnection or either Party terminates the E&P Agreement, to the extent the equipment ordered can be canceled under reasonable terms, Interconnection Customer shall be obligated to pay the associated cancellation costs. To the extent that the equipment cannot be reasonably canceled, Transmission Owner may elect: (i) to take title to the equipment, in which event Transmission Owner shall refund Interconnection Customer any amounts paid by Interconnection Customer for such equipment and shall pay the cost of delivery of such equipment, or (ii) to transfer title to and deliver such equipment to Interconnection Customer, in which event Interconnection Customer shall pay any unpaid balance and cost of delivery of such equipment.

## Section 10. Reserved

## Section 11. Generator Interconnection Agreement (GIA)

### 11.1 Tender.

The Transmission Provider shall tender to the Interconnection Customer a draft GIA together with draft appendices within fifteen (15) Calendar Days of Transmission Provider's request to the Transmission Owner to begin the Interconnection Facilities Study. The draft GIA shall be in the form of the Transmission Provider's FERC-approved standard form GIA, which is in Appendix 6, or Appendix 13 when Western-UGP is a Party, as the Transmission Owner, to the GIA. If the Transmission Provider identifies that Interconnection Facilities or Network Upgrades are required on the Western-UGP Transmission System, the GIA shall be subject to completion of the appropriate NEPA level of Environmental Review. Until the required NEPA decision document is issued, no construction activities relating to the transmission facilities of Western-UGP shall commence and may impact the Commercial Operation Date for the Interconnection Request. Such NEPA related restrictions, if applicable, shall be set forth in the GIA.

### 11.2 Negotiation.

Transmission Provider, Transmission Owner and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft GIA for not more than sixty (60) Calendar Days after tender of the final Interconnection Facilities Study report, unless another time period is agreed upon by all Parties. If Interconnection Customer determines that negotiations are at an impasse, it may request termination of the negotiations at any time after tender of the draft GIA pursuant to Section 11.1 and request submission of the unexecuted GIA with FERC or initiate Dispute Resolution procedures pursuant to Section 13.5. If Interconnection Customer requests termination of the negotiations, but within sixty (60) Calendar Days thereafter fails to request either the filing of the unexecuted GIA or initiate Dispute Resolution, it shall be deemed to have withdrawn its Interconnection Request. Unless otherwise agreed by the Parties, if Interconnection Customer has not executed the GIA, requested filing of an unexecuted GIA, or initiated Dispute Resolution procedures pursuant to Section 13.5 within sixty (60) Calendar Days of tender of draft GIA appendices, it shall be deemed to have withdrawn its Interconnection Request. Transmission Provider shall provide to Interconnection Customer a final GIA within ten (10) Business Days after the completion of the negotiation process.

### 11.3 Execution and Filing.

Within ten (10) Business Days after receipt of the final GIA, Interconnection Customer shall provide Transmission Provider (A) reasonable evidence of continued Site Control or (B) posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, Interconnection Customer also shall provide reasonable evidence that one or

more of the following milestones in the development of the Generating Facility, at Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Generating Facility; (iv) execution of a contract (or comparable evidence) for the sale of electric energy or capacity from the Generating Facility; (v) statement signed by an officer or authorized agent of the Interconnection Customer attesting the Generating Facility is included in an applicable state resource plan; (vi) other information that the Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a Designated Resource; (vii) application for an air, water, or land use permit; (viii) Pre-Confirmed or Confirmed Long-Term Transmission Service Request ("TSR") from the source Generating Facility in the Interconnection Request; (ix) effective Interim Generator Interconnection Agreement associated with the same Interconnection Request; or (x) final detailed Generating Facility Design, and for Inverter-Based Resources, submission of Electromagnetic Transient (EMT) model. The Transmission Provider will not execute the final Generator Interconnection Agreement unless the Interconnection Customer provides the information described in this paragraph.

Within ten (10) Business Days after receipt of the final GIA, the Interconnection Customer shall either: (i) execute the tendered GIA and return to the Transmission Owner and Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC a GIA in unexecuted form. Within ten (10) Business Days of receipt of the tendered GIA the Transmission Owner shall execute and send a copy of the executed GIA to Interconnection Customer and Transmission Provider. As soon as practicable, but not later than thirty (30) Calendar Days after receiving either the executed version of the tendered GIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or ten (10) Business Days after receiving the request to file an unexecuted GIA, Transmission Provider shall file the GIA with FERC, together with its explanation of any matters as to which Interconnection Customer, Transmission Owner and Transmission Provider disagree and support for the costs that Transmission Provider and/or the Transmission Owner propose to charge to Interconnection Customer under the GIA. An unexecuted GIA should contain terms and conditions deemed appropriate by Transmission Provider and the Transmission Owner for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted GIA, they may proceed pending FERC action.

### 11.4 Commencement of Interconnection Activities.

If Interconnection Customer executes the final GIA, Transmission Provider, the Transmission Owner and Interconnection Customer shall perform their respective obligations in accordance with the terms of the GIA, subject to modification by FERC. Upon submission of an unexecuted GIA, Interconnection Customer,

Transmission Owner and Transmission Provider shall promptly comply with the unexecuted GIA, subject to modification by FERC.

## Section 11A. Interim Generator Interconnection Agreement (Interim GIA)

### 11A.1 Availability.

Prior to completion of requisite Interconnection Facilities, Network Upgrades, Distribution Upgrades, or System Protection Facilities, Interconnection Customers with pending Interconnection Requests may request Interim Interconnection Service, execute an Interim Generator Interconnection Agreement (Interim GIA) and receive Interim Interconnection Service pursuant to the terms and conditions of this Section 11A and the Interim GIA. Execution of an Interim GIA and receipt of Interim Interconnection Service is an optional procedure and will not alter the Interconnection Customer's Interconnection Queue Position. Interim Interconnection Service may be terminated at any point that a Generating Facility with an Interconnection Request that has a higher Interconnection Queue Position goes into Commercial Operation and Transmission Provider determines that Interim Interconnection Service and Interconnection Service cannot be provided to more than one Interconnection Customer simultaneously.

### 11A.2 Eligibility.

Interconnection Customers shall be eligible for Interim Interconnection Service under the following conditions:

**11A.2.1** Interconnection Customer has provided Transmission Provider: (i) reasonable evidence of continued Site Control or posting of $250,000, non-refundable additional security, which shall be applied toward future construction costs; and (ii) reasonable evidence that one or more of the following milestones in the development of the Generating Facility, at Interconnection Customer election, has been achieved: (a) the execution of a contract for the supply or transportation of fuel to the Generating Facility; (b) the execution of a contract for the supply of cooling water to the Generating Facility; (c) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Generating Facility; (d) execution of a contract (or comparable evidence) for the sale of electric energy or capacity from the Generating Facility; (e) statement signed by an officer or authorized agent of the Interconnection Customer attesting the Generating Facility is included in an applicable state resource plan; (f) other information that the Transmission Provider deems to be reasonable evidence that the Generating Facility will qualify as a Designated Resource; or (g) application for an air, water, or land use permit. The Transmission Provider will not execute the Interim Generator Interconnection Agreement unless the Interconnection Customer provides the information described in this paragraph.

**11A.2.2** Interconnection Customer has met the terms and conditions to be included in Transmission Provider's Definitive Interconnection System Impact Study Queue pursuant to Section 8.2;

**11A.2.3** Interconnection Customer has submitted in writing to Transmission Provider a request for Interim Interconnection Service;

**11A.2.4** Interconnection Customer has entered into a study agreement pursuant to which it has agreed to pay all costs, including deposits for any additional studies deemed necessary by Transmission Provider to evaluate the feasibility of the Interconnection Customer's requested Interim Interconnection Service;

**11A.2.4.1** The Interim Availability Interconnection System Impact Study will maintain the scope and procedures of the Definitive Interconnection System Impact Study with the exception that certain previous queued Interconnection Requests may not be included in the study. Such exceptions and reasons for those exceptions will be noted in the study. The Interim Availability Interconnection System Impact Study will also include a Short Circuit Ratio and Critical Clearing Time ("SCRCCT") screening. When the SCRCCT screening indicates possible inverter instability, the Transmission Provider will commence an EMT Study as far in advance of the requested Commercial Operation Date as practicable.

**11A.2.4.2** The cost of the Interim Availability Interconnection System Impact Study will be subtracted from the Customer's study deposit submitted for the Definitive Interconnection System Impact Study.

**11A.2.5** Transmission Provider has determined based upon the results of the additional studies, taking into account the Interconnection Customer's In-Service Date and the Transmission System topology upon such date that there will be sufficient stability and reliability margin to accommodate Interim Interconnection Service to the Interconnection Customer's Generating Facility;

**11A.2.6** Interconnection Customer has executed an Interim GIA in accordance with Section 11A.3; and

**11A.2.7** Interconnection Customer has provided security in accordance with Article 11.7 of the Interim GIA.

## 11A.3 Tender, Negotiation, Execution and Filing of Interim GIA.

**11A.3.1** Upon completion of Transmission Provider's analysis referenced in Section 11A.2.5, Transmission Provider shall notify Interconnection Customer in writing whether Interim Interconnection Service is feasible. In the event that Interconnection Customer's requested Interim Interconnection Service is feasible, Transmission Provider shall tender to the Interconnection Customer a draft Interim GIA together with appendices. The draft Interim GIA shall be in the form of the Transmission Provider's FERC-approved standard form Interim GIA, which is in Appendix 8, or in Appendix 14 when Western-UGP is a Party, as the Transmission Owner, to the Interim GIA. If the Transmission Provider identifies that Interconnection Facilities or Network Upgrades are required on the Western-UGP Transmission System, the Interim GIA shall be subject to completion of the appropriate NEPA level of Environmental Review. Until the required NEPA decision document is issued, no construction activities relating to the transmission facilities of Western-UGP shall commence and may impact the Commercial Operation Date for the Interconnection Request. Such NEPA related restrictions, if applicable, shall be set forth in the Interim GIA.

**11A.3.2** Transmission Provider, Transmission Owner and Interconnection Customer shall negotiate concerning any disputed provisions of the appendices to the draft Interim GIA for not more than thirty (30) Calendar Days after tender of the draft Interim GIA, unless another time period is agreed upon by the Parties. At the conclusion of the negotiation period or sooner if the Parties have reached agreement, Transmission Provider shall tender a final Interim GIA and within ten (10) Calendar Days the Interconnection Customer shall either: (i) execute the tendered Interim GIA and return to the Transmission Owner and Transmission Provider; or (ii) request in writing that Transmission Provider file with FERC an Interim GIA in unexecuted form. The Transmission Owner shall also execute the tendered Interim GIA and send a copy of the executed Interim GIA to Interconnection Customer and Transmission Provider. As soon as practicable, but not later than thirty (30) Calendar Days after receiving either the executed version of the tendered Interim GIA (if it does not conform with a FERC-approved standard form of interim interconnection agreement) or ten (10) Business Days after receiving the request to file an unexecuted Interim GIA, Transmission Provider shall file the Interim GIA with FERC, together with its explanation of any matters as to which Interconnection Customer, Transmission Owner and Transmission Provider disagree and support for the costs that Transmission Provider and/or the Transmission Owner propose to charge to

Interconnection Customer under the Interim GIA. An unexecuted Interim GIA should contain terms and conditions deemed appropriate by Transmission Provider and the Transmission Owner for the Interconnection Request. Prior to FERC action, the Parties may agree to proceed with design, procurement, and construction of facilities and upgrades under the terms of the unexecuted Interim GIA.

**11A.4 Commencement of Interim Interconnection Activities.**

If Interconnection Customer executes the Interim GIA, Transmission Provider, the Transmission Owner and Interconnection Customer shall perform their respective obligations in accordance with the terms of the Interim GIA, subject to modification by FERC. Upon submission of an unexecuted Interim GIA, Interconnection Customer, Transmission Owner and Transmission Provider shall promptly comply with the unexecuted Interim GIA, subject to modification by FERC.

**11A.5 Interconnection Service upon Termination of Interim GIA.**

Terminating events for an Interim GIA are given in Article 2.3.1 of the Interim GIA. Upon termination of the Interim GIA for any reason, the Interim Interconnection Service shall cease. Interconnection Service, if any, associated with the Generating Facility shall be provided to Interconnection Customer by Transmission Provider pursuant to the terms and conditions of a final GIA.

**11A.6 Maintenance Review.**

The Transmission Provider will annually perform a re-study of each effective Interim GIA and will determine whether the Interim Interconnection Service determined pursuant to Section 11A.2 continues to be available in the amount specified in the Interim GIA. The Transmission Provider will increase or decrease the amount of service in the Interim GIA based on the results of the annual re-study and subject to Article 4.2.3 of the Interim GIA. The Transmission Provider shall utilize existing studies to the extent practicable when it performs the re-study. The cost of each annual re-study shall be deducted from the study deposit made pursuant to Section 11A.2.4 and the Interconnection Customer shall be responsible for any cost in excess of the study deposit. A determination by the Transmission Provider that Interim Interconnection Service must be reduced pursuant to Article 4.2.2 of the Interim GIA will take precedence over the results of the most recent annual re-study.

## Section 12. Construction of Interconnection Facilities and Network Upgrades

### 12.1 Schedule.

Transmission Provider, the Transmission Owner and Interconnection Customer shall negotiate in good faith concerning a schedule for the construction of Transmission Owner's Interconnection Facilities and the Network Upgrades.

### 12.2 Construction Sequencing of Transmission Owner's Interconnection Facilities, Network Upgrades and Distribution Upgrades.

#### 12.2.1 General.

In general, the In-Service Date of an Interconnection Customer seeking interconnection to the Transmission System will determine the sequence of construction of Interconnection Facilities, Network Upgrades and Distribution Upgrades.

#### 12.2.2 Advance Construction of Network Upgrades that are an Obligation of an Entity other than Interconnection Customer.

An Interconnection Customer with a GIA, in order to maintain its In-Service Date, may request that Transmission Provider advance to the extent necessary the completion of Network Upgrades that: (i) were assumed in the Interconnection Studies for such Interconnection Customer, (ii) are necessary to support such In-Service Date, and (iii) would otherwise not be completed, pursuant to a contractual obligation of an entity other than Interconnection Customer that is seeking interconnection to the Transmission System, in time to support such In-Service Date. Upon such request, Transmission Owner will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Owner: (i) any associated expediting costs and (ii) the cost of such Network Upgrades.

Transmission Provider will refund to Interconnection Customer both the expediting costs and the cost of Network Upgrades, in accordance with Article 11.4 of the GIA. Consequently, the entity with a contractual obligation to construct such Network Upgrades shall be obligated to pay only that portion of the costs of the Network Upgrades that Transmission Provider has not refunded to Interconnection Customer. Payment by that entity shall be due on the date that it would have been due had there been no request for advance construction. Transmission Provider shall forward to Interconnection Customer the amount paid by the entity with a contractual obligation to construct the Network Upgrades as payment in full for the outstanding balance owed to Interconnection Customer. Transmission Provider then shall refund to that entity the amount that it

paid for the Network Upgrades, in accordance with Article 11.4 of the GIA.

**12.2.3 Advancing Construction of Network Upgrades that are Part of an Expansion Plan of the Transmission Provider.**

An Interconnection Customer with a GIA, in order to maintain its In-Service Date, may request that Transmission Owner advance to the extent necessary the completion of Network Upgrades that: (i) are necessary to support such In-Service Date and (ii) would otherwise not be completed, pursuant to an expansion plan of Transmission Provider, in time to support such In-Service Date. Upon such request, Transmission Owner will use Reasonable Efforts to advance the construction of such Network Upgrades to accommodate such request; provided that Interconnection Customer commits to pay Transmission Owner any associated expediting costs.

**12.2.4 Amended Definitive Interconnection System Impact Study.**

A Definitive Interconnection System Impact Study will be amended to determine the facilities necessary to support the requested In-Service Date. This amended study will include those transmission and Generating Facilities that are expected to be in service on or before the requested In-Service Date.

**12.3 Upgrades which will not be constructed by Transmission Owner.**

For all interconnection agreements that identify Network Upgrades and Distribution Upgrades as listed in Appendix A of the GIA which are required to be built by an entity other than the Transmission Owner (as defined in this Attachment V), such upgrades shall be constructed in accordance with the process defined under Section VI of Attachment O to the SPP Tariff.

## Section 13. Miscellaneous

### 13.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by either of the Parties to the other prior to the execution of a GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

#### 13.1.1 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of the GIA; or (6) is required, in accordance with Section 13.1.6, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under the GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

#### 13.1.2 Release of Confidential Information.

Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of

Interconnection Customer, on a need-to-know basis in connection with these procedures, unless such person has first been advised of the confidentiality provisions of this Section 13.1 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 13.1.

**13.1.3 Rights.**

Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

**13.1.4 No Warranties.**

By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

**13.1.5 Standard of Care.**

Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under these procedures or its regulatory requirements.

**13.1.6 Order of Disclosure.**

If a court or a Government Authority or entity with the right, power, and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of the GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

**13.1.7 Remedies.**

The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Section 13.1. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Section 13.1, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Section 13.1, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 13.1.

**13.1.8 Disclosure to FERC, its Staff, or a State.**

Notwithstanding anything in this Section 13.1 to the contrary, and pursuant to 18 CFR section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the GIP, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, consistent with applicable Federal and state laws, rules and regulations.

**13.1.9** Subject to the exception in Section 13.1.8, any information that a Party claims is competitively sensitive, commercial or financial information ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii)

otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIP or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a subregional, regional or national reliability organization or planning group. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

**13.1.10** This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

**13.1.11** Transmission Provider shall, at Interconnection Customer's election, destroy, in a confidential manner, or return the Confidential Information provided at the time of Confidential Information is no longer needed.

### 13.2 Delegation of Responsibility.

Transmission Provider may use the services of subcontractors as it deems appropriate to perform its obligations under this GIP. Transmission Provider shall remain primarily liable to Interconnection Customer for the performance of such subcontractors and compliance with its obligations of this GIP. The subcontractor shall keep all information provided confidential and shall use such information solely for the performance of such obligation for which it was provided and no other purpose.

### 13.3 Obligation for Study Costs.

Except as provided below, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interconnection Studies. Any difference between the study deposit and the actual cost of the applicable Interconnection Study shall be paid by or refunded, except as otherwise provided herein, to Interconnection Customer. Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study. Interconnection Customer shall pay any such undisputed costs within thirty (30) Calendar Days of receipt of an invoice therefore. Transmission Provider shall not be obligated to perform or continue to perform any studies unless Interconnection Customer has paid all undisputed amounts in compliance herewith. Study deposits collected in accordance with Section 8.2 of

the GIP may also be used to pay the study costs for any restudies in accordance with Section 8.13 of the GIP that affect lower-queued Interconnection Customers.

Study deposit funds retained by Transmission Provider as a result of withdrawals will first be used to reduce the DISIS costs for Interconnection Requests that reach Commercial Operation and are in the same DISIS Cluster Study as the Interconnection Request(s) from which Transmission Provider retained the study deposit funds. Transmission Provider will allocate the retained study deposit funds to active Interconnection Requests after the final Interconnection Facilities Study report is posted, and the allocated funds will be released when an active Interconnection Request reaches Commercial Operation. Any remaining study deposit funds will be used to reduce fees associated with Transmission Provider's Tariff Administration Services found in Schedule 1-A of its Open Access Transmission Tariff. Study deposit funds allocated to Interconnection Requests that withdraw after the Interconnection Facilities Study report is posted, but prior to reaching Commercial Operation will be used to fund any restudies caused by the withdrawn Interconnection Request. If Transmission Provider determines the withdrawal does not necessitate a restudy or if there are remaining study deposit funds, then the funds will be used to reduce fees associated with Transmission Provider's Tariff Administration Services found in Schedule 1-A of its Open Access Transmission Tariff.

### 13.4 Third Parties Conducting Studies.

If (i) at the time of the signing of an Interconnection Study Agreement there is disagreement as to the estimated time to complete an Interconnection Study, (ii) Interconnection Customer receives notice pursuant to Section 8.5 of the GIP that Transmission Provider will not complete an Interconnection Study within the applicable timeframe for such Interconnection Study, or (iii) Interconnection Customer receives neither the Interconnection Study nor a notice under Section 8.5 of the GIP within the applicable timeframe for such Interconnection Study, then Interconnection Customer may require Transmission Provider to utilize a third party consultant reasonably acceptable to Interconnection Customer and Transmission Provider to perform such Interconnection Study under the direction of Transmission Provider. At other times, Transmission Provider may also utilize a third party consultant to perform such Interconnection Study, either in response to a general request of Interconnection Customer, or on its own volition.

In all cases, use of a third party consultant shall be in accord with Article 26 of the GIA (Subcontractors) and limited to situations where Transmission Provider determines that doing so will help maintain or accelerate the study process for Interconnection Customer's pending Interconnection Request and not interfere with Transmission Provider's progress on Interconnection Studies for other pending Interconnection Requests. In cases where Interconnection Customer requests use of a third party consultant to perform such Interconnection Study, Interconnection Customer and Transmission Provider shall negotiate all of the pertinent terms and conditions, including reimbursement arrangements and the

estimated study completion date and study review deadline. Transmission Provider shall convey all workpapers, data bases, study results and all other supporting documentation prepared to date with respect to the Interconnection Request as soon as practicable upon Interconnection Customer's request subject to the confidentiality provision in Section 13.1. In any case, such third party contract may be entered into with either Interconnection Customer or Transmission Provider at Transmission Provider's discretion. In the case of (iii) Interconnection Customer maintains its right to submit a claim to Dispute Resolution to recover the costs of such third party study. Such third party consultant shall be required to comply with this GIP, Article 26 of the GIA (Subcontractors), and the relevant Tariff procedures and protocols as would apply if Transmission Provider were to conduct the Interconnection Study and shall use the information provided to it solely for purposes of performing such services and for no other purposes. Transmission Provider shall cooperate with such third party consultant and Interconnection Customer to complete and issue the Interconnection Study in the shortest reasonable time.

**13.5 Disputes.**

**13.5.1** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with the GIP, or their performance, the Parties agree to resolve such dispute using the dispute resolution procedures in Section 12 of the Tariff.

**13.5.2 Non-binding dispute resolution procedures.**

If a Party has submitted a notice of dispute pursuant to Section 13.5.1 of the GIP, and the Parties are unable to resolve the claim or dispute informally within the thirty (30) Calendar Days provided in Section 12.1 of the Tariff, and the Parties cannot reach mutual agreement in Section 12.1 of the Tariff to pursue the arbitration process in Section 12.2 of the Tariff, any Party may request that the other Parties engage in Non-binding Dispute Resolution pursuant to this section by providing written notice to Parties ("Request for Non-binding Dispute Resolution"). Conversely, any Party may file a Request for Non-binding Dispute Resolution pursuant to this section without first seeking mutual agreement to pursue the arbitration process in Section 12.2 of the Tariff. The Non-binding Dispute Resolution process in this Section 13.5.2 of the GIP shall serve as an alternative to, and not a replacement of, the arbitration process in Section 12.2 of the Tariff. Pursuant to this process, the Parties must within thirty (30) Calendar Days of receipt of the Request for Non-binding Dispute Resolution appoint a neutral decision-maker that is an independent subcontractor that shall not have any current or past substantial business or financial relationships with any Party. Unless otherwise agreed by the Parties, the decision-maker shall render a decision within sixty (60) Calendar Days of appointment and shall notify the Parties in writing of such decision and reasons therefore. This decision-maker shall be

authorized only to interpret and apply the provisions of the GIP, Interim GIA, and GIA and shall have no power to modify or change any provision of the GIP, Interim GIA, and GIA in any manner. The result reached in this process is not binding, but, unless otherwise agreed, the Parties may cite the record and decision in the Non-binding Dispute Resolution process in future Dispute Resolution processes, including in arbitration pursuant to Section 12.2 of the Tariff, or in a Federal Power Act section 206 complaint. Each Party shall be responsible for its own costs incurred during the process and the cost of the decision-maker shall be divided equally among each Party to the dispute.

## 13.6 Local Furnishing Bonds.

### 13.6.1 Transmission Owners That Own Facilities Financed by Local Furnishing or Other Tax-Exempt Bonds or That Are Tax Exempt Entities.

This provision is applicable only to a Transmission Owner that has financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds") or facilities with other bonds the interest on which is excluded from gross income under Section 103 of the Internal Revenue Code (“other tax-exempt bonds”), or that are tax-exempt entities, described in Section 501(c) of the Internal Revenue Code. Notwithstanding any other provision of this GIA and GIP, Transmission Provider shall not be required to provide Interconnection Service to Interconnection Customer pursuant to this GIA and GIP if the provision of such Interconnection Service would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance a Transmission Owner’s facilities that would be used in providing such Interconnection Service or would jeopardize the tax-exempt status of the tax-exempt entity.

### 13.6.2 Alternative Procedures for Requesting Interconnection Service.

If Transmission Provider determines that the provision of Interconnection Service requested by Interconnection Customer would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance a Transmission Owner’s facilities that would be used in providing such Interconnection Service or would jeopardize the tax-exempt status of the Transmission Owner, Transmission Provider shall advise the Interconnection Customer within thirty (30) Calendar days of receipt of the Interconnection Request.

Interconnection Customer thereafter may renew its request for interconnection using the process specified in Article 5.2(ii) of the Transmission Provider’s Tariff.

## Section 14. Fast Track Process

### 14.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Distribution System if the Small Generating Facility's capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 14.2.1 below or the Supplemental Review screens in section 14.4.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold, the Interconnection Customer's proposed Small Generating Facility must meet the codes, standards, and certification requirements of Appendices 9 and 10 of these procedures, or the Transmission Owner has to have reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

| Fast Track Eligibility for Inverter-Based Systems | | |
|---|---|---|
| Phase to Phase Line Voltage | Fast Track Eligibility Regardless of Location | Fast Track Eligibility on a Mainline[1] and ≤ 2.5 Electrical Circuit Miles from Substation[2] |
| < 5 kV | ≤ 500 kW | ≤ 500 kW |
| ≥ 5 kV and < 15 kV | ≤ 2 MW | ≤ 3 MW |
| ≥ 15 kV and < 30 kV | ≤ 3 MW | ≤ 4 MW |
| ≥ 30 kV and ≤ 69 kV | ≤ 4 MW | ≤ 5 MW |

[1] For purposes of this table, a mainline is the three-phase backbone of a circuit. It will typically constitute lines with wire sizes of 4/0 American wire gauge, 336.4 kcmil, 397.5 kcmil, 477 kcmil and 795 kcmil.

[2] An Interconnection Customer can determine this information about its proposed interconnection location in advance by requesting a pre-application report pursuant to Section 2.2.

**14.1.1** For purposes of Section 14.1, the Interconnection Request shall be evaluated using the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the Transmission Provider's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Transmission Provider's system. If the Transmission Provider does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system without such limitations. Furthermore, nothing in this section shall prevent a Transmission Provider from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

## 14.2 Initial Review

Interconnection Customer shall submit an application in the form of Attachment A to Appendix 3 along with a deposit of $1000. Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall have the Transmission Owner perform an initial review using the screens set forth below. The Transmission Provider shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Owner's determinations under the screens.

### 14.2.1 Screens

**14.2.1.1** The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Distribution System that is subject to the Tariff.

**14.2.1.2** For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Owner's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

**14.2.1.3** For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment

package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW.

**14.2.1.4** The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

**14.2.1.5** The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

**14.2.1.6** Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Transmission Owner's electric power system due to a loss of ground during the operating time of any anti-islanding function.

| **Primary Distribution Line Type** | **Type of Interconnection to Primary Distribution Line** | **Result/Criteria** |
|---|---|---|
| Three-phase, three wire | 3-phase or single phase, phase-to-phase | Pass screen |
| Three-phase, four wire | Effectively-grounded 3 phase or Single-phase, line-to-neutral | Pass screen |

**14.2.1.7** If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

**14.2.1.8** If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

**14.2.1.9** The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer

feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

**14.2.1.10** No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

**14.2.1.11** Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

**14.2.1.12** The Interconnection Customer must pay any study costs that exceed the deposit without interest within thirty (30) calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within thirty (30) calendar days of the invoice without interest.

**14.2.1.13 Environmental Review.**

In the event the Interconnection Request will result in an interconnection to, or modification to, the transmission facilities of Western-UGP, the Interconnection Request shall be subject to an Environmental Review as described in Section 14.3.4 of this GIP. The Interconnection Customer may request that the Environment Review begin any time after the Interconnection Request is accepted.

**14.2.2** If the proposed interconnection passes the screens, the Interconnection Request shall be approved; provided however, when Western-UGP, as the Transmission Owner, is a Party to the GIA, such approval is subject to completion of the appropriate NEPA level of Environmental Review and issuance of the required NEPA decisional document as will be set forth in the GIA pursuant to Section 14.2.4. Transmission Provider will provide the Interconnection Customer a draft GIA within five Business Days after the determination that requires the Interconnection customer to pay the costs of such system modifications prior to interconnection. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4

**14.2.3** If the proposed interconnection fails the screens, but both the Transmission Provider and the Transmission Owner determine that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Transmission Provider shall provide the

Interconnection Customer a draft GIA within five Business Days after the determination that requires the Interconnection customer to pay the costs of such system modifications prior to interconnection. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4.

**14.2.4** If the Transmission Provider identifies that Interconnection Facilities or Network Upgrades are required on the Western-UGP Transmission System, the GIA shall be subject to completion of the appropriate NEPA level of Environmental Review. Until the required NEPA decision document is issued, no construction activities relating to the transmission facilities of Western-UGP shall commence and may impact the Commercial Operation Date for the Interconnection Request. Such NEPA related restrictions, if applicable, shall be set forth in the GIA. After receiving a draft GIA from the Transmission Provider, the Interconnection Customer and the Transmission Owner shall have 30 Business Days or another mutually agreeable timeframe to sign and return the GIA, or request that the Transmission Provider file an unexecuted GIA with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the GIA, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the GIA is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the GIA.

**14.2.5** If the proposed interconnection fails the screens, and the Transmission Provider and Transmission Owner do not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

## 14.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost; (2) a supplemental study or other additional studies or actions; or (3) incurring significant cost to address safety, reliability, or power quality problems, the Transmission Provider shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider and the Transmission Owner to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider/Transmission Owner shall:

**14.3.1** Offer to perform facility modifications or minor modifications to the Transmission Owner's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Owner's electric system. If the Interconnection Customer agrees to pay for the modifications to the Transmission Provider's electric system, the Transmission Provider will provide the Interconnection Customer with a draft GIA within ten Business Days of the customer options meeting. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4; or

**14.3.2** The Transmission Provider will offer to perform a supplemental review in accordance with Section 14.4 and provide a non-binding good faith estimate of the costs of such review; or

**14.3.3** The Transmission Provider will obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under Sections 2-13.

**14.3.4 Environmental Review.**

This Section 14.3.4 applies only in the event the Interconnection Request will result in an interconnection to, or modification to, the transmission facilities of Western-UGP. Unless previously requested, Western-UGP shall use Reasonable Efforts to tender, within fifteen (15) Calendar Days after the customer options meeting, an Environmental Review agreement authorizing Western-UGP, at Interconnection Customer's expense, to perform environmental review of the proposed interconnection to Western-UGP's transmission facilities, including review under the National Environmental Policy Act (NEPA), 42 U.S.C. §4321, et seq., as amended, and setting forth Interconnection Customer's responsibilities in connection with such environmental review. The Environmental Review agreement shall contain a non-binding good faith estimate of the cost and timeframe for completing the Environmental Review. Interconnection Customer shall execute the environmental review agreement and return it, with the estimated funds set forth in the agreement based upon the level of Environmental Review required, to Western-UGP within thirty (30) Calendar Days after receipt by the Interconnection Customer. If an executed Environmental Review agreement and the required funds are not provided in the manner set forth above, the Interconnection Request shall be deemed withdrawn. Notwithstanding the provisions of Section 3.7 of the GIP, an Interconnection Customer shall have no right to cure the failure to deliver the executed Environmental Review agreement or the required funds in the timeframe identified above. If the costs incurred by Western-UGP are less than the deposit submitted by Interconnection Customer, Western-UGP shall refund the difference, without interest, as soon as the necessary vouchers are prepared. In addition, if at any time prior to the issuance of Western-UGP's final NEPA decisional document the Interconnection Customer fails to comply with the terms of the Environmental Review agreement, Western-UGP shall notify the Transmission Provider of the Interconnection

Customer's failure. Upon such notification, Transmission Provider reserves the right to deem the Interconnection Request withdrawn.

**14.3.4.1 Environmental Review Procedures.**

a. After receipt of an executed Environmental Review agreement, Western-UGP shall use Reasonable Efforts to complete the study and issue a draft study report to Interconnection Customer within eighteen (18) months, or the actual time required to complete the necessary level of Environmental Review.

b. At the request of Interconnection Customer or at any time Western-UGP determines that it will not meet the required time frame for completing the Environmental Review, Western-UGP shall notify Interconnection Customer as to the schedule status of the Environmental Review. If Western-UGP is unable to complete the Environmental Review within the time required, it shall notify Interconnection Customer and provide an estimated completion date and an explanation of the reasons why additional time is required.

c. Western-UGP shall notify the Transmission Provider of the schedule status of the Environmental Review.

## 14.4 Supplemental Review

**14.4.1** To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing and submit a deposit for the estimated costs of the supplemental review in the amount of the Transmission Provider's good faith estimate of the costs of such review, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the Transmission Provider within such timeframe, the Interconnection Request shall continue to be evaluated under the study processes in Sections 2-13 of this GIP unless it is withdrawn by the Interconnection Customer.

**14.4.2** The Interconnection Customer may specify the order in which the Transmission Provider will complete the screens in Section 14.4.4.

**14.4.3** The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 30 calendar days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 30 calendar days of the invoice without interest.

**14.4.4** Within 30 Business Days following receipt of the deposit for a supplemental review, the Transmission Provider shall (1) perform a supplemental review using

the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Transmission Provider shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in Section 14.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this Section 14.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under Section 2 through Section 13; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

**14.4.4.1** Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under Section 14.4.4.

**14.4.4.1.1** The type of generation used by the proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen in Section 14.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e., 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

**14.4.4.1.2** When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Transmission Provider's electric system will be considered as part of the aggregate generation.

**14.4.4.1.3** Transmission Provider will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

**14.4.4.2** Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

**14.4.4.3** Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Transmission Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

**14.4.4.3.1** Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

**14.4.4.3.2** Whether the loading along the line section is uniform or even.

**14.4.4.3.3** Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

**14.4.4.3.4** Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency

are within normal limits for a prescribed time.

**14.4.4.3.5** Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

**14.4.4.3.6** Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

**14.4.5** If the proposed interconnection passes the supplemental screens in Sections 14.4.4.1, 14.4.4.2, and 14.4.4.3 above, the Interconnection Request shall be approved; provided however, if the Interconnection Request will result in an interconnection to, or modification to, the transmission facilities of Western-UGP, as Transmission Owner, such approval is subject to the completion of the appropriate NEPA level of Environmental Review and issuance of the required NEPA decisional document as will be set forth in the GIA pursuant to Section 14.2.4. The Transmission Provider will provide the Interconnection Customer with a draft GIA within the timeframes established in Sections 14.4.5.1 and 14.4.5.2 below. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the study process in Section 3 through Section 13 consistent with Section 14.4.5.3 below.

**14.4.5.1** If the proposed interconnection passes the supplemental screens in Sections 2.4.1.1, 2.4.1.2, and 2.4.1.3 above and does not require construction of facilities by the Transmission Provider on its own system, the draft GIA shall be provided within ten Business Days after the notification of the supplemental review results. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4.

**14.4.5.2** If interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental screens in Sections 14.4.1.1, 14.4.1.2, and 14.4.1.3 above, and the Interconnection Customer agrees to pay for the modifications to the Transmission

Provider's electric system, the draft GIA, along with a non-binding good faith estimate for the interconnection facilities and/or minor modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results. Interconnection Customer and Transmission Owner shall complete negotiation of the GIA as described in Section 14.2.4.

**14.4.5.3** If the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider's system to pass the supplemental screens in Sections 2.4.1.1, 2.4.1.2, and 2.4.1.3 above, the Transmission Provider shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the Section 3 through Section 13 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

# APPENDIX 1 TO GIP

Reserved for Future Use

# APPENDIX 2 TO GIP

Reserved for Future Use

# APPENDIX 3 TO GIP

# GENERATOR INTERCONNECTION STUDY AGREEMENT

**THIS AGREEMENT** is made and entered into this _____ day of _____ 20___ by and between _____ a _____ organized and existing under the laws of the State of _____ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider "). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

## RECITALS

**WHEREAS,** Interconnection Customer is submitting an Interconnection Request to interconnect its Generating Facility with the Transmission System or adding generating capacity addition to an Existing Generating Facility as detailed in Attachment A to this Agreement; and

**WHEREAS,** Interconnection Customer has requested Transmission Provider to perform a Definitive Interconnection System Impact Study to assess the impact of its Interconnection Request to the Transmission System, and of any Affected Systems;

**WHEREAS**, Interconnection Customer has requested that Transmission Provider perform, subject to further confirmation, an Interconnection Facilities Study to specify and estimate the cost and schedule of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Definitive Interconnection System Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

**1.0** When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the Generator Interconnection Procedures ("GIP") in Attachment V of the Transmission Provider's Tariff.

**2.0 Definitive Interconnection System Impact Study**

**2.1** Interconnection Customer elects and Transmission Provider shall cause to be performed a Definitive Interconnection System Impact Study Phase One analysis, consistent with Section 8 of the GIP in accordance with the Tariff.

**2.2** If the Interconnection Customer elects, Transmission Provider shall cause to be performed a Definitive Interconnection System Impact Study Phase Two analysis, consistent with Section 8. of this GIP in accordance with the Tariff.

**2.3** The scope of the Definitive Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment B to this Agreement.

**2.4** The Definitive Interconnection System Impact Study will be based upon the technical information provided by Interconnection Customer. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Definitive Interconnection System Impact Study. If Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the Definitive Interconnection System Impact Study may be extended.

**2.5** The Definitive Interconnection System Impact Study report shall provide the following information:

(i) identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

(ii) identification of any thermal overload or voltage limit violations resulting from the interconnection;

(iii) identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;

(iv) description and non-binding, good faith estimated cost of and schedule for facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues; and

(v) will include a Facilities Analysis as specified in Section 8.4.4 of the GIP that will provide cost estimates for Transmission Owner's Interconnection Facilities and Network Upgrades at the Point of Interconnection.

## 3.0 Interconnection Facilities Study

**3.1** If the Interconnection Customer elects, Transmission Provider shall cause to be performed an Interconnection Facilities Study consistent with Section 8 of the GIP.

**3.2** Interconnection Customer shall meet the milestone requirements specified under Section 8.5.2 of the GIP prior to the performance of the Interconnection Facilities Study

**3.3** The scope of the Interconnection Facilities Study shall be subject to the data provided in Attachment C to this Agreement.

**3.4** The Interconnection Facilities Study report shall provide a description, estimated cost of, and schedule for the following consistent with Section 8.11 of the GIP:

(i) required facilities to interconnect the Generating Facility to the Transmission System and

(ii) the short circuit, instability, and power flow issues identified in the Definitive Interconnection System Impact Study.

**4.0** Interconnection Customer shall provide the deposit specified under Section 8.2 of the GIP for the performance of the Definitive Interconnection System Impact Study and Interconnection Facilities Study.

Upon receipt of each phase of the Definitive Interconnection System Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of each phase of the Definitive Interconnection System Impact Study.

Upon issuance of the final Interconnection Facilities Study report, Transmission Provider shall deduct associated study costs from the Interconnection Customer's study deposits provided in accordance with Section 8.2 of the GIP. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice. Any difference between the study deposit and Interconnection Customer's study cost obligation shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.3 of the GIP.

**5.0** Conditions for Limited Operation. If the Interconnection Customer agrees to proceed under Limited Operation pursuant to Section 8.7 of the GIP, the Interconnection Customer agrees to the following conditions:

1. The Generating Facility will be allowed to operate under Limited Operation in accordance with Section 8.4.3 of the GIP before a Network Upgrades previously approved for construction under Section VI of Attachment O of this Tariff ("Previously Approved Network Upgrade") is placed into service;

2. The Interconnection Customer will meet all requirements of the GIP; and

3. The Interconnection Customer will provide financial security and authorize engineering, procurement, and construction of its cost assigned Network Upgrades and interconnection facilities no later than thirty (30) Calendar Days after the effective date of the GIA in accordance with Article 11.6 of the GIA.

**6.0 Governing Law**

**6.1** **Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

**6.2** **Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

**6.3** **Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

**7.0** **Notices.**

**7.1** **General**. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Manager, GI Studies

To Interconnection Customer:

_____
_____
_____
Attention: _____

**7.2** **Alternative Forms of Notice**. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

**8.0** **Force Majeure**

**8.1** **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

**8.2 Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

## 9.0 Indemnity

**9.1 Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys' action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

**9.1.1 Indemnified Person**. If an indemnified person is entitled to indemnification under this Article 9 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 9.1 to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**9.1.2 Indemnifying Party**. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 9, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**9.1.3 Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 9.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a

Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**9.2 Consequential Damages**. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

## 10.0 Assignment

**10.1 Assignment**. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

## 11.0 Severability

**11.1 Severability**. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

## 12.0 Comparability

**12.1 Comparability**. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

## 13.0 Deposits and Invoice Procedures

**13.1 General**. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**13.2 Study Deposits**. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

**13.3 Final Invoice**. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

**13.4 Payment**. Invoices shall be rendered to the paying Party at the address specified Appendix A to this Agreement. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

**13.5 Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 15 of this Agreement. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due together with accrued interest in accordance with Section 3.7 of this Attachment V.

## 14.0 Representations, Warranties, and Covenants

**14.1 General**. Each Party makes the following representations, warranties and covenants:

**14.1.1 Good Standing**. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

**14.1.2** **Authority**. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**14.1.3** **No Conflict**. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**14.1.4** **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

## 15.0 Breach, Cure and Default

**15.1** **General.** A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Article 15.3 of this Agreement.

**15.2** **Events of Breach.** A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

**15.3 Cure and Default.** Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the "Non-Breaching Party"), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the "Breaching Party") and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

**15.4 Right to Compel Performance.** Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

**16.0 Miscellaneous**

**16.1 Binding Effect**. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**16.2 Conflicts**. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

**16.3 Rules of Interpretation**. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such

successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

**16.4 Entire Agreement**. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

**16.5 No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**16.6 Waiver**. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

**16.7 Headings**. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

**16.8 Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**16.9 Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

**16.10 Modification by the Parties**. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

**16.11 No Partnership**. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

**IN WITNESS THEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

**[Insert name of Transmission Provider]**

By: _____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Title: _____

Date: _____

## Attachment A to Appendix 3

### INTERCONNECTION REQUEST

1. The undersigned Interconnection Customer submits this request to interconnect its Generating Facility with the Transmission System pursuant to the Tariff.

2. This Interconnection Request is for (check one):

   _____ A proposed new Generating Facility.

   _____ An increase in the generating capacity or a Material Modification of an Existing Generating Facility.

   _____ Replacement of Existing Generating Facility with no increase in capacity

3. The type of interconnection service requested (check one):

   _____ Energy Resource Interconnection Service

   _____ Network Resource Interconnection Service

4. All requests for Network Resource Interconnection Service are also studied for Energy Resource Interconnection Service.

5. The Interconnection Customer provides the following information:

   a. Address or location or the proposed new Generating Facility site (to the extent known) or, in the case of an Existing Generating Facility, the name and specific location of the Existing Generating Facility:

   _____

   _____

   Geographic coordinates of the proposed new or Existing Generating Facility site:

   Latitude: ___ degrees, ___ minutes, ___ seconds (North)

   Longitude: ___ degrees, ___ minutes, ___ seconds (West);

   b. Maximum electrical output of the proposed new Generating Facility or the amount of increase in the generating capacity of an Existing Generating Facility;

   Maximum summer electrical output or increase of _____ megawatts at _____ degrees C

Maximum winter electrical output or increase of _____ megawatts at _____ degrees C

c. Preliminary one-line diagram of the Generating Facility;

d. Commercial Operation Date (month/day/year); ____/____/_____;

e. Name, address, telephone number, and e-mail address of Interconnection Customer's contact person in Item 9 below;

f. Geographical map showing the approximate location of the proposed Point of Interconnection and the location of the Generating Facility;

g. Generating Facility Data (set forth in Attachment B to this Appendix 3);

h. Requested capacity (in MW) of Interconnection Service (if lower than the Generating Facility Capacity);

i. Primary frequency response operating range for electric storage resources;

j. For request for Generating Facility Replacement, the planned or actual date of cessation of operation of the Existing Generating Facility: (month/day/year) ___/____/____.

6. Applicable deposit amount (check one).

New or increased Generating Facility or Material Modification:

____ Requested capacity less than or equal to 2 MW – $25,000 deposit.

____ Requested capacity greater than 2 but less than or equal to 20 MW – $35,000 deposit.

____ Requested capacity greater than 20 but less than 75 MW – $50,000 deposit.

____ Requested capacity equal to or greater than 75 MW – $90,000 deposit.

Generating Facility Replacement:

____ $60,000 deposit.

7. Evidence of Site Control as specified in Section 8.2 the GIP:

____ Site Control for the Generating Facility and one of the following:

____ Site Control for at least fifty percent (50%) of the Generating Facility's high voltage tie line to Point of Interconnection; **OR**

_____ Additional financial security in the amount of $80,000 per line right-of-way mile.

8. This Interconnection Request shall be submitted to the representative indicated below:

Manager, GI Studies
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

9. Representative of Interconnection Customer to contact (including e-mail address):

Name of Contact Person: _____

Mailing Address: _____

City, State, Zip_____

Telephone: _____

E-mail address: _____

10. This Interconnection Request is submitted by:

Name of Interconnection Customer (Company): _____

By (signature): _____

Name (type or print): _____

Title:_____

Date:_____

**Attachment B to Appendix 3**

## ASSUMPTIONS USED IN CONDUCTING THE DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY

The Definitive Interconnection System Impact Study will be based upon the information set forth in the Interconnection Requests and results of applicable prior studies, subject to any modifications in accordance with Section 4.4 of the GIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

(Name or description of substation or transmission line and voltage):

_____

Geographic coordinates of the proposed Point of Interconnection:

Latitude: ___ degrees, ___ minutes, ___ seconds (North)

Longitude: ___ degrees, ___ minutes, ___ seconds (West)

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer, Transmission Owner and Transmission Provider]

## GENERATING FACILITY DATA FOR THE DEFINITIVE INTERCONNECTION SYSTEM IMPACT STUDY

### UNIT RATINGS

(for a single generator in a group of generators)

Nameplate kVA _____ °F _____ Voltage _____
Prime Mover type _____
Power Factor: Lead _____ Lag _____
Speed (RPM) _____ Connection (e.g. Wye) _____
Short Circuit Ratio _____ Frequency, Hertz _____
Stator Amperes at Rated kVA _____ Field Volts _____
Max Turbine Power Output Capability: Summer MW _____ °F _____
Winter MW _____ °F _____

Primary frequency response operating range for electric storage resources:
Minimum State of Charge: _____ (Hz)
Maximum State of Charge: _____ (Hz)

### COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = _____ kW sec/kVA

Moment-of-Inertia, $WR^2$ = _____ lb. $ft.^2$

## REACTANCE DATA (PER UNIT-RATED KVA)

| | | DIRECT AXIS | | QUADRATURE AXIS | |
|---|---|---|---|---|---|
| Synchronous – saturated | $X_{dv}$ | _____ | $X_{qv}$ | _____ |
| Synchronous – unsaturated | $X_{di}$ | _____ | $X_{qi}$ | _____ |
| Transient – saturated | $X'_{dv}$ | _____ | $X'_{qv}$ | _____ |
| Transient – unsaturated | $X'_{di}$ | _____ | $X'_{qi}$ | _____ |
| Subtransient – saturated | $X''_{dv}$ | _____ | $X''_{qv}$ | _____ |
| Subtransient – unsaturated | $X''_{di}$ | _____ | $X''_{qi}$ | _____ |
| Negative Sequence – saturated | $X2_v$ | _____ | | |
| Negative Sequence – unsaturated | $X2_i$ | _____ | | |
| Zero Sequence – saturated | $X0_v$ | _____ | | |
| Zero Sequence – unsaturated | $X0_i$ | _____ | | |
| Leakage Reactance | $Xl_m$ | _____ | | |

## FIELD TIME CONSTANT DATA (SEC)

| | | | | |
|---|---|---|---|---|
| Open Circuit | $T'_{do}$ | _____ | $T'_{qo}$ | _____ |
| Three-Phase Short Circuit Transient | $T'_{d3}$ | _____ | $T'_{q}$ | _____ |
| Line to Line Short Circuit Transient | $T'_{d2}$ | _____ | | |
| Line to Neutral Short Circuit Transient | $T'_{d1}$ | _____ | | |
| Short Circuit Subtransient | $T''_{d}$ | _____ | $T''_{q}$ | _____ |
| Open Circuit Subtransient | $T''_{do}$ | _____ | $T''_{qo}$ | _____ |

## ARMATURE TIME CONSTANT DATA (SEC)

| | | |
|---|---|---|
| Three Phase Short Circuit | $T_{a3}$ | _____ |
| Line to Line Short Circuit | $T_{a2}$ | _____ |
| Line to Neutral Short Circuit | $T_{a1}$ | _____ |

NOTE: If requested information is not applicable, indicate by marking "N/A."

## MW CAPABILITY AND PLANT CONFIGURATION
## GENERATING FACILITY DATA

## ARMATURE WINDING RESISTANCE DATA (PER UNIT)

Positive $R_1$ _____
Negative $R_2$ _____
Zero $R_0$ _____

Rotor Short Time Thermal Capacity $I_2^2t$ = _____
Field Current at Rated kVA, Armature Voltage and PF = _____ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = _____ amps
Three Phase Armature Winding Capacitance = _____ microfarad
Field Winding Resistance = _____ ohms _____ °C
Armature Winding Resistance (Per Phase) = _____ ohms _____ °C

## CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

## GENERATOR STEP-UP TRANSFORMER DATA RATINGS

(for a single generator in a group of generators)

Capacity Self-cooled/
Maximum Nameplate
_____/_____kVA

Voltage Ratio (Generator Side/System side/Tertiary)
_____/_____/_____kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
_____/_____/_____

Fixed Taps Available _____

Present Tap Setting _____

Impedance: Positive $Z_1$ (on self-cooled kVA rating)_____ % _____ X/R

Impedance: Zero $Z_0$ (on self-cooled kVA rating)_____ % _____ X/R

## MAIN GENERATOR STEP-UP TRANSFORMER DATA RATINGS

(for a single generator or the step-up from collector system to POI voltage)

Capacity
Self-cooled/Maximum Nameplate

_____/_____kVA

Voltage Ratio (Generator Side/System side/Tertiary)
_____/_____/_____kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
_____/_____/_____

Fixed Taps Available _____

Present Tap Setting _____

Impedance: Positive $Z_1$ (on self-cooled kVA rating)_____ % _____ X/R

Impedance: Zero $Z_0$ (on self-cooled kVA rating)_____ % _____ X/R

## EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

## GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

## MULTIPLE-UNIT GENERATING FACILITIES

Number of generators to be interconnected pursuant to this Interconnection Request:
_____

Elevation: _____ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:
_____

List of adjustable setpoints for the protective equipment or software:
_____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the

Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

## INDUCTION GENERATORS

(*) Field Volts: _____
(*) Field Amperes: _____
(*) Motoring Power (kW): _____
(*) Neutral Grounding Resistor (If Applicable): _____
(*) $I_2^2t$ or K (Heating Time Constant): _____
(*) Rotor Resistance: _____
(*) Stator Resistance: _____
(*) Stator Reactance: _____
(*) Rotor Reactance: _____
(*) Magnetizing Reactance: _____
(*) Short Circuit Reactance: _____
(*) Exciting Current: _____
(*) Temperature Rise: _____
(*) Frame Size: _____
(*) Design Letter: _____
(*) Reactive Power Required In Vars (No Load): _____
(*) Reactive Power Required In Vars (Full Load): _____
(*) Total Rotating Inertia, H: _____Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

## ENERGY STORAGE RESOURCES

Device manufacturer: _____

Technology (Li-ion, Lead Acid, Flow Battery, Pumped Hydro, Flywheel, etc.)_____

Check one of the following:
_____ Stand-alone
_____ Co-located with another Generating Facility (co-located means at the same POI)

Maximum Energy Output Rating (MWh) _____ at Maximum Power Output (MW) _____

### Charging Parameters

Check one of the following:
_____ Yes, the energy storage resource will take energy from the Transmission System when operating in charging mode. The maximum rate of charge capability of the Generating

Facility will be _____ MW. The maximum rate of charge to be utilized (requested maximum) will be_____MW.

Charging Power Factor _____ lag _____ lead at rated output

_____ No, the energy storage resource will never take energy from the Transmission System when operating in charging mode, by either Self-Dispatch or at the direction of SPP. The monitoring and control equipment that will be used to ensure that the Generating Facility never takes energy from the Transmission System when operating in charging mode is described as follows:

_____
_____
_____

***Inverter-Based Resource Data***

*Phase-Locked Loop ("PLL") controller parameters for inverter-based resources:*

- *PLL Proportional Gain* $K_p$ _____
- *PLL Integral Gain* $K_i$ _____
- *PLL Frequency Limits* $\omega_l$ _____ *(rad/sec) and* $\omega_h$ _____ *(rad/sec)*

*The above data applies to a generic structure of the PLL (also commonly known as a synchronous reference frame PLL) and that the actual PLL structure within an Original Equipment Manufacturer's (OEM) device may differ from this generic structure. Should a difference exist, the parameter values of the PLL shall be provided such that the most recent equivalently parameterized generic industry model shows the same trend as the performance shown by actual OEM equipment.*

***Electromagnetic Transient (EMT) Models:***

*See SPP Electromagnetic Transient (EMT) Model Requirements Document*

## Attachment C to Appendix 3

### DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER FOR THE INTERCONNECTION FACILITIES STUDY

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?

_____ Yes _____ No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____ No (Please indicate on one line diagram).

What type of control system or PLC will be located at Interconnection Customer's Generating Facility?

_____

What protocol does the control system or PLC use?

_____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

_____

Bus length from generation to interconnection station:

_____

Line length from interconnection station to Transmission Provider's transmission line.

_____

Tower number observed in the field. (Painted on tower leg)* _____

Number of third party easements required for transmission lines*:

_____

* To be completed in coordination with Transmission Provider.

Is the Generating Facility in the Transmission Provider's service area?

_____ Yes _____ No Local provider: _____

Please provide proposed schedule dates:

| | |
|---|---|
| Begin Construction | Date:_____ |
| Generator step-up transformer receives back feed power | Date: _____ |
| Generation Testing | Date: _____ |
| Commercial Operation | Date: _____ |

# APPENDIX 4 TO GIP

Reserved for Future Use

## APPENDIX 5 TO GIP

## INTERIM AVAILABILITY INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

**THIS AGREEMENT** is made and entered into this _____ day of _____ 20___ by and between _____ a _____ and existing under the laws of the State of _____ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

## RECITALS

**WHEREAS,** Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an Existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated _____; and

**WHEREAS,** Interconnection Customer has a fully executed Generator Interconnection Study Agreement and has submitted all requirements and milestones to be included in the Definitive Interconnection System Impact Study Queue;

**WHEREAS,** Interconnection Customer desires to interconnect the Generating Facility with the Transmission System on an interim basis before all such required studies under the GIP can be completed;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

**1.0** When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

**2.0** Interconnection Customer elects and Transmission Provider shall cause to be performed an Interim Availability Interconnection System Impact Study as described in Section 11A.2.4.1 of this GIP.

**3.0** The scope of the Interim Availability Interconnection System Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

**4.0** The Interim Availability Interconnection System Impact Study will be based upon the technical information provided by Interconnection Customer in the Interconnection Request. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interim Availability Interconnection System Impact Study.

**5.0** The Interim Availability Interconnection System Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection and

- description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues.

**6.0** Interconnection Customer shall provide the deposit specified under Section 8.2 of the GIP for the performance of the Interim Availability Interconnection System Impact Study. Transmission Provider's good faith estimate for the time of completion of the Interim Availability Interconnection System Impact Study is [insert date].

Upon receipt of the Interim Availability Interconnection System Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Interim Availability Interconnection System Impact Study.

Any difference between the deposit and Interconnection Customer’s study cost obligation shall be paid by or refunded to the Interconnection Customer. Section 13.3 of this GIP shall apply to any study deposit funds retained by Transmission Provider as a result of withdrawal or any unused study deposit funds provided under Section 8.2 of this GIP.

**7.0 Governing Law**

**7.1 Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

**7.2 Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

**7.3 Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

**8.0 Notices.**

**8.1** **General**. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Manager, GI Studies

To Interconnection Customer:

_____
_____
_____
Attention: _____

**8.2** **Alternative Forms of Notice**. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

**9.0** **Force Majeure**

**9.1** **Economic Hardship.** Economic hardship is not considered a Force Majeure event.

**9.2** **Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but

shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

**10.0 Indemnity**

**10.1 Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys' action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

**10.1.1 Indemnified Person**. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**10.1.2 Indemnifying Party**. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**10.1.3 Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel

to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**10.2 Consequential Damages**. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

**11.0 Assignment**

**11.1 Assignment**. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such

assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

**12.0 Severability**

**12.1 Severability**. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

**13.0 Comparability**

**13.1 Comparability**. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

**14.0 Deposits and Invoice Procedures**

**14.1 General**. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**14.2 Study Deposits**. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

**14.3 Final Invoice**. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

**14.4 Payment**. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 3 to the GIP. The Party receiving the

invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

**14.5 Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due together with accrued interest in accordance with Section 3.7 of this Attachment V.

## 15.0 Representations, Warranties, and Covenants

**15.1 General**. Each Party makes the following representations, warranties and covenants:

**15.1.1 Good Standing**. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

**15.1.2 Authority**. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**15.1.3 No Conflict**. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such

Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**15.1.4** **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

## 16.0 Breach, Cure and Default

**16.1** **General.** A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

**16.2** **Events of Breach.** A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

**16.3** **Cure and Default.** Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the “Non-Breaching Party”), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the “Breaching Party”) and to any other person a Party to this Agreement identifies in

writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

**16.4 Right to Compel Performance.** Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

**17. Miscellaneous**

**17.1 Binding Effect**. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**17.2 Conflicts**. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

**17.3 Rules of Interpretation**. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

**17.4 Entire Agreement**. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and

contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

**17.5 No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**17.6 Waiver**. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

**17.7 Headings**. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

**17.8 Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**17.9 Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

**17.10 Modification by the Parties**. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

**17.11 No Partnership**. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

**IN WITNESS THEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

**[Insert name of Transmission Provider]**

By: _____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Title: _____

Date: _____

**Attachment A to Appendix 5**
**Interim Availability Interconnection System Impact Study Agreement**

## ASSUMPTIONS USED IN CONDUCTING THE INTERIM AVAILABILITY INTERCONNECTION SYSTEM IMPACT STUDY

The Interim Availability Interconnection System Impact Study will be based upon the information set forth in the Interconnection Requests and results of applicable prior studies, subject to any modifications in accordance with Section 4.4 of the GIP, and the following assumptions:

Designation of Point of Interconnection and configuration to be studied.

[Above assumptions to be completed by Interconnection Customer and other assumptions to be provided by Interconnection Customer, Transmission Owner and Transmission Provider]

## GENERATING FACILITY DATA FOR THE INTERIM AVAILABILITY INTERCONNECTION SYSTEM IMPACT STUDY

### UNIT RATINGS

Nameplate kVA _____ °F _____ Voltage _____
Prime Mover type _____
Power Factor: Lead _____ Lag _____
Speed (RPM) _____ Connection (e.g. Wye) _____
Short Circuit Ratio _____ Frequency, Hertz _____
Stator Amperes at Rated kVA _____ Field Volts _____
Max Turbine Power: Summer MW _____ °F _____
Winter MW _____ °F _____

### COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = _____ kW sec/kVA
Moment-of-Inertia, $WR^2$ = _____ lb. $ft.^2$

### REACTANCE DATA (PER UNIT-RATED KVA)

| | DIRECT AXIS | | QUADRATURE AXIS | |
|---|---|---|---|---|
| Synchronous – saturated | $X_{dv}$ | _____ | $X_{qv}$ | _____ |
| Synchronous – unsaturated | $X_{di}$ | _____ | $X_{qi}$ | _____ |

| | | | | |
|---|---|---|---|---|
| Transient – saturated | $X'_{dv}$ | _____ | $X'_{qv}$ | _____ |
| Transient – unsaturated | $X'_{di}$ | _____ | $X'_{qi}$ | _____ |
| Subtransient – saturated | $X''_{dv}$ | _____ | $X''_{qv}$ | _____ |
| Subtransient – unsaturated | $X''_{di}$ | _____ | $X''_{qi}$ | _____ |
| Negative Sequence – saturated | $X2_v$ | _____ | | |
| Negative Sequence – unsaturated | $X2_i$ | _____ | | |
| Zero Sequence – saturated | $X0_v$ | _____ | | |
| Zero Sequence – unsaturated | $X0_i$ | _____ | | |
| Leakage Reactance | $Xl_m$ | | | |

## FIELD TIME CONSTANT DATA (SEC)

| | | | | |
|---|---|---|---|---|
| Open Circuit | $T'_{do}$ | _____ | $T'_{qo}$ | _____ |
| Three-Phase Short Circuit Transient | $T'_{d3}$ | _____ | $T'_{q}$ | _____ |
| Line to Line Short Circuit Transient | $T'_{d2}$ | _____ | | |
| Line to Neutral Short Circuit Transient | $T'_{d1}$ | _____ | | |
| Short Circuit Subtransient | $T''_{d}$ | _____ | $T''_{q}$ | _____ |
| Open Circuit Subtransient | $T''_{do}$ | _____ | $T''_{qo}$ | _____ |

## ARMATURE TIME CONSTANT DATA (SEC)

| | | |
|---|---|---|
| Three Phase Short Circuit | $T_{a3}$ | _____ |
| Line to Line Short Circuit | $T_{a2}$ | _____ |
| Line to Neutral Short Circuit | $T_{a1}$ | _____ |

NOTE: If requested information is not applicable, indicate by marking "N/A."

## MW CAPABILITY AND PLANT CONFIGURATION
## GENERATING FACILITY DATA

## ARMATURE WINDING RESISTANCE DATA (PER UNIT)

| | | |
|---|---|---|
| Positive | $R_1$ | _____ |
| Negative | $R_2$ | _____ |
| Zero | $R_0$ | _____ |

Rotor Short Time Thermal Capacity $I_2^2t$ = _____
Field Current at Rated kVA, Armature Voltage and PF = _____ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = _____ amps
Three Phase Armature Winding Capacitance = _____ microfarad

Field Winding Resistance = _____ ohms _____ °C
Armature Winding Resistance (Per Phase) = _____ ohms _____ °C

## CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

## GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity Self-cooled/
Maximum Nameplate
/ kVA

Voltage Ratio (Generator Side/System side/Tertiary)
/ / kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
/_____/_____

Fixed Taps Available _____

Present Tap Setting _____

Impedance: Positive $Z_1$ (on self-cooled kVA rating) % X/R

Impedance: Zero $Z_0$ (on self-cooled kVA rating) % X/R

## EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

## GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

## WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request:
_____

Elevation: _____ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:
_____

List of adjustable setpoints for the protective equipment or software:
_____

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

## INDUCTION GENERATORS

(*) Field Volts: _____
(*) Field Amperes: _____
(*) Motoring Power (kW): _____
(*) Neutral Grounding Resistor (If Applicable): _____
(*) $I_2^2t$ or K (Heating Time Constant): _____
(*) Rotor Resistance: _____
(*) Stator Resistance: _____
(*) Stator Reactance: _____
(*) Rotor Reactance: _____
(*) Magnetizing Reactance: _____
(*) Short Circuit Reactance: _____
(*) Exciting Current: _____
(*) Temperature Rise: _____
(*) Frame Size: _____
(*) Design Letter: _____
(*) Reactive Power Required In Vars (No Load): _____
(*) Reactive Power Required In Vars (Full Load): _____
(*) Total Rotating Inertia, H: _____Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

# APPENDIX 6 TO THE GENERATOR INTERCONNECTION PROCEDURES

# GENERATOR INTERCONNECTION AGREEMENT (GIA)

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# GENERATOR INTERCONNECTION AGREEMENT

## THIS GENERATOR INTERCONNECTION AGREEMENT

("Agreement") is made and entered into this ____ day of _____ 20__, by and among _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Generating Facility), Southwest Power Pool, Inc., a corporation organized and existing under the laws of the State of Arkansas ("Transmission Provider") and _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Owner"). Interconnection Customer, Transmission Provider and Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

## Recitals

**WHEREAS,** Transmission Provider functionally controls the operation of the Transmission System; and,

**WHEREAS,** Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

**WHEREAS,** Transmission Owner owns facilities to which the Generating Facility is to be interconnected and may be constructing facilities to allow the interconnection; and,

**WHEREAS,** Interconnection Customer, Transmission Provider and Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

## Article 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Generator Interconnection Agreement.

**Breaching Party** shall mean a Party that is in Breach of the Generator Interconnection Agreement.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting Interconnection Studies.

**Commercial Operation** shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

**Commercial Operation Date** of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Generator Interconnection Agreement.

**Confidential Information** shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

**Contingent Facilities** shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. Contingent Facilities are identified in Appendix A of the Generator Interconnection Agreement.

**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

**Default** shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Generator Interconnection Agreement.

**Definitive Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures. The Definitive Interconnection System Impact Study is conducted in two phases.

**Definitive Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

**Dispute Resolution** shall mean the procedure in Section 13.5 of the Generator Interconnection Procedures for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

**Distribution System** shall mean the Transmission Owner's facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.

**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Electromagnetic Transient Study or EMT Study** shall mean an analysis to determine the electromagnetic transient response of the electric power system due to system disturbances.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner’s Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interconnection Service (ERIS)** shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

**Existing Generating Facility** shall mean a Generating Facility that is currently interconnected to the Transmission System of the Transmission Provider.

**Federal Power Act** shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. A Generating Facility consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generating Facility Modification** shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of the equipment at the Existing Generating Facility.

**Generating Facility Replacement** shall mean the process of replacing one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection as those being decommissioned and electrically disconnected.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in the Transmission Provider's Tariff.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Generator Interconnection Study Agreement** shall mean the study agreement for the Definitive Interconnection System Impact Study and the Interconnection Facilities Study in Appendix 3 of the Generator Interconnection Procedures.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3 of the Generator Interconnection Procedures.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 3 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, to interconnect a Replacement Generating Facility, to increase the capacity of, or make a Material Modification to the operating characteristics of, an Existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Replacement Impact Study, the Reliability Assessment Study, the Definitive Interconnection System Impact Study and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements described in the Generator Interconnection Procedures: the Generator Interconnection Study Agreement.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

**Network Resource Interconnection Service (NRIS)** shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interconnection Service in and of itself does not convey transmission service.

**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

**Notice of Dispute** shall mean a written notice of a dispute or claim that arises out of or in connection with the Generator Interconnection Agreement or its performance.

**Party or Parties** shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

**Point of Change of Ownership** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

**Point of Interconnection** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission System.

**Queue** shall mean the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Reliability Assessment Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of Transmission System during the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility.

**Replacement Generating Facility** shall mean a Generating Facility that replaces an Existing Generating Facility, or a portion thereof, at the same electrical Point of Interconnection pursuant to Section 3.9 of this Attachment V.

**Replacement Impact Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of the Transmission System.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers' Generating Facilities and which is the shared funding responsibility of such Interconnection Customers that may also benefit other Interconnection Customer(s) that are later identified as beneficiaries**.**

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility or Generating Facility's tie line; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

**Small Generating Facility** shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

**Stand Alone Network Upgrades** shall mean Network Upgrades that are not part of an Affected Systems that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Generator Interconnection Agreement. If the Transmission Provider, Transmission Owner and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Owner must provide the Interconnection Customer a written technical explanation outlining why the Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within fifteen (15) days of its determination.

**Surplus Interconnection Service** shall mean any unneeded portion of Interconnection Service established in a Generator Interconnection Agreement, such that if Surplus

Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection substation and at the same voltage level would remain the same.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades, or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

**Variable Energy Resource** shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

## Article 2. Effective Date, Term, and Termination

**2.1 Effective Date.** This GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by

FERC. Transmission Provider shall promptly file this GIA with FERC upon execution in accordance with Article 3.1, if required.

**2.2 Term of Agreement.** Subject to the provisions of Article 2.3, this GIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

**2.3 Termination Procedures.**

**2.3.1 Written Notice.** This GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

**2.3.2 Failure to Achieve Commercial Operation.** If the Generating Facility fails to achieve Commercial Operation for three (3) consecutive years following the Commercial Operation Date, this GIA may be terminated by the Transmission Provider after giving the Interconnection Customer ninety (90) Calendar Days advance written notice. Where a portion of the Generating Facility fails to achieve Commercial Operation for three (3) consecutive years following the Commercial Operation Date, the Transmission Provider shall issue a revised GIA to reflect the amount of the Generating Facility Capacity that achieved Commercial Operation. The revised GIA shall be consistent with the GIP in effect on the Effective Date of the GIA.

**2.3.3 Default.** Any Party may terminate this GIA in accordance with Article 17.

**2.3.4 Notice to FERC.** Notwithstanding Articles 2.3.1, 2.3.2 and 2.3.3, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this GIA, which notice has been accepted for filing by FERC.

**2.4 Termination Costs.** If a Party elects to terminate this Agreement pursuant to Article 2.3 above, Interconnection Customer and Transmission Owner shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by any other Party, as of the date of such Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this GIA. In the event of termination by any Party, all Parties shall use Commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this GIA, unless otherwise ordered or approved by FERC:

**2.4.1** With respect to any portion of Transmission Owner's Interconnection Facilities that have not yet been constructed or installed, Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for

construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this GIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer and the Interconnection Customer's allocated share of Network Upgrade(s) costs as calculated pursuant to Section 4.2.5 of the GIP and as listed in Appendix A of this GIA which are required for service to other Interconnection Customer(s).

**2.4.2** Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

**2.4.3** With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

**2.5 Disconnection.** Upon termination of this GIA, the Parties will take all appropriate steps to disconnect the Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this GIA or such non-terminating Party otherwise is responsible for these costs under this GIA.

**2.6 Survival.** This GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this GIA; to permit payments for any credits under this GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this GIA was in effect; and to permit each Party to have access to the lands of another Party pursuant to this GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

## Article 3. Regulatory Filings

**3.1 Filing.** Transmission Provider shall file this GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

## Article 4. Scope of Service

**4.1 Interconnection Product Options.** Interconnection Customer has selected the following (checked) type of Interconnection Service:

**4.1.1 Energy Resource Interconnection Service.**

**4.1.1.1 The Product.** Energy Resource Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Appendix A.

**4.1.1.2 Transmission Delivery Service Implications.** Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Generating Facility into and deliver power across the Transmission System on an "as available" basis. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

**4.1.2 Network Resource Interconnection Service.**

**4.1.2.1 The Product.** Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Owner shall construct the facilities identified in Appendix A to this GIA.

**4.1.2.2 Transmission Delivery Service Implications.** Network Resource Interconnection Service allows Interconnection Customer's Generating

Facility to be designated by any Network Customer under the Tariff on the Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission System, Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer’s Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission

service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

**4.2 Provision of Service.** Transmission Provider shall provide Interconnection Service for the Generating Facility at the Point of Interconnection.

**4.3 Performance Standards.** Each Party shall perform all of its obligations under this GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this GIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the GIA and submit the amendment to FERC for approval.

**4.4 No Transmission Delivery Service.** The execution of this GIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

**4.5 Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.8.

## Article 5. Interconnection Facilities Engineering, Procurement, and Construction

**5.1 Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Option To Build as described under Article 5.1.2 or the Negotiated Option described under Article 5.1.3, and such dates and selected option, as applicable, shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.2 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer’s designated dates are not acceptable to

Transmission Owner, the Interconnection Customer shall notify Transmission Owner within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

**5.1.1 Standard Option.** Transmission Owner shall design, procure, and construct Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Owner reasonably expects that it will not be able to complete Transmission Owner's Interconnection Facilities, and Network Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

**5.1.2 Option to Build.** Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.1. Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

**5.1.3 Negotiated Option.** If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.2). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1(Standard Option), Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects the Option to Build.

**5.2 General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from Interconnection Customer's construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Owner's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Owner not later than the Commercial Operation Date;

(10) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.2, Interconnection Customer shall pay Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for Transmission Owner to execute the responsibilities enumerated to Transmission Owner under Article 5.2. Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

**5.3 Liquidated Damages.** The actual damages to Interconnection Customer, in the event Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Owner pursuant to subparagraph 5.1.3, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Owner to Interconnection Customer in the event that Transmission Owner does not complete any portion of Transmission Owner's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Owner's Interconnection Facilities and Network Upgrades for which Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Owner to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this GIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for the Generating Facility's Trial Operation or to export power from the Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for Generating Facility's Trial Operation or to export power from the Generating Facility, but for Transmission Owner's delay; (2) Transmission Owner's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into a GIA with Transmission Owner or any cause beyond Transmission Owner's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility

for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

**5.4 Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative. The requirements of this paragraph shall not apply to non-synchronous generators.

**5.5 Equipment Procurement.** If responsibility for construction of Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

**5.5.1** Transmission Provider has completed the Interconnection Facilities Study pursuant to the Generator Interconnection Study Agreement;

**5.5.2** Transmission Owner has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.5.3** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 by the dates specified in Appendix B, Milestones.

**5.6 Construction Commencement.** Transmission Owner shall commence construction of Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

**5.6.1** Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

**5.6.2** Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Owner's Interconnection Facilities and Network Upgrades;

**5.6.3** Transmission Owner has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.6.4** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 by the dates specified in Appendix B, Milestones.

**5.7 Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Parties may, at any time, request a progress report from other Parties. If, at any time, Interconnection Customer determines that the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will be required.

**5.8 Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System, and shall work diligently and in good faith to make any necessary design changes.

**5.9 Limited Operation.** If any of Transmission Owner's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this GIA ("Limited Operation"). Transmission Owner shall permit Interconnection Customer to operate the Generating Facility and Interconnection Customer's Interconnection Facilities under Limited Operation in accordance with the results of such studies performed by Transmission Provider.

**5.10 Interconnection Customer's Interconnection Facilities ('ICIF').** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

**5.10.1 Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

**5.10.2 Transmission Owner's Review.** Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety,

durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner.

**5.10.3 ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. The Interconnection Customer shall provide Transmission Owner specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

**5.10.4 Updated Information Submission by Interconnection Customer.** The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Attachment A to Appendix 3 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Facilities Studies. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study agreements between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to this Article 5.10.4. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

**5.10.5 Information Supplementation.** Prior to the Commercial Operation Date, or as soon as possible thereafter, the Parties shall supplement their information submissions described above in this Article 5 with any and all “as-built”

Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Owner and Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide the Interconnection Customer and Transmission Provider any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

**5.11 Transmission Owner's Interconnection Facilities Construction.** Transmission Owner's Interconnection Facilities and Network Upgrades shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Owner's Interconnection Facilities and Network Upgrades [include appropriate drawings and relay diagrams].

Transmission Owner will obtain control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

**5.12 Access Rights.** Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to any other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if

allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this GIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

**5.13 Lands of Other Property Owners.** If any part of Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

**5.14 Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

**5.15 Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

**5.16 Suspension.**

**5.16.1 Suspension by Interconnection Customer.** Interconnection Customer, upon written notice to Transmission Provider and Transmission Owner, may suspend, for a period not to exceed 18 months, work by Transmission Owner associated with the construction and installation of Transmission Owner’s Interconnection Facilities and/or Network Upgrades required under this GIA under the following terms and conditions,

i. Construction of Network Upgrades that are required to provide Interconnection Service to other Generating Facilities and for which Interconnection Customer shares cost responsibility cannot be suspended pursuant to this Article 5.16.

ii. If the suspension period begins later than or extends beyond six months following the Effective Date of the GIA, the Interconnection Customer shall provide to the Transmission Provider security in the form described under Article 11.7 in an amount equal to the greater of:

a. the Interconnection Customer's allocated share of Network Upgrade(s) as calculated pursuant to Section 4.2.5 of the GIP and as identified in Appendix A of this GIA unless previously provided under Section 8.9 of the GIP; or

b. $5,000,000 if the Generating Facility is greater than or equal to 100 MW; or

c. $2,500,000 if the Generating Facility is greater than or equal to 50 MW and less than 100 MW; or

d. $1,000,000 if the Generating Facility is less than 50 MW; or

e. $500,000 if the Generating Facility is less than or equal to 2 MW.

iii. In the event that this GIA is terminated under this Article 5.16, the Transmission Provider shall retain the security provided pursuant to Article 5.16.1.ii in the amount required to meet Interconnection Customer's obligations pursuant to this GIA. Any difference between the security provided and Interconnection Customer's obligations shall be settled pursuant to Article 12.

iv. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16 and has not requested Transmission Owner to resume the work required under this GIA on or before the expiration of 18 months from the date of suspension, this GIA shall be deemed terminated unless Article 16 applies.

v. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16 and has not complied requirements of Article 5.16.1.ii on or before the later of the expiration of 6 months following the effective date of the GIA or the date the suspension is requested, this GIA shall be deemed terminated by the Interconnection Customer.

vi. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16, the Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Owner's safety and reliability criteria. Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Owner and Transmission Provider (i) have incurred pursuant to this GIA prior to the suspension and (ii) incur in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of

persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Owner shall obtain Interconnection Customer's authorization to do so. Transmission Owner and Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs.

vii. In the event Interconnection Customer provides written notice to resume work for those facilities for which work has been suspended pursuant to this Article 5.16.1, the Interconnection Customer shall receive a refund, including interest, of any payments provided in accordance with Article 5.16.1.ii in excess of the sum of Interconnection Customer's allocated share of Network Upgrade(s) costs and any costs incurred under Article 5.16.1.vi within 30 days of the date of such notice.

**5.16.2 Exemptions.** The Interconnection Customer shall be exempt from the payments described under Article 5.16.1.ii.b, 5.16.1.ii.c and 5.16.1.ii.d if the following occurs or Suspension is requested for the following reasons:

i. Construction of a Network Upgrade or the Generating Facility is prevented by order of a Governmental Authority; or

ii. Transmission Provider determines through an Interconnection Study that the Suspension does not qualify as a modification that has an impact on the cost or timing of any Interconnection Request with an equal or later Queue priority date (Material Modification); or

iii. Transmission Owner or Transmission Provider determines that a Force Majeure event prevents construction of a Network Upgrade.

**5.17 Taxes.**

**5.17.1 Interconnection Customer Payments Not Taxable.** The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Owner for the installation of Transmission Owner's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

**5.17.2 Representations and Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Generating Facility will pass to another party prior to the transmission of the electricity on the Transmission

System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Owner for Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Owner's request, Interconnection Customer shall provide Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Owner represents and covenants that the cost of Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

**5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Owner.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Owner from the cost consequences of any current tax liability imposed against Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Transmission Owner under this GIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Owner.

Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this GIA unless (i) Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Owner to report payments or property as income subject to taxation; provided, however, that Transmission Owner may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Owner upon request of the IRS, to keep these years

open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

**5.17.4 Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the Parties, this means that Interconnection Customer will pay Transmission Owner, in addition to the amount paid for the Interconnection Facilities, and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Transmission Owner under this GIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Owner's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Owner's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

**5.17.5 Private Letter Ruling or Change or Clarification of Law.** At Interconnection Customer's request and expense, Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Owner under this GIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that

authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

**5.17.6 Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Owner's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this GIA terminates and Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

**5.17.7 Contests.** In the event any Governmental Authority determines that Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of

the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Owner for the tax at issue in the contest.

**5.17.8 Refund.** In the event that (a) a private letter ruling is issued to Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this GIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this GIA is not taxable to Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Owner are not subject to federal income tax, or (d) if Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Owner pursuant to this GIA, Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amount paid by Interconnection Customer to Transmission Owner for such taxes which Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Owner, any refund or credit Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Owner's Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

**5.17.9 Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Owner for which Interconnection Customer may be required to reimburse Transmission Owner under the terms of this GIA. Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Owner.

**5.18 Tax Status.** All Parties shall cooperate with each other to maintain their tax status. Nothing in this GIA is intended to adversely affect any Party's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

**5.19 Modification.**

**5.19.1 General.** Each Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility Modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Owner's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

**5.19.2 Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this GIA and Good Utility Practice.

**5.19.3 Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Owner makes to Transmission Owner's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Owner's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

**5.20 Delays .** If a Network Upgrade(s) identified in Appendix A is delayed during the construction process and the Commercial Operation Date for the Generating Facility identified in Appendix B is no longer feasible, the Commercial Operation Date in Appendix B may be modified to no later than six (6) months following the in-service date for the last Network Upgrade identified in Appendix A.

## Article 6. Testing and Inspection

**6.1 Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Owner shall test Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

**6.2 Post-Commercial Operation Date Testing and Modifications.** Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

**6.3 Right to Observe Testing.** Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties have the right, at its own expense, to observe such testing.

**6.4 Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe another Parties' tests and/or inspection of any of its System Protection

Facilities and other protective equipment, including power system stabilizers; (ii) review the settings of the other Parties' System Protection Facilities and other protective equipment; and (iii) review another Parties' maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Any Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by another Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that any Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this GIA.

## Article 7. Metering

**7.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Owner's option, compensated to, the Point of Interconnection. Transmission Owner shall provide metering quantities, in analog and/or digital form, to Interconnection Customer and Transmission Provider on a same-time basis using communication as provided in Article 8. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

**7.2 Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

**7.3 Standards.** Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

**7.4 Testing of Metering Equipment.** Transmission Owner shall inspect and test all Transmission Owner-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Owner shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate

metering, unless the inaccuracy or defect is due to Transmission Owner's failure to maintain, then Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Owner shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

**7.5 Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

## Article 8. Communications

**8.1 Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Owner's Transmission System dispatcher or representative designated by Transmission Owner. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Owner as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Owner. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

**8.2 Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Owner through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Owner.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the

attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

**8.3 No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

**8.4 Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with (i) site-specific meteorological data including: temperature, wind speed, wind direction, relative humidity and atmospheric pressure and (ii) site specific geographic data including location (latitude and longitude) of the Variable Energy Resource and location (latitude and longitude) and height of the facility that will contain the equipment necessary to provide the meteorological data for such resource. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological, geographical and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological, geographical and forced outage data are set forth in Appendix C, Interconnection Details, of this GIA, as they may change from time to time.

**8.5 Phasor Measurement Unit (PMU) Recording Equipment**. Prior to the Initial Synchronization Date of a Generating Facility having a Generating Facility Capacity equal to or greater than 50 MW, phasor measurement recording and communications equipment shall be installed by the Transmission Owner at Interconnection Customer's expense that is capable of gathering phasor measurements as specified in the PMU Communications Handbook. To the extent similar quality equipment is being added or already exists, such as relays or digital fault recorders, that can collect data at least at the

same rate as PMUs and which data is synchronized via a high-accuracy satellite clock, such equipment can be utilized to satisfy this requirement if the equipment is located on the Transmission Owner's side of the Point of Change of Ownership and if mutually agreed to by the Parties. The phasor measurement equipment shall be installed at the Transmission Owner's side of the Point of Change of Ownership and become part of the Transmission Owner Interconnection Facilities. Phasor measurements shall be streamed in IEEE C37.118 or equivalent format and be provided to the Transmission Provider. This data shall at least be sufficient to determine (i) positive-sequence voltage magnitude and angle, (ii) positive-sequence current magnitude and angle, (iii) frequency, and (iv) rate of change of frequency. Such data shall be transmitted over the data circuit(s) as indicated in Article 8.1.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the applicable Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

## Article 9. Operations

**9.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Parties all information that may reasonably be required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

**9.2 Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Control Area in which the Generating Facility will be located. If Interconnection Customer elects to locate the Generating Facility in a Control Area other than the Control Area in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this GIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Control Area.

**9.3 Transmission Provider and Transmission Owner Obligations.** Transmission Provider and Transmission Owner shall cause the Transmission System and Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this GIA. Transmission Provider or Transmission Owner may provide operating instructions to Interconnection Customer consistent with this GIA and Transmission Owner's operating protocols and procedures as they may change from time to time. Transmission Provider and Transmission Owner will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

**9.4 Interconnection Customer Obligations.** Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA. Interconnection Customer shall operate the Generating Facility and

Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that another Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this GIA.

**9.5 Start-Up and Synchronization.** Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission System.

**9.6 Reactive Power and Primary Frequency Response.**

**9.6.1 Power Factor Design Criteria.**

**9.6.1.1 Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

**9.6.1.2 Non-Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that had not executed an interconnection facilities study agreement as of September 21, 2016.

**9.6.2 Voltage Schedules.** Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider and/or Transmission Owner shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Owner's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Owner shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating

Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the Transmission Owner.

**9.6.2.1 Voltage Regulators.** Whenever the Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in Mvars) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition in accordance with Good Utility Practice and Applicable Reliability Standards.

**9.6.3 Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating Facility when Transmission Owner requests Interconnection Customer to operate its Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.8 or such other agreement to which the Parties have otherwise agreed; provided however, to the extent the Tariff contains a provision providing for such compensation, that Tariff provision shall control.

**9.6.4 Primary Frequency Response.** Interconnection Customer shall ensure the primary frequency response capability of its Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband;. or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent

parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Interconnection Customer shall operate the Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Generating Facilities.

**9.6.4.1 Governor or Equivalent Controls.** Whenever the Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Generating Facility's governor or equivalent controls to a minimum whenever the Generating Facility is operated in parallel with the Transmission System.

**9.6.4.2 Timely and Sustained Response.** Interconnection Customer shall ensure that the Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

**9.6.4.3 Exemptions.** Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

**9.6.4.4 Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its GIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating

range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

## 9.7 Outages and Interruptions.

### 9.7.1 Outages.

**9.7.1.1 Outage Authority and Coordination.** Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

**9.7.1.2 Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that

Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

**9.7.1.3 Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

**9.7.2 Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider and/or Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's and/or Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

**9.7.2.1** The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

**9.7.2.2** Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

**9.7.2.3** When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

**9.7.2.4** Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected

duration. Transmission Provider or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Owner;

**9.7.2.5** The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

**9.7.3 Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a generating facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

**9.7.3.1 Frequency Ride Through and Voltage Ride Through for a Generating Facility no larger than 20 MW.** For Generating Facilities no larger than 20 MW, the Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Generating Facility. The Interconnection Customer shall enable these capabilities such that its Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to Article 6.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The Generating Facility’s protective equipment settings shall comply with the Transmission Provider’s automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term “ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied

to other generating facilities in the Balancing Authority on a comparable basis. The term "frequency ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term "voltage ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis.

**9.7.4 System Protection and Other Control Requirements.**

**9.7.4.1 System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Owner's Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

**9.7.4.2** Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

**9.7.4.3** Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

**9.7.4.4** Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

**9.7.4.5** Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

**9.7.4.6** Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals

suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

**9.7.5 Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

**9.7.6 Power Quality.** No Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

**9.8 Switching and Tagging Rules.** Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

**9.9 Use of Interconnection Facilities by Third Parties.**

**9.9.1 Purpose of Interconnection Facilities.** Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

**9.9.2 Third Party Users.** If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Owner's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

**9.10 Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

## Article 10. Maintenance

**10.1 Transmission Owner Obligations.** Transmission Owner shall maintain the Transmission System and Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

**10.2 Interconnection Customer Obligations.** Interconnection Customer shall maintain the Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

**10.3 Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

**10.4 Secondary Systems.** Each Party shall cooperate with the others in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

**10.5 Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner's Interconnection Facilities.

## Article 11. Performance Obligation

**11.1 Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

**11.2 Generating Facility.** Interconnection Customer shall install the Generating Facilities described in Appendix C within three (3) years of the Commercial Operation Date(s) specified in Appendix B.

**11.3 Transmission Owner's Interconnection Facilities.** Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

**11.4 Network Upgrades and Distribution Upgrades.** All Network Upgrades and Distribution Upgrades described in Appendix A shall be constructed in accordance with the process set forth in Section VI of Attachment O. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades that are associated with that Transmission Owner's system. The Distribution Upgrades and Network Upgrades described in Appendix A shall be solely funded by Interconnection Customer unless Transmission Owner elects to fund the capital for the Distribution Upgrades or Network Upgrades. *In the event that the Transmission Owner elects to fund the capital for the Network Upgrade(s) and/or Transmission Owner's System Protection Facilities, then the Parties shall enter into a Facilities Service Agreement. The Facilities Service Agreement shall take the form of the Facilities Service Agreement that is included in Appendix 17 of Attachment V of the Tariff.*

**11.4.1 Agreement to Fund Shared Network Upgrades.** Interconnection Customer agrees to fund Shared Network Upgrades, as determined by Transmission Provider. Where applicable, payments to fund Shared Network Upgrade(s) that are made to Transmission Provider by Interconnection Customer will be disbursed by Transmission Provider to the appropriate entities that are constructing the Shared Network Upgrades in accordance with Attachment O of the Tariff. In the event that Interconnection Customer fails to meet its obligation to fund Shared

Network Upgrades, Transmission Owner and Transmission Provider shall not be responsible for the Interconnection Customer's funding obligation.

**11.4.2 Contingencies Affecting Network Upgrades, System Protection Facilities and Distribution Upgrades**. Network Upgrades, System Protection Facilities and Distribution Upgrades that are required to accommodate the Generating Facility may be modified because (a) a higher queued Interconnection Request withdrew or was deemed to have withdrawn, (b) the GIA associated with a higher queued Interconnection Request was terminated, or (c) changes occur in equipment design standards or reliability criteria giving rise to the need for restudy. The higher queued Interconnection Requests that could impact the Network Upgrades, System Protection Facilities and Distribution Upgrades required to accommodate the Generating Facility, and possible modifications that may result from the above listed events affecting the higher queued Interconnection Requests, to the extent such modifications are reasonably known and can be determined, and estimates of the costs associated with such required Network Upgrades, System Protection Facilities and Distribution Upgrades, shall be provided in Appendix A.

**11.4.3 Agreement to Restudy**. The Interconnection Customer agrees to allow the Transmission Provider to perform a restudy in accordance with Sections 8.8 and 8.13 of the GIP if the Transmission Provider determines a restudy is required because one or more of the contingencies in Article 11.4.2 occurred. If a restudy is required, the Transmission Provider shall provide notice to Interconnection Customer. The Parties agree to amend Appendix A to this GIA in accordance with Article 30.10 to reflect the results of the restudy.

## 11.5 Transmission Credits.

**11.5.1 Credits for Amounts Advanced for Network Upgrades.** Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the Tariff for any Network Upgrades including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8.

**11.5.2 Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the GIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

**11.5.3** Notwithstanding any other provision of this GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to

firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain transmission credits for transmission service that is not associated with the Generating Facility.

**11.6 Initial Payment.**

Interconnection Customer shall make an initial payment ("Initial Payment") equal to the greater of a) twenty (20) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. Any financial security provided in Section 8.2, Section 8.5.1 and Section 8.5.2 of the GIP will be applied to this requirement. The Initial Payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the Initial Payment is not being protested by Interconnection Customer. If this GIA is terminated, then the Initial Payment shall be refunded with accrued interest calculated from the date of the receipt of the Initial Payment to the date of the refund, if any, to the Interconnection Customer less:

a. any costs that have been incurred for the construction of the facilities specified in Appendix A;

b. any funds necessary for the construction of those Shared Network Upgrades, or Network Upgrades, that would be assigned to another interconnection customer where such upgrade costs would not have been assigned but for the termination of the GIA; and

c. any costs that have been incurred for the construction of those Shared Network Upgrades, or Network Upgrades, that are no longer required due to the termination of the GIA that were paid for by another interconnection customer.

**11.7 Provision of Security.** At least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades as defined in Appendix A of this GIA, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Interconnection Facilities, Network Upgrades, or Distribution Upgrades as defined in Appendix A of this GIA and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider or Transmission

Owner for these purposes. If Interconnection Customer requests suspension pursuant to Article 5.16, Interconnection Customer may be required to provide Transmission Provider security in the form described above for its allocated share of Network Upgrade(s) costs as calculated pursuant to Section 4.2.5 of the GIP and defined in Appendix A of this GIA.

In addition:

**11.7.1** The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

**11.7.2** The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.7.3** The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.8 Interconnection Customer Compensation.** If Transmission Provider or Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this GIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to the Tariff. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this GIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

**11.8.1 Interconnection Customer Compensation for Actions During Emergency Condition.** Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.8.

## Article 12. Invoice

The terms of this Article 12 apply to billing between the Parties for construction and operation and maintenance charges. All other billing will be handled according to the Tariff.

**12.1 General.** Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same

date through netting, in which case all amounts a Party owes to the other Party under this GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**12.2 Final Invoice.** Within six months after completion of the construction of Interconnection Facilities and the Network Upgrades, the Interconnection Customer shall receive an invoice of the final cost due under this GIA, including any applicable cost due to termination, which shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnection Customer shall receive a refund of any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

**12.3 Payment.** Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this GIA.

**12.4 Disputes.** In the event of a billing dispute between the Parties, Transmission Owner, and Transmission Provider shall continue to provide Interconnection Service under this GIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

## Article 13. Emergencies

**13.1 Definition.** "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**13.2 Obligations.** Each Party shall comply with the Emergency Condition procedures of NERC, the Applicable Reliability Council, Transmission Provider, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

**13.3 Notice.** Transmission Provider or Transmission Owner shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Owner's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider and Transmission Owner promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

**13.4 Immediate Action.** Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or Transmission Owner or otherwise regarding the Transmission System.

**13.5 Transmission Provider and Transmission Owner Authority.**

**13.5.1 General**. Transmission Provider and/or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider and Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider and/or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer

shall comply with all of Transmission Provider's and Transmission Owner's operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

**13.5.2 Reduction and Disconnection.** Transmission Provider and/or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider and/or Transmission Owner can schedule the reduction or disconnection in advance, Transmission Provider and/or Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider and/or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer, Transmission Provider and/or Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

**13.6 Interconnection Customer Authority.** Consistent with Good Utility Practice and the GIA and the GIP, Interconnection Customer may take actions or inactions with regard to the Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Owner's Interconnection Facilities. Transmission Provider and/or Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

**13.7 Limited Liability.** Except as otherwise provided in Article 11.8.1 of this GIA, no Party shall be liable to the other Parties for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

## Article 14. Regulatory Requirements and Governing Law

**14.1 Regulatory Requirements.** Each Party's obligations under this GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith

seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act the Public Utility Holding Company Act of 2005, or the Public Utility Regulatory Policies Act of 1978 as amended by the 2005 Energy Policy Act.

**14.2 Governing Law.**

**14.2.1** The validity, interpretation and performance of this GIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

**14.2.2** This GIA is subject to all Applicable Laws and Regulations.

**14.2.3** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

**Article 15. Notices.**

**15.1 General.** Unless otherwise provided in this GIA, any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Any Party may change the notice information in this GIA by giving five (5) Business Days written notice prior to the effective date of the change.

**15.2 Billings and Payments.** Billings and payments shall be sent to the addresses set out in Appendix F.

**15.3 Alternative Forms of Notice.** Any notice or request required or permitted to be given by any Party to another and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

**15.4 Operations and Maintenance Notice.** Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

**Article 16. Force Majeure**

**16.1 Force Majeure.**

**16.1.1** Economic hardship is not considered a Force Majeure event.

**16.1.2** No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

## Article 17. Default

### 17.1 Default.

**17.1.1 General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this GIA or the result of an act or omission of another Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

**17.1.2 Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this GIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this GIA.

***17.1.3 Cross-Default.*** *Pursuant to Article 11.4 of this GIA, the Parties shall enter into a Facilities Service Agreement if the Transmission Owner elects to fund the capital for the Network Upgrades and/or Transmission Owner's System Protection Facilities. Notwithstanding anything to the contrary contained in this GIA, a breach by Interconnection Customer of any provision, covenant, or other term or condition contained in the Facilities Service Agreement shall be considered a breach under this GIA. Such breach shall be subject to the terms of Article 17 of this GIA. If a default under this GIA results from the Interconnection Customer's*

*breach of the Facilities Service Agreement and subsequent failure to cure, the Transmission Owner and Transmission Provider shall be entitled, but in no event required, to apply all rights and remedies available by reason of default under the Facilities Service Agreement and this GIA.*

## Article 18. Indemnity, Consequential Damages and Insurance

**18.1 Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Parties' action or inactions of its obligations under this GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

**18.1.1 Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**18.1.2 Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**18.1.3 Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**18.2 Consequential Damages.** Other than the Liquidated Damages heretofore described, in no event shall any Party be liable to any other Party under any provision of this GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which any Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

**18.3 Insurance.** Interconnection Customer and Transmission Owner shall at their own expense, maintain in force throughout the period of this GIA, and until released by all other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

**18.3.1** Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. The minimum limits for the Employers' Liability insurance shall be One Million Dollars ($1,000,000) each accident bodily injury by accident, One Million Dollars ($1,000,000) each employee bodily injury by disease, and One Million Dollars ($1,000,000) policy limit bodily injury by disease.

**18.3.2** Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards (if applicable), independent contractors coverage, coverage for pollution (if exposure is present) and punitive or exemplary damages, with minimum limits of One Million Dollars ($1,000,000) each occurrence/Two Million Dollars ($2,000,000) general aggregate and Two Million Dollars ($2,000,000) products and completed operations aggregate combined single limit for personal injury, bodily injury, including death and property damage.

**18.3.3** Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

**18.3.4** Excess Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) each occurrence/Twenty Million Dollars ($20,000,000) general aggregate.

**18.3.5** The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this GIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

**18.3.6** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

**18.3.7** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed to by all Parties.

**18.3.8** The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnection Customer and Transmission Owner are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

**18.3.9** Within ten (10) days following execution of this GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Interconnection Customer and Transmission Owner shall provide certification of all insurance required in this GIA, executed by each insurer or by an authorized representative of each insurer to the Other Party Group.

**18.3.10** Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

**18.3.11** The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this GIA.

## Article 19. Assignment

**19.1 Assignment.** This GIA may be assigned by any Party only with the written consent of the other Parties; provided that any Party may assign this GIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this GIA; and provided further that Interconnection Customer shall have the right to assign this GIA, without the consent of Transmission Provider or Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider and Transmission Owner of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider and Transmission Owner of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.7 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

## Article 20. Severability

**20.1 Severability.** If any provision in this GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this GIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Negotiated Option (Article 5.1.3), then none of these provisions shall thereafter have any

force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

## Article 21. Comparability

**21.1 Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

## Article 22. Confidentiality

**22.1 Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to another prior to the execution of this GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by any Party, a Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

**22.1.1 Term.** During the term of this GIA, and for a period of three (3) years after the expiration or termination of this GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

**22.1.2 Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this GIA; or (6) is required, in accordance with Article 22.1.7 of the GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

**22.1.3 Release of Confidential Information.** No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

**22.1.4 Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to another Party. The disclosure by any Party to another Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

**22.1.5 No Warranties.** By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

**22.1.6 Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this GIA or its regulatory requirements.

**22.1.7 Order of Disclosure.** If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

**22.1.8 Termination of Agreement.** Upon termination of this GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return

to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

**22.1.9 Remedies.** In the instance where Transmission Owner is a Federal Power Agency, as specified in the opening paragraph of this Agreement, then this Section 22.1.9 shall not apply to Transmission Owner. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

**22.1.10 Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying another Party to this GIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, if consistent with the applicable state rules and regulations.

**22.1.11** Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this GIA ("Confidential Information") shall not be disclosed by another Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIA or as a transmission service provider or a Control

Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

**22.1.12** This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

## Article 23. Environmental Releases

**23.1** Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

## Article 24. Information Requirements

**24.1 Information Acquisition.** Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

**24.2 Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

## Article 25. Information Access and Audit Rights

**25.1 Information Access.** Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which the other Parties are responsible under this GIA; and (ii) carry out its obligations and responsibilities under this GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this GIA.

**25.2 Reporting of Non-Force Majeure Events.** Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Parties receiving such notification to allege a cause for anticipatory breach of this GIA.

**25.3 Audit Rights.** Subject to the requirements of confidentiality under Article 22 of this GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense that other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

**25.4 Audit Rights Periods.**

**25.4.1 Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Owner’s Interconnection Facilities, and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner’s issuance of a final invoice in accordance with Article 12.2.

**25.4.2 Audit Rights Period for All Other Accounts and Records.** Accounts and records related to any Party's performance or satisfaction of all obligations under this GIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other

obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

**25.5 Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

## Article 26. Subcontractors

**26.1 General.** Nothing in this GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

**26.2 Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this GIA. Any applicable obligation imposed by this GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

**26.3 No Limitation by Insurance.** The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

## Article 27. Disputes

**27.1 Submission.** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this GIA or its performance, the Parties agree to resolve such dispute using the dispute resolution procedures of the Generator Interconnection Procedures.

## Article 28. Representations, Warranties, and Covenants

**28.1 General**. Each Party makes the following representations, warranties and covenants:

**28.1.1 Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this GIA.

**28.1.2 Authority.** Such Party has the right, power and authority to enter into this GIA, to become a Party hereto and to perform its obligations hereunder. This GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**28.1.3 No Conflict.** The execution, delivery and performance of this GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**28.1.4 Consent and Approval.** Such Party has sought or obtained, or, in accordance with this GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this GIA, and it will provide to any Governmental Authority notice of any actions under this GIA that are required by Applicable Laws and Regulations.

## Article 29. Joint Operating Committee

**29.1 Joint Operating Committee.** At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer, Transmission Owner and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Party shall notify the other Parties of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of any Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this GIA. All Parties shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

**29.1.1** Establish data requirements and operating record requirements.

**29.1.2** Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

**29.1.3** Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Owner’s and Interconnection Customer's facilities at the Point of Interconnection.

**29.1.4** Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

**29.1.5** Ensure that information is being provided by each Party regarding equipment availability.

**29.1.6** Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

## Article 30. Miscellaneous

**30.1 Binding Effect.** This GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**30.2 Conflicts.** In the event of a conflict between the body of this GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this GIA shall prevail and be deemed the final intent of the Parties.

**30.3 Rules of Interpretation.** This GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this GIA or such Appendix to this GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

**30.4 Entire Agreement.** This GIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this GIA. There are no other agreements, representations, warranties, or covenants which constitute any part of

the consideration for, or any condition to, a Party's compliance with its obligations under this GIA.

**30.5 No Third Party Beneficiaries.** This GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**30.6 Waiver.** The failure of a Party to this GIA to insist, on any occasion, upon strict performance of any provision of this GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this GIA. Termination or Default of this GIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this GIA shall, if requested, be provided in writing.

**30.7 Headings.** The descriptive headings of the various Articles of this GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this GIA.

**30.8 Multiple Counterparts.** This GIA may be executed in three or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**30.9 Amendment.** The Parties may by mutual agreement amend this GIA by a written instrument duly executed by each of the Parties.

**30.10 Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this GIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this GIA upon satisfaction of all Applicable Laws and Regulations.

**30.11 Reservation of Rights.** Transmission Provider shall have the right to make a unilateral filing with FERC to modify this GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this GIA pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

**30.12 No Partnership.** This GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

**IN WITNESS WHEREOF,** the Parties have caused this GIA to be executed by their respective authorized officials, and copies delivered to each Party, to become effective as of the Effective Date.

**SOUTHWEST POWER POOL, INC.**

By: _____

Printed Name:_____

Title: _____

Date: _____

**[Insert name of Transmission Owner]**

By: _____

Printed Name:_____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Printed Name:_____

Title: _____

Date: _____

## APPENDIX A TO GIA

**Interconnection Facilities, Network Upgrades and Distribution Upgrades**

**1. Interconnection Facilities:**

**(a) [insert Interconnection Customer's Interconnection Facilities]:**

**(b) [insert Transmission Owner's Interconnection Facilities]:**

**2. Network Upgrades:**

**(a) [insert Stand Alone Network Upgrades]:**

**(b) [insert Shared Network Upgrades]:**

**(c) [insert Contingent Facilities]:**

**3. Distribution Upgrades:**

**4. Interconnection Service:**

**Interconnection Customer has requested the following (from Appendix 3 of the GIP):**

**____ Energy Resource Interconnection Service**
**____ Network Resource Interconnection Service**

**5. Construction Option Selected by Customer:**

**6. Permits, Licenses, and Authorizations:**

**7. Description of the Point of Change of Ownership:**

**8. Description of the Point of Interconnection:**

**9. Higher-Queued Interconnection Customers:**

**10. Candidate Incremental Long-Term Congestion Rights:**

* Source _____
* Sink _____
* Candidate Incremental LTCR MW _____
* Term (years from in-service date of Network Upgrade) _____

# APPENDIX B TO GIA

## Milestones

# APPENDIX C TO GIA

## Interconnection Details

### 1. Description of Generating Facility:

### Wind Generating Facility Output Reduction

To protect the reliability of the Transmission System, a Generating Facility that is a wind plant shall be capable of reducing its generation output in increments of no more than fifty (50) MW in five (5) minute intervals. The requirements may be met by using: (a) SCADA control of circuit breakers protecting wind farm collector distribution circuits, (b) automatic control of wind turbine power output, or (c) a combination of (a) and (b).

### Inverter-Based Resource EMT Study Results Mitigations

If an Electromagnetic Transient Study is determined to be required by the Transmission Provider and the study results reveal an Adverse System Impact to the Transmission System, mitigation(s) shall be the responsibility of the Interconnection Customer and shall be implemented prior to the injection of power into the Transmission System.

# APPENDIX D TO GIA

## Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

## APPENDIX E TO GIA

## Commercial Operation Date

**[Date]**

_____,_____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

**[Transmission Owner Address]**

Re: _____ Generating Facility

Dear _____:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Generating Facility, effective as of **[Date plus one day]**.

Thank you.

**[Signature]**

**[Interconnection Customer Representative]**

## APPENDIX F TO GIA

### Addresses for Delivery of Notices And Billings

**Notices:**

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

**Billings and Payments:** [Specify addresses for construction invoices, O&M invoices and settlement of ancillary services]

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

**Alternative Forms of Delivery of Notices (telephone, facsimile or email):**

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

**Operational Communications:** [Identify contacts for operations]

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

[To be supplied.]

Interconnection Customer:
[To be supplied.]

## APPENDIX G TO GIA

## Requirements Of Generators Relying On Newer Technologies

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this GIA continue to apply to wind generating plant interconnections.

### A. Technical Standards Applicable to a Wind Generating Plant

#### i. Low Voltage Ride-Through (LVRT) Capability

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a facilities study agreement as of September 21, 2016. A wind generating plant to which this provision applies shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

**Transition Period LVRT Standard**

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing

time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**Post-transition Period LVRT Standard**

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**ii. Power Factor Design Criteria (Reactive Power)**

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this GIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

**iii. Supervisory Control and Data Acquisition (SCADA) Capability**

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for

the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

# APPENDIX 7 TO GIP

## INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Appendix 7 sets forth procedures specific to a wind generating plant. All other requirements of this GIP continue to apply to wind generating plant interconnections.

### A. Special Procedures Applicable to Wind Generators

The wind plant Interconnection Customer, in completing the Interconnection Request required by Section 3.4 of the GIP, may provide to the Transmission Provider a set of preliminary electrical design specifications depicting the wind plant as a single equivalent generator. Upon satisfying these and other applicable Interconnection Request conditions, the wind plant may enter the queue and receive the base case data as provided for in this GIP.

Before returning the Generator Interconnection Study Agreement, the wind plant Interconnection Customer must submit completed detailed electrical design specifications and other data (including collector system layout data) needed to allow the Transmission Provider to complete the System Impact Study.

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# INTERIM GENERATOR INTERCONNECTION AGREEMENT

**THIS INTERIM GENERATOR INTERCONNECTION AGREEMENT** ("Agreement" or "Interim GIA") is made and entered into this ____ day of _____ , by and among _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Generating Facility), Southwest Power Pool, Inc., a corporation organized and existing under the laws of the State of Arkansas ("Transmission Provider") and _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Transmission Owner"). Interconnection Customer, Transmission Provider and Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

## Recitals

**WHEREAS,** Transmission Provider functionally controls the operation of the Transmission System; and,

**WHEREAS,** Interconnection Customer has a pending Interconnection Request and intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

**WHEREAS,** Transmission Owner owns facilities to which the Generating Facility is to be interconnected and may be constructing facilities to allow the interconnection; and,

**WHEREAS**, Transmission Provider has conducted an additional analysis in accordance with Section 11A.2 of the Generator Interconnection Procedures ("GIP") to determine the availability of Interim Interconnection Service at the time of the Interconnection Customer's requested In-Service Date and Commercial Operation Date with the Transmission System topology and in-service generation expected to be in place at that time; and,

**WHEREAS**, Interconnection Customer, in accordance with Section 11A.2.1 of the GIP, has provided Transmission Provider with reasonable evidence of Site Control or additional security and with reasonable evidence that one or more of the milestones listed in Section 11A.2.1 has been achieved; and

**WHEREAS**, Interconnection Customer, Transmission Provider and Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System on an interim basis prior to the completion of the generator interconnection study process set forth in the GIP and execution of a Generator Interconnection Agreement;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Interim GIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff ("Tariff").

## Article 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Interim Generator Interconnection Agreement.

**Breaching Party** shall mean a Party that is in Breach of the Interim Generator Interconnection Agreement.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting Interconnection Studies.

**Commercial Operation** shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

**Commercial Operation Date** of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Interim Generator Interconnection Agreement.

**Confidential Information** shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

**Contingent Facilities** shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. Contingent Facilities are identified in Appendix A of the Interim Generator Interconnection Agreement.

**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

**Default** shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Interim Generator Interconnection Agreement.

**Definitive Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures. The Definitive Interconnection System Impact Study is conducted in two phases.

**Definitive Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

**Dispute Resolution** shall mean the procedure in Section 13.5 of the Generator Interconnection Procedures for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

**Distribution System** shall mean the Transmission Owner's facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.

**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Interim Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Electromagnetic Transient Study or EMT Study** shall mean an analysis to determine the electromagnetic transient response of the electric power system due to system disturbances.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by Interim Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interim Interconnection Service** shall mean an Interim Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

**Existing Generating Facility** shall mean a Generating Facility that is currently interconnected to the Transmission System of the Transmission Provider.

**Federal Power Act** shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. A Generating Facility consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generating Facility Modification** shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of the equipment at the Existing Generating Facility.

**Generating Facility Replacement** shall mean the process of replacing one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection as those being decommissioned and electrically disconnected.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in the Transmission Provider's Tariff.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Generator Interconnection Study Agreement** shall mean the study agreement for the Definitive Interconnection System Impact Study and the Interconnection Facilities Study in Appendix 3 of the Generator Interconnection Procedures.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Higher Queued Projects** shall mean those projects specifically identified as “Higher Queued Projects” in Appendix A.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Interim Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to

physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3 of the Generator Interconnection Procedures.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 3 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, to interconnect a Replacement Generating Facility, to increase the capacity of, or make a Material Modification to the operating characteristics of, an Existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Replacement Impact Study, the Reliability Assessment Study, the Definitive Interconnection System Impact Study, the Interim Availability Interconnection System Impact Study, and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements described in the Generator Interconnection Procedures: the Generator Interconnection Study Agreement or the Interim Availability Interconnection System Impact Study Agreement.

**Interim Availability Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System and, if applicable, an Affected System for the purpose of providing Interim Interconnection Service. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications on an interim basis.

**Interim Availability Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 5 of the Generator Interconnection Procedures for conducting the Interim Availability Interconnection System Impact Study.

**Interim Generator Interconnection Agreement (Interim GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility to allow interconnection to the Transmission System prior to the completion of the Interconnection Study process.

**Interim Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interim Generator Interconnection Agreement and, if applicable, the Tariff.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Interim Generator Interconnection Agreement, on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Interim Generator Interconnection Agreement, at the metering points, including but not limited to instrument transformers, MWh-meters, data

acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

**Network Resource Interim Interconnection Service** shall mean an Interim Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interim Interconnection Service in and of itself does not convey transmission service.

**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

**Notice of Dispute** shall mean a written notice of a dispute or claim that arises out of or in connection with the Interim Generator Interconnection Agreement, or its performance.

**Party or Parties** shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

**Point of Change of Ownership** shall mean the point, as set forth in Appendix A to the Interim Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

**Point of Interconnection** shall mean the point, as set forth in Appendix A to the Interim Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission System.

**Queue** shall mean the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Interim Generator Interconnection Agreement efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Reliability Assessment Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of Transmission System during

the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility.

**Replacement Generating Facility** shall mean a Generating Facility that replaces an Existing Generating Facility, or a portion thereof, at the same electrical Point of Interconnection pursuant to Section 3.9 of this Attachment V.

**Replacement Impact Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of the Transmission System.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers' Generating Facilities and which is the shared funding responsibility of such Interconnection Customers that may also benefit other Interconnection Customer(s) that are later identified as beneficiaries**.**

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility or Generating Facility's tie line; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

**Small Generating Facility** shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

**Stand Alone Network Upgrades** shall mean Network Upgrades that are not part of an Affected Systems that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Interim Generator Interconnection Agreement. If the Transmission Provider, Transmission Owner and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Owner must provide the Interconnection Customer a written technical explanation outlining why the Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within fifteen (15) days of its determination.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating

Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Interim Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Interim Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades, or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

## Article 2. Effective Date, Term, and Termination

**2.1 Effective Date.** This Interim GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this Interim GIA with FERC upon execution in accordance with Article 3.1, if required.

**2.2 Term of Agreement.** This Interim GIA shall remain in effect from its Effective Date until the earliest occurrence of one of the termination events described in Article 2.3.1.

**2.3 Termination Procedures.**

**2.3.1 Termination Events.**

**2.3.1.1** This Interim GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

**2.3.1.2** This Interim GIA shall terminate upon occurrence of one or more of the following events:

(a) The Effective Date of a GIA regarding the Generating Facility that is the subject of this Interim GIA that has been accepted by FERC and/or reported in Transmission Provider's Electric Quarterly Report;

(b) The date of a FERC order rejecting an unexecuted GIA regarding the Generating Facility that is the subject of this Interim GIA;

(c) The date the Interconnection Customer's Interconnection Request is deemed withdrawn pursuant to the GIP;

(d) The Interconnection Customer's failure to pay part or all of the required security pursuant to Article 11.7; or

(e) The Transmission Provider's determination in accordance with Article 4.2.2, that Interim Interconnection Service to Interconnection Customer and the amount of power that Interconnection Customer is permitted to inject into the Transmission System from its Generating Facility pursuant to this Interim GIA is reduced to zero.

**2.3.2 Default.** Any Party may terminate this Interim GIA in accordance with Article 17.

**2.3.3** Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Interim GIA, which notice has been accepted for filing by FERC.

**2.3.4** Upon termination of this Interim GIA for any reason, Interim Interconnection Service under this Interim GIA shall cease and the provisions of Section 11A.5 of the GIP shall apply.

## 2.4 Termination Costs.

**2.4.1** If this Interim GIA is terminated pursuant to Article 2.3.1.2(a), the cost responsibilities of Interconnection Customer and Transmission Owner pursuant to this Interim GIA will be included in the GIA regarding the Generating Facility

that is the subject of this Interim GIA to the extent not satisfied during the term of this Interim GIA.

**2.4.2** If this Interim GIA is terminated pursuant to Article 2.3 for any reason except as specified 2.3.1.2(a), Interconnection Customer and Transmission Owner shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment), and charges assessed by any other Party, as of the date of such Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this Interim GIA. In the event of termination by any Party, all Parties shall use Commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this Interim GIA, unless otherwise ordered or approved by FERC:

**2.4.2.1** With respect to any portion of Transmission Owner's Interconnection Facilities that have not yet been constructed or installed, Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If this Interim GIA is terminated pursuant to Article 2.3 for any reason except as specified in Article 2.3.1.2(a) Interconnection Customer shall be responsible for all costs incurred in association with the Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer and shall forfeit the security paid pursuant to Article 11.7 of this Interim GIA up to the total of the costs and expenses listed in this paragraph.

**2.4.2.2** Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be

responsible for all costs associated with procuring such materials, equipment, or facilities.

**2.4.2.3** With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this Interim GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

**2.5 Disconnection or Limitation of Output**. If this Interim GIA is terminated pursuant to Article 2.3 and disconnection or limitation in generation output is required, then the Parties will take all appropriate steps to either disconnect the Generating Facility from the Transmission System or limit the amount of generation output that can be injected into the transmission system pursuant to Section 4.2.2, whichever is applicable. All costs required to effectuate such disconnection or limitation shall be borne by Interconnection Customer, unless such termination resulted from another Party's Default of this Interim GIA, which in such event the defaulting Party shall be responsible for such disconnection costs.

**2.6 Survival.** Except as provided in this Article 2.6, this Interim GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Interim GIA; to permit payments for any credits under this Interim GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Interim GIA was in effect; and to permit each Party to have access to the lands of another Party pursuant to this Interim GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

## Article 3. Regulatory Filings

**3.1 Filing.** Transmission Provider shall file this Interim GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this Interim GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

## Article 4. Scope of Service

**4.1 Interim Interconnection Product Options.** Interconnection Customer has selected the following (checked) type of Interim Interconnection Service:

### 4.1.1 Energy Resource Interim Interconnection Service.

**4.1.1.1 The Product.** Energy Resource Interim Interconnection Service allows Interconnection Customer to connect the Generating Facility to the

Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interim Interconnection Service for the term of this Interim GIA, unless otherwise specified in Appendix A, Transmission Owner shall construct the facilities listed in Appendix A to this Interim GIA.

**4.1.1.2 Transmission Delivery Service Implications.** Under Energy Resource Interim Interconnection Service, Interconnection Customer will be eligible to inject power from the Generating Facility into and deliver power across the Transmission System on an "as available" basis. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

**4.1.2 Network Resource Interim Interconnection Service.**

**4.1.2.1 The Product.** Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interim Interconnection Service for the term of this Interim GIA, Transmission Owner shall construct the facilities identified in Appendix A to this Interim GIA.

**4.1.2.2 Transmission Delivery Service Implications.** Network Resource Interim Interconnection Service allows Interconnection Customer's Generating Facility to be designated by any Network Customer under the Tariff on the Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interim Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving Network Resource Interim Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be

required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interim Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission System, Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

The Network Resource Interim Interconnection Service studies are done in accordance with the process set out in Attachment Z1 of the Tariff. To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interim Interconnection Service, any future transmission service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

**4.2 Provision of Service.** Transmission Provider shall provide Interim Interconnection Service for the Generating Facility at the Point of Interconnection as specified below.

4.2.1 The provision of Interim Interconnection Service and pre-commercial operation testing pursuant to this Interim GIA are contingent upon the Interconnection Facilities, Network Upgrades, Distribution Upgrades, and other necessary facilities listed in the applicable section of Appendix A to this Interim GIA being completed and in service. In no event shall pre-commercial operation testing or Interim Interconnection Service be permitted until the Interconnection Facilities, Network Upgrades, Distribution Upgrades and any other necessary facilities listed in applicable section of Appendix A to this Interim GIA are complete and in service.

**4.2.1.1** Pre-Commercial Operation Testing. Interconnection Customer shall be able to sync its Generating Facility and its Interconnection Customer's Interconnection Facilities to the Transmission System for the purpose of testing pursuant to Article 6.1, once the applicable facilities described in Appendix A are complete and in service.

**4.2.1.2** Interim Interconnection Service. Interconnection Customer shall be able to sync its Generating Facility and its Interconnection Customer's Interconnection Facilities to the Transmission System for the purpose of receiving Interim Interconnection Service and operating its Generating Facility up to the maximum amount for this Interim GIA, as specified in Appendix A on an "as available" basis once the applicable facilities in Appendix A are in service.

**4.2.2** Interim Interconnection Service and the amount of power that Interconnection Customer is permitted to inject into the Transmission System from its Generating Facility pursuant to this Interim GIA may be reduced in whole or in part in the event that:

(a) one or more Interconnection Customer(s) with a Higher Queued Project (as specified in Appendix A): (i) has executed or subsequently executes an Interim GIA or a GIA that has been accepted by the FERC and/or reported in Transmission Provider's Electric Quarterly Report, or has an unexecuted Interim GIA or GIA filed with and accepted by the FERC for that Higher Queued Project and (ii) begins Commercial Operation of the Higher Queued Project during the term of this Interim GIA; and

(b) Transmission Provider at its sole discretion determines that Interim Interconnection Service and/or Interconnection Service cannot be provided simultaneously under this Interim GIA and to such other Interconnection Customer(s) under its Interim GIA(s) or final GIA(s) in an amount commensurate with the maximum amount specified in the

respective agreements without additional Interconnection Facilities, Network Upgrades, or Distribution Upgrades.

**4.2.3** Any such reduction pursuant to Article 4.2.2 will be based on the Queue Position priority of the Interconnection Customer's Interconnection Request relative to the Queue Position priority of the Higher Queued Projects.

**4.3 Performance Standards.** Each Party shall perform all of its obligations under this Interim GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this Interim GIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the Interim GIA and submit the amendment to FERC for approval.

**4.4 No Transmission Delivery Service.** The execution of this Interim GIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

**4.5 Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this Interim GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.8.

## Article 5. Interconnection Facilities Engineering, Procurement, and Construction

**5.1 Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Option To Build as described under Article 5.1.2 or the Negotiated Option described under Article 5.1.3, and such dates and selected option, as applicable, shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.2 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Transmission Owner, the Interconnection Customer shall notify Transmission Owner within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

**5.1.1 Standard Option.** Transmission Owner shall design, procure, and construct Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment

specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Owner reasonably expects that it will not be able to complete Transmission Owner's Interconnection Facilities, and Network Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

**5.1.2 Option to Build.** Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.1. Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

**5.1.3 Negotiated Option.** If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.2) pursuant to which Transmission Owner is responsible for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1(Standard Option), Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects the Option to Build.

**5.2 General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from Interconnection Customer's construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Owner's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Owner not later than the Commercial Operation Date;

(10) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.2, Interconnection Customer shall pay Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for Transmission Owner to execute the responsibilities enumerated to Transmission Owner under Article 5.2. Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

**5.3 Liquidated Damages.** The actual damages to Interconnection Customer, in the event Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Owner pursuant to subparagraph 5.1.3, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Owner to Interconnection Customer in the event that Transmission Owner does not complete any portion of Transmission Owner's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to ½ of 1 percent per day of the actual cost of Transmission Owner's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Owner has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed 20 percent of the actual cost of Transmission Owner's Interconnection Facilities and Network Upgrades for which Transmission Owner has assumed responsibility to design, procure, and construct. The foregoing payments will be made by Transmission Owner to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time, and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this GIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Owner's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for the Generating Facility's Trial Operation or to export power from the Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Owner's Interconnection Facilities or Network Upgrades to take the delivery of power for Generating Facility's Trial Operation or to export power from the Generating Facility, but for Transmission Owner's delay; (2) Transmission Owner's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an Interim GIA or GIA with Transmission Owner or any cause beyond Transmission Owner's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

**5.4 Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative. The requirements of this paragraph shall not apply to non-synchronous generators.

**5.5 Equipment Procurement.** If responsibility for construction of Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

**5.5.1** Transmission Provider has completed the Interim Availability Interconnection System Impact Study;

**5.5.2** Transmission Owner has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones;

**5.5.3** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 by the dates specified in Appendix B, Milestones; and

**5.5.4** The Parties have executed this Interim GIA.

**5.6 Construction Commencement.** Transmission Owner shall commence construction of Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

**5.6.1** Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

**5.6.2** Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Owner's Interconnection Facilities and Network Upgrades;

**5.6.3** Transmission Owner has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.6.4** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7.

**5.7 Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Parties may, at any time, request a progress report from other Parties. If, at any time, Interconnection Customer determines that the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will be required.

**5.8 Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System, and shall work diligently and in good faith to make any necessary design changes.

**5.9 Reserved.**

**5.10 Interconnection Customer's Interconnection Facilities ("ICIF").** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

**5.10.1 Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Owner at least one hundred eighty (180 ) Calendar Days prior to the Initial Synchronization Date, and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

**5.10.2 Transmission Owner's Review.** Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner.

**5.10.3 ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. The Interconnection Customer shall provide Transmission Owner specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

**5.10.4 Updated Information Submission by Interconnection Customer.** The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Attachment A to Appendix 3 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Facilities Studies. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreements between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to this Article 5.10.4. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

**5.10.5 Information Supplementation.** Prior to the Commercial Operation Date, or as soon as possible thereafter, the Parties shall supplement their information submissions described above in this Article 5 with any and all “as-built” Generating Facility information or “as-tested” performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit “step voltage” test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Owner and Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide the Interconnection Customer and Transmission Provider any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

**5.11 Transmission Owner's Interconnection Facilities Construction.** Transmission Owner's Interconnection Facilities and Network Upgrades shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Owner's Interconnection Facilities and Network Upgrades [include appropriate drawings and relay diagrams].

Transmission Owner will obtain control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

**5.12 Access Rights.** Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to any other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this Interim GIA pursuant to Article 2.5. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere

with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

**5.13 Lands of Other Property Owners.** If any part of Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with state law, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

**5.14 Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

**5.15 Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

**5.16 Reserved**.

**5.17 Taxes.**

**5.17.1 Interconnection Customer Payments Not Taxable.** The Parties intend that all payments or property transfers made by Interconnection Customer to Transmission Owner for the installation of Transmission Owner's Interconnection Facilities and the Network Upgrades shall be non-taxable, either as contributions to capital, or as an advance, in accordance with the Internal Revenue Code and any applicable state income tax laws and shall not be taxable as contributions in aid of construction or otherwise under the Internal Revenue Code and any applicable state income tax laws.

**5.17.2 Representations and Covenants.** In accordance with IRS Notice 2001-82 and IRS Notice 88-129, Interconnection Customer represents and covenants that (i) ownership of the electricity generated at the Generating Facility will pass to

another party prior to the transmission of the electricity on the Transmission System, (ii) for income tax purposes, the amount of any payments and the cost of any property transferred to Transmission Owner for Transmission Owner's Interconnection Facilities will be capitalized by Interconnection Customer as an intangible asset and recovered using the straight-line method over a useful life of twenty (20) years, and (iii) any portion of Transmission Owner's Interconnection Facilities that is a "dual-use intertie," within the meaning of IRS Notice 88-129, is reasonably expected to carry only a de minimis amount of electricity in the direction of the Generating Facility. For this purpose, "de minimis amount" means no more than 5 percent of the total power flows in both directions, calculated in accordance with the "5 percent test" set forth in IRS Notice 88-129. This is not intended to be an exclusive list of the relevant conditions that must be met to conform to IRS requirements for non-taxable treatment.

At Transmission Owner's request, Interconnection Customer shall provide Transmission Owner with a report from an independent engineer confirming its representation in clause (iii), above. Transmission Owner represents and covenants that the cost of Transmission Owner's Interconnection Facilities paid for by Interconnection Customer will have no net effect on the base upon which rates are determined.

**5.17.3 Indemnification for the Cost Consequences of Current Tax Liability Imposed Upon the Transmission Owner.** Notwithstanding Article 5.17.1, Interconnection Customer shall protect, indemnify and hold harmless Transmission Owner from the cost consequences of any current tax liability imposed against Transmission Owner as the result of payments or property transfers made by Interconnection Customer to Transmission Owner under this Interim GIA for Interconnection Facilities, as well as any interest and penalties, other than interest and penalties attributable to any delay caused by Transmission Owner.

Transmission Owner shall not include a gross-up for the cost consequences of any current tax liability in the amounts it charges Interconnection Customer under this Interim GIA unless (i) Transmission Owner has determined, in good faith, that the payments or property transfers made by Interconnection Customer to Transmission Owner should be reported as income subject to taxation or (ii) any Governmental Authority directs Transmission Owner to report payments or property as income subject to taxation; provided, however, that Transmission Owner may require Interconnection Customer to provide security for Interconnection Facilities, in a form reasonably acceptable to Transmission Owner (such as a parental guarantee or a letter of credit), in an amount equal to the cost consequences of any current tax liability under this Article 5.17. Interconnection Customer shall reimburse Transmission Owner for such costs on a fully grossed-up basis, in accordance with Article 5.17.4, within thirty (30) Calendar Days of receiving written notification from Transmission Owner of the amount due, including detail about how the amount was calculated.

The indemnification obligation shall terminate at the earlier of (1) the expiration of the ten year testing period and the applicable statute of limitation, as it may be extended by Transmission Owner upon request of the IRS, to keep these years open for audit or adjustment, or (2) the occurrence of a subsequent taxable event and the payment of any related indemnification obligations as contemplated by this Article 5.17.

**5.17.4 Tax Gross-Up Amount.** Interconnection Customer's liability for the cost consequences of any current tax liability under this Article 5.17 shall be calculated on a fully grossed-up basis. Except as may otherwise be agreed to by the Parties, this means that Interconnection Customer will pay Transmission Owner, in addition to the amount paid for the Interconnection Facilities, and Network Upgrades, an amount equal to (1) the current taxes imposed on Transmission Owner ("Current Taxes") on the excess of (a) the gross income realized by Transmission Owner as a result of payments or property transfers made by Interconnection Customer to Transmission Owner under this Interim GIA (without regard to any payments under this Article 5.17) (the "Gross Income Amount") over (b) the present value of future tax deductions for depreciation that will be available as a result of such payments or property transfers (the "Present Value Depreciation Amount"), plus (2) an additional amount sufficient to permit Transmission Owner to receive and retain, after the payment of all Current Taxes, an amount equal to the net amount described in clause (1).

For this purpose, (i) Current Taxes shall be computed based on Transmission Owner's composite federal and state tax rates at the time the payments or property transfers are received and Transmission Owner will be treated as being subject to tax at the highest marginal rates in effect at that time (the "Current Tax Rate"), and (ii) the Present Value Depreciation Amount shall be computed by discounting Transmission Owner's anticipated tax depreciation deductions as a result of such payments or property transfers by Transmission Owner's current weighted average cost of capital. Thus, the formula for calculating Interconnection Customer's liability to Transmission Owner pursuant to this Article 5.17.4 can be expressed as follows: (Current Tax Rate x (Gross Income Amount – Present Value of Tax Depreciation))/(1-Current Tax Rate). Interconnection Customer's estimated tax liability in the event taxes are imposed shall be stated in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

**5.17.5 Private Letter Ruling or Change or Clarification of Law.** At Interconnection Customer's request and expense, Transmission Owner shall file with the IRS a request for a private letter ruling as to whether any property transferred or sums paid, or to be paid, by Interconnection Customer to Transmission Owner under this Interim GIA are subject to federal income taxation. Interconnection Customer will prepare the initial draft of the request for a private letter ruling, and will certify under penalties of perjury that all facts represented in such request are true and accurate to the best of Interconnection Customer's knowledge. Transmission Owner and Interconnection Customer shall cooperate in good faith with respect to the submission of such request.

Transmission Owner shall keep Interconnection Customer fully informed of the status of such request for a private letter ruling and shall execute either a privacy act waiver or a limited power of attorney, in a form acceptable to the IRS, that authorizes Interconnection Customer to participate in all discussions with the IRS regarding such request for a private letter ruling. Transmission Owner shall allow Interconnection Customer to attend all meetings with IRS officials about the request and shall permit Interconnection Customer to prepare the initial drafts of any follow-up letters in connection with the request.

**5.17.6 Subsequent Taxable Events.** If, within 10 years from the date on which the relevant Transmission Owner's Interconnection Facilities are placed in service, (i) Interconnection Customer Breaches the covenants contained in Article 5.17.2, (ii) a "disqualification event" occurs within the meaning of IRS Notice 88-129, or (iii) this Interim GIA terminates and Transmission Owner retains ownership of the Interconnection Facilities and Network Upgrades, Interconnection Customer shall pay a tax gross-up for the cost consequences of any current tax liability imposed on Transmission Owner, calculated using the methodology described in Article 5.17.4 and in accordance with IRS Notice 90-60.

**5.17.7 Contests.** In the event any Governmental Authority determines that Transmission Owner's receipt of payments or property constitutes income that is subject to taxation, Transmission Owner shall notify Interconnection Customer, in writing, within thirty (30) Calendar Days of receiving notification of such determination by a Governmental Authority. Upon the timely written request by Interconnection Customer and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise oppose such determination. Upon Interconnection Customer's written request and sole expense, Transmission Owner may file a claim for refund with respect to any taxes paid under this Article 5.17, whether or not it has received such a determination. Transmission Owner reserves the right to make all decisions with regard to the prosecution of such appeal, protest, abatement or other contest, including the selection of counsel and compromise or settlement of the claim, but Transmission Owner shall keep Interconnection Customer informed, shall consider in good faith suggestions from Interconnection Customer about the conduct of the contest, and shall reasonably permit Interconnection Customer or an Interconnection Customer representative to attend contest proceedings.

Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement or other contest. At any time during the contest, Transmission Owner may agree to a settlement either with Interconnection Customer's consent or after obtaining written advice from nationally-recognized tax counsel, selected by Transmission Owner, but reasonably acceptable to Interconnection Customer, that the proposed settlement represents a reasonable settlement given the hazards of litigation. Interconnection Customer's obligation shall be based on the amount of the settlement agreed to by Interconnection Customer, or if a higher amount, so much of the settlement that is

supported by the written advice from nationally-recognized tax counsel selected under the terms of the preceding sentence. The settlement amount shall be calculated on a fully grossed-up basis to cover any related cost consequences of the current tax liability. Any settlement without Interconnection Customer's consent or such written advice will relieve Interconnection Customer from any obligation to indemnify Transmission Owner for the tax at issue in the contest.

**5.17.8 Refund.** In the event that (a) a private letter ruling is issued to Transmission Owner which holds that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this Interim GIA is not subject to federal income taxation, (b) any legislative change or administrative announcement, notice, ruling or other determination makes it reasonably clear to Transmission Owner in good faith that any amount paid or the value of any property transferred by Interconnection Customer to Transmission Owner under the terms of this Interim GIA is not taxable to Transmission Owner, (c) any abatement, appeal, protest, or other contest results in a determination that any payments or transfers made by Interconnection Customer to Transmission Owner are not subject to federal income tax, or (d) if Transmission Owner receives a refund from any taxing authority for any overpayment of tax attributable to any payment or property transfer made by Interconnection Customer to Transmission Owner pursuant to this Interim GIA, Transmission Owner shall promptly refund to Interconnection Customer the following:

(i) any payment made by Interconnection Customer under this Article 5.17 for taxes that is attributable to the amount determined to be non-taxable, together with interest thereon,

(ii) interest on any amount paid by Interconnection Customer to Transmission Owner for such taxes which Transmission Owner did not submit to the taxing authority, calculated in accordance with the methodology set forth in FERC's regulations at 18 CFR §35.19a(a)(2)(iii) from the date payment was made by Interconnection Customer to the date Transmission Owner refunds such payment to Interconnection Customer, and

(iii) with respect to any such taxes paid by Transmission Owner, any refund or credit Transmission Owner receives or to which it may be entitled from any Governmental Authority, interest (or that portion thereof attributable to the payment described in clause (i), above) owed to Transmission Owner for such overpayment of taxes (including any reduction in interest otherwise payable by Transmission Owner to any Governmental Authority resulting from an offset or credit); provided, however, that Transmission Owner will remit such amount promptly to Interconnection Customer only after and to the extent that Transmission Owner has received a tax refund, credit or offset from any Governmental Authority for any applicable overpayment of income tax related to Transmission Owner’s Interconnection Facilities.

The intent of this provision is to leave the Parties, to the extent practicable, in the event that no taxes are due with respect to any payment for Interconnection Facilities and Network Upgrades hereunder, in the same position they would have been in had no such tax payments been made.

**5.17.9 Taxes Other Than Income Taxes.** Upon the timely request by Interconnection Customer, and at Interconnection Customer's sole expense, Transmission Owner may appeal, protest, seek abatement of, or otherwise contest any tax (other than federal or state income tax) asserted or assessed against Transmission Owner for which Interconnection Customer may be required to reimburse Transmission Owner under the terms of this Interim GIA. Interconnection Customer shall pay to Transmission Owner on a periodic basis, as invoiced by Transmission Owner, Transmission Owner's documented reasonable costs of prosecuting such appeal, protest, abatement, or other contest. Interconnection Customer and Transmission Owner shall cooperate in good faith with respect to any such contest. Unless the payment of such taxes is a prerequisite to an appeal or abatement or cannot be deferred, no amount shall be payable by Interconnection Customer to Transmission Owner for such taxes until they are assessed by a final, non-appealable order by any court or agency of competent jurisdiction. In the event that a tax payment is withheld and ultimately due and payable after appeal, Interconnection Customer will be responsible for all taxes, interest and penalties, other than penalties attributable to any delay caused by Transmission Owner.

**5.18 Tax Status.** All Parties shall cooperate with each other to maintain their tax status. Nothing in this Interim GIA is intended to adversely affect any Party's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

**5.19 Modification.**

**5.19.1 General.** Each Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility Modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the

Transmission System, Transmission Owner's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

**5.19.2 Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this Interim GIA and Good Utility Practice.

**5.19.3 Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Owner makes to Transmission Owner's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Owner's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

**5.20 Delays .** If a Network Upgrade(s) identified in Appendix A is delayed during the construction process and the Commercial Operation Date for the Generating Facility identified in Appendix B is no longer feasible, the Commercial Operation Date in Appendix B may be modified to no later than six (6) months following the in-service date for the last Network Upgrade identified in Appendix A.

## Article 6. Testing and Inspection

**6.1 Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Owner shall test Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

**6.2 Post-Commercial Operation Date Testing and Modifications.** Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

**6.3 Right to Observe Testing.** Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties have the right, at its own expense, to observe such testing.

**6.4 Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe another Parties' tests and/or inspection of any of its System Protection Facilities and other protective equipment, including power system stabilizers; (ii) review the settings of the other Parties' System Protection Facilities and other protective equipment; and (iii) review another Parties' maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Any Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by another Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that any Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this Interim GIA.

## Article 7. Metering

**7.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Owner's option, compensated to, the Point of Interconnection. Transmission Owner shall provide metering quantities, in analog and/or digital form, to Interconnection Customer and Transmission Provider on a same-time basis using communication as provided in Article 8. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

**7.2 Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this Interim GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

**7.3 Standards.** Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

**7.4 Testing of Metering Equipment.** Transmission Owner shall inspect and test all Transmission Owner-owned Metering Equipment upon installation and at least once

every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Owner shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Owner's failure to maintain, then Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Owner shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

**7.5 Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

## Article 8. Communications

**8.1 Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Owner's Transmission System dispatcher or representative designated by Transmission Owner. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Owner as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Owner. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

**8.2 Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Owner

through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Owner.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

**8.3 No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

**8.4 Phasor Measurement Unit (PMU) Recording Equipment**. Prior to the Initial Synchronization Date of a Generating Facility having a Generating Facility Capacity equal to or greater than 50 MW, phasor measurement recording and communications equipment shall be installed by the Transmission Owner at Interconnection Customer's expense that is capable of gathering phasor measurements as specified in the PMU Communications Handbook. To the extent similar quality equipment is being added or already exists, such as relays or digital fault recorders, that can collect data at least at the same rate as PMUs and which data is synchronized via a high-accuracy satellite clock, such equipment can be utilized to satisfy this requirement if the equipment is located on the Transmission Owner's side of the Point of Change of Ownership and if mutually agreed to by the Parties. The phasor measurement equipment shall be installed at the Transmission Owner's side of the Point of Change of Ownership and become part of the Transmission Owner Interconnection Facilities. Phasor measurements shall be streamed in IEEE C37.118 or equivalent format and be provided to the Transmission Provider. This data shall at least be sufficient to determine (i) positive-sequence voltage magnitude and angle, (ii) positive-sequence current magnitude and angle, (iii) frequency, and (iv) rate of change of frequency. Such data shall be transmitted over the data circuit(s) as indicated in Article 8.1.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the applicable Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

## Article 9. Operations

**9.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Parties all information that may reasonably be required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

**9.2 Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Control Area in which the Generating Facility will be located. If Interconnection Customer elects to locate the Generating Facility in a Control Area other than the Control Area in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this Interim GIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Control Area.

**9.3 Transmission Provider and Transmission Owner Obligations.** Transmission Provider and Transmission Owner shall cause the Transmission System and Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this Interim GIA. Transmission Provider or Transmission Owner may provide operating instructions to Interconnection Customer consistent with this Interim GIA and Transmission Owner's operating protocols and procedures as they may change from time to time. Transmission Provider and Transmission Owner will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

**9.4 Interconnection Customer Obligations.** Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA. Interconnection Customer shall operate the Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this Interim GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that another Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this Interim GIA.

**9.5 Start-Up and Synchronization.** Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission System.

**9.6 Reactive Power and Primary Frequency Response.**

**9.6.1 Power Factor Design Criteria.**

**9.6.1.1 Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

**9.6.1.2 Non-Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that had not executed an interconnection facilities study agreement as of September 21, 2016.

**9.6.2 Voltage Schedules.** Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider and/or Transmission Owner shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Owner's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Owner shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the Transmission Owner.

**9.6.2.1 Voltage Regulators.** Whenever the Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in Mvars) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition in accordance with Good Utility Practice and Applicable Reliability Standards.

**9.6.3 Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating Facility when Transmission Owner requests Interconnection Customer to operate its Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.8 or such other agreement to which the Parties have otherwise agreed; provided however, to the extent the Tariff contains a provision providing for such compensation, that Tariff provision shall control.

**9.6.4 Primary Frequency Response.** Interconnection Customer shall ensure the primary frequency response capability of its Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband;. or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Interconnection Customer shall operate the Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Generating Facilities.

**9.6.4.1 Governor or Equivalent Controls.** Whenever the Generating Facility is operated in parallel with the Transmission System, Interconnection

Customer shall operate the Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Generating Facility's governor or equivalent controls to a minimum whenever the Generating Facility is operated in parallel with the Transmission System.

**9.6.4.2 Timely and Sustained Response.** Interconnection Customer shall ensure that the Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

**9.6.4.3 Exemptions.** Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Generating Facilities that are

behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

**9.6.4.4 Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its GIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a

transition.

## 9.7 Outages and Interruptions.

### 9.7.1 Outages.

**9.7.1.1 Outage Authority and Coordination.** Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

**9.7.1.2 Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

**9.7.1.3 Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed

up as soon as practicable with written notice explaining the nature of the outage.

**9.7.2 Interruption of Service.** In addition to any reduction in Interconnection Service required pursuant to Article 4.2.2, if required by Good Utility Practice to do so, Transmission Provider and/or Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's and/or Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

**9.7.2.1** The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

**9.7.2.2** Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

**9.7.2.3** When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

**9.7.2.4** Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Owner; and

**9.7.2.5** The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

**9.7.3 Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the

Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a generating facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

**9.7.3.1 Frequency Ride Through and Voltage Ride Through for a Generating Facility no larger than 20 MW.** For Generating Facilities no larger than 20 MW, the Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Generating Facility. The Interconnection Customer shall enable these capabilities such that its Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to Article 6.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The Generating Facility’s protective equipment settings shall comply with the Transmission Provider’s automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term “ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority on a comparable basis. The term “frequency ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term “voltage ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis.

**9.7.4 System Protection and Other Control Requirements.**

**9.7.4.1 System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Owner's Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

**9.7.4.2** Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

**9.7.4.3** Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

**9.7.4.4** Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

**9.7.4.5** Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

**9.7.4.6** Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

**9.7.5 Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission System at a site

selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

**9.7.6 Power Quality.** No Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

**9.8 Switching and Tagging Rules.** Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

**9.9 Use of Interconnection Facilities by Third Parties.**

**9.9.1 Purpose of Interconnection Facilities.** Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

**9.9.2 Third Party Users.** If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Owner’s Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

**9.10 Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

## Article 10. Maintenance

**10.1 Transmission Owner Obligations.** Transmission Owner shall maintain the Transmission System and Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA.

**10.2 Interconnection Customer Obligations.** Interconnection Customer shall maintain the Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA.

**10.3 Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

**10.4 Secondary Systems.** Each Party shall cooperate with the others in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

**10.5 Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner's Interconnection Facilities.

## Article 11. Performance Obligation

**11.1 Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

**11.2 Maintenance Review.** The Transmission Provider will annually perform a re-study of this Interim GIA and will determine whether the Interim Interconnection Service determined pursuant to Section 11A.2 of the GIP continues to be available in the amount specified in this Interim GIA. The Transmission Provider will increase or decrease the amount of service in this Interim GIA based on the results of the annual re-study and subject to Article 4.2.3 of this Interim GIA. The Transmission Provider shall utilize existing studies to the extent practicable when it performs the re-study. The cost of each annual re-study shall be deducted from the study deposit made pursuant to Section 11A.2.4 of the GIP and the Interconnection Customer shall be responsible for any cost in excess of the study deposit. A determination by the Transmission Provider that Interim Interconnection Service must be reduced pursuant to Article 4.2.2 of this Interim GIA will take precedence over the results of the most recent annual re-study.

**11.3 Transmission Owner's Interconnection Facilities.** Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

**11.4 Network Upgrades and Distribution Upgrades.** All Network Upgrades and Distribution Upgrades described in Appendix A shall be constructed in accordance with the process set forth in Section VI of Attachment O. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades that are associated with that Transmission Owner's system. The Distribution Upgrades and Network Upgrades described in Appendix A shall be solely funded by Interconnection Customer unless Transmission Owner elects to fund the capital for the Distribution Upgrades or Network Upgrades.

**11.5 Transmission Credits.**

**11.5.1 Credits for Amounts Advanced for Network Upgrades.** Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the Tariff for any Network Upgrades including any tax gross-up or other tax-related payments associated with Network Upgrades, and not refunded to Interconnection Customer pursuant to Article 5.17.8.

**11.5.2 Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the Interim GIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

**11.5.3** Notwithstanding any other provision of this Interim GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or

transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain transmission credits for transmission service that is not associated with the Generating Facility.

**11.6 Initial Payment.**

Interconnection Customer shall make an initial payment ("Initial Payment") equal to the greater of a) twenty (20) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. Any financial security provided in Section 8.2, Section 8.5.1 and Section 8.5.2 of the GIP will be applied to this requirement. The Initial Payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the Initial Payment is not being protested by Interconnection Customer. If this GIA is terminated, then the Initial Payment shall be refunded with accrued interest calculated from the date of the receipt of the Initial Payment to the date of the refund, if any, to the Interconnection Customer less:

a. any costs that have been incurred for the construction of the facilities specified in Appendix A;

b. any funds that have been committed for the construction of those Shared Network Upgrades, or Network Upgrades, assigned to another interconnection customer where such upgrade costs would not have been assigned but for the termination of the GIA; or

c. any costs that has been incurred for the construction of those Shared Network Upgrades, or Network Upgrades, that were paid for by another interconnection customer that are now unnecessary due to the termination of the GIA.

**11.7 Provision of Security.**

**11.7.1 Initial Security.** Within fifteen (15) Business Days of the date that Interconnection Customer delivers to Transmission Provider an executed Interim GIA, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1 in the amount set forth in Appendix A to this Interim GIA. This amount represents either (a) the sum of the estimated costs for which Interconnection Customer will be responsible for the construction, procurement,

and installation of the applicable portion of Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which it will share cost responsibility as determined in the study designated in Appendix A.4. and 100 percent of the costs of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which Interconnection Customer has sole cost responsibility or (b) if the estimated costs above have not been established at the time Interconnection Customer requests Interim Interconnection Service, the initial security amount will be established by the Transmission Provider based on one or more completed studies for comparable interconnection requests.

**11.7.2 Security Adjustment.** In the event that the results of any subsequently posted study (e.g., Definitive Interconnection System Impact Study, Interconnection Facilities Study, or any other study required pursuant to the GIP in connection with Interconnection Service under this Interim GIA) indicates that Interconnection Customer's cost responsibility for Interconnection Facilities, Network Upgrades, or Distribution Upgrades required to interconnect its Generating Facility is less than or greater than the amount set forth in Appendix A, the amount of security required under this Interim GIA shall be adjusted to reflect the Interconnection Customer's revised amount of cost responsibility determined in such posted study. Transmission Provider shall notify Interconnection Customer of the revised security amount when it posts the study. If the security amount increases, Interconnection Customer shall provide the additional amount of security within fifteen (15) Business Days of receipt of such notification. If the security amount decreases, Transmission Provider and Interconnection Customer shall take the appropriate action to reduce the amount of security held by Transmission Provider within fifteen (15) Business Days of Interconnection Customer's receipt of such notification. If Interconnection Customer fails to provide additional security as prescribed in this Article 11.7.2, this Interim GIA will be terminated in accordance with Article 2.3.
In addition:

**11.7.2.1** The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

**11.7.2.2** The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.7.2.3** The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.8 Interconnection Customer Compensation.** If Transmission Provider or Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this Interim GIA, Transmission

Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to the Tariff. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this Interim GIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

**11.8.1 Interconnection Customer Compensation for Actions During Emergency Condition.** Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.8.

## Article 12. Invoice

The terms of this Article 12 apply to billing between the Parties for construction and operation and maintenance charges. All other billing will be handled according to the Tariff.

**12.1 General.** Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this Interim GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**12.2 Final Invoice.** Within six months after completion of the construction of Interconnection Facilities and the Network Upgrades to be constructed pursuant to this Interim GIA, the Interconnection Customer shall receive an invoice of the final cost due under this Interim GIA, including any applicable cost due to termination, which shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnection Customer shall receive a refund of any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

**12.3 Payment.** Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this Interim GIA.

**12.4 Disputes.** In the event of a billing dispute between the Parties, Transmission Owner, and Transmission Provider shall continue to provide Interconnection Service under this Interim GIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

## Article 13. Emergencies

**13.1 Definition.** "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Interim Generator Interconnection Agreement, to possess black start capability.

**13.2 Obligations.** Each Party shall comply with the Emergency Condition procedures of NERC, the Applicable Reliability Council, Transmission Provider, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

**13.3 Notice.** Transmission Provider or Transmission Owner shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Owner's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or Interconnection Customer's Interconnection Facilities.

Interconnection Customer shall notify Transmission Provider and Transmission Owner promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Owner's facilities and

operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

**13.4 Immediate Action.** Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or Transmission Owner or otherwise regarding the Transmission System.

**13.5 Transmission Provider and Transmission Owner Authority.**

**13.5.1 General**. Transmission Provider and/or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider and Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider and/or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's and Transmission Owner's operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

**13.5.2 Reduction and Disconnection.** Transmission Provider and/or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment, reduction, or disconnection of Transmission Provider pursuant to Transmission Provider's Tariff or Articles 2.5, 4.2.2 and 9.7.2. When Transmission Provider and/or Transmission Owner can schedule the reduction or disconnection in advance, Transmission Provider and/or Transmission Owner shall notify

Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider and/or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer, Transmission Provider and/or Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

**13.6 Interconnection Customer Authority.** Consistent with Good Utility Practice and this Interim GIA and the GIP, Interconnection Customer may take actions or inactions with regard to the Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Owner's Interconnection Facilities. Transmission Provider and/or Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

**13.7 Limited Liability.** Except as otherwise provided in Article 11.8.1 of this Interim GIA, no Party shall be liable to the other Parties for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

## Article 14. Regulatory Requirements and Governing Law

**14.1 Regulatory Requirements.** Each Party's obligations under this Interim GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this Interim GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act the Public Utility Holding Company Act of 2005, or the Public Utility Regulatory Policies Act of 1978, as amended by the 2005 Energy Policy Act.

**14.2 Governing Law.**

**14.2.1** The validity, interpretation and performance of this Interim GIA and each of its provisions shall be governed by the laws of the state where the Point of Interconnection is located, without regard to its conflicts of law principles.

**14.2.2** This Interim GIA is subject to all Applicable Laws and Regulations.

**14.2.3** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

## Article 15. Notices

**15.1 General.** Unless otherwise provided in this Interim GIA, any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Any Party may change the notice information in this Interim GIA by giving five (5) Business Days written notice prior to the effective date of the change.

**15.2 Billings and Payments.** Billings and payments shall be sent to the addresses set out in Appendix F.

**15.3 Alternative Forms of Notice.** Any notice or request required or permitted to be given by any Party to another and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

**15.4 Operations and Maintenance Notice.** Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

## Article 16. Force Majeure

### 16.1 Force Majeure.

**16.1.1** Economic hardship is not considered a Force Majeure event.

**16.1.2** No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be

required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

## Article 17. Default

### 17.1 Default.

**17.1.1 General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this Interim GIA or the result of an act or omission of another Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

**17.1.2 Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this Interim GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Interim GIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Interim GIA.

## Article 18. Indemnity, Consequential Damages and Insurance

**18.1 Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Parties' action or inactions of its obligations under this Interim GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

**18.1.1 Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**18.1.2 Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to

the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**18.1.3 Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**18.2 Consequential Damages**. Other than the Liquidated Damages heretofore described, in no event shall any Party be liable to any other Party under any provision of this Interim GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which any Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

**18.3 Insurance.** Interconnection Customer and Transmission Owner shall at their own expense, maintain in force throughout the period of this Interim GIA, and until released by all other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

**18.3.1** Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. The minimum limits for the Employers' Liability insurance shall be One Million Dollars ($1,000,000) each accident bodily injury by accident, One Million Dollars ($1,000,000) each employee bodily injury by disease, and One Million Dollars ($1,000,000) policy limit bodily injury by disease.

**18.3.2** Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards (if applicable), independent contractors coverage, coverage for pollution (if exposure is present) and punitive or exemplary damages, with minimum limits of One Million Dollars ($1,000,000) each occurrence/Two Million Dollars ($2,000,000) general aggregate and Two Million Dollars ($2,000,000) products and completed operations aggregate combined single limit for personal injury, bodily injury, including death and property damage.

**18.3.3** Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

**18.3.4** Excess Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) each occurrence/Twenty Million Dollars ($20,000,000) general aggregate.

**18.3.5** The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Interim GIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

**18.3.6** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain

provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

**18.3.7** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Interim GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed to by all Parties.

**18.3.8** The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnection Customer and Transmission Owner are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

**18.3.9** Within ten (10) days following execution of this Interim GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Interconnection Customer and Transmission Owner shall provide certification of all insurance required in this Interim GIA, executed by each insurer or by an authorized representative of each insurer to the Other Party Group.

**18.3.10** Notwithstanding the foregoing, each Party may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Party's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that a Party's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Party shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that a Party is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

**18.3.11** The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Interim GIA.

## Article 19 Assignment.

**19.1 Assignment.** This Interim GIA may be assigned by any Party only with the written consent of the other Parties; provided that any Party may assign this Interim GIA without the consent of the other Parties to any Affiliate of the assigning Party with an equal or

greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interim GIA; and provided further that Interconnection Customer shall have the right to assign this Interim GIA, without the consent of Transmission Provider or Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider and Transmission Owner of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider and Transmission Owner of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.7 and 18.3. Any assignment under this article not solely for collateral security purposes shall be conditioned on the simultaneous assignment of Interconnection Customer's Queue Position to assignee and assignee demonstrating the ability to enter into and fulfill the obligations of a final GIA. Any attempted assignment that violates this article is void and ineffective. Any assignment under this Interim GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

## Article 20. Severability

**20.1 Severability.** If any provision in this Interim GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Interim GIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Negotiated Option (Article 5.1.3), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

## Article 21. Comparability

**21.1 Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

## Article 22. Confidentiality

**22.1 Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to another prior to the execution of this Interim GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed

orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by any Party, a Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

**22.1.1 Term.** During the term of this Interim GIA, and for a period of three (3) years after the expiration or termination of this Interim GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

**22.1.2 Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Interim GIA; or (6) is required, in accordance with Article 22.1.7 of the Interim GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Interim GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

**22.1.3 Release of Confidential Information.** No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this Interim GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

**22.1.4 Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to another Party. The disclosure by any Party to another Party of Confidential Information shall not be deemed a waiver

by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

**22.1.5 No Warranties.** By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

**22.1.6 Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this Interim GIA or its regulatory requirements.

**22.1.7 Order of Disclosure.** If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this Interim GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

**22.1.8 Termination of Agreement.** Upon termination of this Interim GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

**22.1.9 Remedies.** In the instance where Transmission Owner is a Federal Power Agency, as specified in the opening paragraph of this Agreement, then this section 22.1.9 shall not apply to Transmission Owner. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at

law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

**22.1.10 Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Interim GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying another Party to this Interim GIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the Interim GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, if consistent with the applicable state rules and regulations.

**22.1.11** Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this Interim GIA ("Confidential Information") shall not be disclosed by another Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Interim GIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures

**22.1.12** This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

## Article 23. Environmental Releases

**23.1** Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

## Article 24. Information Requirements

**24.1 Information Acquisition.** Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

**24.2 Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

## Article 25. Information Access and Audit Rights

**25.1 Information Access.** Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which the other Parties are responsible under this Interim GIA; and (ii) carry out its obligations and responsibilities under this Interim GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this Interim GIA.

**25.2 Reporting of Non-Force Majeure Events.** Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this Interim GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information

regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Parties receiving such notification to allege a cause for anticipatory breach of this Interim GIA.

**25.3 Audit Rights.** Subject to the requirements of confidentiality under Article 22 of this Interim GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense that other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this Interim GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this Interim GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

**25.4 Audit Rights Periods.**

**25.4.1 Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Owner's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

**25.4.2 Audit Rights Period for All Other Accounts and Records.** Accounts and records related to any Party's performance or satisfaction of all obligations under this Interim GIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

**25.5 Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

**Article 26. Subcontractors**

**26.1 General.** Nothing in this Interim GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Interim

GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Interim GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

**26.2 Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Interim GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this Interim GIA. Any applicable obligation imposed by this Interim GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

**26.3 No Limitation by Insurance.** The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

## Article 27. Disputes

**27.1 Submission.** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this Interim GIA or its performance, the Parties agree to resolve such dispute using the dispute resolution procedures of the Generator Interconnection Procedures.

## Article 28. Representations, Warranties, and Covenants

**28.1 General**. Each Party makes the following representations, warranties and covenants:

**28.1.1 Good Standing.** Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Interim GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Interim GIA.

**28.1.2 Authority.** Such Party has the right, power and authority to enter into this Interim GIA, to become a Party hereto and to perform its obligations hereunder. This Interim GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**28.1.3 No Conflict.** The execution, delivery and performance of this Interim GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**28.1.4 Consent and Approval.** Such Party has sought or obtained, or, in accordance with this Interim GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Interim GIA, and it will provide to any Governmental Authority notice of any actions under this Interim GIA that are required by Applicable Laws and Regulations.

## Article 29. Joint Operating Committee

**29.1 Joint Operating Committee.** At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer, Transmission Owner and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Party shall notify the other Parties of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of any Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this Interim GIA. All Parties shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

**29.1.1** Establish data requirements and operating record requirements.

**29.1.2** Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

**29.1.3** Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Owner’s and Interconnection Customer's facilities at the Point of Interconnection.

**29.1.4** Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

**29.1.5** Ensure that information is being provided by each Party regarding equipment availability.

**29.1.6** Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

## Article 30. Miscellaneous

**30.1 Binding Effect.** This Interim GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**30.2 Conflicts.** In the event of a conflict between the body of this Interim GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interim GIA shall prevail and be deemed the final intent of the Parties.

**30.3 Rules of Interpretation.** This Interim GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interim GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interim GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this Interim GIA or such Appendix to this Interim GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interim GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

**30.4 Entire Agreement.** This Interim GIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this Interim GIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, a Party's compliance with its obligations under this Interim GIA.

**30.5 No Third Party Beneficiaries.** This Interim GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**30.6 Waiver.** The failure of a Party to this Interim GIA to insist, on any occasion, upon strict performance of any provision of this Interim GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this Interim GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interim GIA. Termination or Default of this Interim GIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Interim GIA shall, if requested, be provided in writing.

**30.7 Headings.** The descriptive headings of the various Articles of this Interim GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interim GIA.

**30.8 Multiple Counterparts.** This Interim GIA may be executed in three or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**30.9 Amendment.** The Parties may by mutual agreement amend this Interim GIA by a written instrument duly executed by each of the Parties.

**30.10 Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this Interim GIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Interim GIA upon satisfaction of all Applicable Laws and Regulations.

**30.11 Reservation of Rights.** Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Interim GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interim GIA pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interim GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

**30.12 No Partnership.** This Interim GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

**IN WITNESS WHEREOF,** the Parties have caused this Interim GIA to be executed by their respective authorized officials, and copies delivered to each Party, to become effective as of the Effective Date.

**SOUTHWEST POWER POOL, INC.**

By: _____

Printed Name:_____

Title: _____

Date: _____

**[Insert name of Transmission Owner]**

By: _____

Printed Name:_____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Printed Name:_____

Title: _____

Date: _____

## Appendix A to Interim GIA

**Interconnection Facilities, Network Upgrades, Distribution Upgrades, Security, Type and Amount of Interconnection Service, Construction Option, and Higher Queued Project List**

**1. Interconnection Facilities: [include description, responsible party, and estimated costs]:**

**A. Interconnection Customer's Interconnection Facilities**

**B. Transmission Owner Interconnection Facilities**

**2. Network Upgrades: [include description, responsible party, and estimated costs]:**

**A. Stand Alone Network Upgrades**

**B. Network Upgrades For Which Interconnection Customer Is Solely Responsible**

**C. Network Upgrades For Which Interconnection Customer Shares Cost Responsibility**

**3. Distribution Upgrades: [include description, responsible party, and estimated costs]:**

**4. Security, Credits and Taxes:**

**A.** The amount of initial security to be provided by Interconnection Customer in accordance with Article 11.7.1 is $_____. The required amount of security required pursuant to this Interim GIA may be adjusted pursuant to Article 11.7.2 of this Agreement.

**B.** The estimated portion of the Network Upgrades identified in Section 2 of this Appendix A that could be subject to the credits described in Article 11.5 of this Agreement is $_____.

**C.** Interconnection Customer's estimated liability for reimbursement of Transmission Owner for taxes, interest and/or penalties under Article 5.17.3 of this Agreement is $_____.

**5. Type and Amount of Interim Interconnection Service:**

The type of Interim Interconnection Service to be provided pursuant to this Interim GIA shall be [Energy Resource or Network Resource] Interim Interconnection Service in the amount of _____ MW.

**6. Construction Option For Stand Alone Upgrades and Transmission Owner Interconnection Facilities:**

The Parties have agreed to the construction options for the Stand Alone Network Upgrades and Transmission Owner Interconnection Facilities as specified below:

**A. Stand Alone Network Upgrades:**

**[List the Stand Alone Network Upgrade and the construction option]**

**B. Transmission Owner Interconnection Facilities:**

**[List the Transmission Owner Interconnection Facility and the option]**

**7. Higher Queued Projects:**

**[list Higher Queued Projects]**

**8. Permits, Licenses and Authorizations:**

**9. Penalty, Redispatch or Market-Related Costs:**

**10. One-Line Diagram:**

**11. Candidate Incremental Long-Term Congestion Rights:**

* Source _____
* Sink _____
* Candidate Incremental LTCR MW _____
* Term (years from in-service date of Network Upgrade) _____

# Appendix B to Interim GIA

## Milestones

## Appendix C to Interim GIA

## Interconnection Details

This Appendix C is an integral part of this Interim GIA.

**1. Description of Generating Facility:**
**Inverter-Based Resource EMT Study Results Mitigations**

If an Electromagnetic Transient Study is determined to be required by the Transmission Provider and the study results reveal an Adverse System Impact to the Transmission System, mitigation(s) shall be the responsibility of the Interconnection Customer and shall be implemented prior to the injection of power into the Transmission System.

**2. Description of Point of Change of Ownership:**

**3. Description of Point of Interconnection:**

**4. Interconnection Guidelines:**
The unique requirements of each generation interconnection will dictate the establishment of mutually agreeable interconnection guidelines that further define the requirements of this Agreement. The interconnection guidelines will address, but not be limited to, the following:

## Appendix D to Interim GIA

## Infrastructure and Operational Security Arrangements

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

## Appendix E to Interim GIA

## Commercial Operation Date

**[Date]**

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

**[Transmission Owner Address]**

Re: _____

Dear _____:

On **[Date]**, _____ has completed Trial Operation of referenced generation facility in the Interim Generator Interconnection Agreement dated _____. This letter confirms that _____ commenced Commercial Operation of the referenced generation facility, effective as of **[Date plus one day]**.

Thank you.

**[Signature]**

**[Interconnection Customer Representative]**

## Appendix F to Interim GIA

## Addresses for Delivery of Notices And Billings

**Notices:**

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

**[To be Supplied]**

Interconnection Customer:

**[To be Supplied]**

**Billings and Payments:** [Specify addresses for construction invoices, O&M invoices and settlement of ancillary services]

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

**[To be Supplied]**

Interconnection Customer:

**[To be Supplied]**

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

**[TO BE SUPPLIED]**

Interconnection Customer:

**[TO BE SUPPLIED]**

**Operational Communications:** [Identify contacts for operations]

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

**[TO BE SUPPLIED]**

Interconnection Customer:

**[TO BE SUPPLIED]**

## Appendix G to Interim GIA

## Requirements Of Generators Relying On Newer Technologies

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this Interim GIA continue to apply to wind generating plant interconnections.

### A. Technical Standards Applicable to a Wind Generating Plant

#### i. Low Voltage Ride-Through (LVRT) Capability

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a facilities study agreement as of September 21, 2016. A wind generating plant to which this provision applies shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

**Transition Period LVRT Standard**

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or

"GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**Post-transition Period LVRT Standard**

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating

plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**ii. Power Factor Design Criteria (Reactive Power)**

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this Interim GIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

**iii. Supervisory Control and Data Acquisition (SCADA) Capability**

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for

the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

# APPENDIX 9 TO GIP

## CERTIFICATION CODES AND STANDARDS

Certification and interconnection of Interconnection Customer's facilities with Transmission Owner's facilities shall be governed by all applicable local, state and federal statutes and regulations. In addition, Interconnection Customer's facilities shall be installed in accordance with all provisions set forth in Transmission Owner's Facility Connection Standard, Transmission Owner Service Standard and the National Electrical Safety Code (ANSIC2), National Electrical Code (NFPA70), North American Electric Reliability Council (NERC), Regional Reliability Councils, American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE), or other regulatory or governing body having jurisdiction. Connection of Interconnection Customer's facilities with Transmission Owner's facilities shall further be governed by any applicable statute, rule, order, provision, guide, or code of an organization, council, institute, regulatory or governing body having jurisdiction over such matters.

A sample list of such requirements is shown below (Note this list is not all-inclusive and the entities responsible for these requirements may update them at any time. The current versions shall be applicable.):

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

# APPENDIX 10 TO GIP

## CERTIFICATION OF SMALL GENERATOR EQUIPMENT PACKAGES

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in GIP Appendix 9, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the Parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these GIP shall be considered certified under these procedures for use in that state.

## APPENDIX 11 TO GIP

## APPLICATION, PROCEDURES, AND TERMS AND CONDITIONS FOR INTERCONNECTING A CERTIFIED INVERTER-BASED SMALL GENERATING FACILITY NO LARGER THAN 10 KW ("10 KW INVERTER PROCESS")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider.

2.0 The Transmission Provider acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Transmission Provider evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Transmission Provider verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in Section 14 of the Generator Interconnection Procedures (GIP). The Transmission Provider has 15 Business Days to complete this process. Unless the Transmission Provider determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Transmission Provider approves the Application and returns it to the Customer. Note to Customer: Please check with the Transmission Provider before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Transmission Provider and Transmission Owner. Prior to parallel operation, the Transmission Provider and Transmission Owner may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Transmission Owner notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Transmission Owner

has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Transmission Owner is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Transmission Owner does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Transmission Provider, that contact information must be provided on the Application.

8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

**Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW**

This Application is considered complete when it provides all applicable and correct information required below. Documentation of Site Control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $500 must accompany this Application.

Interconnection Customer

Name: _____

Contact Person: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Contact (if different from Interconnection Customer)

Name: _____

Address: _____

City: _____ State: _____ Zip: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Owner of the facility (include % ownership by any electric utility): _____

Small Generating Facility Information

Location (if different from above): _____

Electric Service Company: _____

Account Number: _____

Inverter Manufacturer:_____Model_____

Nameplate Rating: _____ (kW) _____ (kVA) _____ (AC Volts)

Single Phase _____ Three Phase_____

System Design Capacity: _____ (kW) _____ (kVA)

Prime Mover: Photovoltaic ☐ Reciprocating Engine ☐ Fuel Cell ☐

Turbine ☐ Other _____

Energy Source: Solar ☐ Wind ☐ Hydro ☐ Diesel ☐ Natural Gas ☐

Fuel Oil ☐ Other (describe) _____

Is the equipment UL1741 Listed? Yes No ___

If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: _____ Estimated In-Service Date: _____

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Appendix 9 and 10of the Generator Interconnection Procedures (GIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

| Equipment Type | Certifying Entity |
|---|---|
| 1. _____ | _____ |
| 2. _____ | _____ |
| 3. _____ | _____ |
| 4. _____ | _____ |
| 5. _____ | _____ |

**Interconnection Customer Signature**

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: _____

Title: _____ Date: _____

Contingent Approval to Interconnect the Small Generating Facility

(For Transmission Provider use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Transmission Provider Signature: _____

Title: _____ Date: _____

Application ID number: _____

Transmission Provider waives inspection/witness test? Yes___No___

Transmission Owner Signature: _____

Title: _____ Date: _____

Application ID number: _____

Transmission Owner waives inspection/witness test? Yes___No___

## Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes_____ No _____

Interconnection Customer: _____

Contact Person:_____

Address: _____

Location of the Small Generating Facility (if different from above):

_____

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Electrician:

Name: _____

Address: _____

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

License number: _____

Date Approval to Install Facility granted by the Transmission Provider: _____

Application ID number: _____

Date Approval to Install Facility granted by the Transmission Owner: _____

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local

building/electrical code of _____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

_____

Print Name: _____

Date: _____

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Transmission Provider information below):

Name: _____, _____

Company: Southwest Power Pool, Inc.

Address: 201 Worthen Drive

City, State ZIP: Little Rock, AR 72223-4936

Fax: (501) 482-2022

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Approval to Energize the Small Generating Facility (For Transmission Provider use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Transmission Provider Signature: _____

Title: _____ Date: _____

# Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

## 1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider approves the Interconnection Request (the "Application") and returns it to the Customer.

## 2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Transmission System or Distribution System once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Transmission Provider and Transmission Owner, and

2.3 The Transmission Owner has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Transmission Owner, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Transmission Owner shall provide a written statement to the Customer and the Transmission Provider that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Transmission Owner does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Transmission Owner waives the right to inspect the Small Generating Facility.

2.4 The Transmission Owner has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

## 3.0 **Safe Operations and Maintenance**

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

## 4.0 **Access**

The Transmission Owner shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Transmission Owner shall provide reasonable notice to the Customer when possible prior to using its right of access.

## 5.0 **Disconnection**

The Transmission Owner may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Transmission Owner shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Parties, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7. 0 **Insurance**

The Parties each agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 **Limitation of Liability**

Each Party’s liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall a Party be liable to the other Parties for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

## 9.0 **Termination**

The agreement to operate in parallel may be terminated under the following conditions:

### 9.1 **By the Customer**

By providing written notice to the Company.

### 9.2 **By the Company**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

### 9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

### 9.4 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

## 10.0 **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

## 11.0 **No Applicability to Transmission Service.**

Nothing in this Agreement shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

# APPENDIX 12 TO GIP

## CONSENT TO ASSIGNMENT OF GIA GEN-____-___ EFFECTIVE __/__/____

To Whom It May Concern:

Southwest Power Pool, Inc. ("Transmission Provider") and _____ ("Transmission Owner") have been asked to provide written consent to the assignment of that certain Generator Interconnection Agreement GEN-____-___ entered into on __/__/____ among Transmission Provider, _____ ("Interconnection Customer") and Transmission Owner (the "GIA")*. Pursuant to Article 19.1 of the GIA, Interconnection Customer desires to assign GIA to _____ ("Assignee"), and Assignee desires to assume the GIA.

Consistent with Article 19.1 of the GIA, Interconnection Customer represents to Transmission Provider and Transmission Owner that Assignee shall take assignment of the GIA and the related Interconnection Request number and queue position subject to the terms and conditions provided in the GIA, and the terms and conditions governing interconnection procedure and queue position contained in SPP's Open Access Transmission Tariff ("OATT"), including but not limited to, all performance obligations, responsibilities and liabilities. Upon assignment of the GIA, Interconnection Customer will notify the Transmission Provider and Transmission Owner of the assignment. Further, to the knowledge of the undersigned representative of Interconnection Customer, after due inquiry, no default exists in the performance of Interconnection Customer's obligations under the GIA.

Transmission Provider and Transmission Owner acknowledge that Interconnection Customer has the right to assign the GIA, either as a general assignment of the GIA or for purposes of obtaining financing, and does hereby expressly consent to such assignment. Interconnection Customer assigns the GIA and Assignee takes assignment subject to the provisions of Article 19.1 of the GIA. In granting consent, neither Transmission Provider nor Transmission Owner makes any other acknowledgments, representations or warranties of any kind.

This Consent to Assignment may be executed in one or more identical counterparts, including an electronic or facsimile copy hereof (and specifically including counterparts executed by the individual parties to indicate acknowledgement and agreement), each of which when executed by any one party and delivered to the Interconnection Customer shall be deemed an original and all of which taken together shall constitute a single instrument.

ACKNOWLEDGED AND AGREED

**Southwest Power Pool, Inc.**

By: _____
Name: _____
Title: _____
Date: _____

**_____ (Transmission Owner)**

By: _____
Name: _____
Title: _____
Date: _____

**_____ (Interconnection Customer)**

By: _____
Name: _____
Title: _____
Date: _____

* The agreement may have been executed under an older version of the pro forma OATT or for interim interconnection service; therefore it may be identified herein as a Large Generator Interconnection Agreement ("LGIA") or an Interim Generator Interconnection Agreement ("Interim GIA").

# APPENDIX 13 TO THE GENERATOR INTERCONNECTION PROCEDURES

# GENERATOR INTERCONNECTION AGREEMENT (GIA)

(For use when Western-UGP is a Party to the GIA, as the Transmission Owner)

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# GENERATOR INTERCONNECTION AGREEMENT

**THIS GENERATOR INTERCONNECTION AGREEMENT** ("Agreement") is made and entered into this ____ day of _____ 20__, by and among _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Generating Facility), Southwest Power Pool, Inc., a corporation organized and existing under the laws of the State of Arkansas ("Transmission Provider") and Western Area Power Administration-Upper Great Plains Region ("Western-UGP"), a Federal power marketing agency organized under the United States Department of Energy ("Transmission Owner"). Interconnection Customer, Transmission Provider and Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

## Recitals

**WHEREAS,** Transmission Provider functionally controls the operation of the Transmission System; and,

**WHEREAS,** Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

**WHEREAS,** Transmission Owner owns facilities to which the Generating Facility is to be interconnected and may be constructing facilities to allow the interconnection; and,

**WHEREAS,** Interconnection Customer, Transmission Provider and Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

## Article 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Generator Interconnection Agreement.

**Breaching Party** shall mean a Party that is in Breach of the Generator Interconnection Agreement.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting Interconnection Studies.

**Commercial Operation** shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

**Commercial Operation Date** of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Generator Interconnection Agreement.

**Confidential Information** shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

**Contingent Facilities** shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. Contingent Facilities are identified in Appendix A of the Generator Interconnection Agreement.

**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

**Default** shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Generator Interconnection Agreement.

**Definitive Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures. The Definitive Interconnection System Impact Study is conducted in two phases.

**Definitive Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

**Dispute Resolution** shall mean the procedure in Section 13.5 of the Generator Interconnection Procedures for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

**Distribution System** shall mean the Transmission Owner's facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.

**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Electromagnetic Transient Study or EMT Study** shall mean an analysis to determine the electromagnetic transient response of the electric power system due to system disturbances.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interconnection Service (ERIS)** shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

**Environmental Review** shall mean a study conducted by the Transmission Owner that contains a review of the proposed interconnection to the Transmission Owner's transmission facilities, pursuant to the National Environmental Policy Act (NEPA), 42 U.S.C. §4321, et seq.,

as amended, and setting forth Interconnection Customer's responsibilities in connection with such review of the interconnection.

**Existing Generating Facility** shall mean a Generating Facility that is currently interconnected to the Transmission System of the Transmission Provider.

**Federal Power Act** shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. A Generating Facility consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generating Facility Modification** shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of the equipment at the Existing Generating Facility.

**Generating Facility Replacement** shall mean the process of replacing one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection as those being decommissioned and electrically disconnected.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in the Transmission Provider's Tariff.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Generator Interconnection Study Agreement** shall mean the study agreement for the Definitive Interconnection System Impact Study and the Interconnection Facilities Study in Appendix 3 of the Generator Interconnection Procedures.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3 of the Generator Interconnection Procedures.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 3 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, to interconnect a Replacement Generating Facility, to increase the capacity of, or make a Material Modification to the operating characteristics of, an Existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Replacement Impact Study, the Reliability Assessment Study, the Definitive Interconnection System Impact Study and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements described in the Generator Interconnection Procedures: the Generator Interconnection Study Agreement.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Generator Interconnection Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Generator Interconnection Agreement at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

**Network Resource Interconnection Service (NRIS)** shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interconnection Service in and of itself does not convey transmission service.

**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

**Notice of Dispute** shall mean a written notice of a dispute or claim that arises out of or in connection with the Generator Interconnection Agreement or its performance.

**Party or Parties** shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

**Point of Change of Ownership** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

**Point of Interconnection** shall mean the point, as set forth in Appendix A to the Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission System.

**Queue** shall mean the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Reliability Assessment Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of Transmission System during the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility.

**Replacement Generating Facility** shall mean a Generating Facility that replaces an Existing Generating Facility, or a portion thereof, at the same electrical Point of Interconnection pursuant to Section 3.9 of this Attachment V.

**Replacement Impact Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of the Transmission System.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers' Generating Facilities and which is the shared funding responsibility of such Interconnection Customers that may also benefit other Interconnection Customer(s) that are later identified as beneficiaries**.**

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility or Generating Facility's tie line; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

**Small Generating Facility** shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

**Stand Alone Network Upgrades** shall mean Network Upgrades that are not part of an Affected Systems that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Generator Interconnection Agreement. If the Transmission Provider, Transmission Owner and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Owner must provide the Interconnection Customer a written technical explanation outlining why the Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within fifteen (15) days of its determination.

**Surplus Interconnection Service** shall mean any unneeded portion of Interconnection Service established in a Generator Interconnection Agreement, such that if Surplus Interconnection Service is utilized the total amount of Interconnection Service at the Point of Interconnection substation and at the same voltage level would remain the same.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades, or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

**Variable Energy Resource** shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

**Western Area Power Administration-Upper Great Plains Region ("Western-UGP")** shall mean **a** division of the Western Area Power Administration, a Federal power marketing agency, and Transmission Owner, that markets and transmits Federal power over Federal transmission facilities that have been transferred to the functional control of the Transmission Provider.

## Article 2. Effective Date, Term, and Termination

**2.1 Effective Date.** This GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this GIA with FERC upon execution in accordance with Article 3.1, if required.

**2.2 Term of Agreement.** Subject to the provisions of Article 2.3, this GIA shall remain in effect for a period of ten (10) years from the Effective Date or such other longer period as Interconnection Customer may request (Term to be specified in individual agreements) and shall be automatically renewed for each successive one-year period thereafter.

Notwithstanding this Article 2.2 or 2.3, the maximum effective period of this GIA shall be forty (40) years from the Effective Date. Five years prior to termination, Interconnection Customer shall provide written notice of its intention to extend the GIA. Upon receiving such notice, Transmission Provider and Transmission Owner shall enter into good faith discussions regarding an extension of the GIA at Interconnection Customer's request.

**2.3 Termination Procedures.**

**2.3.1 Written Notice.** This GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

**2.3.2 Failure to Achieve Commercial Operation.** If the Generating Facility fails to achieve Commercial Operation for three (3) consecutive years following the Commercial Operation Date, this GIA may be terminated by the Transmission Provider after giving the Interconnection Customer ninety (90) Calendar Days advance written notice. Where a portion of the Generating Facility fails to achieve Commercial Operation for three (3) consecutive years following the Commercial Operation Date, the Transmission Provider shall issue a revised GIA to reflect the amount of the Generating Facility Capacity that achieved Commercial Operation. The revised GIA shall be consistent with the GIP in effect on the Effective Date of the GIA.

**2.3.3 Default.** Any Party may terminate this GIA in accordance with Article 17.

**2.3.4 Notice to FERC.** Notwithstanding Articles 2.3.1, 2.3.2 and 2.3.3, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this GIA, which notice has been accepted for filing by FERC.

**2.4 Termination Costs.** If a Party elects to terminate this Agreement pursuant to Article 2.3 above, Interconnection Customer and Transmission Owner shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by any other Party, as of the date of such Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this GIA. In the event of termination by any Party, all Parties shall use Commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this GIA:

**2.4.1** With respect to any portion of Transmission Owner's Interconnection Facilities that have not yet been constructed or installed, Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If an Interconnection Customer terminates this GIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for

Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer and the Interconnection Customer's allocated share of Network Upgrade(s) costs as calculated pursuant to Section 4.2.5 of the GIP and as listed in Appendix A of this GIA which are required for service to other Interconnection Customer(s).

**2.4.2** Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

**2.4.3** With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

**2.5 Disconnection.** Upon termination of this GIA, the Parties will take all appropriate steps to disconnect the Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this GIA or such non-terminating Party otherwise is responsible for these costs under this GIA.

**2.6 Survival.** This GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this GIA; to permit payments for any credits under this GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this GIA was in effect; and to permit each Party to have access to the lands of another Party pursuant to this GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

## Article 3. Regulatory Filings

**3.1 Filing.** Transmission Provider shall file this GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

## Article 4. Scope of Service

**4.1 Interconnection Product Options.** Interconnection Customer has selected the following (checked) type of Interconnection Service:

**4.1.1 Energy Resource Interconnection Service.**

**4.1.1.1 The Product.** Energy Resource Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Appendix A.

**4.1.1.2 Transmission Delivery Service Implications.** Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Generating Facility into and deliver power across the Transmission System on an "as available" basis. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

**4.1.2 Network Resource Interconnection Service.**

**4.1.2.1 The Product.** Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interconnection Service, Transmission Owner shall construct the facilities identified in Appendix A to this GIA.

**4.1.2.2 Transmission Delivery Service Implications.** Network Resource Interconnection Service allows Interconnection Customer's Generating Facility to be designated by any Network Customer under the Tariff on the Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving Network Resource Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided

that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission System, Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

There is no requirement either at the time of study or interconnection, or at any point in the future, that Interconnection Customer’s Generating Facility be designated as a Network Resource by a Network Service Customer under the Tariff or that Interconnection Customer identify a specific buyer (or sink). To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission System, such request may require additional

studies and upgrades in order for Transmission Provider to grant such request.

**4.2 Provision of Service.** Transmission Provider shall provide Interconnection Service for the Generating Facility at the Point of Interconnection.

**4.3 Performance Standards.** Each Party shall perform all of its obligations under this GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this GIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the GIA and Transmission Provider shall submit the amendment to FERC for approval.

**4.4 No Transmission Delivery Service.** The execution of this GIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

**4.5 Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.9.

## Article 5. Interconnection Facilities Engineering, Procurement, and Construction

**5.1 Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Option To Build as described under Article 5.1.2 or the Negotiated Option described under Article 5.1.3, and such dates and selected option, as applicable, shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.2 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Transmission Owner, the Interconnection Customer shall notify Transmission Owner within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

**5.1.1 Standard Option.** Transmission Owner shall design, procure, and construct Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission

Owner reasonably expects that it will not be able to complete Transmission Owner's Interconnection Facilities, and Network Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

**5.1.2 Option to Build.** Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.1. Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

**5.1.3 Negotiated Option.** If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates, the provision of incentives or the procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.2). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1(Standard Option), Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects the Option to Build.

**5.2 General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from Interconnection Customer's construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Owner's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Owner not later than the Commercial Operation Date;

(10) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.2, Interconnection Customer shall pay Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for Transmission Owner to execute the responsibilities enumerated to Transmission Owner under Article 5.2.

Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

**5.3 Reserved.**

**5.4 Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative. The requirements of this paragraph shall not apply to non-synchronous generators.

**5.5 Equipment Procurement.** If responsibility for construction of Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

**5.5.1** Transmission Provider has completed the Interconnection Facilities Study pursuant to the Generator Interconnection Study Agreement;

**5.5.2** Transmission Owner has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.5.3** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 and advance payment to Transmission Owner in accordance with Article 11.8 by the dates specified in Appendix B, Milestones.

**5.6 Construction Commencement.** Transmission Owner shall commence construction of Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

**5.6.1** Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

**5.6.2** Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Owner's Interconnection Facilities and Network Upgrades;

**5.6.3** Transmission Owner has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.6.4** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 and advance payment to Transmission Owner in accordance with Article 11.8 by the dates specified in Appendix B, Milestones.

**5.7 Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Parties may, at any time, request a progress report from other Parties. If, at any time, Interconnection Customer determines that the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will be required.

**5.8 Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System, and shall work diligently and in good faith to make any necessary design changes.

**5.9 Limited Operation.** If any of Transmission Owner's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Generating Facility and Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Owner's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice, and this GIA ("Limited Operation"). Transmission Owner shall permit Interconnection Customer to operate the Generating Facility and Interconnection Customer's Interconnection Facilities under Limited Operation in accordance with the results of such studies performed by Transmission Provider.

**5.10 Interconnection Customer's Interconnection Facilities ('ICIF').** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

**5.10.1 Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Owner at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date; and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner and comment on such specifications within thirty (30) Calendar Days of

Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

**5.10.2 Transmission Owner's Review.** Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner.

**5.10.3 ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. The Interconnection Customer shall provide Transmission Owner specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

**5.10.4 Updated Information Submission by Interconnection Customer.** The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Attachment A to Appendix 3 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Facilities Studies. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study agreements between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to

this Article 5.10.4. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

**5.10.5 Information Supplementation.** Prior to the Commercial Operation Date, or as soon as possible thereafter, the Parties shall supplement their information submissions described above in this Article 5 with any and all "as-built" Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Owner and Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide the Interconnection Customer and Transmission Provider any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

**5.11 Transmission Owner's Interconnection Facilities Construction.** Transmission Owner's Interconnection Facilities and Network Upgrades shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Owner's Interconnection Facilities and Network Upgrades [include appropriate drawings and relay diagrams].

Transmission Owner will obtain control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

**5.12 Access Rights.** Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to any other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this GIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

**5.13 Lands of Other Property Owners.** If any part of Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with Federal or state law, as applicable, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

**5.14 Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

**5.15 Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

## 5.16 Suspension.

**5.16.1 Suspension by Interconnection Customer.** Interconnection Customer, upon written notice to Transmission Provider and Transmission Owner, may suspend, for a period not to exceed 18 months, work by Transmission Owner associated with the construction and installation of Transmission Owner's Interconnection Facilities and/or Network Upgrades required under this GIA under the following terms and conditions,

i. Construction of Network Upgrades that are required to provide Interconnection Service to other Generating Facilities and for which Interconnection Customer shares cost responsibility cannot be suspended pursuant to this Article 5.16.

ii. If the suspension period begins later than or extends beyond six months following the Effective Date of the GIA, the Interconnection Customer shall provide to the Transmission Provider security in the form described under Article 11.7 in an amount equal to the greater of:

a. the Interconnection Customer's allocated share of Network Upgrade(s) as calculated pursuant to Section 4.2.5 of the GIP and as identified in Appendix A of this GIA unless previously provided under Section 8.9 of the GIP; or

b. $5,000,000 if the Generating Facility is greater than or equal to 100 MW; or

c. $2,500,000 if the Generating Facility is greater than or equal to 50 MW and less than 100 MW; or

d. $1,000,000 if the Generating Facility is less than 50 MW; or

e. $500,000 if the Generating Facility is less than or equal to 2 MW.

iii. In the event that this GIA is terminated under this Article 5.16, the Transmission Provider shall retain the security provided pursuant to Article 5.16.1.ii in the amount required to meet Interconnection Customer's obligations pursuant to this GIA. Any difference between the security provided and Interconnection Customer's obligations shall be settled pursuant to Article 12.

iv. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16 and has not requested Transmission Owner to resume the work required under this GIA on or before the expiration of 18 months from the date of suspension, this GIA shall be deemed terminated unless Article 16 applies.

v. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16 and has not complied requirements of Article 5.16.1.ii on or before the later of the expiration of 6 months following the effective date of the GIA or the date the suspension is requested, this GIA shall be deemed terminated by the Interconnection Customer.

vi. In the event Interconnection Customer suspends work by Transmission Owner required under this GIA pursuant to this Article 5.16, the Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Owner's safety and reliability criteria. Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Owner and Transmission Provider (i) have incurred pursuant to this GIA prior to the suspension and (ii) incur in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Owner cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Owner shall obtain Interconnection Customer's authorization to do so. Transmission Owner and Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs.

vii. In the event Interconnection Customer provides written notice to resume work for those facilities for which work has been suspended pursuant to this Article 5.16.1, the Interconnection Customer shall receive a refund, including interest, of any payments provided in accordance with Article 5.16.1.ii in excess of the sum of Interconnection Customer's allocated share of Network Upgrade(s) costs and any costs incurred under Article 5.16.1.vi within 30 days of the date of such notice.

**5.16.2 Exemptions.** The Interconnection Customer shall be exempt from the payments described under Article 5.16.1.ii.b, 5.16.1.ii.c and 5.16.1.ii.d if the following occurs or Suspension is requested for the following reasons:

i. Construction of a Network Upgrade or the Generating Facility is prevented by order of a Governmental Authority; or

ii. Transmission Provider determines through an Interconnection Study that the Suspension does not qualify as a modification that has an impact on the cost or timing of any Interconnection Request with an equal or later Queue priority date (Material Modification); or

iii. Transmission Owner or Transmission Provider determines that a Force Majeure event prevents construction of a Network Upgrade.

**5.17 Reserved.**

**5.18 Tax Status.** All Parties shall cooperate with each other to maintain their tax status. Nothing in this GIA is intended to adversely affect any Party's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

**5.19 Modification.**

**5.19.1 General.** Each Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility Modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Owner's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

**5.19.2 Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this GIA and Good Utility Practice.

**5.19.3 Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Owner makes to Transmission Owner's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Owner's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

**5.20 Delays .** If a Network Upgrade(s) identified in Appendix A is delayed during the construction process and the Commercial Operation Date for the Generating Facility identified in Appendix B is no longer feasible, the Commercial Operation Date in Appendix B may be modified to no later than six (6) months following the in-service date for the last Network Upgrade identified in Appendix A.

**Article 6. Testing and Inspection**

**6.1 Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Owner shall test Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

**6.2 Post-Commercial Operation Date Testing and Modifications.** Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

**6.3 Right to Observe Testing.** Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties have the right, at its own expense, to observe such testing.

**6.4 Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe another Parties' tests and/or inspection of any of its System Protection Facilities and other protective equipment, including power system stabilizers; (ii) review the settings of the other Parties' System Protection Facilities and other protective equipment; and (iii) review another Parties' maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Any Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by another Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that any Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this GIA.

## Article 7. Metering

**7.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Owner's option, compensated to, the Point of Interconnection. Transmission Owner shall provide metering quantities, in analog and/or digital form, to Interconnection Customer and Transmission Provider on a same-time basis using communication as provided in

Article 8. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

**7.2 Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

**7.3 Standards.** Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

**7.4 Testing of Metering Equipment.** Transmission Owner shall inspect and test all Transmission Owner-owned Metering Equipment in accordance with Transmission Owner's meter testing policies. If requested to do so by Interconnection Customer, Transmission Owner shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than the periods set forth in the Transmission Owner's meter testing policies. Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Owner's failure to maintain, then Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Owner shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

**7.5 Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

## Article 8. Communications

**8.1 Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Owner's Transmission System

dispatcher or representative designated by Transmission Owner. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Owner as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Owner. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

**8.2 Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Owner through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Owner.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

**8.3 No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

**8.4 Provision of Data from a Variable Energy Resource.** The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider’s development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with (i) site-specific meteorological data including: temperature, wind speed, wind direction, relative humidity and atmospheric pressure and (ii) site specific geographic data including location (latitude and longitude) of the Variable Energy Resource and location (latitude and longitude) and height of the facility that will contain the equipment necessary to provide the meteorological data for such resource. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission

Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological, geographical and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological, geographical and forced outage data are set forth in Appendix C, Interconnection Details, of this GIA, as they may change from time to time.

**8.5 Phasor Measurement Unit (PMU) Recording Equipment**. Prior to the Initial Synchronization Date of a Generating Facility having a Generating Facility Capacity equal to or greater than 50 MW, phasor measurement recording and communications equipment shall be installed by the Transmission Owner at Interconnection Customer's expense that is capable of gathering phasor measurements as specified in the PMU Communications Handbook. To the extent similar quality equipment is being added or already exists, such as relays or digital fault recorders, that can collect data at least at the same rate as PMUs and which data is synchronized via a high-accuracy satellite clock, such equipment can be utilized to satisfy this requirement if the equipment is located on the Transmission Owner's side of the Point of Change of Ownership and if mutually agreed to by the Parties. The phasor measurement equipment shall be installed at the Transmission Owner's side of the Point of Change of Ownership and become part of the Transmission Owner Interconnection Facilities. Phasor measurements shall be streamed in IEEE C37.118 or equivalent format and be provided to the Transmission Provider. This data shall at least be sufficient to determine (i) positive-sequence voltage magnitude and angle, (ii) positive-sequence current magnitude and angle, (iii) frequency, and (iv) rate of change of frequency. Such data shall be transmitted over the data circuit(s) as indicated in Article 8.1.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the applicable Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

## Article 9. Operations

**9.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Parties all information that may reasonably be

required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

**9.2 Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Control Area in which the Generating Facility will be located. If Interconnection Customer elects to locate the Generating Facility in a Control Area other than the Control Area in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this GIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Control Area.

**9.3 Transmission Provider and Transmission Owner Obligations.** Transmission Provider and Transmission Owner shall cause the Transmission System and Transmission Owner's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this GIA. Transmission Provider or Transmission Owner may provide operating instructions to Interconnection Customer consistent with this GIA and Transmission Owner's operating protocols and procedures as they may change from time to time. Transmission Provider and Transmission Owner will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

**9.4 Interconnection Customer Obligations.** Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA. Interconnection Customer shall operate the Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that another Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this GIA.

**9.5 Start-Up and Synchronization.** Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission System.

**9.6 Reactive Power and Primary Frequency Response.**

**9.6.1 Power Factor Design Criteria.**

**9.6.1.1 Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established

different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

**9.6.1.2 Non-Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that had not executed an interconnection facilities study agreement as of September 21, 2016.

**9.6.2 Voltage Schedules.** Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider and/or Transmission Owner shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Owner's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Owner shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the Transmission Owner.

**9.6.2.1 Voltage Regulators.** Whenever the Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in Mvars) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition in

accordance with Good Utility Practice and Applicable Reliability Standards.

**9.6.3 Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating Facility when Transmission Owner requests Interconnection Customer to operate its Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.9 or such other agreement to which the Parties have otherwise agreed; provided however, to the extent the Tariff contains a provision providing for such compensation, that Tariff provision shall control.

**9.6.4 Primary Frequency Response.** Interconnection Customer shall ensure the primary frequency response capability of its Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband;. or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Interconnection Customer shall operate the Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Generating Facilities.

**9.6.4.1 Governor or Equivalent Controls.** Whenever the Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Generating Facility's governor or equivalent controls to a minimum whenever the Generating Facility is operated in parallel with the Transmission System.

**9.6.4.2 Timely and Sustained Response.** Interconnection Customer shall ensure that the Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

**9.6.4.3 Exemptions.** Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

**9.6.4.4 Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its GIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage

resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

## 9.7 Outages and Interruptions.

### 9.7.1 Outages.

**9.7.1.1 Outage Authority and Coordination.** Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to all Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

**9.7.1.2 Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

**9.7.1.3 Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide

the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

**9.7.2 Interruption of Service.** If required by Good Utility Practice to do so, Transmission Provider and/or Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's and/or Transmission Owner's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

**9.7.2.1** The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

**9.7.2.2** Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

**9.7.2.3** When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

**9.7.2.4** Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Owner;

**9.7.2.5** The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

**9.7.3 Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and

over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a generating facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

**9.7.3.1 Frequency Ride Through and Voltage Ride Through for a Generating Facility no larger than 20 MW.** For Generating Facilities no larger than 20 MW, the Interconnection Customer shall ensure “frequency ride through” capability and “voltage ride through” capability of its Generating Facility. The Interconnection Customer shall enable these capabilities such that its Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to Article 6.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The Generating Facility’s protective equipment settings shall comply with the Transmission Provider’s automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term “ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority on a comparable basis. The term “frequency ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term “voltage ride through” as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other

generating facilities in the Balancing Authority Area on a comparable basis.

**9.7.4 System Protection and Other Control Requirements.**

**9.7.4.1 System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Owner's Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

**9.7.4.2** Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

**9.7.4.3** Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

**9.7.4.4** Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

**9.7.4.5** Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

**9.7.4.6** Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

**9.7.5 Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Owner's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the

Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

**9.7.6 Power Quality.** No Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

**9.8 Switching and Tagging Rules.** Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

**9.9 Use of Interconnection Facilities by Third Parties.**

**9.9.1 Purpose of Interconnection Facilities.** Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

**9.9.2 Third Party Users.** If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Owner’s Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with

Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

**9.10 Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

## Article 10. Maintenance

**10.1 Transmission Owner Obligations.** Transmission Owner shall maintain the Transmission System and Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

**10.2 Interconnection Customer Obligations.** Interconnection Customer shall maintain the Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this GIA.

**10.3 Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

**10.4 Secondary Systems.** Each Party shall cooperate with the others in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

**10.5 Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner's Interconnection Facilities.

## Article 11. Performance Obligation

**11.1 Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer's

Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

**11.2 Generating Facility.** Interconnection Customer shall install the Generating Facilities described in Appendix C within three (3) years of the Commercial Operation Date(s) specified in Appendix B.

**11.3 Transmission Owner's Interconnection Facilities.** Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

**11.4 Network Upgrades and Distribution Upgrades.** All Network Upgrades and Distribution Upgrades described in Appendix A shall be constructed in accordance with the process set forth in Section VI of Attachment O. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades that are associated with that Transmission Owner's system. The Distribution Upgrades and Network Upgrades described in Appendix A shall be solely funded by Interconnection Customer unless Transmission Owner elects to fund the capital for the Distribution Upgrades or Network Upgrades. *In the event that the Transmission Owner elects to fund the capital for the Network Upgrade(s) and/or Transmission Owner's System Protection Facilities, then the Parties shall enter into a Facilities Service Agreement. The Facilities Service Agreement shall take the form of the Facilities Service Agreement that is included in Appendix 17 of Attachment V of the Tariff.*

**11.4.1 Agreement to Fund Shared Network Upgrades.** Interconnection Customer agrees to fund Shared Network Upgrades, as determined by Transmission Provider. Where applicable, payments to fund Shared Network Upgrade(s) that are made to Transmission Provider by Interconnection Customer will be disbursed by Transmission Provider to the appropriate entities that are constructing the Shared Network Upgrades in accordance with Attachment O of the Tariff. In the event that Interconnection Customer fails to meet its obligation to fund Shared Network Upgrades, Transmission Owner and Transmission Provider shall not be responsible for the Interconnection Customer's funding obligation.

**11.4.2 Contingencies Affecting Network Upgrades, System Protection Facilities and Distribution Upgrades**. Network Upgrades, System Protection Facilities and Distribution Upgrades that are required to accommodate the Generating Facility may be modified because (a) a higher queued Interconnection Request withdrew or was deemed to have withdrawn, (b) the GIA associated with a higher queued Interconnection Request was terminated, or (c) changes occur in equipment design standards or reliability criteria giving rise to the need for restudy. The higher queued Interconnection Requests that could impact the Network Upgrades, System Protection Facilities and Distribution Upgrades required

to accommodate the Generating Facility, and possible modifications that may result from the above listed events affecting the higher queued Interconnection Requests, to the extent such modifications are reasonably known and can be determined, and estimates of the costs associated with such required Network Upgrades, System Protection Facilities and Distribution Upgrades, shall be provided in Appendix A.

**11.4.3 Agreement to Restudy**. The Interconnection Customer agrees to allow the Transmission Provider to perform a restudy in accordance with Sections 8.8 and 8.13 of the GIP if the Transmission Provider determines a restudy is required because one or more of the contingencies in Article 11.4.2 occurred. If a restudy is required, the Transmission Provider shall provide notice to Interconnection Customer. The Parties agree to amend Appendix A to this GIA in accordance with Article 30.10 to reflect the results of the restudy.

## 11.5 Transmission Credits.

**11.5.1 Credits for Amounts Advanced for Network Upgrades.** Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the Tariff for any Network Upgrades including any tax gross-up or other tax-related payments associated with Network Upgrades.

**11.5.2 Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the GIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

**11.5.3** Notwithstanding any other provision of this GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain transmission credits for transmission service that is not associated with the Generating Facility.

## 11.6 Initial Payment.

Interconnection Customer shall make an initial payment ("Initial Payment") equal to the greater of a) twenty (20) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. Any

financial security provided in Section 8.2, Section 8.5.1 and Section 8.5.2 of the GIP will be applied to this requirement. The Initial Payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the Initial Payment is not being protested by Interconnection Customer. If this GIA is terminated, then the Initial Payment shall be refunded with accrued interest calculated from the date of the receipt of the Initial Payment to the date of the refund, if any, to the Interconnection Customer less:

a. any costs that have been incurred for the construction of the facilities specified in Appendix A;

b. any funds necessary for the construction of those Shared Network Upgrades, or Network Upgrades, that would be assigned to another interconnection customer where such upgrade costs would not have been assigned but for the termination of the GIA; and

c. any costs that have been incurred for the construction of those Shared Network Upgrades, or Network Upgrades, that are no longer required due to the termination of the GIA that were paid for by another interconnection customer.

**11.7 Provision of Security.** Payments for any upgrades installed by the Transmission Owner will be addressed in accordance with Article 11.8 of this GIA. For Network Upgrades and Distribution Upgrades that are not installed by the Transmission Owner, at least thirty (30) Calendar Days prior to the commencement of the procurement, installation, or construction of a discrete portion of Network Upgrades, or Distribution Upgrades as defined in Appendix A of this GIA, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1. Such security for payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Network Upgrades or Distribution Upgrades as defined in Appendix A of this GIA and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes. If Interconnection Customer requests suspension pursuant to Article 5.16, Interconnection Customer may be required to provide Transmission Provider security in the form described above for its allocated share of Network Upgrade(s) costs as calculated pursuant to Section 4.2.5 of the GIP and defined in Appendix A of this GIA.

In addition:

**11.7.1** The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that

guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

**11.7.2** The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.7.3** The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.8 Advance Payment.**

**11.8.1** For Transmission Owner's Interconnection Facilities, Network Upgrades and Distribution Upgrades constructed by Transmission Owner, Interconnection Customer shall be required to pay Transmission Owner for all actual costs incurred by Transmission Owner for the procurement, installation, or construction of a discrete portion of a Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall pay Transmission Owner, in advance, for all work to be conducted by the Transmission Owner, under the terms and conditions set forth in this GIA. Such advance payments shall be considered estimated costs for project planning, management, design, engineering, land purchase, environmental investigations, procurement, construction, inspection and commissioning activities for which such advance payments are then due. The funds shall be deposited by Interconnection Customer according to the instructions on individual invoices from Transmission Owner, which shall be delivered by Transmission Owner to Interconnection Customer at least ten (10) Business Days prior to the date of such payment being due. Transmission Owner shall not provide any labor, equipment, materials, parts, travel, or incur incidental costs associated with tasks described above, or commence any other work until applicable advance payment(s) is/are received in full.

**11.8.2** Interconnection Customer shall not be required to make any subsequent payment to the Transmission Owner in the event tasks relating to the prior payment have not been substantially completed.

**11.8.3** Transmission Owner shall keep detailed records for actual costs incurred. Interconnection Customer shall be entitled, during normal business hours and at its own expense, to review such records and supporting documentation. If, during procurement, installation, or construction of a discrete portion of a Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, or upon close-out of any phase of such activities, costs by Transmission Owner are expected to exceed the sum of payments made by Interconnection Customer, Transmission Owner will inform Interconnection Customer of the additional expenses and provide a written revision to the estimate, together with an invoice for the amount due. Interconnection Customer shall then promptly pay Transmission Owner in full and without interest for the billed amount. If, upon completion of the procurement, installation, or construction of a discrete portion of Transmission Owner's

Interconnection Facilities, Network Upgrades, or Distribution Upgrades, costs incurred by Transmission Owner are less than the sum of payment(s) made to Transmission Owner by Interconnection Customer, Transmission Owner shall refund the difference, unless such payments are otherwise non-refundable pursuant to Article 11.6 (Initial Payment), without interest, as soon as the necessary vouchers may be prepared.

**11.9 Interconnection Customer Compensation.** If Transmission Provider or Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this GIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to the Tariff. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this GIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

**11.9.1 Interconnection Customer Compensation for Actions During Emergency Condition.** Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.9.

## Article 12. Invoice

The terms of this Article 12 apply to billing between the Parties for construction and operation and maintenance charges. All other billing will be handled according to the Tariff.

**12.1 General.** Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**12.2 Final Invoice.** Within six months after completion of the construction of Interconnection Facilities and the Network Upgrades, the Interconnection Customer shall receive an invoice of the final cost due under this GIA, including any applicable cost due to termination, which shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if

any, from the cost estimates. Interconnection Customer shall receive a refund of any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

**12.3 Payment.** Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this GIA.

**12.4 Disputes.** In the event of a billing dispute between the Parties, Transmission Owner, and Transmission Provider shall continue to provide Interconnection Service under this GIA as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due, with the Transmission Provider and Interconnection Customer to pay the amount due with the accrued interest, if any.

## Article 13. Emergencies

**13.1 Definition.** "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the Generator Interconnection Agreement to possess black start capability.

**13.2 Obligations.** Each Party shall comply with the Emergency Condition procedures of NERC, the Applicable Reliability Council, Transmission Provider, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

**13.3 Notice.** Transmission Provider or Transmission Owner shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Owner's Interconnection Facilities or the Transmission System that may

reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider and Transmission Owner promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

**13.4 Immediate Action.** Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or Transmission Owner or otherwise regarding the Transmission System.

**13.5 Transmission Provider and Transmission Owner Authority.**

**13.5.1 General**. Transmission Provider and/or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider and Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider and/or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with blackstart (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's and Transmission Owner's operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

**13.5.2 Reduction and Disconnection.** Transmission Provider and/or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider and/or Transmission Owner can schedule the reduction or disconnection in advance, Transmission Provider and/or Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider and/or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer, Transmission Provider and/or Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

**13.6 Interconnection Customer Authority.** Consistent with Good Utility Practice and the GIA and the GIP, Interconnection Customer may take actions or inactions with regard to the Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Owner's Interconnection Facilities. Transmission Provider and/or Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

**13.7 Limited Liability.** Except as otherwise provided in Article 11.9.1 of this GIA, no Party shall be liable to the other Parties for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

## Article 14. Regulatory Requirements and Governing Law

**14.1 Regulatory Requirements.** Each Party's obligations under this GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act the Public Utility Holding Company Act of 2005, or the Public Utility Regulatory Policies Act of 1978 as amended by the 2005 Energy Policy Act.

**14.2 Governing Law.**

**14.2.1** The validity, interpretation and performance of this GIA and each of its provisions shall be governed by Federal law or by the laws of the state where the Point of Interconnection is located, as applicable.

**14.2.2** This GIA is subject to all Applicable Laws and Regulations.

**14.2.3** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

**Article 15. Notices.**

**15.1 General.** Unless otherwise provided in this GIA, any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Any Party may change the notice information in this GIA by giving five (5) Business Days written notice prior to the effective date of the change.

**15.2 Billings and Payments.** Billings and payments shall be sent to the addresses set out in Appendix F.

**15.3 Alternative Forms of Notice.** Any notice or request required or permitted to be given by any Party to another and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

**15.4 Operations and Maintenance Notice.** Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

**Article 16. Force Majeure**

**16.1 Force Majeure.**

**16.1.1** Economic hardship is not considered a Force Majeure event.

**16.1.2** No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full

particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

## Article 17. Default

### 17.1 Default.

**17.1.1 General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this GIA or the result of an act or omission of another Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

**17.1.2 Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this GIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this GIA.

***17.1.3 Cross-Default.*** *Pursuant to Article 11.4 of this GIA, the Parties shall enter into a Facilities Service Agreement if the Transmission Owner elects to fund the capital for the Network Upgrades and/or Transmission Owner's System Protection Facilities. Notwithstanding anything to the contrary contained in this GIA, a breach by Interconnection Customer of any provision, covenant, or other term or condition contained in the Facilities Service Agreement shall be considered a breach under this GIA. Such breach shall be subject to the terms of Article 17 of this GIA. If a default under this GIA results from the Interconnection Customer's breach of the Facilities Service Agreement and subsequent failure to cure, the Transmission Owner and Transmission Provider shall be entitled, but in no event required, to apply all rights and remedies available by reason of default under the Facilities Service Agreement and this GIA.*

## Article 18. Indemnity, Consequential Damages and Insurance

**18.1 Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Parties' action or inactions of its obligations under this GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party. Notwithstanding the provisions of this Article 18, the liability of the Transmission Owner shall be limited to and determined in accordance with the Federal Tort Claims Act, 28. U.S.C. § 1346(b), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

**18.1.1 Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**18.1.2 Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**18.1.3 Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**18.2 Consequential Damages.** In no event shall any Party be liable to any other Party under any provision of this GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which any Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

**18.3 Interconnection Customer Insurance.** Interconnection Customer shall at its own expense, maintain in force throughout the period of this GIA, and until released by all other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

**18.3.1** Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. The minimum limits for the Employers' Liability insurance shall be One Million Dollars ($1,000,000) each accident bodily injury by accident, One Million Dollars ($1,000,000) each employee bodily injury by disease, and One Million Dollars ($1,000,000) policy limit bodily injury by disease.

**18.3.2** Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards (if applicable), independent contractors coverage, coverage for pollution (if exposure is present) and punitive or exemplary damages, with minimum limits of One Million Dollars ($1,000,000) each occurrence/Two Million Dollars ($2,000,000) general aggregate and Two Million Dollars ($2,000,000) products and completed operations aggregate combined single limit for personal injury, bodily injury, including death and property damage.

**18.3.3** Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

**18.3.4** Excess Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) each occurrence/Twenty Million Dollars ($20,000,000) general aggregate.

**18.3.5** The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this GIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

**18.3.6** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

**18.3.7** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed to by all Parties.

**18.3.8** The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnection Customer are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

**18.3.9** Within ten (10) days following execution of this GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Interconnection Customer shall provide certification of all insurance required in this GIA, executed by each insurer or by an authorized representative of each insurer to the Other Party Group.

**18.3.10** Notwithstanding the foregoing, Interconnection Customer may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Interconnection Customer's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that an Interconnection Customer's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, such Interconnection Customer shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that Interconnection Customer is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

**18.3.11** The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this GIA.

**18.4 Transmission Owner Insurance.** Transmission Owner is self-insured in accordance with its status as a Federal agency.

## Article 19. Assignment

**19.1 Assignment.** This GIA may be assigned by any Party only with the written consent of the other Parties to any Affiliate of the assigning Party, or other third party, with an acceptable credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this GIA. Interconnection Customer shall have the right to assign this GIA, with the written consent of Transmission Provider and Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility. Any financing arrangement entered into by the Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider and Transmission Owner of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.7 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Consent to assignment will not be unreasonably withheld, conditioned or delayed.

## Article 20. Severability

**20.1 Severability.** If any provision in this GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such

determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this GIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Negotiated Option (Article 5.1.3), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

## Article 21. Comparability

**21.1 Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

## Article 22. Confidentiality

**22.1 Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to another prior to the execution of this GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by any Party, a Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

**22.1.1 Term.** During the term of this GIA, and for a period of three (3) years after the expiration or termination of this GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

**22.1.2 Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this GIA; or (6) is required, in accordance with Article 22.1.7 of the GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise

required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

**22.1.3 Release of Confidential Information.** No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

**22.1.4 Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to another Party. The disclosure by any Party to another Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

**22.1.5 No Warranties.** By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

**22.1.6 Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this GIA or its regulatory requirements.

**22.1.7 Order of Disclosure.** If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that

confidential treatment will be accorded any Confidential Information so furnished.

**22.1.8 Termination of Agreement.** Upon termination of this GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

**22.1.9 Remedies.** This Section 22.1.9 shall not apply to the Transmission Owner. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

**22.1.10 Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying another Party to this GIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, if consistent with the applicable Federal and state laws, rules and regulations.

**22.1.11** Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this GIA

("Confidential Information") shall not be disclosed by another Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this GIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

**22.1.12** This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

## Article 23. Environmental Releases

**23.1** Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

**23.2** Each Party shall remedy as soon as practicable all releases of Hazardous Substances brought to, or created at, real property it owns underlying the Generating Facility or Interconnection Facilities, and any such substances migrating from real property it owns at the Generating Facility site. The Party that caused the release shall bear the costs of the remedial action, which shall meet applicable Federal and state environmental standards at the time of the action. Such costs may include, but are not limited to, Federal and state supervision, remedial action plans, removal and remedial actions, and negotiation of voluntary and judicial agreements required to meet such environmental standards.

**23.3** The Parties agree to comply fully with the substantive requirements of all applicable Federal, state and local environmental laws in the performance of their obligations hereunder, and to mitigate and abate adverse environmental impacts accordingly.

## Article 24. Information Requirements

**24.1 Information Acquisition.** Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

**24.2 Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

## Article 25. Information Access and Audit Rights

**25.1 Information Access.** Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which the other Parties are responsible under this GIA; and (ii) carry out its obligations and responsibilities under this GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this GIA.

**25.2 Reporting of Non-Force Majeure Events.** Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Parties receiving such notification to allege a cause for anticipatory breach of this GIA.

**25.3 Audit Rights.** Subject to the requirements of confidentiality under Article 22 of this GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense that other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate

responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

**25.4 Audit Rights Periods.**

**25.4.1 Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Owner's Interconnection Facilities, and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner's issuance of a final invoice in accordance with Article 12.2.

**25.4.2 Audit Rights Period for All Other Accounts and Records.** Accounts and records related to any Party's performance or satisfaction of all obligations under this GIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

**25.5 Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

**Article 26. Subcontractors**

**26.1 General.** Nothing in this GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

**26.2 Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this GIA. Any applicable obligation imposed by this GIA upon the

hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

**26.3 No Limitation by Insurance.** The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

## Article 27. Disputes

**27.1 Submission.** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this GIA or its performance, the Parties agree to resolve such dispute using the dispute resolution procedures of the Generator Interconnection Procedures.

## Article 28. Representations, Warranties, and Covenants

**28.1 General**. Each Party makes the following representations, warranties and covenants:

**28.1.1 Good Standing.** Such Party is duly organized, validly existing and in good standing under Federal laws or the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this GIA.

**28.1.2 Authority.** Such Party has the right, power and authority to enter into this GIA, to become a Party hereto and to perform its obligations hereunder. This GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**28.1.3 No Conflict.** The execution, delivery and performance of this GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**28.1.4 Consent and Approval.** Such Party has sought or obtained, or, in accordance with this GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this GIA, and it will provide to any Governmental Authority notice of any actions under this GIA that are required by Applicable Laws and Regulations.

## Article 29. Joint Operating Committee

**29.1 Joint Operating Committee.** At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer, Transmission Owner and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Party shall notify the other Parties of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of any Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this GIA. All Parties shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

**29.1.1** Establish data requirements and operating record requirements.

**29.1.2** Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

**29.1.3** Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Owner’s and Interconnection Customer's facilities at the Point of Interconnection.

**29.1.4** Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

**29.1.5** Ensure that information is being provided by each Party regarding equipment availability.

**29.1.6** Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

## Article 30. Miscellaneous

**30.1 Binding Effect.** This GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**30.2 Conflicts.** In the event of a conflict between the body of this GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this GIA shall prevail and be deemed the final intent of the Parties.

**30.3 Rules of Interpretation.** This GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this GIA,

and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this GIA or such Appendix to this GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

**30.4 Entire Agreement.** This GIA, including all Appendices and Schedules attached hereto, and also incorporating through reference Section 39.3 of the Tariff as if it were a part hereof, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this GIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, a Party's compliance with its obligations under this GIA.

**30.5 No Third Party Beneficiaries.** This GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**30.6 Waiver.** The failure of a Party to this GIA to insist, on any occasion, upon strict performance of any provision of this GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this GIA. Termination or Default of this GIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this GIA shall, if requested, be provided in writing.

**30.7 Headings.** The descriptive headings of the various Articles of this GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this GIA.

**30.8 Multiple Counterparts.** This GIA may be executed in three or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**30.9 Amendment.** The Parties may by mutual agreement amend this GIA by a written instrument duly executed by each of the Parties.

**30.10 Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this GIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this GIA upon satisfaction of all Applicable Laws and Regulations.

**30.11 Reservation of Rights.** Transmission Provider shall have the right to make a unilateral filing with FERC to modify this GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Transmission Owner and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this GIA pursuant to Section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

**30.12 No Partnership.** This GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

**IN WITNESS WHEREOF,** the Parties have caused this GIA to be executed by their respective authorized officials, and copies delivered to each Party, to become effective as of the Effective Date.

**SOUTHWEST POWER POOL, INC.**

By: _____

Printed Name: _____

Title: _____

Date: _____

**[Insert name of Transmission Owner]**

By: _____

Printed Name: _____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Printed Name: _____

Title: _____

Date: _____

## APPENDIX A TO GIA

**Interconnection Facilities, Network Upgrades and Distribution Upgrades**

**1. Interconnection Facilities:**

**(a) [insert Interconnection Customer's Interconnection Facilities]:**

**(b) [insert Transmission Owner's Interconnection Facilities]:**

**2. Network Upgrades:**

**(a) [insert Stand Alone Network Upgrades]:**

**(b) [insert Shared Network Upgrades]:**

**(c) [insert Contingent Facilities]:**

**3. Distribution Upgrades:**

**4. Interconnection Service:**

**Interconnection Customer has requested the following (from Appendix 3 of the GIP):**

**____ Energy Resource Interconnection Service**
**____ Network Resource Interconnection Service**

**5. Construction Option Selected by Customer:**

**6. Permits, Licenses, and Authorizations:**

**7. Description of the Point of Change of Ownership:**

**8. Description of the Point of Interconnection:**

**9. Higher-Queued Interconnection Customers:**

**10. Environmental Requirements:**

This GIA is subject to completion of the appropriate National Environmental Policy Act (NEPA) level of Environmental Review. **Until a NEPA decision document is issued, no construction activities relating to Transmission Owner's Interconnection Facilities and/or Network Upgrades may commence.**

**(a)** [Insert Environmental Requirements for an Environmental Impact Statement (EIS) level of Environmental Review]

**(b)** [Insert Environmental Requirements for an Environmental Assessment (EA) level of Envionmental Review]

## 11. Candidate Incremental Long-Term Congestion Rights:

* Source _____
* Sink _____
* Candidate Incremental LTCR MW _____
* Term (years from in-service date of Network Upgrade) _____

# APPENDIX B TO GIA

## Milestones

# APPENDIX C TO GIA

## Interconnection Details

## 1. Description of Generating Facility:

### Wind Generating Facility Output Reduction

To protect the reliability of the Transmission System, a Generating Facility that is a wind plant shall be capable of reducing its generation output in increments of no more than fifty (50) MW in five (5) minute intervals. The requirements may be met by using: (a) SCADA control of circuit breakers protecting wind farm collector distribution circuits, (b) automatic control of wind turbine power output, or (c) a combination of (a) and (b).

### Inverter-Based Resource EMT Study Results Mitigations

If an Electromagnetic Transient Study is determined to be required by the Transmission Provider and the study results reveal an Adverse System Impact to the Transmission System, mitigation(s) shall be the responsibility of the Interconnection Customer and shall be implemented prior to the injection of power into the Transmission System.

# APPENDIX D TO GIA

## Security Arrangements Details

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the National Infrastructure Advisory Council and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

## APPENDIX E TO GIA

## Commercial Operation Date

**[Date]**

_____,_____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

**[Transmission Owner Address]**

Re: _____ Generating Facility

Dear _____:

On **[Date] [Interconnection Customer]** has completed Trial Operation of Unit No. ___. This letter confirms that [Interconnection Customer] commenced Commercial Operation of Unit No. ___ at the Generating Facility, effective as of **[Date plus one day]**.

Thank you.

**[Signature]**

**[Interconnection Customer Representative]**

## APPENDIX F TO GIA

### Addresses for Delivery of Notices And Billings

**Notices:**

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

**Billings and Payments:** [Specify addresses for construction invoices, O&M invoices and settlement of ancillary services]

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

**Alternative Forms of Delivery of Notices (telephone, facsimile or email):**

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive

Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

[To be supplied.]

Interconnection Customer:

[To be supplied.]

**Operational Communications:** [Identify contacts for operations]

Transmission Provider:

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

[To be supplied.]

Interconnection Customer:
[To be supplied.]

# APPENDIX G TO GIA

## Requirements Of Generators Relying On Newer Technologies

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this GIA continue to apply to wind generating plant interconnections.

### A. Technical Standards Applicable to a Wind Generating Plant

#### i. Low Voltage Ride-Through (LVRT) Capability

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a facilities study agreement as of September 21, 2016. A wind generating plant to which this provision applies shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

**Transition Period LVRT Standard**

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or "GSU"), after which, if the fault remains following the location-specific normal clearing

time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**Post-transition Period LVRT Standard**

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**ii. Power Factor Design Criteria (Reactive Power)**

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this GIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

**iii. Supervisory Control and Data Acquisition (SCADA) Capability**

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for

the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

# APPENDIX 14 TO THE GENERATOR INTERCONNECTION PROCEDURES

# INTERIM GENERATOR INTERCONNECTION AGREEMENT (INTERIM GIA)

(For use when Western-UGP is a Party to the Interim GIA, as the Transmission Owner)

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# INTERIM GENERATOR INTERCONNECTION AGREEMENT

**THIS INTERIM GENERATOR INTERCONNECTION AGREEMENT** ("Agreement" or "Interim GIA") is made and entered into this ____ day of _____ , by and among _____, a _____ organized and existing under the laws of the State/Commonwealth of _____ ("Interconnection Customer" with a Generating Facility), Southwest Power Pool, Inc., a corporation organized and existing under the laws of the State of Arkansas ("Transmission Provider") and Western Area Power Administration- Upper Great Plains Region ("Western-UGP"), a Federal power marketing agency organized under the United States Department of Energy ("Transmission Owner"). Interconnection Customer, Transmission Provider and Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

## Recitals

**WHEREAS,** Transmission Provider functionally controls the operation of the Transmission System; and,

**WHEREAS,** Interconnection Customer has a pending Interconnection Request and intends to own, lease and/or control and operate the Generating Facility identified as a Generating Facility in Appendix C to this Agreement; and,

**WHEREAS,** Transmission Owner owns facilities to which the Generating Facility is to be interconnected and may be constructing facilities to allow the interconnection; and,

**WHEREAS**, Transmission Provider has conducted an additional analysis in accordance with Section 11A.2 of the Generator Interconnection Procedures ("GIP") to determine the availability of Interim Interconnection Service at the time of the Interconnection Customer's requested In-Service Date and Commercial Operation Date with the Transmission System topology and in-service generation expected to be in place at that time; and,

**WHEREAS**, Interconnection Customer, in accordance with Section 11A.2.1 of the GIP, has provided Transmission Provider with reasonable evidence of Site Control or additional security and with reasonable evidence that one or more of the milestones listed in Section 11A.2.1 has been achieved; and

**WHEREAS**, Interconnection Customer, Transmission Provider and Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Generating Facility with the Transmission System on an interim basis prior to the completion of the generator interconnection study process set forth in the GIP and execution of a Generator Interconnection Agreement;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Interim GIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff ("Tariff").

## Article 1. Definitions

**Adverse System Impact** shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

**Affected System** shall mean an electric system other than the Transmission System that may be affected by the proposed interconnection.

**Affected System Operator** shall mean the entity that operates an Affected System.

**Affiliate** shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

**Ancillary Services** shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.

**Applicable Laws and Regulations** shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

**Applicable Reliability Council** shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

**Applicable Reliability Standards** shall mean the requirements and guidelines of NERC, the Applicable Reliability Council, and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

**Base Case** shall mean the base case power flow, short circuit, and stability data bases used for the Interconnection Studies by the Transmission Provider.

**Breach** shall mean the failure of a Party to perform or observe any material term or condition of the Interim Generator Interconnection Agreement.

**Breaching Party** shall mean a Party that is in Breach of the Interim Generator Interconnection Agreement.

**Business Day** shall mean Monday through Friday, excluding Federal Holidays.

**Calendar Day** shall mean any day including Saturday, Sunday or a Federal Holiday.

**Clustering** shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting Interconnection Studies.

**Commercial Operation** shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

**Commercial Operation Date** of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the Interim Generator Interconnection Agreement.

**Confidential Information** shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection, or otherwise.

**Contingent Facilities** shall mean those unbuilt Interconnection Facilities and Network Upgrades upon which the Interconnection Request's costs, timing, and study findings are dependent, and if delayed or not built, could cause a need for restudies of the Interconnection Request or a reassessment of the Interconnection Facilities and/or Network Upgrades and/or costs and timing. Contingent Facilities are identified in Appendix A of the Interim Generator Interconnection Agreement.

**Control Area** shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

**Default** shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the Interim Generator Interconnection Agreement.

**Definitive Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, or that may be caused by the withdrawal or addition of an Interconnection Request, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Generator Interconnection Procedures. The Definitive Interconnection System Impact Study is conducted in two phases.

**Definitive Interconnection System Impact Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for a Definitive Interconnection System Impact Study.

**Dispute Resolution** shall mean the procedure in Section 13.5 of the Generator Interconnection Procedures for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

**Distribution System** shall mean the Transmission Owner's facilities and equipment that are not included in the Transmission System. The voltage levels at which Distribution Systems operate differ among areas.

**Distribution Upgrades** shall mean the additions, modifications, and upgrades to the Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to effect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

**Effective Date** shall mean the date on which the Interim Generator Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by FERC, or if filed unexecuted, upon the date specified by FERC.

**Electromagnetic Transient Study or EMT Study** shall mean an analysis to determine the electromagnetic transient response of the electric power system due to system disturbances.

**Emergency Condition** shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System or the electric systems of others to which the Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by Interim Generator Interconnection Agreement to possess black start capability.

**Energy Resource Interim Interconnection Service** shall mean an Interim Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

**Engineering & Procurement (E&P) Agreement** shall mean an agreement that authorizes the Transmission Owner to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

**Environmental Law** shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

**Environmental Review** shall mean a study conducted by the Transmission Owner that contains a review of the proposed interconnection to the Transmission Owner's transmission facilities, pursuant to the National Environmental Policy Act (NEPA), 42 U.S.C. §4321, et seq., as amended, and setting forth Interconnection Customer's responsibilities in connection with such review of the interconnection.

**Existing Generating Facility** shall mean a Generating Facility that is currently interconnected to the Transmission System of the Transmission Provider.

**Federal Power Act** shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

**FERC** shall mean the Federal Energy Regulatory Commission (Commission) or its successor.

**Force Majeure** shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

**Generating Facility** shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities. A Generating Facility consists of one or more generating unit(s) and/or storage device(s) which usually can operate independently and be brought online or taken offline individually.

**Generating Facility Capacity** shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

**Generating Facility Modification** shall mean modification to an Existing Generating Facility, including comparable replacement of only a portion of the equipment at the Existing Generating Facility.

**Generating Facility Replacement** shall mean the process of replacing one or more generating units and/or storage devices at an Existing Generating Facility with one or more new generating units or storage devices at the same electrical Point of Interconnection as those being decommissioned and electrically disconnected.

**Generator Interconnection Agreement (GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility that is included in the Transmission Provider's Tariff.

**Generator Interconnection Procedures (GIP)** shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Generating Facility that are included in the Transmission Provider's Tariff.

**Generator Interconnection Study Agreement** shall mean the study agreement for the Definitive Interconnection System Impact Study and the Interconnection Facilities Study in Appendix 3 of the Generator Interconnection Procedures.

**Good Utility Practice** shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

**Governmental Authority** shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include Interconnection Customer, Transmission Provider, Transmission Owner or any Affiliate thereof.

**Hazardous Substances** shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

**Higher Queued Projects** shall mean those projects specifically identified as “Higher Queued Projects” in Appendix A.

**Initial Synchronization Date** shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

**In-Service Date** shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Owner's Interconnection Facilities to obtain back feed power.

**Interconnection Customer** shall mean any entity, including the Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission System.

**Interconnection Customer's Interconnection Facilities** shall mean all facilities and equipment, as identified in Appendix A of the Interim Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

**Interconnection Facilities** shall mean the Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

**Interconnection Facilities Study** shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Owner's Interconnection Facilities and Network Upgrades as identified in the Definitive Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission System. The scope of the study is defined in Section 8 of the Generator Interconnection Procedures.

**Interconnection Facilities Study Queue** shall mean a Transmission Provider separately maintained queue for valid Interconnection Requests for an Interconnection Facilities Study.

**Interconnection Queue Position** shall mean the order of a valid Interconnection Request within the Interconnection Facilities Study Queue, relative to all other pending valid Interconnection Requests within the Interconnection Facilities Study Queue, which is established based upon the requirements in Section 4.1.3 of the Generator Interconnection Procedures.

**Interconnection Request** shall mean an Interconnection Customer's request, in the form of Appendix 3 to the Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, to interconnect a Replacement Generating Facility, to increase the capacity of, or make a Material Modification to the operating characteristics of, an Existing Generating Facility that is interconnected with the Transmission System.

**Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Generator Interconnection Agreement and, if applicable, the Tariff.

**Interconnection Study** shall mean any of the following studies: the Replacement Impact Study, the Reliability Assessment Study, the Definitive Interconnection System Impact Study, the Interim Availability Interconnection System Impact Study, and the Interconnection Facilities Study described in the Generator Interconnection Procedures.

**Interconnection Study Agreement** shall mean any of the following agreements described in the Generator Interconnection Procedures: the Generator Interconnection Study Agreement or the Interim Availability Interconnection System Impact Study Agreement.

**Interim Availability Interconnection System Impact Study** shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of the Transmission System and, if applicable, an Affected System for the purpose of providing Interim Interconnection Service. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications on an interim basis.

**Interim Availability Interconnection System Impact Study Agreement** shall mean the form of agreement contained in Appendix 5 of the Generator Interconnection Procedures for conducting the Interim Availability Interconnection System Impact Study.

**Interim Generator Interconnection Agreement (Interim GIA)** shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Generating Facility to allow interconnection to the Transmission System prior to the completion of the Interconnection Study process.

**Interim Interconnection Service** shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Interim Generator Interconnection Agreement and, if applicable, the Tariff.

**IRS** shall mean the Internal Revenue Service.

**Joint Operating Committee** shall be a group made up of representatives from Interconnection Customer, Transmission Owner and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

**Loss** shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's performance, or non-performance of its obligations under the Interim Generator Interconnection Agreement, on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

**Material Modification** shall mean (1) modification to an Interconnection Request in the queue that has a material adverse impact on the cost or timing of any other Interconnection Request with a later Queue priority date; or (2) planned modification to an Existing Generating Facility that is undergoing evaluation for a Generating Facility Modification or Generating Facility Replacement, and has a material adverse impact on the Transmission System with respect to: i) steady-state thermal or voltage limits, ii) dynamic system stability and response, or iii) short-circuit capability limit; compared to the impacts of the Existing Generating Facility prior to the modification or replacement.

**Metering Equipment** shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the Interim Generator Interconnection Agreement, at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines, and fiber optics.

**NERC** shall mean the North American Electric Reliability Corporation or its successor organization.

**Network Resource** shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

**Network Resource Interim Interconnection Service** shall mean an Interim Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission System in a manner comparable to that in which the Transmission Owner integrates its generating facilities to serve Native Load Customers as a Network Resource. Network Resource Interim Interconnection Service in and of itself does not convey transmission service.

**Network Upgrades** shall mean the additions, modifications, and upgrades to the Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission System to accommodate the interconnection of the Generating Facility to the Transmission System.

**Notice of Dispute** shall mean a written notice of a dispute or claim that arises out of or in connection with the Interim Generator Interconnection Agreement, or its performance.

**Party or Parties** shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

**Point of Change of Ownership** shall mean the point, as set forth in Appendix A to the Interim Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Owner's Interconnection Facilities.

**Point of Interconnection** shall mean the point, as set forth in Appendix A to the Interim Generator Interconnection Agreement, where the Interconnection Facilities connect to the Transmission System.

**Queue** shall mean the Definitive Interconnection System Impact Study Queue, or the Interconnection Facilities Study Queue, as applicable.

**Reasonable Efforts** shall mean, with respect to an action required to be attempted or taken by a Party under the Interim Generator Interconnection Agreement efforts that are timely

and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

**Reliability Assessment Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of Transmission System during the time period between the date that the Existing Generating Facility ceases commercial operations and the Commercial Operation Date of the Replacement Generating Facility.

**Replacement Generating Facility** shall mean a Generating Facility that replaces an Existing Generating Facility, or a portion thereof, at the same electrical Point of Interconnection pursuant to Section 3.9 of this Attachment V.

**Replacement Impact Study** shall mean an engineering study that evaluates the impact of a proposed Generating Facility Replacement on the reliability of the Transmission System.

**Scoping Meeting** shall mean the meeting between representatives of the Interconnection Customer, Transmission Owner and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.

**Shared Network Upgrade** shall mean a Network Upgrade listed in Appendix A of the Generator Interconnection Agreement that is needed for the interconnection of multiple Interconnection Customers' Generating Facilities and which is the shared funding responsibility of such Interconnection Customers that may also benefit other Interconnection Customer(s) that are later identified as beneficiaries**.**

**Site Control** shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site of sufficient size for the purpose of constructing the Generating Facility or Generating Facility's tie line; (2) an option to purchase or acquire a leasehold site of sufficient size for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site of sufficient size for such purpose.

**Small Generating Facility** shall mean a Generating Facility that has an aggregate net Generating Facility Capacity of no more than 2 MW.

**Stand Alone Network Upgrades** shall mean Network Upgrades that are not part of an Affected Systems that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. The Transmission Provider, Transmission Owner and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the Interim Generator Interconnection Agreement. If the Transmission Provider, Transmission Owner and Interconnection Customer disagree about whether a particular Network Upgrade is a Stand Alone Network Upgrade, the Transmission Owner must provide the Interconnection Customer a written

technical explanation outlining why the Transmission Owner does not consider the Network Upgrade to be a Stand Alone Network Upgrade within fifteen (15) days of its determination.

**System Protection Facilities** shall mean the equipment, including necessary protection signal communications equipment, required to protect (1) the Transmission System from faults or other electrical disturbances occurring at the Generating Facility and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission System or on other delivery systems or other generating systems to which the Transmission System is directly connected.

**Tariff** shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

**Transmission Owner** shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Interim Generator Interconnection Agreement to the extent necessary.

**Transmission Provider** shall mean the public utility (or its Designated Agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

**Transmission Owner's Interconnection Facilities** shall mean all facilities and equipment owned, controlled or operated by the Transmission Owner from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Interim Generator Interconnection Agreement, including any modifications, additions or upgrades to such facilities and equipment. Transmission Owner's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades, or Network Upgrades.

**Transmission System** shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

**Trial Operation** shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

**Western Area Power Administration-Upper Great Plains Region ("Western-UGP")** shall mean **a** division of the Western Area Power Administration, a Federal power marketing agency, and Transmission Owner, that markets and transmits Federal power over Federal transmission facilities that have been transferred to the functional control of the Transmission Provider.

## Article 2. Effective Date, Term, and Termination

**2.1 Effective Date.** This Interim GIA shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by FERC. Transmission Provider shall promptly file this Interim GIA with FERC upon execution in accordance with Article 3.1, if required.

**2.2 Term of Agreement.** This Interim GIA shall remain in effect from its Effective Date until the earliest occurrence of one of the termination events described in Article 2.3.1. Notwithstanding this Article 2.2 or 2.3, the maximum effective period of this Interim GIA shall be two (2) years from the Effective Date.

**2.3 Termination Procedures.**

**2.3.1 Termination Events.**

**2.3.1.1** This Interim GIA may be terminated by Interconnection Customer after giving Transmission Provider and Transmission Owner ninety (90) Calendar Days advance written notice, or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

**2.3.1.2** This Interim GIA shall terminate upon occurrence of one or more of the following events:

(a) The Effective Date of a GIA regarding the Generating Facility that is the subject of this Interim GIA that has been accepted by FERC and/or reported in Transmission Provider's Electric Quarterly Report;

(b) The date of a FERC order rejecting an unexecuted GIA regarding the Generating Facility that is the subject of this Interim GIA;

(c) The date the Interconnection Customer's Interconnection Request is deemed withdrawn pursuant to the GIP;

(d) The Interconnection Customer's failure to pay part or all of the required security pursuant to Article 11.7; or

(e) The Transmission Provider's determination in accordance with Article 4.2.2, that Interim Interconnection Service to Interconnection Customer and the amount of power that Interconnection Customer is permitted to inject into the Transmission System from its Generating Facility pursuant to this Interim GIA is reduced to zero.

**2.3.2 Default.** Any Party may terminate this Interim GIA in accordance with Article 17.

**2.3.3** Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination, including the filing with FERC of a notice of termination of this Interim GIA, which notice has been accepted for filing by FERC.

**2.3.4** Upon termination of this Interim GIA for any reason, Interim Interconnection Service under this Interim GIA shall cease and the provisions of Section 11A.5 of the GIP shall apply.

## 2.4 Termination Costs.

**2.4.1** If this Interim GIA is terminated pursuant to Article 2.3.1.2(a), the cost responsibilities of Interconnection Customer and Transmission Owner pursuant to this Interim GIA will be included in the GIA regarding the Generating Facility that is the subject of this Interim GIA to the extent not satisfied during the term of this Interim GIA.

**2.4.2** If this Interim GIA is terminated pursuant to Article 2.3 for any reason except as specified 2.3.1.2(a), Interconnection Customer and Transmission Owner shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment), and charges assessed by any other Party, as of the date of such Party's receipt of such notice of termination, that are the responsibility of the Terminating Party under this Interim GIA. In the event of termination by any Party, all Parties shall use Commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination. Upon termination of this Interim GIA:

**2.4.2.1** With respect to any portion of Transmission Owner's Interconnection Facilities that have not yet been constructed or installed, Transmission Owner shall to the extent possible and with Interconnection Customer's authorization cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment, and contracts, and Transmission Owner shall deliver such material and equipment, and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Owner for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Owner shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Owner to cancel any pending orders of or return such materials, equipment, or contracts.

If this Interim GIA is terminated pursuant to Article 2.3 for any reason except as specified in Article 2.3.1.2(a) Interconnection Customer shall be responsible for all costs incurred in association with the Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment, and other expenses including any Network Upgrades for which Transmission Owner has incurred expenses and has not been reimbursed by Interconnection Customer and shall forfeit the security paid pursuant to Article 11.7 of this Interim GIA up to the total of the costs and expenses listed in this paragraph.

**2.4.2.2** Transmission Owner may, at its option, retain any portion of such materials, equipment, or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Owner shall be responsible for all costs associated with procuring such materials, equipment, or facilities.

**2.4.2.3** With respect to any portion of the Interconnection Facilities, and any other facilities already installed or constructed pursuant to the terms of this Interim GIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment, or facilities.

**2.5 Disconnection or Limitation of Output**. If this Interim GIA is terminated pursuant to Article 2.3 and disconnection or limitation in generation output is required, then the Parties will take all appropriate steps to either disconnect the Generating Facility from the Transmission System or limit the amount of generation output that can be injected into the transmission system pursuant to Section 4.2.2, whichever is applicable. All costs required to effectuate such disconnection or limitation shall be borne by Interconnection Customer, unless such termination resulted from another Party's Default of this Interim GIA, which in such event the defaulting Party shall be responsible for such disconnection costs.

**2.6 Survival.** Except as provided in this Article 2.6, this Interim GIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this Interim GIA; to permit payments for any credits under this Interim GIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this Interim GIA was in effect; and to permit each Party to have access to the lands of another Party pursuant to this Interim GIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

## Article 3. Regulatory Filings

**3.1 Filing.** Transmission Provider shall file this Interim GIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of

Article 22. If Interconnection Customer has executed this Interim GIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

## Article 4. Scope of Service

**4.1 Interim Interconnection Product Options.** Interconnection Customer has selected the following (checked) type of Interim Interconnection Service:

### 4.1.1 Energy Resource Interim Interconnection Service.

**4.1.1.1 The Product.** Energy Resource Interim Interconnection Service allows Interconnection Customer to connect the Generating Facility to the Transmission System and be eligible to deliver the Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interim Interconnection Service for the term of this Interim GIA, unless otherwise specified in Appendix A, Transmission Owner shall construct the facilities listed in Appendix A to this Interim GIA.

**4.1.1.2 Transmission Delivery Service Implications.** Under Energy Resource Interim Interconnection Service, Interconnection Customer will be eligible to inject power from the Generating Facility into and deliver power across the Transmission System on an "as available" basis. The Interconnection Customer's ability to inject its Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of the Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of Firm Point-To-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

### 4.1.2 Network Resource Interim Interconnection Service.

**4.1.2.1 The Product.** Transmission Provider must conduct the necessary studies and construct the Network Upgrades needed to integrate the Generating Facility in a manner comparable to that in which Transmission Owner integrates its generating facilities to serve Native Load Customers as all Network Resources. To the extent Interconnection Customer wants to receive Network Resource Interim Interconnection Service for the term of this Interim GIA, Transmission Owner shall construct the facilities identified in Appendix A to this Interim GIA.

**4.1.2.2 Transmission Delivery Service Implications.** Network Resource Interim Interconnection Service allows Interconnection Customer's Generating Facility to be designated by any Network Customer under the Tariff on the

Transmission System as a Network Resource, up to the Generating Facility's full output, on the same basis as existing Network Resources interconnected to the Transmission System, and to be studied as a Network Resource on the assumption that such a designation will occur. Although Network Resource Interim Interconnection Service does not convey a reservation of transmission service, any Network Customer under the Tariff can utilize its network service under the Tariff to obtain delivery of energy from the interconnected Interconnection Customer's Generating Facility in the same manner as it accesses Network Resources. A Generating Facility receiving Network Resource Interim Interconnection Service may also be used to provide Ancillary Services after technical studies and/or periodic analyses are performed with respect to the Generating Facility's ability to provide any applicable Ancillary Services, provided that such studies and analyses have been or would be required in connection with the provision of such Ancillary Services by any existing Network Resource. However, if an Interconnection Customer's Generating Facility has not been designated as a Network Resource by any load, it cannot be required to provide Ancillary Services except to the extent such requirements extend to all generating facilities that are similarly situated. The provision of Network Integration Transmission Service or Firm Point-To-Point Transmission Service may require additional studies and the construction of additional upgrades. Because such studies and upgrades would be associated with a request for delivery service under the Tariff, cost responsibility for the studies and upgrades would be in accordance with FERC's policy for pricing transmission delivery services.

Network Resource Interim Interconnection Service does not necessarily provide Interconnection Customer with the capability to physically deliver the output of its Generating Facility to any particular load on the Transmission System without incurring congestion costs. In the event of transmission constraints on the Transmission System, Interconnection Customer's Generating Facility shall be subject to the applicable congestion management procedures in Transmission Provider's Transmission System in the same manner as Network Resources.

The Network Resource Interim Interconnection Service studies are done in accordance with the process set out in Attachment Z1 of the Tariff. To the extent a Network Customer does designate the Generating Facility as a Network Resource, it must do so pursuant to Transmission Provider's Tariff.

Once an Interconnection Customer satisfies the requirements for obtaining Network Resource Interim Interconnection Service, any future transmission service request for delivery from the Generating Facility within the Transmission System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional

studies be performed or that any further upgrades associated with such Generating Facility be undertaken, regardless of whether or not such Generating Facility is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the Generating Facility. However, the reduction or elimination of congestion or redispatch costs may require additional studies and the construction of additional upgrades.

To the extent Interconnection Customer enters into an arrangement for long term transmission service for deliveries from the Generating Facility outside the Transmission System, such request may require additional studies and upgrades in order for Transmission Provider to grant such request.

**4.2 Provision of Service.** Transmission Provider shall provide Interim Interconnection Service for the Generating Facility at the Point of Interconnection as specified below.

4.2.1 The provision of Interim Interconnection Service and pre-commercial operation testing pursuant to this Interim GIA are contingent upon the Interconnection Facilities, Network Upgrades, Distribution Upgrades, and other necessary facilities listed in the applicable section of Appendix A to this Interim GIA being completed and in service. In no event shall pre-commercial operation testing or Interim Interconnection Service be permitted until the Interconnection Facilities, Network Upgrades, Distribution Upgrades and any other necessary facilities listed in applicable section of Appendix A to this Interim GIA are complete and in service.

**4.2.1.1** Pre-Commercial Operation Testing. Interconnection Customer shall be able to sync its Generating Facility and its Interconnection Customer's Interconnection Facilities to the Transmission System for the purpose of testing pursuant to Article 6.1, once the applicable facilities described in Appendix A are complete and in service.

**4.2.1.2** Interim Interconnection Service. Interconnection Customer shall be able to sync its Generating Facility and its Interconnection Customer's Interconnection Facilities to the Transmission System for the purpose of receiving Interim Interconnection Service and operating its Generating Facility up to the maximum amount for this Interim GIA, as specified in Appendix A on an "as available" basis once the applicable facilities in Appendix A are in service.

**4.2.2** Interim Interconnection Service and the amount of power that Interconnection Customer is permitted to inject into the Transmission System from its Generating Facility pursuant to this Interim GIA may be reduced in whole or in part in the event that:

(a) one or more Interconnection Customer(s) with a Higher Queued Project (as specified in Appendix A): (i) has executed or subsequently executes an Interim GIA or a GIA that has been accepted by the FERC and/or reported in Transmission Provider's Electric Quarterly Report, or has an unexecuted Interim GIA or GIA filed with and accepted by the FERC for that Higher Queued Project and (ii) begins Commercial Operation of the Higher Queued Project during the term of this Interim GIA; and

(b) Transmission Provider at its sole discretion determines that Interim Interconnection Service and/or Interconnection Service cannot be provided simultaneously under this Interim GIA and to such other Interconnection Customer(s) under its Interim GIA(s) or final GIA(s) in an amount commensurate with the maximum amount specified in the respective agreements without additional Interconnection Facilities, Network Upgrades, or Distribution Upgrades.

**4.2.3** Any such reduction pursuant to Article 4.2.2 will be based on the Queue Position priority of the Interconnection Customer's Interconnection Request relative to the Queue Position priority of the Higher Queued Projects.

**4.3 Performance Standards.** Each Party shall perform all of its obligations under this Interim GIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice, and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this Interim GIA for its compliance therewith. If such Party is a Transmission Provider or Transmission Owner, then that Party shall amend the Interim GIA and Transmission Provider shall submit the amendment to FERC for approval.

**4.4 No Transmission Delivery Service.** The execution of this Interim GIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff, and does not convey any right to deliver electricity to any specific customer or Point of Delivery.

**4.5 Interconnection Customer Provided Services.** The services provided by Interconnection Customer under this Interim GIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.9.

## Article 5. Interconnection Facilities Engineering, Procurement, and Construction

**5.1 Options.** Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date, and Commercial Operation Date; and either the Option To Build as described under Article 5.1.2 or the Negotiated Option described under Article 5.1.3, and such dates and selected option, as applicable, shall be set forth in Appendix B, Milestones. At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build

set forth in Article 5.1.2 below. If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Transmission Owner, the Interconnection Customer shall notify Transmission Owner within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build.

**5.1.1 Standard Option.** Transmission Owner shall design, procure, and construct Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event Transmission Owner reasonably expects that it will not be able to complete Transmission Owner's Interconnection Facilities, and Network Upgrades by the specified dates, Transmission Owner shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

**5.1.2 Option to Build.** Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.1. Transmission Owner and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

**5.1.3 Negotiated Option.** If the dates designated by Interconnection Customer are not acceptable to Transmission Owner, the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates, the provision of incentives or the procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.2). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1(Standard Option), Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects the Option to Build.

**5.2 General Conditions Applicable to Option to Build.** If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) Interconnection Customer shall engineer, procure equipment, and construct Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Owner;

(2) Interconnection Customer's engineering, procurement and construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(3) Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider and Transmission Owner a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider and Transmission Owner;

(5) At any time during construction, Transmission Owner shall have the right to gain unrestricted access to Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(6) At any time during construction, should any phase of the engineering, equipment procurement, or construction of Transmission Owner’s Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Owner, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(7) Interconnection Customer shall indemnify Transmission Provider and Transmission Owner for claims arising from Interconnection Customer's construction of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 Indemnity;

(8) The Interconnection Customer shall transfer control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

(9) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Owner's Interconnection Facilities and Stand-Alone Network Upgrades to Transmission Owner not later than the Commercial Operation Date;

(10) Transmission Owner shall approve and accept for operation and maintenance Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2; and

(11) Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information, and any other documents that are reasonably required by Transmission Owner to assure that the Interconnection Facilities and Stand-Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

(12) If Interconnection Customer exercises the Option to Build pursuant to Article 5.1.2, Interconnection Customer shall pay Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for Transmission Owner to execute the responsibilities enumerated to Transmission Owner under Article 5.2. Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

**5.3 Reserved.**

**5.4 Power System Stabilizers.** The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Generating Facility. If the Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative. The requirements of this paragraph shall not apply to non-synchronous generators.

**5.5 Equipment Procurement.** If responsibility for construction of Transmission Owner's Interconnection Facilities or Network Upgrades is to be borne by Transmission Owner, then Transmission Owner shall commence design of Transmission Owner's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

**5.5.1** Transmission Provider has completed the Interim Availability Interconnection System Impact Study;

**5.5.2** Transmission Owner has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones;

**5.5.3** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 and advance payment to Transmission

Owner in accordance with Article 11.8 by the dates specified in Appendix B, Milestones; and

**5.5.4** The Parties have executed this Interim GIA.

**5.6 Construction Commencement.** Transmission Owner shall commence construction of Transmission Owner's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

**5.6.1** Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

**5.6.2** Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Owner's Interconnection Facilities and Network Upgrades;

**5.6.3** Transmission Owner has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

**5.6.4** Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.7 and advance payment to Transmission Owner in accordance with Article 11.8.

**5.7 Work Progress.** The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Parties may, at any time, request a progress report from other Parties. If, at any time, Interconnection Customer determines that the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider and Transmission Owner of such later date upon which the completion of Transmission Owner's Interconnection Facilities and Network Upgrades will be required.

**5.8 Information Exchange.** As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with the Transmission System, and shall work diligently and in good faith to make any necessary design changes.

**5.9 Reserved.**

**5.10 Interconnection Customer's Interconnection Facilities ("ICIF").** Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

**5.10.1 Interconnection Customer's Interconnection Facility Specifications.** Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Owner at least one hundred eighty (180 ) Calendar Days prior to the Initial Synchronization Date, and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Owner shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

**5.10.2 Transmission Owner's Review.** Transmission Owner's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing, or providing a warranty as to the design, fitness, safety, durability or reliability of the Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Owner, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control, and safety requirements of Transmission Owner.

**5.10.3 ICIF Construction.** The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Owner "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities connecting the Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Generating Facility. The Interconnection Customer shall provide Transmission Owner specifications for the excitation system, automatic voltage regulator, Generating Facility control and protection settings, transformer tap settings, and communications, if applicable.

**5.10.4 Updated Information Submission by Interconnection Customer.** The updated information submission by the Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date. Interconnection Customer shall submit a completed copy of the Generating Facility data requirements contained in Attachment A to Appendix 3 to the GIP. It shall also include any additional information provided to Transmission Provider for the Interconnection Facilities Studies. Information in this submission shall be the most current Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there

is no compatible model, the Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If the Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreements between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on the Transmission System based on the actual data submitted pursuant to this Article 5.10.4. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

**5.10.5 Information Supplementation.** Prior to the Commercial Operation Date, or as soon as possible thereafter, the Parties shall supplement their information submissions described above in this Article 5 with any and all "as-built" Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Generating Facility to verify proper operation of the Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent (5 percent) change in Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Generating Facility terminal or field voltages is provided. Generating Facility testing shall be conducted and results provided to the Transmission Provider for each individual generating unit in a station.

Subsequent to the Commercial Operation Date, the Interconnection Customer shall provide Transmission Owner and Transmission Provider any information changes due to equipment replacement, repair, or adjustment. Transmission Owner shall provide the Interconnection Customer and Transmission Provider any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Owner-owned substation that may affect the Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

**5.11 Transmission Owner's Interconnection Facilities Construction.** Transmission Owner's Interconnection Facilities and Network Upgrades shall be designed and

constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Owner shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Owner's Interconnection Facilities and Network Upgrades [include appropriate drawings and relay diagrams].

Transmission Owner will obtain control of Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

**5.12 Access Rights.** Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish at no cost to any other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (i) interconnect the Generating Facility with the Transmission System; (ii) operate and maintain the Generating Facility, the Interconnection Facilities and the Transmission System; and (iii) disconnect or remove the Access Party's facilities and equipment upon termination of this Interim GIA pursuant to Article 2.5. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

**5.13 Lands of Other Property Owners.** If any part of Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Owner, Transmission Owner shall at Interconnection Customer's expense use efforts, similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with Federal or state law, as applicable, to procure from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

**5.14 Permits.** Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses, and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

**5.15 Early Construction of Base Case Facilities.** Interconnection Customer may request Transmission Owner to construct, and Transmission Owner shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or

any portion of any Network Upgrades required for Interconnection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

**5.16 Reserved**.

**5.17 Reserved.**

**5.18 Tax Status.** All Parties shall cooperate with each other to maintain their tax status. Nothing in this Interim GIA is intended to adversely affect any Party's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

**5.19 Modification.**

**5.19.1 General.** Each Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect another Party's facilities, that Party shall provide to the other Parties sufficient information regarding such modification so that the other Parties may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans, and specifications to the other Parties at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Generating Facility Modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Owner shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Owner's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

**5.19.2 Standards.** Any additions, modifications, or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this Interim GIA and Good Utility Practice.

**5.19.3 Modification Costs.** Interconnection Customer shall not be directly assigned for the costs of any additions, modifications, or replacements that Transmission Owner makes to Transmission Owner's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to

Transmission Owner's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications, or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

**5.20 Delays .** If a Network Upgrade(s) identified in Appendix A is delayed during the construction process and the Commercial Operation Date for the Generating Facility identified in Appendix B is no longer feasible, the Commercial Operation Date in Appendix B may be modified to no later than six (6) months following the in-service date for the last Network Upgrade identified in Appendix A.

## Article 6. Testing and Inspection

**6.1 Pre-Commercial Operation Date Testing and Modifications.** Prior to the Commercial Operation Date, Transmission Owner shall test Transmission Owner's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Generating Facility only if it has arranged for the delivery of such test energy.

**6.2 Post-Commercial Operation Date Testing and Modifications.** Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

**6.3 Right to Observe Testing.** Each Party shall notify the other Parties in advance of its performance of tests of its Interconnection Facilities. The other Parties have the right, at its own expense, to observe such testing.

**6.4 Right to Inspect.** Each Party shall have the right, but shall have no obligation to: (i) observe another Parties' tests and/or inspection of any of its System Protection Facilities and other protective equipment, including power system stabilizers; (ii) review the settings of the other Parties' System Protection Facilities and other protective equipment; and (iii) review another Parties' maintenance records relative to the Interconnection Facilities, the System Protection Facilities and other protective equipment. Any Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Parties. The exercise or non-exercise by another Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of

the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability, or reliability of same. Any information that any Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this Interim GIA.

## Article 7. Metering

**7.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Owner shall install Metering Equipment at the Point of Interconnection prior to any operation of the Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Generating Facility shall be measured at or, at Transmission Owner's option, compensated to, the Point of Interconnection. Transmission Owner shall provide metering quantities, in analog and/or digital form, to Interconnection Customer and Transmission Provider on a same-time basis using communication as provided in Article 8. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

**7.2 Check Meters.** Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Owner's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this Interim GIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Owner or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

**7.3 Standards.** Transmission Owner shall install, calibrate, and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

**7.4 Testing of Metering Equipment.** Transmission Owner shall inspect and test all Transmission Owner-owned Metering Equipment in accordance with Transmission Owner's meter testing policies. If requested to do so by Interconnection Customer, Transmission Owner shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than the periods set forth in the Transmission Owner's meter testing policies. Transmission Owner shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Owner's failure to maintain, then Transmission Owner shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two percent from the measurement made by the standard meter used in the test, Transmission Owner shall adjust the measurements by correcting all measurements for the period during which

Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

**7.5 Metering Data.** At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Owner and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Generating Facility to the Point of Interconnection.

## Article 8. Communications

**8.1 Interconnection Customer Obligations.** Interconnection Customer shall maintain satisfactory operating communications with Transmission Owner's Transmission System dispatcher or representative designated by Transmission Owner. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Owner as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Generating Facility to the location(s) specified by Transmission Owner. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances, and hourly and daily load data.

**8.2 Remote Terminal Unit.** Prior to the Initial Synchronization Date of the Generating Facility, a Remote Terminal Unit, or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Owner at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Owner through use of a dedicated point-to-point data circuit(s) as indicated in Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Owner. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Owner.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

**8.3 No Annexation.** Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and

manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

**8.4 Phasor Measurement Unit (PMU) Recording Equipment**. Prior to the Initial Synchronization Date of a Generating Facility having a Generating Facility Capacity equal to or greater than 50 MW, phasor measurement recording and communications equipment shall be installed by the Transmission Owner at Interconnection Customer's expense that is capable of gathering phasor measurements as specified in the PMU Communications Handbook. To the extent similar quality equipment is being added or already exists, such as relays or digital fault recorders, that can collect data at least at the same rate as PMUs and which data is synchronized via a high-accuracy satellite clock, such equipment can be utilized to satisfy this requirement if the equipment is located on the Transmission Owner's side of the Point of Change of Ownership and if mutually agreed to by the Parties. The phasor measurement equipment shall be installed at the Transmission Owner's side of the Point of Change of Ownership and become part of the Transmission Owner Interconnection Facilities. Phasor measurements shall be streamed in IEEE C37.118 or equivalent format and be provided to the Transmission Provider. This data shall at least be sufficient to determine (i) positive-sequence voltage magnitude and angle, (ii) positive-sequence current magnitude and angle, (iii) frequency, and (iv) rate of change of frequency. Such data shall be transmitted over the data circuit(s) as indicated in Article 8.1.

Each Party will promptly advise the other Parties if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the applicable Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

## Article 9. Operations

**9.1 General.** Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Parties all information that may reasonably be required by the other Parties to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

**9.2 Control Area Notification.** At least three months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider and Transmission Owner in writing of the Control Area in which the Generating Facility will be located. If Interconnection Customer elects to locate the Generating Facility in a Control Area other than the Control Area in which the Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this Interim GIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Generating Facility in the other Control Area.

**9.3 Transmission Provider and Transmission Owner Obligations.** Transmission Provider and Transmission Owner shall cause the Transmission System and Transmission Owner's

Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this Interim GIA. Transmission Provider or Transmission Owner may provide operating instructions to Interconnection Customer consistent with this Interim GIA and Transmission Owner's operating protocols and procedures as they may change from time to time. Transmission Provider and Transmission Owner will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

**9.4 Interconnection Customer Obligations.** Interconnection Customer shall at its own expense operate, maintain and control the Generating Facility and the Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA. Interconnection Customer shall operate the Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this Interim GIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Any Party may request that another Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this Interim GIA.

**9.5 Start-Up and Synchronization.** Consistent with the Parties' mutually acceptable procedures, the Interconnection Customer is responsible for the proper synchronization of the Generating Facility to the Transmission System.

**9.6 Reactive Power and Primary Frequency Response.**

**9.6.1 Power Factor Design Criteria.**

**9.6.1.1 Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established different requirements that apply to all synchronous generators in the Control Area on a comparable basis.

**9.6.1.2 Non-Synchronous Generation.** Interconnection Customer shall design the Generating Facility to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation at a power factor within the range of 0.95 leading to 0.95 lagging, unless the Transmission Provider has established a different power factor range that applies to all non-synchronous generators in the Control Area on a comparable basis. This power factor range standard shall be dynamic and can be met using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors, or a combination of the two. This requirement shall only apply to newly interconnecting non-synchronous generators that had not executed an interconnection facilities study agreement as of September 21, 2016.

**9.6.2 Voltage Schedules.** Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Transmission Provider and/or Transmission Owner shall require Interconnection Customer to operate the Generating Facility to produce or absorb reactive power within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Owner's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Owner shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance, and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the Transmission Owner.

**9.6.2.1 Voltage Regulators.** Whenever the Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Generating Facility with its voltage regulators in automatic operation. If the Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify Transmission Owner's system operator, or its designated representative, and ensure that such Generating Facility's reactive power production or absorption (measured in Mvars) are within the design capability of the Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Generating Facility for an under or over frequency condition in accordance with Good Utility Practice and Applicable Reliability Standards.

**9.6.3 Payment for Reactive Power.** Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Generating Facility when Transmission Owner requests Interconnection Customer to operate its Generating Facility outside the range specified in Article 9.6.1. Payments shall be pursuant to Article 11.9 or such other agreement to which the Parties have otherwise agreed; provided however, to the extent the Tariff contains a provision providing for such compensation, that Tariff provision shall control.

**9.6.4 Primary Frequency Response.** Interconnection Customer shall ensure the primary frequency response capability of its Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the

required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) with a maximum 5 percent droop and ±0.036 Hz deadband;. or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) based on the nameplate capacity of the Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Generating Facility with the Transmission System, Interconnection Customer shall operate the Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Generating Facilities.

**9.6.4.1 Governor or Equivalent Controls.** Whenever the Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) in coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Generating Facility with its governor or equivalent

controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) the operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Generating Facility's governor or equivalent controls to a minimum whenever the Generating Facility is operated in parallel with the Transmission System.

**9.6.4.2 Timely and Sustained Response.** Interconnection Customer shall ensure that the Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

**9.6.4.3 Exemptions.** Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

**9.6.4.4 Electric Storage Resources.** Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix

C of its GIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

## 9.7 Outages and Interruptions.

### 9.7.1 Outages.

**9.7.1.1 Outage Authority and Coordination.** Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such

removal on a date and time mutually acceptable to all Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Parties of such removal.

**9.7.1.2 Outage Schedules.** Transmission Provider shall post scheduled outages of its transmission facilities on the OASIS. Interconnection Customer shall submit its planned maintenance schedules for the Generating Facility to Transmission Provider for a minimum of a rolling twenty-four month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided, however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

**9.7.1.3 Outage Restoration.** If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects another Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Parties, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

**9.7.2 Interruption of Service.** In addition to any reduction in Interconnection Service required pursuant to Article 4.2.2, if required by Good Utility Practice to do so, Transmission Provider and/or Transmission Owner may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's and/or Transmission Owner’s ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

**9.7.2.1** The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice;

**9.7.2.2** Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System;

**9.7.2.3** When the interruption or reduction must be made under circumstances which do not allow for advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer by telephone as soon as practicable of the reasons for the curtailment, interruption, or reduction, and, if known, its expected duration. Telephone notification shall be followed by written notification as soon as practicable;

**9.7.2.4** Except during the existence of an Emergency Condition, when the interruption or reduction can be scheduled without advance notice, Transmission Provider or Transmission Owner shall notify Interconnection Customer in advance regarding the timing of such scheduling and further notify Interconnection Customer of the expected duration. Transmission Provider or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to schedule the interruption or reduction during periods of least impact to Interconnection Customer and Transmission Owner; and

**9.7.2.5** The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Generating Facility, Interconnection Facilities, and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

**9.7.3 Under-Frequency and Over Frequency Conditions.** The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a generating facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

**9.7.3.1 Frequency Ride Through and Voltage Ride Through for a Generating Facility no larger than 20 MW.** For Generating Facilities no larger than 20 MW, the Interconnection Customer shall ensure “frequency ride

through" capability and "voltage ride through" capability of its Generating Facility. The Interconnection Customer shall enable these capabilities such that its Generating Facility shall not disconnect automatically or instantaneously from the system or equipment of the Transmission Provider and any Affected Systems for a defined under-frequency or over-frequency condition, or an under-voltage or over-voltage condition, as tested pursuant to Article 6.1 of this agreement. The defined conditions shall be in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The Generating Facility's protective equipment settings shall comply with the Transmission Provider's automatic load-shed program. The Transmission Provider shall review the protective equipment settings to confirm compliance with the automatic load-shed program. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority on a comparable basis. The term "frequency ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis. The term "voltage ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the system or equipment of the Transmission Provider and any Affected Systems during system disturbances within a range of under-voltage and over-voltage conditions, in accordance with Good Utility Practice and consistent with any standards and guidelines that are applied to other generating facilities in the Balancing Authority Area on a comparable basis.

**9.7.4 System Protection and Other Control Requirements.**

**9.7.4.1 System Protection Facilities.** Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Owner shall install at Interconnection Customer's expense any System Protection Facilities that may be required on Transmission Owner's Interconnection Facilities or the Transmission System as a result of the interconnection of the Generating Facility and the Interconnection Customer's Interconnection Facilities.

**9.7.4.2** Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

**9.7.4.3** Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

**9.7.4.4** Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

**9.7.4.5** Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

**9.7.4.6** Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

**9.7.5 Requirements for Protection.** In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own, and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Owner’s equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage, and generator loss-of-field. Interconnection Customer shall be solely responsible to disconnect the Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Generating Facility.

**9.7.6 Power Quality.** No Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or

any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

**9.8 Switching and Tagging Rules.** Each Party shall provide the other Parties a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

**9.9 Use of Interconnection Facilities by Third Parties.**

**9.9.1 Purpose of Interconnection Facilities.** Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Generating Facility to the Transmission System and shall be used for no other purpose.

**9.9.2 Third Party Users.** If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Owner's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually-agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Owner, all third party users, and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

**9.10 Disturbance Analysis Data Exchange.** The Parties will cooperate with one another in the analysis of disturbances to either the Generating Facility or the Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records, and any disturbance information required by Good Utility Practice.

## Article 10. Maintenance

**10.1 Transmission Owner Obligations.** Transmission Owner shall maintain the Transmission System and Transmission Owner's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA.

**10.2 Interconnection Customer Obligations.** Interconnection Customer shall maintain the Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this Interim GIA.

**10.3 Coordination.** The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Generating Facility and the Interconnection Facilities.

**10.4 Secondary Systems.** Each Party shall cooperate with the others in the inspection, maintenance, and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers, and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact another Party. Each Party shall provide advance notice to the other Parties before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers, or potential transformers.

**10.5 Operating and Maintenance Expenses.** Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing, and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Owner's Interconnection Facilities.

## Article 11. Performance Obligation

**11.1 Interconnection Customer Interconnection Facilities.** Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

**11.2 Maintenance Review.** The Transmission Provider will annually perform a re-study of this Interim GIA and will determine whether the Interim Interconnection Service determined pursuant to Section 11A.2 of the GIP continues to be available in the amount specified in this Interim GIA. The Transmission Provider will increase or decrease the amount of service in this Interim GIA based on the results of the annual re-study and subject to Article 4.2.3 of this Interim GIA. The Transmission Provider shall utilize existing studies to the extent practicable when it performs the re-study. The cost of each annual re-study shall be deducted from the study deposit made pursuant to Section 11A.2.4 of the GIP and the Interconnection Customer shall be responsible for any cost in

excess of the study deposit. A determination by the Transmission Provider that Interim Interconnection Service must be reduced pursuant to Article 4.2.2 of this Interim GIA will take precedence over the results of the most recent annual re-study.

**11.3 Transmission Owner's Interconnection Facilities.** Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Owner's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

**11.4 Network Upgrades and Distribution Upgrades.** All Network Upgrades and Distribution Upgrades described in Appendix A shall be constructed in accordance with the process set forth in Section VI of Attachment O. Transmission Owner shall design, procure, construct, install, and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades that are associated with that Transmission Owner's system. The Distribution Upgrades and Network Upgrades described in Appendix A shall be solely funded by Interconnection Customer unless Transmission Owner elects to fund the capital for the Distribution Upgrades or Network Upgrades.

**11.5 Transmission Credits.**

**11.5.1 Credits for Amounts Advanced for Network Upgrades.** Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the Tariff for any Network Upgrades including any tax gross-up or other tax-related payments associated with Network Upgrades.

**11.5.2 Special Provisions for Affected Systems.** Unless Transmission Provider provides, under the Interim GIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

**11.5.3** Notwithstanding any other provision of this Interim GIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain transmission credits for transmission service that is not associated with the Generating Facility.

**11.6 Initial Payment.**

Interconnection Customer shall make an initial payment ("Initial Payment") equal to the greater of a) twenty (20) percent of the total cost of Network Upgrades, Shared Network Upgrades, Transmission Owner Interconnection Facilities and/or Distribution Upgrades

listed in Appendix A or b) $4,000/MW of the size of the Generating Facility. Any financial security provided in Section 8.2, Section 8.5.1 and Section 8.5.2 of the GIP will be applied to this requirement. The Initial Payment shall be provided to Transmission Owner or Transmission Provider as required in Appendix B by Interconnection Customer pursuant to this Article 11.6 within the later of a) thirty (30) days of the execution of the GIA by all Parties, or b) thirty (30) days of acceptance by FERC if the GIA is filed unexecuted and the payment is being protested by Interconnection Customer, or c) thirty (30) days of the filing if the GIA is filed unexecuted and the Initial Payment is not being protested by Interconnection Customer. If this GIA is terminated, then the Initial Payment shall be refunded with accrued interest calculated from the date of the receipt of the Initial Payment to the date of the refund, if any, to the Interconnection Customer less:

a. any costs that have been incurred for the construction of the facilities specified in Appendix A;

b. any funds that have been committed for the construction of those Shared Network Upgrades, or Network Upgrades, assigned to another interconnection customer where such upgrade costs would not have been assigned but for the termination of the GIA; or

c. any costs that has been incurred for the construction of those Shared Network Upgrades, or Network Upgrades, that were paid for by another interconnection customer that are now unnecessary due to the termination of the GIA.

**11.7 Provision of Security.**

**11.7.1 Initial Security.** Payments for any upgrades installed by the Transmission Owner will be addressed in accordance with Article 11.8 of this Interim GIA. Within fifteen (15) Business Days of the date that Interconnection Customer delivers to Transmission Provider an executed Interim GIA, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider and is consistent with the Uniform Commercial Code of the jurisdiction identified in Article 14.2.1 in the amount set forth in Appendix A to this Interim GIA. This amount represents either (a) the sum of the estimated costs for which Interconnection Customer will be responsible for the construction, procurement, and installation of the applicable portion of Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which it will share cost responsibility as determined in the study designated in Appendix A.4. and 100 percent of the costs of Interconnection Facilities, Network Upgrades, or Distribution Upgrades for which Interconnection Customer has sole cost responsibility less the amounts required by Transmission Owner for Transmission Owner's Interconnection Facilities, Network Upgrades and Distribution Upgrades funded through Article 11.8 or (b) if the estimated costs above have not been established at the time Interconnection Customer requests Interim Interconnection Service, the initial security amount

will be established by the Transmission Provider based on one or more completed studies for comparable interconnection requests less the amounts required by Transmission Owner for Transmission Owner's Interconnection Facilities, Network Upgrades and Distribution Upgrades funded through Article 11.8.

**11.7.2 Security Adjustment.** In the event that the results of any subsequently posted study (e.g., Definitive Interconnection System Impact Study, Interconnection Facilities Study, or any other study required pursuant to the GIP in connection with Interconnection Service under this Interim GIA) indicates that Interconnection Customer's cost responsibility for Interconnection Facilities, Network Upgrades, or Distribution Upgrades required to interconnect its Generating Facility is less than or greater than the amount set forth in Appendix A, the amount of security required under this Interim GIA shall be adjusted to reflect the Interconnection Customer's revised amount of cost responsibility determined in such posted study less the amounts required by Transmission Owner for Transmission Owner's Interconnection Facilities, Network Upgrades and Distribution Upgrades funded through Article 11.8. Transmission Provider shall notify Interconnection Customer of the revised security amount when it posts the study. If the security amount increases, Interconnection Customer shall provide the additional amount of security within fifteen (15) Business Days of receipt of such notification. If the security amount decreases, Transmission Provider and Interconnection Customer shall take the appropriate action to reduce the amount of security held by Transmission Provider within fifteen (15) Business Days of Interconnection Customer's receipt of such notification. If Interconnection Customer fails to provide additional security as prescribed in this Article 11.7.2, this Interim GIA will be terminated in accordance with Article 2.3. In addition:

**11.7.2.1** The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

**11.7.2.2** The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

**11.7.2.3** The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

## 11.8 Advance Payment.

**11.8.1** For Transmission Owner's Interconnection Facilities, Network Upgrades and Distribution Upgrades constructed by Transmission Owner under this Interim GIA, Interconnection Customer shall be required to pay Transmission Owner for all actual costs incurred by Transmission Owner for the procurement, installation,

or construction of a discrete portion of a Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall pay Transmission Owner, in advance, for all work to be conducted by the Transmission Owner, under the terms and conditions set forth in this Interim GIA. Such advance payments shall be considered estimated costs for project planning, management, design, engineering, land purchase, environmental investigations, procurement, construction, inspection and commissioning activities for which such advance payments are then due. The funds shall be deposited by Interconnection Customer according to the instructions on individual invoices from Transmission Owner, which shall be delivered by Transmission Owner to Interconnection Customer at least ten (10) Business Days prior to the date of such payment being due. Transmission Owner shall not provide any labor, equipment, materials, parts, travel, or incur incidental costs associated with tasks described above, or commence any other work until applicable advance payment(s) is/are received in full.

**11.8.2** Interconnection Customer shall not be required to make any subsequent payment to the Transmission Owner in the event tasks relating to the prior payment have not been substantially completed.

**11.8.3** Transmission Owner shall keep detailed records for actual costs incurred. Interconnection Customer shall be entitled, during normal business hours and at its own expense, to review such records and supporting documentation. If, during procurement, installation, or construction of a discrete portion of a Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, or upon close-out of any phase of such activities, costs by Transmission Owner are expected to exceed the sum of payments made by Interconnection Customer, Transmission Owner will inform Interconnection Customer of the additional expenses and provide a written revision to the estimate, together with an invoice for the amount due. Interconnection Customer shall then promptly pay Transmission Owner in full and without interest for the billed amount. If, upon completion of the procurement, installation, or construction of a discrete portion of Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, costs incurred by Transmission Owner are less than the sum of payment(s) made to Transmission Owner by Interconnection Customer, Transmission Owner shall refund the difference, unless such payments are otherwise non-refundable pursuant to Article 11.6 (Initial Payment), without interest, as soon as the necessary vouchers may be prepared.

**11.9 Interconnection Customer Compensation.** If Transmission Provider or Transmission Owner requests or directs Interconnection Customer to provide a service pursuant to Articles 9.6.3 (Payment for Reactive Power), or 13.5.1 of this Interim GIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to the Tariff. Interconnection Customer shall serve Transmission Provider with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent

that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this Interim GIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided, however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

**11.9.1 Interconnection Customer Compensation for Actions During Emergency Condition.** Transmission Provider shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.9.

## Article 12. Invoice

The terms of this Article 12 apply to billing between the Parties for construction and operation and maintenance charges. All other billing will be handled according to the Tariff.

**12.1 General.** Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this Interim GIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**12.2 Final Invoice.** Within six months after completion of the construction of Interconnection Facilities and the Network Upgrades to be constructed pursuant to this Interim GIA, the Interconnection Customer shall receive an invoice of the final cost due under this Interim GIA, including any applicable cost due to termination, which shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Interconnection Customer shall receive a refund of any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

**12.3 Payment.** Invoices shall be rendered to the paying Party at the address specified in Appendix F. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this Interim GIA.

**12.4 Disputes.** In the event of a billing dispute between the Parties, Transmission Owner, and Transmission Provider shall continue to provide Interconnection Service under this Interim GIA as long as Interconnection Customer: (i) continues to make all payments not

in dispute; and (ii) pays to Transmission Owner or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Owner may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due, with the Transmission Provider and Interconnection Customer to pay the amount due with the accrued interest, if any.

## Article 13. Emergencies

**13.1 Definition.** "Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Transmission Owner, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, Transmission Owner's Interconnection Facilities; or (4) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by the Interim Generator Interconnection Agreement, to possess black start capability.

**13.2 Obligations.** Each Party shall comply with the Emergency Condition procedures of NERC, the Applicable Reliability Council, Transmission Provider, Applicable Laws and Regulations, and any emergency procedures agreed to by the Joint Operating Committee.

**13.3 Notice.** Transmission Provider or Transmission Owner shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Owner's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Generating Facility or Interconnection Customer's Interconnection Facilities.

Interconnection Customer shall notify Transmission Provider and Transmission Owner promptly when it becomes aware of an Emergency Condition that affects the Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Owner's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Owner's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken. The initial notice shall be followed as soon as practicable with written notice.

**13.4 Immediate Action.** Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Owner, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or Transmission Owner or otherwise regarding the Transmission System.

**13.5 Transmission Provider and Transmission Owner Authority.**

**13.5.1 General**. Transmission Provider and/or Transmission Owner may take whatever actions or inactions with regard to the Transmission System or Transmission Owner's Interconnection Facilities it deems necessary during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Transmission System or Transmission Owner's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service.

Transmission Provider and Transmission Owner shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider and/or Transmission Owner may, on the basis of technical considerations, require the Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Generating Facility; implementing a reduction or disconnection pursuant to Article 13.5.2; directing Interconnection Customer to assist with black start (if available) or restoration efforts; or altering the outage schedules of the Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's and Transmission Owner's operating instructions concerning Generating Facility real power and reactive power output within the manufacturer's design limitations of the Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

**13.5.2 Reduction and Disconnection.** Transmission Provider and/or Transmission Owner may reduce Interconnection Service or disconnect the Generating Facility or Interconnection Customer's Interconnection Facilities, when such reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment, reduction, or disconnection of Transmission Provider pursuant to Transmission Provider's Tariff or Articles 2.5, 4.2.2 and 9.7.2. When Transmission Provider and/or Transmission Owner can schedule the reduction or disconnection in advance, Transmission Provider and/or Transmission Owner shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider and/or Transmission Owner shall coordinate with Interconnection Customer using Good Utility Practice to

schedule the reduction or disconnection during periods of least impact to Interconnection Customer, Transmission Provider and/or Transmission Owner. Any reduction or disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Generating Facility, the Interconnection Facilities, and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

**13.6 Interconnection Customer Authority.** Consistent with Good Utility Practice and this Interim GIA and the GIP, Interconnection Customer may take actions or inactions with regard to the Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to (i) preserve public health and safety, (ii) preserve the reliability of the Generating Facility or Interconnection Customer's Interconnection Facilities, (iii) limit or prevent damage, and (iv) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Owner's Interconnection Facilities. Transmission Provider and/or Transmission Owner shall use Reasonable Efforts to assist Interconnection Customer in such actions.

**13.7 Limited Liability.** Except as otherwise provided in Article 11.9.1 of this Interim GIA, no Party shall be liable to the other Parties for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

## Article 14. Regulatory Requirements and Governing Law

**14.1 Regulatory Requirements.** Each Party's obligations under this Interim GIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this Interim GIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act the Public Utility Holding Company Act of 2005, or the Public Utility Regulatory Policies Act of 1978, as amended by the 2005 Energy Policy Act.

**14.2 Governing Law.**

**14.2.1** The validity, interpretation and performance of this Interim GIA and each of its provisions shall be governed by Federal law or by the laws of the state where the Point of Interconnection is located, as applicable.

**14.2.2** This Interim GIA is subject to all Applicable Laws and Regulations.

**14.2.3** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

## Article 15. Notices

**15.1 General.** Unless otherwise provided in this Interim GIA, any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Any Party may change the notice information in this Interim GIA by giving five (5) Business Days written notice prior to the effective date of the change.

**15.2 Billings and Payments.** Billings and payments shall be sent to the addresses set out in Appendix F.

**15.3 Alternative Forms of Notice.** Any notice or request required or permitted to be given by any Party to another and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F.

**15.4 Operations and Maintenance Notice.** Each Party shall notify the other Parties in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

## Article 16. Force Majeure

### 16.1 Force Majeure.

**16.1.1** Economic hardship is not considered a Force Majeure event.

**16.1.2** No Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Parties in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

## Article 17. Default

**17.1 Default.**

**17.1.1 General.** No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this Interim GIA or the result of an act or omission of another Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

**17.1.2 Right to Terminate.** If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this Interim GIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Interim GIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this Interim GIA.

**Article 18. Indemnity, Consequential Damages and Insurance**

**18.1 Indemnity.** The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Parties' action or inactions of its obligations under this Interim GIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party. Notwithstanding the provisions of Article 18, the liability of the Transmission Owner shall be limited to and determined in accordance with the Federal Tort Claims Act, 28. U.S.C. § 1346(b), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

**18.1.1 Indemnified Person.** If an indemnified person is entitled to indemnification under this Article 18 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 18.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**18.1.2 Indemnifying Party.** If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 18, the amount owing to

the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**18.1.3 Indemnity Procedures.** Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**18.2 Consequential Damages**. In no event shall any Party be liable to any other Party under any provision of this Interim GIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which any Party may be liable to another Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

**18.3 Interconnection Customer Insurance.** Interconnection Customer shall at its own expense, maintain in force throughout the period of this Interim GIA, and until released by all other Parties, the following minimum insurance coverages, with insurers authorized to do business in the state where the Point of Interconnection is located:

**18.3.1** Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located. The minimum limits for the Employers' Liability insurance shall be One Million Dollars ($1,000,000) each accident bodily injury by accident, One Million Dollars ($1,000,000) each employee bodily injury by disease, and One Million Dollars ($1,000,000) policy limit bodily injury by disease.

**18.3.2** Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards (if applicable), independent contractors coverage, coverage for pollution (if exposure is present) and punitive or exemplary damages, with minimum limits of One Million Dollars ($1,000,000) each occurrence/Two Million Dollars ($2,000,000) general aggregate and Two Million Dollars ($2,000,000) products and completed operations aggregate combined single limit for personal injury, bodily injury, including death and property damage.

**18.3.3** Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death, and property damage.

**18.3.4** Excess Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) each occurrence/Twenty Million Dollars ($20,000,000) general aggregate.

**18.3.5** The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the other Party, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this Interim GIA against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

**18.3.6** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain

provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Each Party shall be responsible for its respective deductibles or retentions.

**18.3.7** The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Interim GIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed to by all Parties.

**18.3.8** The requirements contained herein as to the types and limits of all insurance to be maintained by the Interconnection Customer are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

**18.3.9** Within ten (10) days following execution of this Interim GIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, Interconnection Customer shall provide certification of all insurance required in this Interim GIA, executed by each insurer or by an authorized representative of each insurer to the Other Party Group.

**18.3.10** Notwithstanding the foregoing, Interconnection Customer may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, such Interconnection Customer's senior secured debt is rated at investment grade or better by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that an Interconnection Customer's senior secured debt is unrated by Standard & Poor's or is rated at less than investment grade by Standard & Poor's, Interconnection Customer shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that Interconnection Customer is permitted to self-insure pursuant to this article, it shall notify the other Party that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

**18.3.11** The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Interim GIA.

**18.4 Transmission Owner Insurance.** Transmission Owner is self-insured in accordance with its status as a Federal agency.

## Article 19 Assignment.

**19.1 Assignment.** This Interim GIA may be assigned by any Party only with the written consent of the other Parties to any Affiliate of the assigning Party, or other third party, with an acceptable credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Interim GIA. Interconnection Customer shall have the right to assign this Interim GIA, with the written consent of Transmission Provider and Transmission Owner, for collateral security purposes to aid in providing financing for the Generating Facility. Any financing arrangement entered into by the Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider and Transmission Owner of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.7 and 18.3. Any assignment under this article not solely for collateral security purposes shall be conditioned on the simultaneous assignment of Interconnection Customer's Queue Position to assignee and assignee demonstrating the ability to enter into and fulfill the obligations of a final GIA. Any attempted assignment that violates this article is void and ineffective. Any assignment under this Interim GIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Consent to assignment will not be unreasonably withheld, conditioned or delayed.

## Article 20. Severability

**20.1 Severability.** If any provision in this Interim GIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Interim GIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Owner) seeks and obtains such a final determination with respect to any provision of the Negotiated Option (Article 5.1.3), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

## Article 21. Comparability

**21.1 Comparability.** The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

## Article 22. Confidentiality

**22.1 Confidentiality.** Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs, and pricing, and any information supplied by any of the Parties to another prior to the execution of this Interim GIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by any Party, a Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

**22.1.1 Term.** During the term of this Interim GIA, and for a period of three (3) years after the expiration or termination of this Interim GIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

**22.1.2 Scope.** Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this Interim GIA; or (6) is required, in accordance with Article 22.1.7 of the Interim GIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this Interim GIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

**22.1.3 Release of Confidential Information.** No Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), subcontractors, employees, consultants, or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this Interim GIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

**22.1.4 Rights.** Each Party retains all rights, title, and interest in the Confidential Information that each Party discloses to another Party. The disclosure by any Party to another Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

**22.1.5 No Warranties.** By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

**22.1.6 Standard of Care.** Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this Interim GIA or its regulatory requirements.

**22.1.7 Order of Disclosure.** If a court or a Governmental Authority or entity with the right, power, and apparent authority to do so requests or requires a Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Parties with prompt notice of such request(s) or requirement(s) so that the other Parties may seek an appropriate protective order or waive compliance with the terms of this Interim GIA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

**22.1.8 Termination of Agreement.** Upon termination of this Interim GIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

**22.1.9 Remedies.** This section 22.1.9 shall not apply to the Transmission Owner. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Parties shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be

deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

**22.1.10 Disclosure to FERC, its Staff, or a State.** Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 C.F.R. Section 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this Interim GIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. Section 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying another Party to this Interim GIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to the Interim GIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. Section 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner, if consistent with the applicable Federal and state laws, rules and regulations.

**22.1.11** Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this Interim GIA ("Confidential Information") shall not be disclosed by another Party to any person not employed or retained by the other Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this Interim GIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures

**22.1.12** This provision shall not apply to any information that was or is hereafter in the public domain (except as a result of a Breach of this provision).

## Article 23. Environmental Releases

**23.1** Each Party shall notify the other Party, first orally and then in writing, of the release of any Hazardous Substances, any asbestos or lead abatement activities, or any type of remediation activities related to the Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Party. The notifying Party shall: (i) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than twenty-four hours after such Party becomes aware of the occurrence; and (ii) promptly furnish to the other Party copies of any publicly available reports filed with any Governmental Authorities addressing such events.

**23.2** Each Party shall remedy as soon as practicable all releases of Hazardous Substances brought to, or created at, real property it owns underlying the Generating Facility or Interconnection Facilities, and any such substances migrating from real property it owns at the Generating Facility site. The Party that caused the release shall bear the costs of the remedial action, which shall meet applicable Federal and state environmental standards at the time of the action. Such costs may include, but are not limited to, Federal and state supervision, remedial action plans, removal and remedial actions, and negotiation of voluntary and judicial agreements required to meet such environmental standards.

**23.3** The Parties agree to comply fully with the substantive requirements of all applicable Federal, state and local environmental laws in the performance of their obligations hereunder, and to mitigate and abate adverse environmental impacts accordingly.

## Article 24. Information Requirements

**24.1 Information Acquisition.** Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

**24.2 Information Submission by Transmission Provider.** The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

## Article 25. Information Access and Audit Rights

**25.1 Information Access.** Each Party (the "disclosing Party") shall make available to the other Parties information that is in the possession of the disclosing Party and is necessary in order for the other Parties to: (i) verify the costs incurred by the disclosing Party for which the other Parties are responsible under this Interim GIA; and (ii) carry out its obligations and responsibilities under this Interim GIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this Interim GIA.

**25.2 Reporting of Non-Force Majeure Events.** Each Party (the "notifying Party") shall notify the other Parties when the notifying Party becomes aware of its inability to comply with the provisions of this Interim GIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Parties receiving such notification to allege a cause for anticipatory breach of this Interim GIA.

**25.3 Audit Rights.** Subject to the requirements of confidentiality under Article 22 of this Interim GIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to another Party, to audit at its own expense that other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this Interim GIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this Interim GIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

**25.4 Audit Rights Periods.**

**25.4.1 Audit Rights Period for Construction-Related Accounts and Records.** Accounts and records related to the design, engineering, procurement, and construction of Transmission Owner’s Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four months following Transmission Owner’s issuance of a final invoice in accordance with Article 12.2.

**25.4.2 Audit Rights Period for All Other Accounts and Records.** Accounts and records related to any Party's performance or satisfaction of all obligations under this Interim GIA other than those described in Article 25.4.1 shall be subject to audit as follows: (i) for an audit relating to cost obligations, the applicable audit

rights period shall be twenty-four months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (ii) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four months after the event for which the audit is sought.

**25.5 Audit Results.** If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

## Article 26. Subcontractors

**26.1 General.** Nothing in this Interim GIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Interim GIA; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Interim GIA in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

**26.2 Responsibility of Principal.** The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Interim GIA. The hiring Party shall be fully responsible to the other Parties for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall Transmission Owner be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this Interim GIA. Any applicable obligation imposed by this Interim GIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

**26.3 No Limitation by Insurance.** The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

## Article 27. Disputes

**27.1 Submission.** In the event any Party has a dispute, or asserts a claim, that arises out of or in connection with this Interim GIA or its performance, the Parties agree to resolve such dispute using the dispute resolution procedures of the Generator Interconnection Procedures.

## Article 28. Representations, Warranties, and Covenants

**28.1 General**. Each Party makes the following representations, warranties and covenants:

**28.1.1 Good Standing.** Such Party is duly organized, validly existing and in good standing under Federal law or the laws of the state in which it is organized, formed, or incorporated, as applicable; that it is qualified to do business in the state or states in which the Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located**;** and that it has

the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Interim GIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Interim GIA.

**28.1.2 Authority.** Such Party has the right, power and authority to enter into this Interim GIA, to become a Party hereto and to perform its obligations hereunder. This Interim GIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**28.1.3 No Conflict.** The execution, delivery and performance of this Interim GIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**28.1.4 Consent and Approval.** Such Party has sought or obtained, or, in accordance with this Interim GIA will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Interim GIA, and it will provide to any Governmental Authority notice of any actions under this Interim GIA that are required by Applicable Laws and Regulations.

## Article 29. Joint Operating Committee

**29.1 Joint Operating Committee.** At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer, Transmission Owner and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Party shall notify the other Parties of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of any Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this Interim GIA. All Parties shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

**29.1.1** Establish data requirements and operating record requirements.

**29.1.2** Review the requirements, standards, and procedures for data acquisition equipment, protective equipment, and any other equipment or software.

**29.1.3** Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Owner's and Interconnection Customer's facilities at the Point of Interconnection.

**29.1.4** Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Generating Facility and other facilities that impact the normal operation of the interconnection of the Generating Facility to the Transmission System.

**29.1.5** Ensure that information is being provided by each Party regarding equipment availability.

**29.1.6** Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

## Article 30. Miscellaneous

**30.1 Binding Effect.** This Interim GIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**30.2 Conflicts.** In the event of a conflict between the body of this Interim GIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Interim GIA shall prevail and be deemed the final intent of the Parties.

**30.3 Rules of Interpretation.** This Interim GIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Interim GIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Interim GIA), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this Interim GIA or such Appendix to this Interim GIA, or such Section to the GIP or such Appendix to the GIP, as the case may be; (6) "hereunder", "hereof", "herein", "hereto" and words of similar import shall be deemed references to this Interim GIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including", "to" means "to but excluding" and "through" means "through and including".

**30.4 Entire Agreement.** This Interim GIA, including all Appendices and Schedules attached hereto, and also incorporating through reference Section 39.3 of the Tariff as if it were a part hereof, constitutes the entire agreement among the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, among the Parties with respect to the subject matter of this Interim GIA. There are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, a Party's compliance with its obligations under this Interim GIA.

**30.5 No Third Party Beneficiaries.** This Interim GIA is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**30.6 Waiver.** The failure of a Party to this Interim GIA to insist, on any occasion, upon strict performance of any provision of this Interim GIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by a Party of its rights with respect to this Interim GIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Interim GIA. Termination or Default of this Interim GIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Interim GIA shall, if requested, be provided in writing.

**30.7 Headings.** The descriptive headings of the various Articles of this Interim GIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Interim GIA.

**30.8 Multiple Counterparts.** This Interim GIA may be executed in three or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**30.9 Amendment.** The Parties may by mutual agreement amend this Interim GIA by a written instrument duly executed by each of the Parties.

**30.10 Modification by the Parties.** The Parties may by mutual agreement amend the Appendices to this Interim GIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Interim GIA upon satisfaction of all Applicable Laws and Regulations.

**30.11 Reservation of Rights.** Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Interim GIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under Section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Transmission Owner and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Interim GIA pursuant to Section 206

or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Interim GIA shall limit the rights of the Parties or of FERC under Sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

**30.12 No Partnership.** This Interim GIA shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership among the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, another Party.

**IN WITNESS WHEREOF,** the Parties have caused this Interim GIA to be executed by their respective authorized officials, and copies delivered to each Party, to become effective as of the Effective Date.

**SOUTHWEST POWER POOL, INC.**

By: _____

Printed Name:_____

Title: _____

Date: _____

**[Insert name of Transmission Owner]**

By: _____

Printed Name:_____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Printed Name:_____

Title: _____

Date: _____

## Appendix A to Interim GIA

**Interconnection Facilities, Network Upgrades, Distribution Upgrades, Security, Type and Amount of Interconnection Service, Construction Option, and Higher Queued Project List**

**1. Interconnection Facilities: [include description, responsible party, and estimated costs]:**

**A. Interconnection Customer's Interconnection Facilities**

**B. Transmission Owner Interconnection Facilities**

**2. Network Upgrades: [include description, responsible party, and estimated costs]:**

**A. Stand Alone Network Upgrades**

**B. Network Upgrades For Which Interconnection Customer Is Solely Responsible**

**C. Network Upgrades For Which Interconnection Customer Shares Cost Responsibility**

**3. Distribution Upgrades: [include description, responsible party, and estimated costs]:**

**4. Security, Credits and Taxes:**

**A.** The amount of initial security to be provided by Interconnection Customer in accordance with Article 11.7.1 is $_____. The required amount of security required pursuant to this Interim GIA may be adjusted pursuant to Article 11.7.2 of this Agreement.

**B.** The estimated portion of the Network Upgrades identified in Section 2 of this Appendix A that could be subject to the credits described in Article 11.5 of this Agreement is $_____.

**5. Type and Amount of Interim Interconnection Service:**

The type of Interim Interconnection Service to be provided pursuant to this Interim GIA shall be [Energy Resource or Network Resource] Interim Interconnection Service in the amount of _____ MW.

**6. Construction Option For Stand Alone Upgrades and Transmission Owner Interconnection Facilities:**

The Parties have agreed to the construction options for the Stand Alone Network Upgrades and Transmission Owner Interconnection Facilities as specified below:

**A. Stand Alone Network Upgrades:**

**[List the Stand Alone Network Upgrade and the construction option]**

**B. Transmission Owner Interconnection Facilities:**

**[List the Transmission Owner Interconnection Facility and the option]**

**7. Higher Queued Projects:**

**[list Higher Queued Projects]**

**8. Permits, Licenses and Authorizations:**

**9. Penalty, Redispatch or Market-Related Costs:**

**10. One-Line Diagram:**

**11. Environmental Requirements:**

This Interim GIA is subject to completion of the appropriate National Environmental Policy Act (NEPA) level of Environmental Review. **Until a NEPA decision document is issued, no construction activities relating to Transmission Owner's Interconnection Facilities and/or Network Upgrades may commence.**

**(a)** [Insert Environmental Requirements for an Environmental Impact Statement (EIS) level of Environmental Review]
**(b)** [Insert Environmental Requirements for an Environmental Assessment (EA) level of Environmental Review]

**12. Candidate Incremental Long-Term Congestion Rights:**

* Source _____
* Sink _____

* Candidate Incremental LTCR MW _____

* Term (years from in-service date of Network Upgrade) _____

# Appendix B to Interim GIA

## Milestones

## Appendix C to Interim GIA

## Interconnection Details

This Appendix C is an integral part of this Interim GIA.

**1. Description of Generating Facility:**
**Inverter-Based Resource EMT Study Results Mitigations**

If an Electromagnetic Transient Study is determined to be required by the Transmission Provider and the study results reveal an Adverse System Impact to the Transmission System, mitigation(s) shall be the responsibility of the Interconnection Customer and shall be implemented prior to the injection of power into the Transmission System.

**2. Description of Point of Change of Ownership:**

**3. Description of Point of Interconnection:**

**4. Interconnection Guidelines:**
The unique requirements of each generation interconnection will dictate the establishment of mutually agreeable interconnection guidelines that further define the requirements of this Agreement. The interconnection guidelines will address, but not be limited to, the following:

## Appendix D to Interim GIA

## Infrastructure and Operational Security Arrangements

Infrastructure security of Transmission System equipment and operations and control hardware and software is essential to ensure day-to-day Transmission System reliability and operational security. FERC will expect all Transmission Providers, market participants, and Interconnection Customers interconnected to the Transmission System to comply with the recommendations offered by the National Infrastructure Advisory Council and, eventually, best practice recommendations from the electric reliability authority. All public utilities will be expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

## Appendix E to Interim GIA

## Commercial Operation Date

**[Date]**

_____, _____
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

**[Transmission Owner Address]**

Re: _____

Dear _____:

On **[Date]**, _____ has completed Trial Operation of referenced generation facility in the Interim Generator Interconnection Agreement dated _____. This letter confirms that _____ commenced Commercial Operation of the referenced generation facility, effective as of **[Date plus one day]**.

Thank you.

**[Signature]**

**[Interconnection Customer Representative]**

## Appendix F to Interim GIA

## Addresses for Delivery of Notices And Billings

**Notices:**

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

**[To be Supplied]**

Interconnection Customer:

**[To be Supplied]**

**Billings and Payments:** [Specify addresses for construction invoices, O&M invoices and settlement of ancillary services]

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

Transmission Owner:

**[To be Supplied]**

Interconnection Customer:

**[To be Supplied]**

Alternative Forms of Delivery of Notices (telephone, facsimile or email):

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

**[TO BE SUPPLIED]**

Interconnection Customer:

**[TO BE SUPPLIED]**

**Operational Communications:** [Identify contacts for operations]

Transmission Provider:

_____, _____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Phone: _____
Facsimile: 501-482-2022

Transmission Owner:

**[TO BE SUPPLIED]**

Interconnection Customer:

**[TO BE SUPPLIED]**

## Appendix G to Interim GIA

## Requirements Of Generators Relying On Newer Technologies

Appendix G sets forth requirements and provisions specific to a wind generating plant. All other requirements of this Interim GIA continue to apply to wind generating plant interconnections.

### A. Technical Standards Applicable to a Wind Generating Plant

#### i. Low Voltage Ride-Through (LVRT) Capability

The following reactive power requirements apply only to a newly interconnecting wind generating plant that has executed a facilities study agreement as of September 21, 2016. A wind generating plant to which this provision applies shall be able to remain online during voltage disturbances up to the time periods and associated voltage levels set forth in the standard below. The LVRT standard provides for a transition period standard and a post-transition period standard.

**Transition Period LVRT Standard**

The transition period standard applies to wind generating plants subject to FERC Order 661 that have either: (i) interconnection agreements signed and filed with the Commission, filed with the Commission in unexecuted form, or filed with the Commission as non-conforming agreements between January 1, 2006 and December 31, 2006, with a scheduled in-service date no later than December 31, 2007, or (ii) wind generating turbines subject to a wind turbine procurement contract executed prior to December 31, 2005, for delivery through 2007.

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at a voltage as low as 0.15 p.u., as measured at the high side of the wind generating plant step-up transformer (i.e. the transformer that steps the voltage up to the transmission interconnection voltage or

"GSU"), after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU or to faults that would result in a voltage lower than 0.15 per unit on the high side of the GSU serving the facility.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator, etc.) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**Post-transition Period LVRT Standard**

All wind generating plants subject to FERC Order No. 661 and not covered by the transition period described above must meet the following requirements:

1. Wind generating plants are required to remain in-service during three-phase faults with normal clearing (which is a time period of approximately 4 – 9 cycles) and single line to ground faults with delayed clearing, and subsequent post-fault voltage recovery to prefault voltage unless clearing the fault effectively disconnects the generator from the system. The clearing time requirement for a three-phase fault will be specific to the wind generating plant substation location, as determined by and documented by the transmission provider. The maximum clearing time the wind generating plant shall be required to withstand for a three phase fault shall be 9 cycles after which, if the fault remains following the location-specific normal clearing time for three-phase faults, the wind generating plant may disconnect from the transmission system. A wind generating

plant shall remain interconnected during such a fault on the transmission system for a voltage level as low as zero volts, as measured at the high voltage side of the wind GSU.

2. This requirement does not apply to faults that would occur between the wind generator terminals and the high side of the GSU.
3. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
4. Wind generating plants may meet the LVRT requirements of this standard by the performance of the generators or by installing additional equipment (e.g., Static var Compensator) within the wind generating plant or by a combination of generator performance and additional equipment.
5. Existing individual generator units that are, or have been, interconnected to the Transmission System at the same location at the effective date of the Appendix G LVRT Standard are exempt from meeting the Appendix G LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Appendix G LVRT Standard.

**ii. Power Factor Design Criteria (Reactive Power)**

A wind generating plant shall maintain a power factor within the range of 0.95 leading to 0.95 lagging, measured at the Point of Interconnection as defined in this Interim GIA, if the Transmission Provider's System Impact Study shows that such a requirement is necessary to ensure safety or reliability. The power factor range standard can be met by using, for example, power electronics designed to supply this level of reactive capability (taking into account any limitations due to voltage level, real power output, etc.) or fixed and switched capacitors if agreed to by the Transmission Provider, or a combination of the two. The Interconnection Customer shall not disable power factor equipment while the wind plant is in operation. Wind plants shall also be able to provide sufficient dynamic voltage support in lieu of the power system stabilizer and automatic voltage regulation at the generator excitation system if the System Impact Study shows this to be required for system safety or reliability.

**iii. Supervisory Control and Data Acquisition (SCADA) Capability**

The wind plant shall provide SCADA capability to transmit data and receive instructions from the Transmission Provider to protect system reliability. The Transmission Provider and the wind plant Interconnection Customer shall determine what SCADA information is essential for

the proposed wind plant, taking into account the size of the plant and its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area.

## APPENDIX 15 TO GIP

## SURPLUS INTERCONNECTION SERVICE IMPACT STUDY AGREEMENT

**THIS AGREEMENT** is made and entered into this _____ day of _____ 20___ by and between _____ a _____ and existing under the laws of the State of _____ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

### RECITALS

**WHEREAS,** Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an Existing Generating Facility consistent with the Surplus Interconnection Service Request submitted by Interconnection Customer dated _____; and

**WHEREAS,** Interconnection Customer desires to interconnect the Generating Facility with the Transmission System;

**WHEREAS,** Interconnection Customer wishes to participate in the Surplus Interconnection Service Impact Study or has requested Transmission Provider to perform a Surplus Interconnection Service Impact Study to assess the impact of interconnecting the Generating Facility to the Transmission System, and of any Affected Systems;

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

**1.0** When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

**2.0** Interconnection Customer elects and Transmission Provider shall cause to be performed a Surplus Interconnection Service Impact Study consistent with Section 3.3.4.1 of the GIP in accordance with the Tariff.

**3.0** The scope of the Surplus Interconnection Service Impact Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

**4.0** The Surplus Interconnection Service Impact Study will be based upon the technical information provided by Interconnection Customer in the Surplus Interconnection Service Request, subject to any modifications in accordance with Section 4.4 of the GIP. Transmission Provider reserves the right to request additional technical information from Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Surplus Interconnection Service Impact Study. If Interconnection Customer modifies its Interconnection Request, or the technical information

provided therein is modified, the time to complete the Surplus Interconnection Service Impact Study may be extended.

**5.0** The Surplus Interconnection Service Impact Study report shall provide the following information:

- identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

- identification of any thermal overload or voltage limit violations resulting from the interconnection;

- identification of any instability or inadequately damped response to system disturbances resulting from the interconnection;

- description and non-binding, good faith estimated cost of facilities required to interconnect the Generating Facility to the Transmission System and to address the identified short circuit, instability, and power flow issues; and

- will include a Facilities Analysis as specified in Section 8.4.4 that will provide cost estimates for Transmission Owner's Interconnection Facilities and Network Upgrades at the Point of Interconnection.

**6.0** Interconnection Customer shall provide the deposit specified under Section 3.3.1.2 of the GIP for the performance of the Surplus Interconnection Service Impact Study. Transmission Provider's good faith estimate for the time of completion of the Surplus Interconnection Service Impact Study is sixty (60) Calendar Days following receipt of an application for Surplus Interconnection Service.

Upon receipt of the Surplus Interconnection Service Impact Study results, Transmission Provider shall charge and Interconnection Customer shall pay the actual costs of the Surplus Interconnection Service Impact Study.

Any difference between the deposit and Interconnection Customer's study cost obligation shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.3 of the Generator Interconnection Procedures.

**7.0 Governing Law**

**7.1 Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

**7.2 Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

**7.3 Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

**8.0 Notices.**

**8.1 General**. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Manager, GI Studies

To Interconnection Customer:

_____
_____
_____
Attention: _____

**8.2 Alternative Forms of Notice**. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

**9.0 Force Majeure**

**9.1 Economic Hardship.** Economic hardship is not considered a Force Majeure event.

**9.2 Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied

upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

**10.0 Indemnity**

**10.1 Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys' action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

**10.1.1 Indemnified Person**. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**10.1.2 Indemnifying Party**. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**10.1.3 Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified

persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**10.2 Consequential Damages**. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

**11.0 Assignment**

**11.1 Assignment**. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this

Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

**12.0 Severability**

**12.1 Severability**. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

**13.0 Comparability**

**13.1 Comparability**. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

**14.0 Deposits and Invoice Procedures**

**14.1 General**. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**14.2 Study Deposits**. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

**14.3 Final Invoice**. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for

estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

**14.4 Payment**. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

**14.5 Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due together with accrued interest in accordance with Section 3.7 of this Attachment V.

## 15.0 Representations, Warranties, and Covenants

**15.1 General**. Each Party makes the following representations, warranties and covenants:

**15.1.1 Good Standing**. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

**15.1.2 Authority**. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by

general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**15.1.3** **No Conflict**. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**15.1.4** **Consent and Approval**. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

## 16.0 Breach, Cure and Default

**16.1** **General.** A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

**16.2** **Events of Breach.** A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or

data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

**16.3 Cure and Default.** Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the "Non-Breaching Party"), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the "Breaching Party") and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

**16.4 Right to Compel Performance.** Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

**17.0 Miscellaneous**

**17.1 Binding Effect**. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**17.2 Conflicts**. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

**17.3 Rules of Interpretation**. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and

Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

**17.4 Entire Agreement**. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

**17.5 No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**17.6 Waiver**. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

**17.7 Headings**. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

**17.8 Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**17.9 Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

**17.10 Modification by the Parties**. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

**17.11 No Partnership**. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

**IN WITNESS THEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

**[Insert name of Transmission Provider]**

By: _____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Title: _____

Date: _____

**Attachment A to Appendix 15**
**Surplus Interconnection Service Impact**
**Study Agreement**

## ASSUMPTIONS USED IN CONDUCTING THE SURPLUS INTERCONNECTION SERVICE IMPACT STUDY

The Surplus Interconnection Service Impact Study will be based upon the information set forth in the Interconnection Requests and results of applicable prior studies, subject to any modifications in accordance with Section 4.4 of the GIP, and the following assumptions:

## GENERATING FACILITY DATA FOR THE SURPLUS INTERCONNECTION SERVICE IMPACT STUDY

### UNIT RATINGS

Nameplate kVA _____ °F _____ Voltage _____
Prime Mover type _____
Power Factor: Lead _____ Lag _____
Speed (RPM) _____ Connection (e.g. Wye) _____
Short Circuit Ratio _____ Frequency, Hertz _____
Stator Amperes at Rated kVA _____ Field Volts _____
Max Turbine Power: Summer MW _____ °F _____
Winter MW _____ °F _____

### COMBINED TURBINE-GENERATOR-EXCITER INERTIA DATA

Inertia Constant, H = _____ kW sec/kVA
Moment-of-Inertia, $WR^2$ = _____ lb. $ft.^2$

### REACTANCE DATA (PER UNIT-RATED KVA)

| | DIRECT AXIS | | QUADRATURE AXIS | |
|---|---|---|---|---|
| Synchronous – saturated | $X_{dv}$ | _____ | $X_{qv}$ | _____ |
| Synchronous – unsaturated | $X_{di}$ | _____ | $X_{qi}$ | _____ |
| Transient – saturated | $X'_{dv}$ | _____ | $X'_{qv}$ | _____ |
| Transient – unsaturated | $X'_{di}$ | _____ | $X'_{qi}$ | _____ |
| Subtransient – saturated | $X''_{dv}$ | _____ | $X''_{qv}$ | _____ |
| Subtransient – unsaturated | $X''_{di}$ | _____ | $X''_{qi}$ | _____ |
| Negative Sequence – saturated | $X2_v$ | _____ | | |
| Negative Sequence – unsaturated | $X2_i$ | _____ | | |
| Zero Sequence – saturated | $X0_v$ | _____ | | |
| Zero Sequence – unsaturated | $X0_i$ | _____ | | |

Leakage Reactance $Xl_m$ _____

## FIELD TIME CONSTANT DATA (SEC)

| | | | | |
|---|---|---|---|---|
| Open Circuit | $T'_{do}$ | _____ | $T'_{qo}$ | _____ |
| Three-Phase Short Circuit Transient | $T'_{d3}$ | _____ | $T'_{q}$ | _____ |
| Line to Line Short Circuit Transient | $T'_{d2}$ | _____ | | |
| Line to Neutral Short Circuit Transient | $T'_{d1}$ | _____ | | |
| Short Circuit Subtransient | $T''_{d}$ | _____ | $T''_{q}$ | _____ |
| Open Circuit Subtransient | $T''_{do}$ | _____ | $T''_{qo}$ | _____ |

## ARMATURE TIME CONSTANT DATA (SEC)

| | | |
|---|---|---|
| Three Phase Short Circuit | $T_{a3}$ | _____ |
| Line to Line Short Circuit | $T_{a2}$ | _____ |
| Line to Neutral Short Circuit | $T_{a1}$ | _____ |

NOTE: If requested information is not applicable, indicate by marking "N/A."

## MW CAPABILITY AND PLANT CONFIGURATION
## GENERATING FACILITY DATA

## ARMATURE WINDING RESISTANCE DATA (PER UNIT)

| | | |
|---|---|---|
| Positive | $R_1$ | _____ |
| Negative | $R_2$ | _____ |
| Zero | $R_0$ | _____ |

Rotor Short Time Thermal Capacity $I_2^2t$ = _____
Field Current at Rated kVA, Armature Voltage and PF = _____ amps
Field Current at Rated kVA and Armature Voltage, 0 PF = _____ amps
Three Phase Armature Winding Capacitance = _____ microfarad
Field Winding Resistance = _____ ohms _____ °C
Armature Winding Resistance (Per Phase) = _____ ohms _____ °C

## CURVES

Provide Saturation, Vee, Reactive Capability, Capacity Temperature Correction curves. Designate normal and emergency Hydrogen Pressure operating range for multiple curves.

## GENERATOR STEP-UP TRANSFORMER DATA RATINGS

Capacity
Self-cooled/Maximum Nameplate
_____/_____kVA

Voltage Ratio (Generator Side/System side/Tertiary)
_____/_____/_____kV

Winding Connections (Low V/High V/Tertiary V (Delta or Wye))
_____/_____/_____

Fixed Taps Available _____

Present Tap Setting _____

Impedance: Positive $Z_1$ (on self-cooled kVA rating)_____ % _____ X/R

Impedance: Zero $Z_0$ (on self-cooled kVA rating)_____ % _____ X/R

## EXCITATION SYSTEM DATA

Identify appropriate IEEE model block diagram of excitation system and power system stabilizer (PSS) for computer representation in power system stability simulations and the corresponding excitation system and PSS constants for use in the model.

## GOVERNOR SYSTEM DATA

Identify appropriate IEEE model block diagram of governor system for computer representation in power system stability simulations and the corresponding governor system constants for use in the model.

## WIND GENERATORS

Number of generators to be interconnected pursuant to this Interconnection Request:
_____

Elevation: _____ _____ Single Phase _____ Three Phase

Inverter manufacturer, model name, number, and version:
_____

List of adjustable setpoints for the protective equipment or software:

Note: A completed General Electric Company Power Systems Load Flow (PSLF) data sheet or other compatible formats, such as IEEE and PTI power flow models, must be supplied with the Interconnection Request. If other data sheets are more appropriate to the proposed device, then they shall be provided and discussed at Scoping Meeting.

## INDUCTION GENERATORS

(*) Field Volts: _____
(*) Field Amperes: _____
(*) Motoring Power (kW): _____
(*) Neutral Grounding Resistor (If Applicable): _____
(*) $I_2^2t$ or K (Heating Time Constant): _____
(*) Rotor Resistance: _____
(*) Stator Resistance: _____
(*) Stator Reactance: _____
(*) Rotor Reactance: _____
(*) Magnetizing Reactance: _____
(*) Short Circuit Reactance: _____
(*) Exciting Current: _____
(*) Temperature Rise: _____
(*) Frame Size: _____
(*) Design Letter: _____
(*) Reactive Power Required In Vars (No Load): _____
(*) Reactive Power Required In Vars (Full Load): _____
(*) Total Rotating Inertia, H: _____Per Unit on KVA Base

Note: Please consult Transmission Provider prior to submitting the Interconnection Request to determine if the information designated by (*) is required.

## APPENDIX 16 TO GIP

## SURPLUS INTERCONNECTION SERVICE FACILITIES STUDY AGREEMENT

**THIS AGREEMENT** is made and entered into this ____ of _____ 20___ by and between _____ a _____ and existing under the laws of the State of _____ ("Interconnection Customer") and Southwest Power Pool, Inc. a non-profit organization under the laws of the State of Arkansas ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

### RECITALS

**WHEREAS,** Interconnection Customer is proposing to develop a Generating Facility or generating capacity addition to an Existing Generating Facility consistent with the Interconnection Request submitted by Interconnection Customer dated _____, and

**WHEREAS,** Interconnection Customer desires to interconnect the Generating Facility with the Transmission System;

**WHEREAS,** Transmission Provider has completed a Surplus Interconnection Service Impact Study (the "Service Impact Study") and provided the results of said study to Interconnection Customer; and

**WHEREAS,** Interconnection Customer has requested Transmission Provider to perform a Surplus Interconnection Service Facilities Study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the Service Impact Study in accordance with Good Utility Practice to physically and electrically connect the Generating Facility to the Transmission System.

**NOW, THEREFORE,** in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

**1.0** When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in Transmission Provider's FERC-approved GIP.

**2.0** Interconnection Customer elects and Transmission Provider shall cause a Surplus Interconnection Service Facilities Study consistent with Section 3.3.4.2 of the GIP to be performed in accordance with the Tariff.

**3.0** The scope of the Surplus Interconnection Service Facilities Study shall be subject to the assumptions set forth in Attachment A and the data provided in Attachment B to this Agreement.

**4.0** The Surplus Interconnection Service Facilities Study report (i) shall provide a description, estimated cost of (consistent with Attachment A), schedule for required facilities to interconnect the Generating Facility to the Transmission

System and (ii) shall address the short circuit, instability, and power flow issues identified in the Service Impact Study.

**5.0** Interconnection Customer shall meet the milestone requirements specified under Section 8.9 of the GIP prior to the performance of the Interconnection Facilities Study. The time for completion of the Surplus Interconnection Service Facilities Study is specified in Attachment A.

Transmission Provider shall invoice Interconnection Customer on a monthly basis for the work to be conducted on the Surplus Interconnection Service Facilities Study each month. Interconnection Customer shall pay invoiced amounts within thirty (30) Calendar Days of receipt of invoice. Transmission Provider shall continue to hold the amounts on deposit until settlement of the final invoice. Any difference between the deposit and Interconnection Customer's study cost obligation shall be paid by or refunded to Interconnection Customer, as appropriate per Section 13.3 of the Generator Interconnection Procedures.

**6.0 Reserved.**

**7.0 Governing Law**

**7.1 Governance.** The validity, interpretation and performance of this Agreement and each of its provisions shall be governed by the laws of the United States of America except to the extent that the laws of the state of Arkansas may apply.

**7.2 Applicability.** This Agreement is subject to all applicable federal and state Laws and Regulations.

**7.3 Reservation of Rights.** Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules, or regulations of a Governmental Authority.

**8.0 Notices.**

**8.1 General**. Unless otherwise provided in this Agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party.

To Transmission Provider:

Southwest Power Pool, Inc.
201 Worthen Drive

Little Rock, AR 72223-4936
Attention: Manager, GI Studies

To Interconnection Customer:

_____
_____
_____
Attention: _____

**8.2 Alternative Forms of Notice**. Any notice or request required or permitted to be given by a Party to the other and not required by this Agreement to be given in writing may be so given by telephone, facsimile or email.

**9.0 Force Majeure**

**9.1 Economic Hardship.** Economic hardship is not considered a Force Majeure event.

**9.2 Default.** Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 10), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state the full details of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

**10.0 Indemnity**

**10.1 Indemnity**. The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Partys' action or inactions of its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

**10.1.1** **Indemnified Person**. If an indemnified person is entitled to indemnification under this Article 10 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under Article 10.1, to assume the defense of such claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

**10.1.2** **Indemnifying Party**. If an indemnifying Party is obligated to indemnify and hold any indemnified person harmless under this Article 10, the amount owing to the indemnified person shall be the amount of such indemnified person's actual Loss, net of any insurance or other recovery.

**10.1.3** **Indemnity Procedures**. Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 10.1 may apply, the indemnified person shall notify the indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying Party.

The Indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding

involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

**10.2 Consequential Damages**. Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this Agreement for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

## 11.0 Assignment

**11.1 Assignment**. This Agreement may be assigned by either Party only with the written consent of the other Party; provided that either Party may assign this Agreement without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of Transmission Provider for collateral security purposes to aid in providing financing for the Generating Facility, provided that the Interconnection Customer will require any secured party, trustee or mortgagee to notify the Transmission Provider of any such assignment. Any financing arrangement entered into by the Interconnection Customer pursuant to this Article will provide that prior to or upon the exercise of the secured party’s, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify the Transmission Provider of the date and particulars of any such exercise of assignment right. Any attempted assignment that violates this Article or Applicable Laws and Regulations is void and ineffective. Any assignment under this Agreement shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

## 12.0 Severability

**12.1 Severability**. If any provision in this Agreement is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this Agreement.

**13.0 Comparability**

**13.1 Comparability**. The Parties will comply with all applicable comparability and code of conduct laws, rules and regulations, as amended from time to time.

**14.0 Deposits and Invoice Procedures**

**14.1 General**. The Transmission Provider and the Interconnection Customer may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under the GIP, including credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

**14.2 Study Deposits**. The Interconnection Customer shall provide study deposits, in accordance with the GIP to the Transmission Provider. The study deposits amounts and schedule shall be in accordance with the GIP.

**14.3 Final Invoice**. Within six months after completion of the studies Transmission Provider shall provide an invoice of the final cost of the studies and shall set forth such costs in sufficient detail to enable the Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of the studies within thirty (30) Calendar Days of the issuance of such final study invoice.

**14.4 Payment**. Invoices shall be rendered to the paying Party at the address specified in the Interconnection Request in Appendix 1 to the GIP. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under the GIP.

**14.5 Disputes.** In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide studies for Interconnection Service under the GIP as long as Interconnection Customer: (i) continues to make all payments not in dispute; and (ii) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then

Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 16. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due together with accrued interest in accordance with Section 3.7 of this Attachment V.

## 15.0 Representations, Warranties, and Covenants

**15.1 General**. Each Party makes the following representations, warranties and covenants:

**15.1.1 Good Standing**. Such Party is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this Agreement and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this Agreement.

**15.1.2 Authority**. Such Party has the right, power and authority to enter into this Agreement, to become a party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

**15.1.3 No Conflict**. The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

**15.1.4 Consent and Approval**. Such Party has sought or obtained, or, in accordance with this Agreement will seek or obtain, each consent, approval, authorization, order, or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this Agreement, and it will provide to any Governmental Authority notice of any actions under this Agreement that are required by Applicable Laws and Regulations.

## 16.0 Breach, Cure and Default

**16.1 General.** A breach of this Agreement ("Breach") shall occur upon the failure by a Party to perform or observe any material term or condition of this Agreement. A default of this Agreement ("Default") shall occur upon the failure of a Party in Breach of this Agreement to cure such Breach in accordance with the provisions of Section 17.4.

**16.2 Events of Breach.** A Breach of this Agreement shall include:

(a) The failure to pay any amount when due;

(b) The failure to comply with any material term or condition of this Agreement, including but not limited to any material Breach of a representation, warranty or covenant made in this Agreement;

(c) If a Party: (1) becomes insolvent; (2) files a voluntary petition in bankruptcy under any provision of any federal or state bankruptcy law or shall consent to the filing of any bankruptcy or reorganization petition against it under any similar law; (3) makes a general assignment for the benefit of its creditors; or (4) consents to the appointment of a receiver, trustee or liquidator;

(d) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;

(e) Failure of any Party to provide information or data to the other Party as required under this Agreement, provided the Party entitled to the information or data under this Agreement requires such information or data to satisfy its obligations under this Agreement.

**16.3 Cure and Default.** Upon the occurrence of an event of Breach, the Party not in Breach (hereinafter the "Non-Breaching Party"), when it becomes aware of the Breach, shall give written notice of the Breach to the Breaching Party (the "Breaching Party") and to any other person a Party to this Agreement identifies in writing to the other Party in advance. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach. Upon receiving written notice of the Breach hereunder, the Breaching Party shall have thirty (30) days to cure such Breach. If the Breach is such that it cannot be cured within thirty (30) days, the Breaching Party will commence in good faith all steps as are reasonable and appropriate to cure the Breach within such thirty (30) day time period and thereafter diligently pursue such action to completion. In the event the Breaching Party fails to cure the Breach, or to commence reasonable and appropriate steps to cure the Breach, within thirty (30) days of becoming aware of the Breach, the Breaching Party will be in Default of the Agreement.

**16.4 Right to Compel Performance.** Notwithstanding the foregoing, upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (1) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof, and (2) exercise such other rights and remedies as it may have in equity or at law.

**17.0 Miscellaneous**

**17.1 Binding Effect**. This Agreement and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

**17.2 Conflicts**. In the event of a conflict between the body of this Agreement and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this Agreement shall prevail and be deemed the final intent of the Parties.

**17.3 Rules of Interpretation**. This Agreement, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this Agreement), document, instrument or tariff means such agreement, document, instrument, or tariff as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended, modified, codified, or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder.

**17.4 Entire Agreement**. This Agreement, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

**17.5 No Third Party Beneficiaries.** This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

**17.6 Waiver**. The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or Default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

**17.7 Headings**. The descriptive headings of the various Articles of this Agreement have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this Agreement.

**17.8 Multiple Counterparts.** This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

**17.9 Amendment.** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by the Parties.

**17.10 Modification by the Parties**. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

**17.11 No Partnership**. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

**IN WITNESS WHEREOF,** the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

**[Insert name of Transmission Provider]**

By: _____

Title: _____

Date: _____

**[Insert name of Interconnection Customer]**

By: _____

Title: _____

Date: _____

**Attachment A To Appendix 16**
**Surplus Interconnection Service Facilities**
**Study Agreement**

## INTERCONNECTION CUSTOMER SCHEDULE ELECTION FOR CONDUCTING THE SURPLUS INTERCONNECTION SERVICE FACILITIES STUDY

Transmission Provider shall use Reasonable Efforts to complete the study and issue a draft Surplus Interconnection Service Facilities Study report to Interconnection Customer within the following number of days after receipt of an executed copy of this Surplus Interconnection Service Facilities Study Agreement:

- ninety (90) Calendar Days with no more than a +/- 20 percent cost estimate contained in the report.

**Attachment B to Appendix 16**
**Surplus Interconnection Service Facilities**
**Study Agreement**

## DATA FORM TO BE PROVIDED BY INTERCONNECTION CUSTOMER WITH THE SURPLUS INTERCONNECTION SERVICE FACILITIES STUDY AGREEMENT

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections:

On the one line diagram indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)

On the one line diagram indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

Will an alternate source of auxiliary power be available during CT/PT maintenance?

_____ Yes _____ No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? _____Yes _____ No (Please indicate on one line diagram).

What type of control system or PLC will be located at Interconnection Customer's Generating Facility?

_____

What protocol does the control system or PLC use?

_____

Please provide a 7.5-minute quadrangle of the site. Sketch the plant, station, transmission line, and property line.

Physical dimensions of the proposed interconnection station:

_____

Bus length from generation to interconnection station:

_____

Line length from interconnection station to Transmission Provider's transmission line.

_____

Tower number observed in the field. (Painted on tower leg)* _____

Number of third party easements required for transmission lines*:

_____

* To be completed in coordination with Transmission Provider.

Is the Generating Facility in the Transmission Provider's service area?

_____ Yes _____ No Local provider: _____

Please provide proposed schedule dates:

| | |
|---|---|
| Begin Construction | Date:_____ |
| Generator step-up transformer receives back feed power | Date: _____ |
| Generation Testing | Date: _____ |
| Commercial Operation | Date: _____ |

# ATTACHMENT W
# INDEX OF GRANDFATHERED AGREEMENTS

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 6 | City of Skiatook | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 7 | 345/KV Transmission Agreement | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 8 | 345/KV Transmission Agreement | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 10 | WFEC/BANK | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 15 | CSWS/GRDA Network Load/Pryor Others | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 16 | AECI/GRDA Interconnect Agreement | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 17 | AECI/GRDA Interconnect Agreement | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 18 | Agreement between Western Farmers Electric Cooperative and the Anadarko Public Works Authority, Anadarko, Oklahoma | Western Farmers Electric Cooperative | Anadarko, Oklahoma Public Works Authority | | All requirements wholesale power supply agreement | Agreement shall remain in effect until cancelled by either party giving written notice to the other delivered at least two years prior to July 31, 2007, or thereafter upon one years' written notice on any annual anniversary of agreement. |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 23 | Wholesale Power Contract with Member Cooperatives | Western Farmers Electric Cooperative | Western Farmers Electric Cooperative and its Member Co-ops | | All requirements wholesale power supply agreement | Agreement shall continue in effect until July 1, 2065, and thereafter until terminated by either party's giving to the other not less than six months' written notice of its desire to terminate. |
| 29 | Contract for Electric Service between Public Service Company of Oklahoma and South Coffeyville Public Works Authority | Public Service Company of Oklahoma | City of S. Coffeyville, Oklahoma | | Full RQ | year-to-year |
| 39 | Amended Agreement for Interchange of Electric Power and Energy between Grand River Dam Authority and Public Service Company of Oklahoma | Public Service Company of Oklahoma | Grand River Dam Authority | | Firm TS | until canceled |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 57 | AMENDED INTERCHANGE AGREEMENT BY AND AMONG ASSOCIATED ELECTRIC COOPERATIVE, INC., THE EMPIRE DISTRICT ELECTRIC COMPANY, GRAND RIVER DAM AUTHORITY, SOUTHWESTERN ELECTRIC POWER COMPANY, AND BOARD OF PUBLIC UTILITIES OF SPRINGFIELD, MISSOURI FOR THE GRDA COAL PLANT - FLINT CREEK POWER PLANT – BROOKLINE – MORGAN 345 KILOVOLT INTERCONNECTION | | | | Point To Point | On-going |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 58 | UNITED STATES DEPARTMENT OF ENERGY SOUTHWESTERN POWER ADMINISTRATION POWER SALES CONTRACT between UNITED STATES OF AMERICA and BOARD OF PUBLIC UTILITIES OF THE CITY OF SPRINGFIELD, MISSOURI | City Utilities of Springfield, MO | Southwestern Power Administration | | Point To Point | (Will be extended) On-going |
| 62 | Transmission Service Contract | Ponca City Utility Authority | Oklahoma Municipal Power Authority | | Ponca City Utility Authority agrees to receive power energy not to exceed the Interconnection Capacity. | May be terminated by either party after December 31, 2014, on any December 31st with a 5 year prior written notice to the other party. |
| 63 | SPA Transmission Service Contract | Southwestern Power Administration | Oklahoma Municipal Power Authority | | | Either party can terminate the contract provided they give 60 days notice to the other party. |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 93 | Federal | Southwestern Power Administration | Augusta, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 94 | Federal | Southwestern Power Administration | Arkansas Electric Co-op | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 95 | Federal | Southwestern Power Administration | Arkansas Electric Co-op | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 96 | Federal | Southwestern Power Administration | Arkansas Electric Co-op | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 97 | Federal | Arkansas Electric Co-op | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 98 | Federal | Arkansas Electric Co-op | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 99 | Federal | Southwestern Power Administration | Arkansas Electric Co-op | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 102 | Federal | Southwestern Power Administration | Associated Electric | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 103 | Federal | Associated Electric | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 104 | Federal | Southwestern Power Administration | Associated Electric | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 105 | Federal | Associated Electric | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 108 | SPA Pre-OATT Service | Southwestern Power Administration | Associated Electric | | Pre-Order 888 Service With Redirect Rights Firm in nature | Through 03/31/2026. To be converted to Interconnection Facilities Service pursuant to Attachment AD thereafter. |
| 109 | Federal | Southwestern Power Administration | Public Service Company of Oklahoma | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 110 | Federal | Southwestern Power Administration | Anthony, KS | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 111 | Federal | Southwestern Power Administration | Beauregard | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 112 | Federal | Southwestern Power Administration | Bentonville, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 113 | Federal | Southwestern Power Administration | Brazos | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 115 | Federal | Southwestern Power Administration | Carthage, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 117 | Federal | Carthage, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 118 | SPA Pre-OATT Service | Southwestern Power Administration | Sikeston, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | Through 6/30/2025. To be converted to Interconnection Facilities Service pursuant to Attachment AD thereafter. |
| 119 | Federal | Southwestern Power Administration | Fulton, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 120 | Federal | Southwestern Power Administration | Claiborne | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 121 | Federal | Southwestern Power Administration | Clarksville, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 123 | Federal | Southwestern Power Administration | Coffeyville, KS | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 124 | Federal | Southwestern Power Administration | Comanche, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 125 | Federal | Southwestern Power Administration | Concordia | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 126 | Federal | Southwestern Power Administration | Copan, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 127 | Federal | Southwestern Power Administration | Dixie Electric | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 128 | Federal | Southwestern Power Administration | DOD - McAlester | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 129 | Federal | Southwestern Power Administration | Duncan, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 130 | Federal | Southwestern Power Administration | Eldorado, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 131 | Federal | Empire District Electric Company | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 132 | Federal | Southwestern Power Administration | Empire District Electric Company | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 133 | Federal | ES | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 134 | SPA Pre-OATT Service | Southwestern Power Administration | ES | | Pre-Order 888 Service With Redirect Rights Firm in nature | Through 6/30/2023. To be converted to Interconnection Facilities Service pursuant to Attachment AD thereafter. |
| 135 | Federal | Southwestern Power Administration | Fort Sill, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 136 | Federal | Southwestern Power Administration | Goltry, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 137 | Federal | Southwestern Power Administration | Granite, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 138 | Federal | Grand River Dam Authority | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 139 | Federal | Southwestern Power Administration | Grand River Dam Authority | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 140 | Federal | Grand River Dam Authority | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 141 | Federal | Southwestern Power Administration | Grand River Dam Authority | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 142 | SPA Pre-OATT Service | Southwestern Power Administration | Grand River Dam Authority | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 143 | SPA Pre-OATT Service | Southwestern Power Administration | Associated Electric | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 144 | SPA Pre-OATT Service | Southwestern Power Administration | Associated Electric | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 145 | Federal | Southwestern Power Administration | Hermann, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 146 | Federal | Southwestern Power Administration | Higginsville, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 147 | Federal | Southwestern Power Administration | Hominy, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 149 | Federal | Southwestern Power Administration | Jefferson Davis | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 150 | Federal | Southwestern Power Administration | Jonesboro, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 151 | Federal | Southwestern Power Administration | Jonesboro, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 152 | Federal | Jonesboro, AR | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 153 | Federal | Southwestern Power Administration | Kansas City, KS | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 154 | Federal | Southwestern Power Administration | Kaw Valley | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 155 | Federal | Southwestern Power Administration | Kennett, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 156 | Federal | Southwestern Power Administration | Kennett, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 157 | Federal | Kennett, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 158 | Federal | Southwestern Power Administration | Kennett, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 160 | Federal | Southwestern Power Administration | KEPCO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 161 | Federal | Southwestern Power Administration | KMEA | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 162 | Federal | Southwestern Power Administration | Lafayette, LA | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 163 | Federal | Southwestern Power Administration | Lamar, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 164 | Federal | Southwestern Power Administration | Louisiana Energy and Power Authority | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 165 | Federal | Southwestern Power Administration | Lexington, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 166 | Federal | Southwestern Power Administration | Malden, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 167 | Federal | Southwestern Power Administration | Malden, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 168 | Federal | Malden, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 169 | Federal | Southwestern Power Administration | Malden, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 170 | Federal | Malden, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 172 | Federal | Southwestern Power Administration | Manitou, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 173 | Federal | Southwestern Power Administration | Minden, LA | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 174 | Federal | Southwestern Power Administration | Natchitoches, LA | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 175 | Federal | Southwestern Power Administration | Nemaha-Marshall | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 176 | Federal | Southwestern Power Administration | New Madrid, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 178 | Federal | Southwestern Power Administration | Nixa, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 180 | Federal | Southwestern Power Administration | Northeast Louisiana | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 181 | Federal | Southwestern Power Administration | Northeast Texas Electric Cooperative | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 182 | Federal | Southwestern Power Administration | Northeast Texas Electric Cooperative | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 183 | Federal | Southwestern Power Administration | Northeast Texas Electric Cooperative | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 184 | Federal | Northeast Texas Electric Cooperative | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 187 | Federal | Southwestern Power Administration | Olustee, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 188 | Federal | Southwestern Power Administration | Paragould, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 190 | Federal | Southwestern Power Administration | Paragould, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 191 | Federal | Paragould, AR | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 192 | Federal | Southwestern Power Administration | Paris, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 195 | Federal | Southwestern Power Administration | Piggott, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 197 | Federal | Southwestern Power Administration | Piggott, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 198 | Federal | Piggott, AR | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 199 | Federal | Southwestern Power Administration | Piggott, AR | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 200 | Federal | Piggott, AR | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 201 | Federal | Southwestern Power Administration | Pointe Coupee | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 202 | Federal | Southwestern Power Administration | Poplar Bluff, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 203 | Federal | Southwestern Power Administration | Poplar Bluff, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 204 | Federal | Poplar Bluff, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 206 | Federal | Southwestern Power Administration | Purcell, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 207 | Federal | Southwestern Power Administration | Rayburn Country | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 208 | Federal | Southwestern Power Administration | Ryan, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 209 | Federal | Southwestern Power Administration | Sam Rayburn Dam EC | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 210 | Federal | Southwestern Power Administration | Sam Rayburn MPA | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 211 | Federal | Southwestern Power Administration | Sikeston, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 212 | Federal | Southwestern Power Administration | Sikeston, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 213 | Federal | Sikeston, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 214 | SPA Pre-OATT Service | Southwestern Power Administration | Sikeston, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | Through 6/30/2025. To be converted to Interconnection Facilities Service pursuant to Attachment AD thereafter. |
| 215 | Federal | Southwestern Power Administration | Skiatook, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 216 | Federal | Southwestern Power Administration | South Louisiana | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 217 | Federal | Southwestern Power Administration | Southwest Louisiana | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 218 | Federal | Southwestern Power Administration | Spiro, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 219 | Federal | Southwestern Power Administration | Springfield, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 220 | Federal | Southwestern Power Administration | Springfield, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 221 | Federal | Springfield, MO | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 223 | Federal | Southwestern Power Administration | East Texas Electric Cooperative, Inc. | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 224 | Federal | Southwestern Power Administration | Thayer, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 225 | Federal | Southwestern Power Administration | Valley | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 226 | Federal | Southwestern Power Administration | Vance Air Force Base, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 227 | Federal | Southwestern Power Administration | Walters, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 228 | Federal | Southwestern Power Administration | WAPA | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 229 | Federal | WAPA | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 230 | Federal | Southwestern Power Administration | Washington-St Tammany | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 231 | Federal | Southwestern Power Administration | West Plains, MO | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 232 | Federal | Southwestern Power Administration | Wetumka, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 233 | Federal | Southwestern Power Administration | Western Farmers Electric Cooperative | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 234 | Federal | Western Farmers Electric Company | Southwestern Power Administration | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 235 | Federal | Southwestern Power Administration | Western Farmers Electric Cooperative | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 238 | Federal | Southwestern Power Administration | Western Farmers Electric Cooperative | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 239 | Federal | Southwestern Power Administration | Yale, OK | | Pre-Order 888 Service With Redirect Rights Firm in nature | None |
| 270 | Electric Interconnection Agreement | Evergy Kansas Central, Inc. | City of McPherson, Kansas | FERC rate schedule 127 dockets E-7893, ER78-196, ER78-626, ER80-527, ER83-616, ER92-379 | Long-term firm service agreement | 5/31/2039 & then year to year, (5) years prior written notice. |
| 306 | Border Customer Agreement | Evergy Kansas Central, Inc. | BPU-Kansas City, KS | | Service to border customers | |
| 307 | Electrical Interconnection Agreement | Evergy Kansas Central, Inc. | BPU-Kansas City, KS | FERC rate schedule EKC-272 dockets ER94-125 | Interconnection | 4/26/06 and then year to year 10 yr prior notice |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 317 | Electric Interconnection and Interchange Agreement | Evergy Kansas Central, Inc. | Nebraska Public Power District | Rate schedule FERC No. 343 | Interconnection | 12/24/2020<br>12 mo prior notice |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 326 | Jeffrey Energy Center Transmission Agreement | Evergy Kansas Central, Inc. | Evergy Missouri West, Inc. | 256 dockets ER89-485, ER90-235, ER90-300, ER90-478, ER90-500, ER92-29, ER92-239, ER96-1728, ER96-1728 | Interconnection | This agreement supports the Joint Ownership of the Jeffrey Energy Center Terminates upon the retirement of the last generating unit in which Evergy Missouri West, Inc. has an ownership share at the Jeffrey Energy Center or upon the transfer of any or all of Evergy Missouri West, Inc.'s interest in the Jeffrey Energy Center pursuant to the ownership agreement, whichever comes first. Up to 8% of the output of the Jeffrey Energy Center plus reassigned amounts. Current year amount is 338 MW. |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 329 | Electric Interchange Agreement | Evergy Kansas Central, Inc. | Evergy Missouri West, Inc. | FERC rate schedule EMW-18, EKC. -84 | Interchange | 05/31/2023<br>Year to Year<br>36 mos prior notice |
| 343 | Interchange Agreement (UE) | Evergy Metro, Inc. | AMRN | 104 - ER94-1101-002 | Point To Point | year to year, 36 mo notice |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 391 | Municipal Participation Agreement | Evergy Metro, Inc. | Board of Public Utilities - Kansas City Kansas | 54 - ER94-1101-002 | Point To Point | year to year, 42 mo notice |
| 398 | Facilities Use Agreement | Responsibility of Evergy Missouri West, Inc./Evergy Metro, Inc. | | 107 - ER91-41-000 | | |
| 399 | Cooper-Fairport-St. Joseph Interconnection (MINT) | Evergy Metro, Inc. | | 107 - ER91-41-000 | | year to year, 48 mo notice |

| Line No | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Type | Other |
|---|---|---|---|---|---|---|---|---|---|
| 445 | Cooper-Fairport: St. Joseph Interconnection (MINT) | | | 107-ER91-41-000 | | Year to year, 48 mo notice | | | |

| Line No | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Type | Other |
|---|---|---|---|---|---|---|---|---|---|
| 457 | Interconnection Agreement | Sunflower Electric Power Corporation | Midwest Energy, INC | | Network | 3 years prior written notice | | | |
| 463 | Interconnection Agreement | Sunflower Electric Power Corporation | Western Area Power Administration | | | September 30, 2024 | October 221<br>November 207<br>December 236<br>January 228<br>February 236<br>March 264<br>April 255<br>May 232<br>June 180<br>July 285<br>August 247<br>September 240 | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | OASIS Reference |
|---|---|---|---|---|---|---|---|---|
| 466 | MINT Coordinating Agreement, Cooper - Fairport-St. Joseph Interconnection (MINT) Dated March 5, 1990 and associated agreements | MINT Participants-Responsibility of EMW/EMC | MINT Participants | N/A | Point to Point Service Rights | Initial term 50 years, extended thereafter on year to year basis, 4 years notice to withdraw | See Transmission Capacity Rights in contract | |
| 468 | MINT Transmission Exchange Agreement dated February 15, 1990 | LES & NPPD | LES & NPPD | N/A | Exchange of a portion of LES firm capacity rights on MINT Line to NPPD for Point to Point rights on NPPD transmission System | Agreement shall remain in force as long as LES is a participant in the MINT Project (See MINT). No notice provisions | See Transmission Capacity Rights Exchange in Article II &III | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | OASIS Reference |
|---|---|---|---|---|---|---|---|---|
| 471 | Electric Interconnection and Interchange Agreement dated June 20, 1988 as amended | LES and OPPD | LES and OPPD | N/A | Interconnection and Interchange of Power and Energy Between Systems | Agreement extends to January 1 2040 and thereafter year to year with 5 years written notice | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | OASIS Reference |
|---|---|---|---|---|---|---|---|---|
| 472 | Gerald Gentlemen Station Power Sales Contract | LES | NPPD | N/A | Tranformation Capacity in the LES 345kv West Substation up to 50mw | Agreement expires when Gerald Gentleman removed from commercial operation | Up to 50 mw | |
| 473 | Interconnection Agreement dated May 1, 1977 as amended | LES and NPPD | LES and NPPD | N/A | Interconnection and Interchange of Power and Energy Between Systems pursuant to various Service Schedules to the Agreement | Agreement extends 30 years or until all Service Schedules have terminated whichever is last to occur. Thereafter continues with notice requirement of 4 years. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | OASIS Reference |
|---|---|---|---|---|---|---|---|---|
| 476 | Transmission Service Contract [99-L22-23] | Nebraska Public Power District | LES | N/A | Point to Point Drive In Service for MBPP Laramie River Station to load | 12/31/2040 | 190mw | |
| 477 | Gerald Gentleman Station Participation Power Sales Agreement [96-L22-44] | Nebraska Public Power District | LES | N/A | Point to Point Service Contract Rights, BTS Capacity Rights Exchange | Life of Plant | 109 mw | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 479 | Electric Interconnection and Interchange Agreement [95-L22-60] | Nebraska Public Power District | MidAmerican Energy Company (IPS) | | Transmission Interconnection | 1/1/2010 and annual thereafter (4 yr Notice) | | |
| 480 | Transmission Operating Agmt. [06-L22-15] | Nebraska Public Power District | MidAmerican Energy Company (IPS) | | Point to Point Service and Contract Rights | 6/30/2009 or MEC participation in CNS or MINT Line (4 Yr Notice) | 250 | Oasis Reservation # 842306 |
| 482 | Electric Interconnection and Interchange Agreement [96-L22-53] | Nebraska Public Power District | Omaha Public Power District | | Point to Point Service, Transmission Interconnection and Service Per Parties Rate Schedules | 1/1/2005 or contingent on OPPD participation in MINT line | 10 | Oasis Reservation # 1282819 |
| 483 | Wind Facility Share Participation Agreement [04-L22-30] | Nebraska Public Power District | Omaha Public Power District | | Point to Point Service OPPD responsible for Transmission at Wind Sub delivery point | 10/27/2024 Subject to renewals | 8<br>2 | Oasis Reservation # 1217482 1217220 |
| 484 | Interconnection Agreement [96-L22-50], Service Schedule 4 | Nebraska Public Power District | City of Lincoln, Ne (LES) | | Point to Point Service, Generator Outlet & Contract Delivery (WAPA Peaking) | 5/1/2007 or decommission of NPPD's Cooper Nuclear Station | 97<br>75 | Oasis Reservation # 178307 178299 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 485 | Interconnection Agreement [96-L22-50] Service Schedule 9 | Nebraska Public Power District | City of Lincoln, Ne (LES) | | Point to Point Service Contract Delivery, (WAPA Firm) | Through term of WAPA contracts | 59 | Oasis Reservation # 178297 |
| 486 | Interconnection Agreement [96-L22-50] Service Schedule 10 | Nebraska Public Power District | City of Lincoln, Ne (LES) | | Contract Rights Exchange for Service (MINT) | Through Term of MINT contract | | |
| 487 | MINT Rights Exchange Agreement [99-L22-13] | Nebraska Public Power District | City of Lincoln, Ne (LES) | | Contract Rights Exchange for Service | Through Term of MINT contract | | |
| 488 | Interconnection Agreement [96-L22-50] Service Schedule 12 | Nebraska Public Power District | City of Lincoln, Ne (LES) | | Pre-OATT Point to Point service. Gentleman Station delivery | Agreement terminates with end of Gentleman Station Power Sales Agreement | | |
| 489 | Gerald Gentleman Station Participation Power Sales Agreement [96-L22-44] | Nebraska Public Power District | City of Lincoln, Ne (LES) | | Point to Point Service Contract Rights, BTS Capacity Rights Exchange | Life of Plant | 109 | Oasis Reservation # 178301 |
| 490 | Bulk Transmission System Loss Factor Letter Agreement [99-L22-21] | Nebraska Public Power District | City of Lincoln, Ne (LES) / Basin Electric Power Cooperative | | BTS Loss Compensation Calculation Procedure | In conjunction with Base Contracts | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 491 | Amended and Restated Coordinating Agreement for the Cooper-Fairport-St.Joseph 345 kV Line (MINT) [98-L21-18] | Nebraska Public Power District | Associated Electric Cooperative, Inc./ Kansas City Power & Light/ St. Joseph Light & Power Company/ MidAmerican Energy Company/ Omaha Public Power District/ City of Lincoln, NE | | Point to Point Service Interconnection Capacity and Transmission Service | 3/4/2040 | See capacity rights identified in the contract | Oasis Reservation # 178323 178322 178321 178317 |
| 492 | Transmission Line Terminal Facilities Agreement [99-L22-12] | Nebraska Public Power District | Omaha Public Power District/ City of Lincoln, NE (LES)/ MidAmerican Energy Company | | Use of Cooper MINT Terminal Facilities for deliveries at contract rate | 3/4/2040 | | |
| 493 | Electric Interconnect & Interchange Agreement. [96-L22-110] | Nebraska Public Power District | SEC Corporation (Sunflower Electric) | | Interconnection | 5/1/2006 evergreen thereafter (4 Yr Notice) | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 495 | Agreement for Common Use of Switching Station and Transmission Facilities - Big Springs Tap [95-L21-612] | Nebraska Public Power District | Tri-State Generation and Transmission Association, Inc. | | Transmission Capacity Allocation | November 30, 2007 Evergreen thereafter (1 yr. notice) | | |
| 496 | Transmission Service Contract [99-L22-23] | Nebraska Public Power District | Basin Electric Power Cooperative | | Point to Point Service Bulk Transmission Service - Contract Rate | 12/31/2040 | 272<br>190 | Oasis Reservation # 520962<br>178300 |
| 497 | Agreement for Construction and Joint Use of Substation and Transmission Facilities [94-L21-502] | Nebraska Public Power District | Basin Electric /Rushmore Cooperative /Cherry-Todd Cooperative / LaCreek Electric Association | | Network Transmission and SubT service for joint use facilities (Cody - Niobrara) | 6/18/2015 or as long as facilities in use. | | |
| 498 | Agreement for Joint Use of Substation and Transmission Facilities [94-L21-383] | Nebraska Public Power District | Wheat Belt Public Power District | | Joint Use of 115/34.5 Substation at Blue Creek | Year to Year, one year notice | | |
| 499 | Stegall DC Tie Loss Compensation Agreement [99-L22-24] | Nebraska Public Power District | Basin Electric Power Cooperative | | Loss procedure of DC Tie interconnection | 9/16/2011 subject to renewal | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 500 | Loveland Area Projects for Firm Electric Service [96-L22-103] | Nebraska Public Power District | U.S. Department of Energy - Western Area Power Administration (Rocky Mountain Region) | | NPPD Firm Electric Service from the Loveland Area Projects | 9/30/2024 | | |
| 502 | Electric Power Service 93-BAO-667 [96-L22-60] | Nebraska Public Power District | U.S. Department of Energy - Western Area Power Administration (Upper Great Plains Region) | | Point to Point Service Transmission Interconnection and Service | 12/31/2020 | 64<br>492 | Oasis Reservation # 1282494<br>1282491 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 506 | Contract For Bill Crediting Program Arrangements [00-L22-305] | Nebraska Public Power District | U.S. Department of Energy - Western Area Power Administration (Upper Great Plains Region) / Santee Sioux Tribe of Nebraska / Nebraska Electric G & T Cooperative, Inc. / North Central Public Power District | | Provides Firm Electric Power Benefit to Santee Sioux Tribe utilizing existing delivery systems | Successive Annual Periods through 12/31/2020 (termination 90 days notice, anytime) | | |
| 507 | Contract For Bill Crediting Program Arrangements [01-L22-20] | Nebraska Public Power District | U.S. Department of Energy - Western Area Power Administration (Upper Great Plains Region) / Oglala Sioux Tribe of Nebraska | | Provides Firm Electric Power Benefit to Oglala Sioux Tribe utilizing existing delivery systems | Successive Annual Periods through 12/31/2020 (termination 90 days notice, anytime) | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 509 | Contract For Bill Crediting Program Arrangements [01-L22-22] | Nebraska Public Power District | U.S. Department of Energy - Western Area Power Administration (Upper Great Plains Region) / Winnebago Tribe of Nebraska | | Provides Firm Electric Power Benefit to Winnebago Tribe utilizing existing delivery systems | Successive Annual Periods through 12/31/2020 (termination 90 days notice, anytime) | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 512 | Network Transmission Service Agrmt [06-L22-2] | Nebraska Public Power District | Municipal Energy Agency of Nebraska (MEAN) | | Network Firm Transmission Service | 1/1/2031 | | |
| 513 | Lincoln Delivery Agreement [03-L22-9] | Nebraska Public Power District | Municipal Energy Agency of Nebraska (MEAN) | | Bulk Transmission Service for share of Laramie River (sale from LES) | 2/28/2026 | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 517 | Electric Interconnection and Interchange Agreement [94-L22-10] | Nebraska Public Power District | City of Grand Island, Nebraska | | Point to Point Service Transmission Interconnection Service | 1/1/2005, yearly thereafter (4 Yr Notice) | 9 | Oasis Reservation # 662099 |
| 520 | Wind Facility Share Participation Agreement [04-L22-45] | Nebraska Public Power District | City of Grand Island, Nebraska | | Point to Point Service G.I. responsible for Transmission at Wind Sub delivery point | 11/22/2024 renewals possible | 1 | Oasis Reservation # 990218 |
| 521 | Interconnection and Interchange Agreement [94-L22-11] | Nebraska Public Power District | City of Hastings, Nebraska | | Point to Point Service Transmission Interconnection Service | 3/31/2009, yearly thereafter (6 Mo. Notice) | 13 | Oasis Reservation # 224052 |
| 523 | Whelan Energy Center 2 Transmission Facilities Agreement [07-L22-130] | Nebraska Public Power District | Public Power Generating Agency / City of Hastings, NE | | Transmission Credit for facility costs | Until all obligations fulfilled, including crediting obligations | | |
| 524 | Mission - St. Francis - Valentine 115 KV Transmission Line Agreement [04-L21-14] | Nebraska Public Power District | Cherry-Todd Electric Cooperative / Nebraska Electric Generation and Transmission Cooperative, Inc. | | Transmission Service | 8/23/2012, and thereafter as long as line in service | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 525 | Interconnection Agreement [03-L20-106] | Nebraska Public Power District | Cherry-Todd Electric Cooperative / Nebraska Electric Generation and Transmission Cooperative, Inc. | | Transmission Interconnection and Service | Continues until terminated, (12 Mo. Notice). | | |
| 527 | Facilities Modifications and Construction Agreement for Cooper South Flowgate Upgrades [06-L22-22] | Nebraska Public Power District | Aquila, Inc./ MidAmerican Energy Company/ Omaha Public Power District | | Transmission Capacity Rights established. | Through completion of project and all final payments made | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 529 | Kingsley Project Power Sales Agreement [95-L21-121 and 122] | Nebraska Public Power District | Central Nebraska Public Power and Irrigation District | | NPPD purchase of Hydro output / Transmission Capacity Rights | Bonds Paid or Retirement of Plant, the later | | |
| 531 | Reservation 79207350 for NPPD's transmission rights under the MINT Line Agreement previously represented under reservation 809481 as Cooper Nuclear Station Unit Participation Agreement [03-L21-75] | Nebraska Public Power District | Nebraska Public Power District | | Point to Point Service to AQN from CNS / Transmission Service | 5/01/2040 | 57 | Oasis Reservation # 79207350 |
| 533 | Generator Interconnection Agreement [08-L22-98] | Nebraska Public Power District | Elkhorn Ridge Wind, LLC | | Generator Interconnection Service on NPPD Transmission System | 12 Month termination notice or contract terms | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 534 | Wholesale Power Contract | Nebraska Public Power District | Sutton 94-L22-71 | | Full Requirements Wholesale Power contract | Through 4-10-15; year to year thereafter; 5 yrs notice. | | |
| 536 | Wholesale Power Contract | Nebraska Public Power District | Hemingford 94-L22-48 | | Full Requirements Wholesale Power contract | Through 10-31-18; year to year thereafter; 5 yrs notice. | | |
| 538 | Wholesale Power Contract | Nebraska Public Power District | Arapahoe 94-L22-26 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 539 | Wholesale Power Contract | Nebraska Public Power District | Auburn 01-L22-11 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 540 | Wholesale Power Contract | Nebraska Public Power District | Battle Creek 94-L22-27 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 541 | Wholesale Power Contract | Nebraska Public Power District | Beatrice 94-L22-29 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 542 | Wholesale Power Contract | Nebraska Public Power District | Bradshaw 94-L22-30 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 543 | Wholesale Power Contract | Nebraska Public Power District | Brainard 94-L22-31 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 544 | Wholesale Power Contract | Nebraska Public Power District | Central City 94-L22-32 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 545 | Wholesale Power Contract | Nebraska Public Power District | Chester 94-L22-34 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 546 | Wholesale Power Contract | Nebraska Public Power District | Cozad 94-L22-35 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 547 | Wholesale Power Contract | Nebraska Public Power District | Davenport 94-L22-36 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 548 | Wholesale Power Contract | Nebraska Public Power District | David City 94-L22-37 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 549 | Wholesale Power Contract | Nebraska Public Power District | Deshler 01-L22-9 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 550 | Wholesale Power Contract | Nebraska Public Power District | DeWitt 94-L22-38 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 551 | Wholesale Power Contract | Nebraska Public Power District | Dorchester 94-L22-39 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 553 | Wholesale Power Contract | Nebraska Public Power District | Fairmont 94-L22-41 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 554 | Wholesale Power Contract | Nebraska Public Power District | Friend 94-L22-42 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 555 | Wholesale Power Contract | Nebraska Public Power District | Giltner 94-L22-44 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 556 | Wholesale Power Contract | Nebraska Public Power District | Gothenburg 94-L22-45 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 557 | Wholesale Power Contract | Nebraska Public Power District | Hampton 94-L22-46 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 559 | Wholesale Power Contract | Nebraska Public Power District | Hildreth 94-L22-49 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 560 | Wholesale Power Contract | Nebraska Public Power District | Holdrege 94-L22-50 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 561 | Wholesale Power Contract | Nebraska Public Power District | Lexington 94-L22-51 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 562 | Wholesale Power Contract | Nebraska Public Power District | Lodgepole 94-L22-52 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 563 | Wholesale Power Contract | Nebraska Public Power District | Lyons 94-L22-54 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 564 | Wholesale Power Contract | Nebraska Public Power District | Madison 94-L22-55 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 565 | Wholesale Power Contract | Nebraska Public Power District | Minden 94-L22-56 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 566 | Wholesale Power Contract | Nebraska Public Power District | Nelson 94-L22-58 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 567 | Wholesale Power Contract | Nebraska Public Power District | North Platte 94-L22-60 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 568 | Wholesale Power Contract | Nebraska Public Power District | Ord 94-L22-61 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 569 | Wholesale Power Contract | Nebraska Public Power District | Polk 94-L22-62 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 570 | Wholesale Power Contract | Nebraska Public Power District | Prague 94-L22-63 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 571 | Wholesale Power Contract | Nebraska Public Power District | Randolph 94-L22-64 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 572 | Wholesale Power Contract | Nebraska Public Power District | Scribner 94-L22-65 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 573 | Wholesale Power Contract | Nebraska Public Power District | Seward 94-L22-66 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 574 | Wholesale Power Contract | Nebraska Public Power District | South Sioux City 94-L22-68 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 575 | Wholesale Power Contract | Nebraska Public Power District | Summerfield, KS 94-L22-69 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 576 | Wholesale Power Contract | Nebraska Public Power District | Superior 94-L22-70 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 577 | Wholesale Power Contract | Nebraska Public Power District | Valentine 94-L22-72 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 578 | Wholesale Power Contract | Nebraska Public Power District | Wahoo 01-L22-14 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 579 | Wholesale Power Contract | Nebraska Public Power District | Wakefield 94-L22-73 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 580 | Wholesale Power Contract | Nebraska Public Power District | Walthill 94-L22-74 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 581 | Wholesale Power Contract | Nebraska Public Power District | Wauneta 94-L22-75 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 582 | Wholesale Power Contract | Nebraska Public Power District | Wayne 94-L22-76 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 583 | Wholesale Power Contract | Nebraska Public Power District | Webber, KS 94-L22-77 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 584 | Wholesale Power Contract | Nebraska Public Power District | Wilcox 94-L22-78 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 585 | Wholesale Power Contract | Nebraska Public Power District | Wymore 94-L22-79 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 586 | Wholesale Power Contract | Nebraska Public Power District | Nebraska Electric G&T 96-L22-52 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 587 | Wholesale Power Contract | Nebraska Public Power District | Norris PPD 94-L22-59 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 588 | Wholesale Power Contract | Nebraska Public Power District | Southern PD 01-L22-25 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |
| 589 | Wholesale Power Contract | Nebraska Public Power District | Loup River PPD 05-L22-13 | | Full Requirements Wholesale Power contract | Through 12-31-21; year to year thereafter; 5 yrs notice. | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 601 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | 6/1/2029 | 150 | Oasis Reservation # 1282622 |
| 602 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | 6/1/2029 | 25 | Oasis Reservation # 1282619 |
| 603 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | 5/1/2029 | 30 | Oasis Reservation # 784417 |
| 604 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power Marketing | | Point to Point | 5/1/2029 | 3 | Oasis Reservation # 72190701 |
| 605 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | 1/1/2025 | 4 | Oasis Reservation # 345442 |
| 606 | NPPD Professional Retail Operations Service Agreements and Service Area Agreements | Nebraska Public Power District | Nebraska Public Power District | | Full Requirements Wholesale contract, Firm Network Service, Distribution Services | Various Termination Dates Ranging From 12-31-14 to 7-1-32 With Renewal Rights | | NPPD has PRO-Service Agreements with 81 Nebraska Municipals |

| Line No. | Contract Title | OASIS # | Selling Party | Buying Party | FERC Schedule | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|---|
| 609 | Service Agreement and OASIS Reservation | 1589101 | OPPD | Independence, MO | | Point-to-Point | 5/1/2034 |
| 612 | Service Agreement and OASIS Reservation | 1585194 | OPPD | Lincoln Electric System | | Point-to-Point | 5/1/2036 |
| 613 | Service Agreement and OASIS Reservation | 1585195 | OPPD | Lincoln Electric System | | Point-to-Point | 5/1/2036 |
| 614 | Service Agreement and OASIS Reservation | 1585192 | OPPD | Lincoln Electric System | | Point-to-Point | 3/1/2036 |
| 615 | Nebraska City Unit 2 Transmission Facilities Cost Agreement | | OPPD | NPPD, Independence, MO, Central Minnesota Municipal Power Agency, Falls City, Grand Island, Missouri Joint Muni Electric Utility Commission, Nebraska City | | Planning and facilities cost arrangement | Until payment and crediting obligations are satisfied |
| 616 | Service Agreement and OASIS Reservation | 1588942 | OPPD | Missouri Joint Municipal Electric Utility Commission | | Point-to-Point | 6/1/2029 |
| 617 | Electric Interconnection and Interchange Agreement | 78711378 | OPPD | NPPD | | Interconnection & Point-to-Point Transmission service to Cooper Nuclear Station | Pre-OATT. Effective until cancelled w/ 4-yr notice |

| Line No. | Contract Title | OASIS # | Selling Party | Buying Party | FERC Schedule | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|---|
| 618 | Amended and Restated Coordinating Agreement (MINT) & OASIS | | OPPD | Associated Electric, Kansas City Power & Light, Aquila, NPPD, OPPD, LES, MidAmerican Energy | | Joint ownership & Point-to-Point | Pre-OATT. Effective through 2040. Thereafter cancellable by any party w/ 4-yr notice |
| 619 | OASIS Reservation | 91351621 | OPPD | Auburn Board of Public Works | | Point-to-Point | 1/1/2023 |
| 620 | OASIS Reservation | 1585186 | OPPD | NPPD | | Point-to-Point | 1/1/2023 |
| 621 | OASIS Reservation | 1585627 | OPPD | NPPD | | Point-to-Point | 6/1/2029 |
| 622 | OASIS Reservation | 1585630 | OPPD | NPPD | | Point-to-Point | 6/1/2029 |
| 623 | Service Agreement and OASIS Reservation | 78450303 | OPPD | Grand Island | | Point-to-Point | 5/1/2029 |
| 624 | Service Agreement and OASIS Reservation | 78450466 | OPPD | Grand Island | | Point-to-Point | 5/1/2029 |
| 625 | OASIS Reservation | 1585595 | OPPD | Falls City | | Point-to-Point | 5/1/2036 |
| 626 | OASIS Reservation | 1585604 | OPPD | Nebraska City | | Point-to-Point | 5/1/2036 |

| Line No. | Contract Title | OASIS # | Selling Party | Buying Party | FERC Schedule | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|---|
| 640 | OASIS Reservation | 73224364 | OPPD | OPPD | | Point-to-Point | 4/1/2040 |
| 644 | OASIS Reservation | 1585182 | OPPD | OPPD | | Point-to-Point | 9/1/2025 |
| 645 | OASIS Reservation | 1585607 | OPPD | OPPD | | Point-to-Point | 9/1/2029 |
| 646 | OASIS Reservation | 1585605 | OPPD | OPPD | | Point-to-Point | 9/1/2029 |
| 647 | OASIS Reservation | 1585606 | OPPD | OPPD | | Point-to-Point | 9/1/2029 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | OASIS Reference |
|---|---|---|---|---|---|---|---|---|
| 652 | LES OASIS Reservation Bloomfield Wind Turbines Purchase (LES_ELKHORN_WT) | LES | LES | N/A | Point to Point Firm Service | 1/1/2029 | 6 MW | 72403386 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | OASIS Reference |
|---|---|---|---|---|---|---|---|---|
| 656 | Bulk Transmission System Loss Factor Agreement (NPPD and LES) | LES | LES | N/A | Return of BTS Losses from LES to NPPD according to BTS Loss Compensation Calculation Procedure | Term and Amount varies with LES & NPPD Transmission and Power Supply Contracts termination dates | 15 MW | 1589036 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 657 | Transmission Service Agreement Between Nebraska Public Power District and City of Deshler, Nebraska | Nebraska Public Power District | City of Deshler | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 659 | Transmission Service Agreement Between Nebraska Public Power District and City of Laurel, Nebraska | Nebraska Public Power District | City of Laurel | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 660 | Transmission Service Agreement Between Nebraska Public Power District and City of Madison, Nebraska | Nebraska Public Power District | City of Madison | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 661 | Transmission Service Agreement Between Nebraska Public Power District and City of Mullen, Nebraska | Nebraska Public Power District | City of Mullen | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 663 | Transmission Service Agreement Between Nebraska Public Power District and City of Randolph, Nebraska | Nebraska Public Power District | City of Randolph | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 664 | Transmission Service Agreement Between Nebraska Public Power District and City of Schuyler, Nebraska | Nebraska Public Power District | City of Schuyler | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 666 | Transmission Service Agreement Between Nebraska Public Power District and City of Wahoo, Nebraska | Nebraska Public Power District | City of Wahoo | | Network Service | Co-Term with City's WAPA Allocation Contract | | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 668 | Transmission Service Agreement Between Nebraska Public Power District and City of Wilber, Nebraska | Nebraska Public Power District | City of Wilber | | Network Service | Co-Term with City's WAPA Allocation Contract | | |
| 669 | Generator Interconnection Agreement Between Community Wind Energy Transmission, LLC and Nebraska Public Power District | Nebraska Public Power District | Community Wind Energy Transmission, LLC | | Generator Interconnection | Until Terminated | | |
| 671 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 15 | Oasis Reservation # 1299178 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 672 | Oasis Transaction | Nebraska Public Power District | Municipal Energy Agency of Nebraska (MEAN) | | Point to Point | | 35 | Oasis Reservation # 1587827 |
| 673 | Oasis Transaction | Nebraska Public Power District | Municipal Energy Agency of Nebraska (MEAN) | | Point to Point | | 10 | Oasis Reservation # 1587828 |
| 675 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 81 | Oasis Reservation # 71792232 |
| 676 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 42 | Oasis Reservation # 71792980 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 677 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 71 | Oasis Reservation # 72062051 |
| 678 | Oasis Transaction | Nebraska Public Power District | Lincoln Electric System | | Point to Point | | 6 | Oasis Reservation # 72403321 |
| 679 | Oasis Transaction | Nebraska Public Power District | Omaha Public Power District | | Point to Point | | 25 | Oasis Reservation # 72426676 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 682 | Oasis Transaction | Nebraska Public Power District | GrandIsland | | Point to Point | | 1 | Oasis Reservation # 72441570 |
| 683 | Oasis Transaction | Omaha Public Power District | Nebraska Public Power District | | Point to Point | | 175 | Oasis Reservation # 72589960 |
| 688 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 80 | Oasis Reservation # 72797870 |
| 690 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 65 | Oasis Reservation # 72830114 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 693 | Oasis Transaction | Nebraska Public Power District | Nebraska Public Power District | | Point to Point | | 106 | Oasis Reservation # 72970088 |
| 694 | Oasis Transaction | Nebraska Public Power District | Lincoln Electric System | | Point to Point | | 47 | Oasis Reservation 72979719 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) | Other |
|---|---|---|---|---|---|---|---|---|
| 700 | Oasis Transaction | Nebraska Public Power District | Lincoln Electric System | | Point to Point | | 15 | Oasis Reservation SPP# 1589037 |

| Line No. | Contract Title | OASIS # | Selling Party | Buying Party | FERC Schedule | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|---|
| 704 | OASIS Reservation | 1585179 | OPPD | OPPD | | Yearly Network | 1/1/2037 |
| 705 | OASIS Reservation | 1585180 | OPPD | OPPD | | Yearly Network | 1/1/2037 |
| 706 | OASIS Reservation | 1585225 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2040 |
| 707 | OASIS Reservation | 1585243 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2040 |
| 708 | OASIS Reservation | 1585244 | OPPD | OPPD | | Yearly Network | 1/1/2037 |
| 709 | OASIS Reservation | 1585245 | OPPD | OPPD | | Yearly Network | 1/1/2037 |
| 713 | OASIS Reservation | 1585574 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2040 |
| 714 | OASIS Reservation | 1585576 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2029 |
| 715 | OASIS Reservation | 1585579 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2030 |
| 716 | OASIS Reservation | 1585588 | OPPD | OPPD | | Yearly Network | 1/1/2037 |
| 718 | OASIS Reservation | 1588958 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2040 |
| 719 | OASIS Reservation | 1588959 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2040 |

| Line No. | Contract Title | OASIS # | Selling Party | Buying Party | FERC Schedule | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|---|
| 722 | OASIS Reservation | 1589060 | OPPD | OPPD | | Monthly Point-to-Point | 1/1/2040 |
| 725 | Service Agreement and OASIS Reservation | 1589102 | OPPD | Independence, MO | | Monthly Point-to-Point | 1/1/2040 |
| 727 | Service Agreement and OASIS Reservation | 1589110 | OPPD | Municipal Energy Agency of Nebraska | | Monthly Point-to-Point | 1/1/2031 |
| 728 | OASIS Reservation | 1594743 | OPPD | OPPD | | Monthly Point-to-Point | 4/1/2040 |
| 729 | OASIS Reservation | 1594744 | OPPD | OPPD | | Monthly Point-to-Point | 4/1/2040 |
| 730 | OASIS Reservation | 1594748 | OPPD | OPPD | | Monthly Point-to-Point | 9/1/2040 |
| 732 | OASIS Reservation | 73224372 | OPPD | OPPD/Falls City | | Yearly Point-to-Point | 5/1/2036 |
| 733 | Joint Operating Agreement | 1256070 | SPS/PSCo | PSCo/SPS | FERC Orders in Docket Nos. EC96-2, ER96-2572-000, EC99-101-000, ER04-1174-000 et al., and ER-08-313-000, et al. | Transmission Service implementing the Xcel Energy Operating Companies' Joint Operating Agreement | None |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Sch. | Type of Service | Termination Provisions | Capacity (MW) |
|---|---|---|---|---|---|---|---|
| 735 | Generator Interconnection Agreement (GIA) Entered Into By Lea County Electric Cooperative, Inc. and LCEC Generation, LLC | Lea County Electric Cooperative, Inc. | LCEC Generation, LLC | | Generator Interconnection | Until Terminated | |
| 736 | Generator Interconnection Agreement (GIA) Entered Into By Lea County Electric Cooperative, Inc. and Wild Cat Wind LLC | Lea County Electric Cooperative, Inc. | LCEC Generation, LLC | | Generator Interconnection | Until Terminated | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 737 | City of Coffeyville | Grand River Dam Authority | Grand River Dam Authority | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 738 | WFEC/BANK | Western Farmers Electric Company | Western Farmers Electric Company | | Point To Point | Through 1/1/2035 with rollover provisions thereafter |
| 740 | Interchange Agreement (AmerenUE) | Evergy Metro, Inc. | AMRN | 104, Supp. No. 5 to Sched. G | Point To Point | Year to year, 30 mo. Notice |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 763 | MISO OATT GFA 17: Contract and as amended thereto, IES Rate Schedule 12 ER94-437-000 | ITC Midwest LLC/Corn Belt Power | ITC Midwest LLC/Corn Belt Power | | Transmission Service | Until terminated |
| 764 | MISO OATT GFA 22: Transmission Facilities Operating Agreement George Neal Unit No. 4 Transmission | MidAmerican Energy Company/ITC Midwest/ Interstate Power Company/ Northwestern Public Service Company/ Corn Belt Power Cooperative/ Northwest Iowa Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Falls Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Utilities/ Laurens Municipal Light & Power Plant/ Milford Municipal Utilities/ Spencer Municipal Utilities/ City of Webster City/Grundy Center Municipal Utilities | MidAmerican Energy Company/ITC Midwest/ Interstate Power Company/ Northwestern Public Service Company/ Corn Belt Power Cooperative/ Northwest Iowa Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Falls Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Utilities/ Laurens Municipal Light & Power Plant/ Milford Municipal Utilities/ Spencer Municipal Utilities/ City of Webster City/Grundy Center Municipal Utilities | | Joint Ownership/ Transmission Rights | 10/24/2044 |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 765 | MISO OATT GFA 32: Duane Arnold Energy Center Agreement for Transmission, Transformation, Switching, and Related Facilities | ITC Midwest LLC/Corn Belt Power Cooperative/Central Iowa Power Cooperative | ITC Midwest LLC/Corn Belt Power Cooperative/Central Iowa Power Cooperative | | Joint Ownership/ Transmission Rights | Until termination of the Duane Arnold Ownership Agreement |
| 766 | MISO OATT GFA 33: Duane Arnold Energy Center Operating Agreement | ITC Midwest LLC/Corn Belt Power Cooperative/Central Iowa Power Cooperative | ITC Midwest LLC/Corn Belt Power Cooperative/Central Iowa Power Cooperative | | Joint Ownership/ Transmission Rights | Until termination of the Duane Arnold Ownership Agreement |
| 767 | MISO OATT GFA 42: Neal 3 Transmission Assignments for Capacity Schedule – Sycamore to Lehigh | ITC Midwest LLC/ MidAmerican Energy Company | Corn Belt Power Cooperative | | Transmission Assignment/ Outlet Rights | |
| 768 | MISO OATT GFA 43: Neal 3 Transmission Assignments for Capacity Schedule - Raun to Lehigh | ITC Midwest LLC/ MidAmerican Energy Company | Corn Belt Power Cooperative | | Transmission Assignment/ Outlet Rights | |
| 769 | MISO OATT GFA 44: Neal 3 Transmission Assignments for Capacity Schedule - Raun to Lehigh | ITC Midwest LLC/ MidAmerican Energy Company | Corn Belt Power Cooperative | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 770 | MISO OATT GFA 45: Neal 3 Transmission Assignments for Capacity Schedule – Sycamore to Lehigh | ITC Midwest LLC/ MidAmerican Energy Company | Corn Belt Power Cooperative | | Transmission Assignment/ Outlet Rights | |
| 771 | MISO OATT GFA 46: Neal 3 Transmission Assignments for Capacity Schedule - Raun to Lehigh Corn Belt Power Cooperative | ITC Midwest LLC/ MidAmerican Energy Company | Corn Belt Power Cooperative | | Transmission Assignment/ Outlet Rights | |
| 772 | MISO OATT GFA 53: Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh City of Webster City | ITC Midwest LLC/ MidAmerican Energy Company | City of Webster City, Iowa | | Transmission Assignment/ Outlet Rights | |
| 773 | MISO OATT GFA 54: Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh City of Webster City | ITC Midwest LLC/ MidAmerican Energy Company | City of Webster City, Iowa | | Transmission Assignment/ Outlet Rights | |
| 774 | MISO OATT GFA 55: Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh City of Webster City | ITC Midwest LLC/ MidAmerican Energy Company | City of Webster City, Iowa | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 775 | MISO OATT GFA 469: Lehigh-Webster Transmission and Facilities Operating Agreement, Rate Schedule MidAmerican 63 | Corn Belt Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Fall Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Light Plant/ Laurens Municipal Light & Power/ Milford Municipal Utilities/ Spencer Municipal Utilities/ Webster City/ MidAmerican Energy Company/Sumner Municipal Light Plant | Corn Belt Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Fall Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Light Plant/ Laurens Municipal Light & Power/ Milford Municipal Utilities/ Spencer Municipal Utilities/ Webster City/ MidAmerican Energy Company/Sumner Municipal Light Plant | | Joint Ownership/ Transmission Rights | 5/11/2039 |
| 776 | MISO OATT GFA 470: Operating Agreement – Council Bluffs (Walter Scott) Generating Station Unit 3 Electric Transmission and Substation Facilities | MidAmerican Energy Company/Cedar Falls Utilities/ Atlantic Board of Waterworks/ Cedar Falls Municipal Electric Utility/Central Iowa Power Cooperative/Corn Belt Power Cooperative | MidAmerican Energy Company/Cedar Falls Utilities/ Atlantic Board of Waterworks/ Cedar Falls Municipal Electric Utility/Central Iowa Power Cooperative/Corn Belt Power Cooperative | | Joint Ownership/ Transmission Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 777 | MISO OATT GFA 473: Transmission Service Agreement (For 25 MW of Neal Unit No. 4), Rate Schedule MidAmerican 68 | MidAmerican Energy Company | Corn Belt Power Cooperative | | Transmission Service | Until Terminated |
| 778 | MISO OATT GFA 477: Electric Transmission Interconnection Agreement, Rate Schedule MidAmerican 62 | MidAmerican Energy Company/Corn Belt Power Cooperative | MidAmerican Energy Company/Corn Belt Power Cooperative | | Transmission Service and Coordination Agreement | Until Terminated |
| 779 | MISO OATT GFA 478: Facilities Agreement, Rate Schedule MidAmerican 8 | MidAmerican Energy Company/Corn Belt Power Cooperative | MidAmerican Energy Company/Corn Belt Power Cooperative | | Transmission Service | Until Terminated |
| 780 | MISO OATT GFA 483: Letters of Intent, between Corn Belt Power Cooperative, Alliant, and MidAmerican | MidAmerican Energy Company/ITC Midwest LLC/Corn Belt | MidAmerican Energy Company/ITC Midwest LLC/Corn Belt | | Transmission and Cost Sharing Agreement | Until Terminated |
| 781 | Common Transmission System Agreement | Corn Belt Power Cooperative/North Iowa Municipal Electric Cooperative Association | Corn Belt Power Cooperative/North Iowa Municipal Electric Cooperative Association | | Transmission Service/ Coordination Agreement | Until Terminated |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 782 | MISO OATT GFA 22: Transmission Facilities Operating Agreement George Neal Unit No. 4 Transmission | MidAmerican Energy Company/ITC Midwest/ Interstate Power Company/ Northwestern Public Service Company/ Corn Belt Power Cooperative/ Northwest Iowa Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Falls Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Utilities/ Laurens Municipal Light & Power Plant/ Milford Municipal Utilities/ Spencer Municipal Utilities/ City of Webster City | MidAmerican Energy Company/ITC Midwest/ Interstate Power Company/ Northwestern Public Service Company/ Corn Belt Power Cooperative/ Northwest Iowa Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Falls Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Utilities/ Laurens Municipal Light & Power Plant/ Milford Municipal Utilities/ Spencer Municipal Utilities/ City of Webster City | | Joint Ownership/ Transmission Rights | 10/24/2044 |
| 783 | MISO OATT GFA 47; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Bancroft Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Bancroft | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 784 | MISO OATT GFA 48; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Bancroft Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Bancroft | | Transmission Assignment/ Outlet Rights | |
| 785 | MISO OATT GFA 49; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Bancroft Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Bancroft | | Transmission Assignment/ Outlet Rights | |
| 786 | MISO OATT GFA 50; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Bancroft Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Coon Rapids | | Transmission Assignment/ Outlet Rights | |
| 787 | MISO OATT GFA 51; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Bancroft Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Coon Rapids | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 788 | MISO OATT GFA 52; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Bancroft Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Coon Rapids | | Transmission Assignment/ Outlet Rights | |
| 789 | MISO OATT GFA 56; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Graettinger Municipal Light Plant | ITC Midwest LLC/ MidAmerican Energy Company | City of Graettinger | | Transmission Assignment/ Outlet Rights | |
| 790 | MISO OATT GFA 57; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Graettinger Municipal Light Plant | ITC Midwest LLC/ MidAmerican Energy Company | City of Graettinger | | Transmission Assignment/ Outlet Rights | |
| 791 | MISO OATT GFA 58; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Graettinger Municipal Light Plant | ITC Midwest LLC/ MidAmerican Energy Company | City of Graettinger | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 792 | MISO OATT GFA 59; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Laurens Municipal Light & Power Plant | ITC Midwest LLC/ MidAmerican Energy Company | City of Laurens | | Transmission Assignment/ Outlet Rights | |
| 793 | MISO OATT GFA 60; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Laurens Municipal Light & Power Plant | ITC Midwest LLC/ MidAmerican Energy Company | City of Laurens | | Transmission Assignment/ Outlet Rights | |
| 794 | MISO OATT GFA 61; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Laurens Municipal Light & Power Plant | ITC Midwest LLC/ MidAmerican Energy Company | City of Laurens | | Transmission Assignment/ Outlet Rights | |
| 795 | MISO OATT GFA 62; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Milford Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Milford | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 796 | MISO OATT GFA 63; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Milford Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Milford | | Transmission Assignment/ Outlet Rights | |
| 797 | MISO OATT GFA 64; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Milford Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Milford | | Transmission Assignment/ Outlet Rights | |
| 798 | MISO OATT GFA 65; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Spencer Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Spencer | | Transmission Assignment/ Outlet Rights | |
| 799 | MISO OATT GFA 66; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Spencer Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Spencer | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 800 | MISO OATT GFA 67; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Spencer Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Spencer | | Transmission Assignment/ Outlet Rights | |
| 801 | MISO OATT GFA 71; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Algona Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Algona | | Transmission Assignment/ Outlet Rights | |
| 802 | MISO OATT GFA 72; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Algona Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Algona | | Transmission Assignment/ Outlet Rights | |
| 803 | MISO OATT GFA 73; Neal 3 Transmission Assignments for Capacity Schedule Raun to Lehigh Algona Municipal Utilities | ITC Midwest LLC/ MidAmerican Energy Company | City of Algona | | Transmission Assignment/ Outlet Rights | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 805 | MISO OATT GFA 22: Transmission Facilities Operating Agreement George Neal Unit No. 4 Transmission | MidAmerican Energy Company/ITC Midwest/ Interstate Power Company/ Northwestern Public Service Company/ Corn Belt Power Cooperative/ Northwest Iowa Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Falls Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Utilities/ Laurens Municipal Light & Power Plant/ Milford Municipal Utilities/ Spencer Municipal Utilities/ City of Webster City | MidAmerican Energy Company/ITC Midwest/ Interstate Power Company/ Northwestern Public Service Company/ Corn Belt Power Cooperative/ Northwest Iowa Power Cooperative/ Algona Municipal Utilities/ Bancroft Municipal Utilities/ Cedar Falls Utilities/ Coon Rapids Municipal Utilities/ Graettinger Municipal Utilities/ Laurens Municipal Light & Power Plant/ Milford Municipal Utilities/ Spencer Municipal Utilities/ City of Webster City | | Joint Ownership/ Transmission Rights | 10/24/2044 |
| 806 | MISO OATT GFA 479; Electric Interconnection Agreement | Northwest Iowa Power Cooperative/ MidAmerican Energy Company | Northwest Iowa Power Cooperative/ MidAmerican Energy Company | | Interconnection/ Transmission Service | Until terminated on four years' notice |
| 807 | MISO OATT GFA 480; Electric Interconnection Agreement | Northwest Iowa Power Cooperative/ MidAmerican Energy Company | Northwest Iowa Power Cooperative/ MidAmerican Energy Company | | Interconnection/ Transmission Service | Until terminated on four years' notice |
| 808 | MISO OATT GFA 482; Letter of Intent 5-27-81 | Northwest Iowa Power Cooperative/ MidAmerican Energy Company | Northwest Iowa Power Cooperative/ MidAmerican Energy Company | | Interconnection/ Transmission Service | |

| Line No. | Contract Title | Selling Party | Buying Party | FERC Rate Schedule No. | Type of Service | Termination Provisions |
|---|---|---|---|---|---|---|
| 809 | Termination and Settlement Agreement | Watertown Municipal Utilities Department | NorthWestern Energy | | Interconnection/Transmission Service | 4/15/2026 |

# ATTACHMENT X

# SOUTHWEST POWER POOL, INC. CREDIT POLICY

# ARTICLE ONE

## General Provisions

**1.1 Policy Statement.** In furtherance of competition and the orderly administration of the Tariff, Southwest Power Pool ("SPP") shall administer, implement and enforce this Credit Policy. This Credit Policy is intended to encourage the maximum participation of large and small participants in all market sectors while minimizing the likelihood of losses due to default and to establish eligibility requirements for market participation.

**1.2 Applicability of Credit Policy and Overview.**

**1.2.1** This Credit Policy is applicable to each Credit Customer. It applies to each Credit Customer regardless of whether SPP previously extended credit to, or established a Total Credit Limit for, the Credit Customer. .

**1.2.2** As a condition to taking any service subject to this Credit Policy, SPP must determine that the Credit Customer satisfies SPP's credit requirements and minimum criteria for market participation under this Credit Policy and the terms and conditions for an extension of credit. SPP's determination is a Credit Assessment. The Credit Assessment is based upon quantitative and qualitative credit scoring under the formulae and procedures set forth in this Credit Policy. This Credit Policy provides for initial and ongoing Credit Assessments. In order to facilitate continuous evaluation of credit, it requires the submission of Credit Information to SPP periodically and, additionally, upon the occurrence of certain events. Based upon the ongoing Credit Assessment, SPP is authorized, at any time, to revise a Credit Customer's Total Credit Limit and the terms and conditions for the extension of credit.

**1.2.3** SPP shall conduct initial and ongoing Credit Assessments for each Credit Customer, based, as applicable, upon the Credit Application, Credit Information, and Credit Ratings. Credit Information includes: (a) the information contained in and submitted with the Credit Customer's duly executed Credit Application; and (b) updated and additional information the Credit Customer is required to submit from time to time under this Credit Policy. Credit Information and Credit Ratings, if any, shall be sufficient to enable SPP to determine under this Credit Policy whether to approve an extension of credit, and the amount, terms, and conditions thereof, including the extent and nature of any Guaranty or Financial Security.

**1.2.4** Based upon its Credit Assessment, SPP will: (a) determine the Credit Customer's Total Potential Exposure; (b) determine the amount of credit the Credit Customer requires; (c) determine whether to grant, and the amount of, any Unsecured Credit Allowance; (d) evaluate any Guaranty the Credit Customer offers to provide, including a Credit Assessment for the proposed Guarantor; (e) determine the amount of any required Financial Security; and (f) determine if the Credit Customer meets the minimum criteria for market participation under Sections

3.1.1.8 and 3.1.1.9. Based on these determinations, which shall include consideration of the Credit Customer's ability to fulfill SPP's requirements to obtain credit, SPP will set the Total Credit Limit for the Credit Customer.

**1.2.5** To facilitate the Credit Assessment, each Credit Customer shall submit a duly executed Credit Application in the form attached as Appendix "A," and the Credit Information required under this Credit Policy. If SPP determines that an extension of credit to a Credit Customer must be supported by Financial Security, the Credit Customer shall, upon SPP's request, duly execute the Credit and Security Agreement in the form attached as Appendix "B," without variation. Any Irrevocable Letter of Credit shall be substantially in the form attached as Appendix "C," any Guaranty shall be substantially in the form attached as Appendix "D," and any Surety Bond shall be substantially in the form attached as Appendix "F." Any variations in the forms of Irrevocable Letter of Credit, Guaranty, or Surety Bond must be approved by SPP, and may not materially modify or impair SPP's rights under such form, in SPP's sole discretion.

**1.2.6** This Credit Policy also sets forth separately stated Financial Security requirements for Transmission Congestion Rights.

**1.3 Components of Credit Policy.** This Credit Policy includes the following elements:

**1.3.1** Requirements for the establishment and maintenance of credit applicable to Credit Customers.

**1.3.2** The basis for establishing a Total Credit Limit for a Credit Customer in order to extend credit, but diminish the possibility of failure of payment under the Tariff and Agreements.

**1.3.3** Forms of Guaranty and Financial Security acceptable to SPP, to be provided if SPP does not approve an Unsecured Credit Allowance sufficient to cover the Credit Customer's Total Potential Exposure or to cover Transmission Congestion Right activity.

**1.3.4** Requirements to facilitate ongoing Credit Assessments.

**1.3.5** Specification of Defaults under this Credit Policy and remedies.

**1.3.6** Minimum criteria for market participation.

**1.4 Fairness, Objectivity, and Non-Discrimination.** SPP will seek and receive information and explanation from a Credit Customer as appropriate to help ensure that the Credit Assessment is fair and thorough. SPP will base each Credit Assessment upon SPP's evaluation of the Credit Information, Credit Ratings, and other pertinent indicators of financial strength identified under this Credit Policy. SPP shall make each Credit Assessment objectively and without undue discrimination in favor of or against any

market sector. Whenever this Credit Policy permits SPP to exercise discretion in the implementation of the provisions of this Credit Policy, SPP shall exercise that discretion in a fair and impartial manner that treats all Credit Customers in a non-discriminatory manner.

**1.5 Construction and Interpretation.**

**1.5.1** The word "including" shall be understood to mean "including without limitation." The singular form of a word shall be understood to include the plural form, and vice versa, as appropriate to implement the applicable term or condition.

**1.5.2** Except as otherwise stated, the words "Section" and "Article" refer to sections and articles of this Credit Policy. A Section reference includes all subsections and subparts of the Section.

**1.5.3** All references to amounts of cash, cash deposits, and to monies paid, provided, due or otherwise, shall be construed to refer to United States dollars.

**1.6 Disputes.** Any disputes arising under this Credit Policy will be subject to the dispute resolution procedures set forth in Section 12 of the Tariff.

# ARTICLE TWO

## Definitions

**2.1 Definitions**. The following definitions apply in this Credit Policy. Capitalized terms used herein and not defined herein shall be given the meaning assigned to them under the Tariff.

**Affiliate**
A business concern, organization, or individual is an affiliate of another business concern, organization, or individual, including a Credit Customer, that directly or indirectly: (a) has the power to control or is controlled by it; or (b) is under common control of a third party. Elements of control include interlocking management or ownership, shared facilities and equipment, and common use of employees.

**Affiliated Credit Customers**
Credit Customers that are Affiliates.

**Agreements**
The Tariff, including this Credit Policy, any and all agreements entered into by the Credit Customer under, pursuant to or in connection with the Tariff and/or this Credit Policy, and any and all other Agreements to which SPP and the Credit Customer are parties.

**Auction Clearing Price**
This term shall have the meaning given in Attachment AE of the Tariff.

**Auction Revenue Right (ARR)**
This term shall have the meaning given in Attachment AE of the Tariff.

**Bid**
This term shall have the meaning given in Attachment AE of the Tariff.

**Business Day**
A day on which the Federal Reserve System is open for business.

**Cash Deposit**
Cash collateral provided to SPP to secure a Credit Customer's performance under the Tariff, this Credit Policy, and/or any other Agreements, and any other cash to which the Credit Customer has title or rights in the possession of SPP (cash SPP has applied to payment of an obligation under the Tariff or Agreements is not cash to which a Credit Customer has title or rights).

**Central Prevailing Time**
As established by national time standards, either Central Standard Time or Central Day-Light Time.

**Composite Credit Score or Credit Score**
This term shall have the meaning given in Section 4.2.

**Credit and Security Agreement**
A legal document, outlining certain terms pursuant to which a security interest in certain collateral is granted to SPP, in the form incorporated herein as Appendix "B".

**Credit Application**
The completed, executed, and submitted Credit Application in the form attached as Appendix "A" hereto, together with the Credit Information required under this Credit Policy.

**Credit Assessment**
This term shall have the meaning given in Article Three.

**Credit Contact**
This term shall have the meaning given in Section 9.1.

**Credit Customer**
Any person that takes or seeks to take service under the Tariff including all Transmission Service or other services under the Tariff, including any market services.

**Credit Information**
This term shall have the meaning given in Section 1.2.3.

**Credit Ratings**
Rating assigned by a Rating Agency based on an obligor's creditworthiness to pay financial obligations.

**Day-Ahead Market**
This term shall have the meaning given in Attachment AE of the Tariff.

**Day-Ahead Market Marginal Congestion Component (MCC)**
This term shall have the meaning given in Section 8.3.1.2 of Attachment AE of the Tariff.

**Default or Event of Default**
Any default under Article Eight or otherwise under this Credit Policy.

**Estimated TCR Exposure (ETCRE)**
This term shall have the meaning given in Section 5A.1.3.

**Estimated Virtual Exposure ("EVE")**
This term shall have the meaning given in Section 4A.2.

**ETCRE Bid**
This term shall have the meaning given in Section 5A.4.

**ETCRE Hold**
This term shall have the meaning given in Section 5A.2.

**ETCRE Offer**
This term shall have the meaning given in Section 5A.5.

**Federal Power Marketing Agency**
For purposes of this Credit Policy, this term shall have the same definition that is set forth in the Federal Power Act at 16 U.S.C. § 796(19), which defines a "Federal power marketing agency" as "any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy[.]"

**FERC**
The Federal Energy Regulatory Commission.

**Financial Security**
A Cash Deposit, Irrevocable Letter of Credit, Surety Bond, or Federal Power Marketing Agency Letter in amount and in forms as described in Article Seven of this Credit Policy, provided by a Credit Customer to SPP as security.

**Financial Statements**
This term shall have the meaning given in Section 3.1.1.1.

**Guarantor**
An entity that guarantees the obligation of another entity under a Guaranty.

**Guaranty**
A legal document used by an Affiliate of a Credit Customer pursuant to Article Six to guarantee the obligations of such Credit Customer for the benefit of SPP.

**Incremental Long-Term Congestion Right (ILTCR)**
This term shall have the meaning given in Part I. Section 1 of this Tariff.

**Irrevocable Letter of Credit**
An irrevocable standby letter of credit, with SPP as beneficiary, substantially in the form attached as Appendix “C” to this Credit Policy and acceptable to SPP.

**Large Company Credit Customers or Large Company**
This term shall have the meaning given in Section 4.2.1.

**Locational Marginal Price**
This term shall have the meaning given in Attachment AE of the Tariff.

**Long-Term Congestion Right (LTCR)**
This term shall have the meaning given in Attachment AE of this Tariff.

**Market Exposure**
This term has the meaning given in Section 5.2.1.

**Material**
The lesser of (i) the materiality standard established by the certified public accounting firm performing the Credit Customer's annual audit, (ii) an amount that equals or exceeds five percent (5%) of the Credit Customer's Tangible Net Worth using the last audited financial statements, calculated in accordance with generally acceptable accounting principles; and (iii) a change, event, proceeding, or other occurrence, that results (or if adversely determined could result) in a change of five percent (5%) or more in the Credit Customer's Tangible Net Worth compared to the Tangible Net Worth of the Credit Customer using the last audited financial statements, calculated in accordance with generally acceptable accounting principles.

**Material Adverse Change**
This term shall have the meaning given in Section 3.2.7.

**Minimum Offer Segment**
This term shall have the meaning given in Section 5A.5.3.

**Minimum Segment Hold**
This term shall have the meaning given in Section 5A.4.3.

**Minimum TCR Collateral Requirement**
This term has the meaning given in Section 5A.3.6.

**Not-For Profit Credit Customers or Not-For-Profit**
This term shall have the meaning given in Section 4.2.3.

**Offer**
This term shall have the meaning given in Attachment AE of the Tariff.

**Operating Day**
This term shall have the meaning given in Attachment AE of the Tariff.

**Operating Hour**
This term shall have the meaning given in Attachment AE of the Tariff.

**Peak Market Activity Day**
The day in which a Credit Customer's calculated charges owed to SPP are the greatest, over a specified period.

**Potential Exposure Window**
The number of days of credit exposure for a Credit Customer equal to the sum of days of service that have been invoiced but not paid, days of service that have been calculated but not invoiced, days of service in the cure period, and days before service can be terminated.

**Qualitative Score**
This term has the meanings applicable under Article Four.

**Quantitative Score**
This term has the meanings applicable under Article Four.

**Rating Agency(ies)**
Any Rating Agency that is a "Nationally Recognized Statistical Rating Organizations" as defined by the US Securities Exchange Commission. Currently there are four — Dominion Bond Rating Service Ltd., Fitch, Inc., Moody's Investors Service, and the Standard & Poor's Division of the McGraw Hill Companies Inc.

**Real-Time**
This term shall have the meaning given in Attachment AE of the Tariff.

**Real-Time Balancing Market**
This term shall have the meaning given in Attachment AE of the Tariff.

**SEC**
The Securities and Exchange Commission.

**Settlement Location**
This term shall have the meaning given in Attachment AE of the Tariff.

**Settlement Statement**
This term shall have the meaning given in Attachment AE of the Tariff.

**Small Company Credit Customers or Small Company**
This term shall have the meaning given in Section 4.2.2.

**Surety Bond**
A surety bond, with SPP as beneficiary, substantially in the form attached as Appendix "F" to this Credit Policy and acceptable to SPP.

**Tangible Net Worth**
This term shall have the meaning given in Section 4.3.

**TCR Final Reference Price**
This term shall have the meaning given in Section 5A.2.1.

**TCR Mean Price**
This term shall have the meaning given in Section 5A.2.1.

**TCR Portfolio Credit Requirement**
This term shall have the meaning given in Section 5A.3.

**TCR Stress Test Price**
This term shall have the meaning given in Section 5A.2.1.

**Total Credit Limit**
This term shall have the meaning given in Section 4.5.

**Total Potential Exposure or TPE**
SPP's estimate of the Credit Customer's current or anticipated transaction activity and resulting obligations for all services under the Tariff or otherwise, excluding Transmission Congestion Rights activity.

**Total Potential Exposure Violation**
This term shall have the meaning given in Section 5.4.1.

**Total TCR Credit Requirement**
Total TCR Credit Requirement is the amount of Financial Security a Credit Customer must provide in order to support the TCR positions that it holds and/or for which it is submitting Bids and Offers.

**Transmission Congestion Right (TCR)**
This term shall have the meaning given in Attachment AE of the Tariff.

**Transmission Congestion Right Auction (TCR Auction)**
This term shall have the meaning given in Attachment AE of the Tariff.

**Transmission Service Potential Exposure**
This term shall have the meaning give in Section 5.2.2.

**Unsecured Credit Allowance**
This term shall have the meaning given in Section 4.3.

**Virtual Energy Bid,**
This term shall have the meaning given in Attachment AE of the Tariff.

**Virtual Energy Offer**
This term shall have the meaning given in Attachment AE of the Tariff.

# ARTICLE THREE

## Credit Assessment

### 3.1 Minimum Criteria for Market Participation and Initial Credit Assessment.

**3.1.1 Credit Application and Credit Information.** A Credit Customer must submit a completed and duly executed Credit Application. The Credit Application shall be renewed and updated for each successive year and shall be submitted to SPP no later than April 30 of each year. A completed Credit Application includes submission of the Credit Application form (Appendix "A"), all information required under Section 3.1.1, and additional information that SPP may request. The Credit Customer must submit the following information with its Credit Application.

**3.1.1.1 Audited Financial Statements and Related Information.** All annual Financial Statements submitted must be audited. Financial Statements are the following.

a. If the Credit Customer is subject to SEC reporting requirements, Financial Statements are:

i. Annual Reports on Form 10-K for the three fiscal years most recently ended, together with any amendments thereto;

ii. Quarterly Reports on Form 10-Q for each completed fiscal quarter of the then current fiscal year, together with any amendments thereto; and

iii. Form 8-K reports, if any, filed after the most recent Form 10-K.

b. If the Credit Customer is not subject to SEC reporting requirements, Financial Statements are:

i. For each of the three fiscal years most recently ended, the Report of Independent Accountants (for each of the three fiscal years most recently ended);

and audited financial statements, including balance sheet, income statement, statement of cash flow, and statement of stockholder's equity;

ii. For each completed fiscal quarter of the then current fiscal year; financial statements as described in (i) above. Unaudited quarterly financial statements are acceptable.

iii. Notes to financial statements; and

iv. Management's discussion and analysis, if any.

c. The Credit Customer may submit Financial Statements by informing SPP, in writing, where the Financial Statements can be retrieved through the internet. Successful retrieval by SPP will satisfy the Financial Statements submission requirements of this Section. If SPP is not satisfied with the retrieval through the internet, it may require the Credit Customer to submit Financial Statements in hard copy form.

d. In the event any parts of the Financial Statements required under this Section are inapplicable to the Credit Customer, SPP may specify alternate requirements. SPP may request additional Financial Statements and related information at its sole discretion.

e. For Not-For-Profit Credit Customers, some of the above financial submittals may not be applicable, and alternate requirements may be specified by SPP.

f. In the credit evaluation of Not-For-Profit Credit Customers, SPP may request additional information as part of the overall financial review process and will consider other relevant factors in determining financial strength and creditworthiness.

**3.1.1.2** **References.** The Credit Customer must provide at least one bank reference and at least three references from entities that have significant commercial relationships with the Credit Customer.

**3.1.1.3** **Loss Contingencies.** The Credit Customer must fully and accurately identify and describe each of the following, or state that there are no such matters applicable to the Credit Customer:

a. known pending or, to the Credit Customer's knowledge, threatened, court actions, arbitration proceeding, investigations, commitments, claims, contingencies, or existing or potential liabilities that are or would be Material if determined adversely to the Credit Customer;

b. ongoing investigations by the SEC, the FERC, or of any other governing, regulatory, or standards body that is Material or would be Material if determined adversely to the Credit Customer;

c. prior bankruptcy declarations or petitions, voluntary or involuntary, by or against the Credit Customer, its predecessors, subsidiaries or Affiliates; and

d. Material defalcations or fraud by or involving the Credit Customer, its predecessors, subsidiaries or Affiliates, or any of their respective assets.

**3.1.1.4** **Affiliates.** The Credit Customer must identify all Affiliates that are Credit Customers.

**3.1.1.5** **Total Potential Exposure Information.** The Credit Customer shall provide an estimate of its current or anticipated transaction activity for all services under the Tariff or otherwise over the succeeding twelve months, excluding Transmission Congestion Rights activity, sufficient to permit SPP to determine the Credit Customer's Total Potential Exposure.

**3.1.1.6 Attestation Minimum Criteria for Market Participation and of Risk Management Capabilities.** Each applying Market Participant shall submit to SPP a notarized statement signed by an authorized officer in the form attached as "Appendix E" to this Attachment X, attesting that:

a. The officer has signature authority to make the statement;

b. Employees or agents transacting in markets and services provided pursuant to the Tariff on behalf of the applying Market Participant have received, or will receive, applicable training with regard to their participation under this Tariff as a condition of being authorized to transact on behalf of the Market Participant;

c. The applying Market Participant will maintain current written risk management policies and procedures that address those risks that could materially affect the applying Market Participant's ability to pay its SPP invoices when due;

d. The applying Market Participant has available appropriate personnel resources, operating procedures, and technical abilities to promptly and effectively respond to SPP communications and directions related to, but not limited to, settlements, billing, credit requirements and other financial matters;

e. The applying Market Participant will maintain the minimum capitalization or alternate capitalization requirements set forth in Section 3.1.1.8 of this Attachment X; and

f. Certifying that the Market Participant meets the minimum criteria for market participation set forth in Section 3.1.1.8.

Such attestation shall be renewed and updated for each successive year of market participation, and shall be submitted to SPP no later than April 30 of each year.

The applying Market Participant shall be declined participation in all SPP markets if: (i) the risk management capabilities of the applying Market Participant are deemed insufficient by SPP for the type of service that will be undertaken, (ii) SPP determines that the applying Market Participant does not meet the minimum criteria for market participation, (iii) the attestation is deemed insufficient by SPP to determine the risk management capabilities of the applying Market Participant, or (iv) the attestation is deemed insufficient by SPP to determine whether the applying Market Participant meets the minimum criteria for market participation. An applying Market Participant will have two (2) Business Days

from receipt of notice from SPP that its attestation was deemed insufficient to cure any deficiency identified by SPP prior to being declined participation in SPP markets.

**3.1.1.7 Additional Information.** At any time and from time to time, SPP may request such additional information as SPP determines is necessary and appropriate for the Credit Assessment and the Credit Customer shall timely provide such additional information. At any time, the Credit Customer may provide SPP with additional information that the Credit Customer considers relevant to the Credit Assessment.

**3.1.1.8 Minimum Criteria for Market Participation.**

**3.1.1.8.1 Minimum Eligibility Requirements**

In order to be eligible to transact in the Integrated Marketplace, each Market Participant must demonstrate to SPP that it qualifies as one of the following:

a. An "appropriate person," as defined under Section 4(c)(3)(A) through (J) of the Commodity Exchange Act (7 U.S.C. § 6(c)(3)(A) through (J)). A Market Participant may qualify as an "appropriate person" by providing either: (i) an unlimited Corporate Guaranty in a form acceptable to SPP as described in Article 6 of this Attachment X and Appendix D of this Attachment X from an entity that demonstrates to SPP that it has in excess of $1 million of total net worth or in excess of $5 million of total assets per Market Participant for which that guarantor has issued an unlimited Corporate Guaranty, or (ii) an Irrevocable Letter of Credit or Surety Bond in an amount of $5 million or greater that the Market Participant acknowledges is separate from, and cannot be applied to

meet, its credit requirements under this Attachment X.

b. An "eligible contract participant," as defined in Section 1a(18) of the Commodity Exchange Act (7 U.S.C. § 1a(18)) and in the Commodity Futures Trading Commission's regulation 1.3(m) (17 C.F.R. § 1.3(m))

c. A person or entity that is in the business of: (1) generating, transmitting or distributing electric energy or (2) providing electric services that are necessary to support the reliable operation of the transmission system (78 Fed. Reg. 19880, page 19914).

For purposes of meeting the minimum criteria for market participation under this Credit Policy, SPP shall accept annual audited Financial Statements prepared according to either United States Generally Accepted Accounting Principles (US GAAP) or International Financial Reporting Standards (IFRS).

If a Market Participant is unable to meet the minimum eligibility requirements for market participation set forth in this Section 3.1.1.8.1, the Market Participant shall immediately notify SPP and immediately cease conducting transactions in the Integrated Marketplace. When SPP receives such notification from a Market Participant or determines that a Market Participant does not meet the minimum eligibility requirements set forth in this Section 3.1.1.8.1, SPP shall immediately terminate that Market Participant's transaction rights in the Integrated Marketplace.

In the event that a Market Participant is no longer able to demonstrate that it meets the minimum eligibility requirements set forth in this Section 3.1.1.8.1, and possesses, obtains, or has rights to possess or obtain any open or forward position in

the Integrated Marketplace, SPP may take any action it deems necessary with respect to such open or forward positions. Such action may include but is not limited to, liquidation, transfer, assignment, or sale. The Market Participant will be entitled to any positive market value of such positions, net of any obligations due to SPP, notwithstanding its ineligibility to participate in the Integrated Marketplace. Nothing in this paragraph shall restrict SPP's ability to enforce SPP's rights to pursue and collect any amounts Market Participants may owe to SPP.

#### 3.1.1.8.2 Minimum Capitalization Requirements

Each Market Participant that meets the minimum eligibility requirements in Section 3.1.1.8.1 shall also, at a minimum, possess:

a. A Tangible Net Worth of One Million Dollars ($1,000,000) for a Market Participant not transacting in the Transmission Congestion Rights market or a Tangible Net Worth of Ten Million Dollars ($10,000,000) that does not include cash deposits held at any other Independent System Operator or Regional Transmission Organization, including, without limitation, the Electric Reliability Council of Texas, Inc., the Alberta Electric System Operator, and the Independent Electricity System Operator, for a Market Participant transacting in the Transmission Congestion Rights market as evidenced in the most recent fiscal year end audited financial statements as described in Section 3.1.1.1; or

b. Ten Million Dollars ($10,000,000) in assets for a Market Participant not transacting in the Transmission Congestion Rights market or Twenty Million Dollars ($20,000,000) in assets that does not include cash deposits held at any other Independent System Operator or Regional Transmission Organization, including, without limitation, the Electric Reliability Council of Texas,

Inc., the Alberta Electric System Operator, and the Independent Electricity System Operator, for a Market Participant transacting in the Transmission Congestion Rights market as evidenced in the most recent fiscal year end audited financial statement as described in Section 3.1.1.1; or

c. A Credit Rating of, or equivalent to, BBB-; or

d. A Guaranty as described in Article Six of this Attachment X, and approved by SPP, through which the audited financials or Credit Rating of the Guarantor is used to meet at least one of the alternatives specified in (a) through (c) above; or

e. In the event a Market Participant cannot meet at least one of the alternatives specified in (a) through (d) above, the Market Participant shall, at a minimum, deposit with SPP Two Hundred Thousand Dollars ($200,000) in Financial Security to be segregated and unavailable to secure any market or transmission activity. A Market Participant transacting in the Transmission Congestion Rights market who cannot meet at least one of the alternatives specified in (a) through (d) above shall, at a minimum, deposit with SPP Two Million Dollars ($2,000,000) in Financial Security to be segregated and unavailable to secure any market or transmission activity. Pursuant to election of this alternative, if the anticipated activity at time of application or actual market activity as determined in Article Five and Article Five A, of the Market Participant exceeds One Hundred Thousand Dollars ($100,000) in Market Exposure and/or Total TCR Credit Requirement, the Market Participant shall provide SPP twice the amount of Financial Security that would otherwise be required of the Market Participant pursuant to Section 4.4.

If the applying Market Participant is unable to meet the applicable minimum capitalization requirements in this Section 3.1.1.8.2, the applying Market

Participant shall be declined participation in the applicable SPP markets.

Failure at any time of a Market Participant to continue to satisfy these minimum capitalization requirements in this Section 3.1.1.8.2 shall be deemed a Material Adverse Change pursuant to Section 3.2.7.

### 3.1.1.9 Minimum Criteria and Risk Management Verification Process

Through a periodic compliance verification process, SPP shall review and verify Market Participants' eligibility for market participation based upon SPP's minimum criteria for market participation, risk management policies, practices, and procedures pertaining to the Market Participants' activities in the SPP markets. Such review shall include verification that:

1. The risk management framework is documented in a risk policy addressing market, credit, and liquidity risks;
2. The Market Participant maintains an organizational structure with clearly defined roles and responsibilities that clearly segregates trading and risk management functions;
3. There is clarity of authority specifying the types of transactions into which traders are allowed to enter;
4. The Market Participant has requirements that traders have adequate training or expertise relative to their authority in the systems and SPP markets in which they transact;
5. As appropriate, risk limits are in place to control risk exposures;
6. Reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization;
7. Processes are in place for qualified independent review of trading activities; and
8. As appropriate, there is periodic valuation or mark-to-market of risk positions.
9. The Market Participant meets the minimum participation criteria, including capitalization requirements, set forth in Section 3.1.1.8.

SPP may select Market Participants for review on a random basis and/or based on identified risk factors such as, but not limited to, the SPP markets in which the Market Participant is transacting, the magnitude of the Market Participant's transactions, or the volume

of the Market Participant's open positions. Those Market Participants notified by SPP that they have been selected for review shall, upon fourteen (14) calendar days notice, provide a copy of their current governing risk control policies, procedures, and controls applicable to their SPP market activities and shall also provide such further information or documentation pertaining to the Market Participants' activities in the SPP markets as SPP may reasonably request. Market Participants selected for risk management verification through a random process and satisfactorily verified by SPP shall be excluded from such verification process based on a random selection for the subsequent two years. SPP shall annually randomly select for review no more than twenty percent (20%) of the Market Participants.

Each selected Market Participant's continued eligibility to participate in the SPP markets is conditioned upon SPP notifying the Market Participant of successful completion of SPP's verification, provided, however, that if SPP notifies the Market Participant in writing that it could not successfully complete the verification process, SPP shall allow such Market Participant fourteen (14) calendar days to provide sufficient evidence for verification prior to declaring the Market Participant as ineligible to continue to participate in SPP's markets, which declaration shall be in writing with an explanation of why SPP could not complete the verification. If, prior to the expiration of such fourteen (14) calendar days, the Market Participant demonstrates to SPP that it has filed with the Federal Energy Regulatory Commission an appeal of SPP's risk management verification determination, then the Market Participant shall retain its transaction rights, pending the Commission's determination on the Market Participant's appeal. SPP may retain outside expertise to perform the review and verification function described in this section. SPP and any third party it may retain will treat as confidential the documentation provided by a Market Participant under this section, consistent with the applicable provisions of the Tariff.

**3.1.2 Rating Agency Information.** In the initial Credit Assessment and in subsequent and ongoing assessments, SPP will consider Rating Agency reports applicable to the Credit Customer. This review will be focused on the Credit Customer's unsecured, senior long-term debt ratings. If these ratings are not available, SPP will consider issuer ratings.

**3.1.3 Power Supply Agent Disclosure Requirements.** A Not-For-Profit Credit Customer may request that its suggested Unsecured Credit Allowance calculation reflect as equity the outstanding balance of revenue bonds issued by the Not-For-Profit Credit Customer when such revenue bonds are issued solely in support of the Not-For-Profit Credit Customer's role as power supply agent for not-for-profit electric distribution utilities. In support of such request, the Not-For-Profit Credit Customer must provide SPP with the following information:

(a) Management representation letter stating:

(i) Principal amount, in dollars, of revenue bonds outstanding;

(ii) Prior to default and after default, debt service on the revenue bonds is payable only after operating expenses are paid;

(iii) Amounts payable to SPP under this Tariff are operating expenses for purposes of the revenue bonds; and

(iv) The trustee for the revenue bonds has a valid and binding security interest in the revenues or net revenues from the power supply contracts to secure payment of the revenue bonds and the Not-For-Profit Customer has not granted any lien thereon prior to the lien of the bond resolution.

(b) Opinion of counsel stating:

(i) The power supply contracts are binding obligations of the Not-For-Profit Credit Customer enforceable in accordance with their terms;

(ii) The trustee of the revenue bonds has a valid and binding security interest in, or assignment and pledge of, the revenues or net revenues from the power supply contracts to secure payment of the revenue bonds;

(iii) The resolution or other document creating the security interest or pledge and providing for the priority of payment is enforceable in accordance with its terms;

(iv) Prior to default and after default, debt service on the revenue bonds is payable only after operating expenses are paid; and

(v) All amounts payable to SPP arising from transactions under this Tariff are operating expenses for purposes of the revenue bonds.

(c) All Rating Agency ratings on revenue bond(s).

The opinion of counsel referenced above shall be provided to SPP together with copies of the most recent written opinions of counsel, if any, for each member of the Not-For-Profit Credit Customer that relate to the enforceability of the power supply contract(s).

**3.1.4 Guaranties.** If the Credit Customer proposes a Guaranty to establish, contribute to, or maintain an Unsecured Credit Allowance, Credit Information required under Section 3.1.1 must be submitted with respect to both the Credit Customer and the proposed Guarantor.

## 3.2. Annual and Other Ongoing Credit Assessments.

**3.2.1 Purpose of Annual and Other Ongoing Credit Assessments.** At least once annually, SPP will review and update its Credit Assessment for each Credit Customer. This will include a review of the Credit Customer's creditworthiness and consideration of revisions of the Credit Customer's (a) Unsecured Credit Allowance; (b) Financial Security requirements; and (c) Total Credit Limit. In its sole discretion, SPP may conduct additional reviews and updates, including reviews in response to new facts or occurrences that may bear upon the Credit Customer's creditworthiness. Unless otherwise stated, all annual information required under Section 3.2 shall be provided to SPP no later than 120 days after the end of the Credit Customer's fiscal year.

**3.2.2 Procedures for Posting Additional Financial Security or Taking Other Corrective Measures.** In the event a Credit Customer experiences a Material Adverse Change, SPP may invoke its right to require the Credit Customer to post additional Financial Security, cease one or more transactions, or take other measures to restore confidence in the Credit Customer's ability to transact safely. In addition, based upon the annual or other Credit Assessment, SPP may, at any time, revise any (a) Unsecured Credit Allowance; (b) Financial Security requirements; and (c) Total Credit Limit, applicable to the Credit Customer. If SPP has upwardly revised the required amount of Financial Security, the Credit Customer will have two (2) Business Days from receipt of the notice from SPP to provide the required Financial Security, in an amount and form acceptable to SPP. Failure to provide additional required Financial Security shall be a Default under this Credit Policy and a default under the Tariff.

**3.2.3 Rating Agency Information.** The Credit Customer will give notice to SPP of any changes to its Credit Ratings within five (5) Business Days of the announcement of the change.

**3.2.4 Financial Statements.** On an annual basis, and except as otherwise stated with respect to quarterly reports, each Credit Customer must provide SPP with updated Financial Statements within ten (10) days after they become available, and in no event later than 120 days after the end of the Credit Customer's fiscal year. Quarterly reports must be provided quarterly, within ten (10) days after they become available. Financial Statements may be submitted in the manner provided under Section 3.1.1.1.

**3.2.5 Power Supply Agent Disclosure Requirements.** A Not-For-Profit Credit Customer that initially qualified to have its suggested Unsecured Credit Allowance calculation reflect as equity the outstanding balance of revenue bonds issued by the Not-For-Profit Credit Customer, and is requesting to continue to have its suggested Unsecured Credit Allowance calculation reflect as equity the outstanding balance of revenue bonds issued by the Not-For-Profit Credit Customer when such revenue bonds are issued solely in support of the Not-For-Profit Credit Customer's role as power supply agent for not-for-profit electric distribution utilities, must at all times comply with the following information reporting requirements:

(a) The Not-For-Profit Credit Customer must advise SPP of the principal amount of revenue bonds outstanding on an annual basis;

(b) The Not-For-Profit Credit Customer must advise SPP within ten (10) days if the principal amount of the revenue bonds outstanding is reduced by more than twenty percent (20%) from the amount last certified by the Not-For-Profit Credit Customer;

(c) The Not-For-Profit Credit Customer must advise SPP immediately if the security interest of the trustee is released or the Not-For-Profit Credit Customer grants any lien prior to the lien of the bond resolution; and

(d) The Not-For-Profit Credit Customer must advise SPP within ten (10) days of any downgrade of any of the Not-For-Profit Credit Customer's revenue bond ratings issued by a Rating Agency.

**3.2.6 Other Credit Information.** On an annual basis, each Credit Customer must provide SPP with the information specified in Section 3.1.1.3 (Loss Contingencies), 3.1.1.4 (Affiliates), 3.1.1.6 (Additional Information).

**3.2.7 Material Adverse Changes.** Each Credit Customer must give SPP notice of any Material Adverse Change in its financial condition (and, as applicable, the financial condition of its Guarantor) within two (2) Business Days of the occurrence of the Material Adverse Change. If a Credit Customer or Guarantor files a Form 10-K, Form 10-Q, or Form 8-K with the SEC, notice of such filing, timely delivered to SPP in accordance herewith, will suffice on the condition that such notice states that the filing addresses a Material Adverse Change.

A Material Adverse Change in financial condition includes any Material change in operations or financial condition that a reasonable examiner of creditworthiness would deem material to decisions concerning the extension of credit, including but not limited to, any of the following ("Material Adverse Change"):

a. A downgrade of any debt rating or issuer rating, or change in the outlook of any Credit Rating, including debt rating or issuer rating;

b. Any placement on a credit watch with negative implication by a Rating Agency;

c. The filing of a lawsuit or initiation of an arbitration, investigation or other proceeding (including regulatory proceeding) which if decided adversely could have a Material effect on any current or future financial results or financial condition;

d. The merger, acquisition or any other form of business combination involving the credit customer.

e. Any adverse changes in financial condition which, individually, or in the aggregate, are Material;

f. Any adverse changes, events or occurrences which, individually or in the aggregate, could affect the ability of the Credit Customer to pay its debts as they become due or could have a Material adverse effect on any current or future financial results or financial condition;

g. Discovery or disclosure of conflict of interest issues;

h. Resignation or removal of a key officer or director;

i. Any action requiring the filing of a Form 8-K;

j. Any report of a quarterly or annual loss or a decline in earnings of ten (10) percent or greater compared to the prior period;

k. Any restatement of prior financial statements; and

l. Failure of a Market Participant to continue to satisfy the minimum capitalization criteria for market participation specified in 3.1.1.8.2.

**3.2.7.1 Notification of a Material Adverse Change by SPP to a Credit Customer**. Upon the occurrence of a Material Adverse Change and prior to SPP compelling a Credit Customer to post additional Financial Security, cease one or more transactions, or take other measures to restore confidence in the Credit Customer's ability to transact business safely as a result of any Material Adverse Change, SPP shall provide, when feasible, reasonable advance notice in writing, by fax, electronic mail, hand delivery, reputable overnight courier, or first-class mail, to the Credit Contact designated by the Credit Customer pursuant to Section 9.1 of this Credit Policy. If delivery to the Credit Contact fails, then SPP may effect delivery to any officer, executive, or manager of the Credit Customer. Such notice shall identify the reasoning behind the invocation of the Material Adverse Change clause and be signed by an authorized representative of SPP.

**3.2.8 Affiliates.** Each Credit Customer must identify all Affiliates that are Credit Customers.

**3.2.9 Additional Information.** At any time and from time to time, SPP may request such additional information as SPP determines is necessary and appropriate for the Credit Assessment and the Credit Customer shall timely provide such additional information. At any time, the Credit Customer may provide SPP with additional information that the Credit Customer considers relevant to the Credit Assessment.

**3.2.10 Guaranties.** If the Credit Customer relies upon a Guaranty to maintain an Unsecured Credit Allowance, Credit Information required under Section 3.2 must be submitted with respect to both the Credit Customer and the Guarantor.

**3.2.11 Alternate Requirements.** For Not-For-Profit Credit Customers, some of the above financial submittals may not be applicable, and alternate requirements may be specified by SPP.

**3.2.12** In the credit evaluation of Not-For-Profit Credit Customers, SPP may request additional information as part of the overall financial review process and will consider other relevant factors in determining financial strength and creditworthiness.

**3.3 SPP Rights to Use Other Information.** Notwithstanding any provision of this Credit Policy, SPP shall have the right to utilize, in a Credit Assessment, any information of which it is aware concerning the Credit Customer.

**3.4 Positive Material Change in Financial Condition of the Credit Customer.** If there is a positive Material change in the financial condition of the Credit Customer, a significant reduction in the Total Potential Exposure of the Credit Customer, or any other change that the Credit Customer believes may warrant an increase in the Credit Customer's Unsecured Credit Allowance and/or a reduction in the Financial Security required of the Credit Customer, the Credit Customer may make a written request to SPP to update the Credit Assessment and include or refer to any supporting information. SPP may request any Credit Information described in Section 3.2 to evaluate the merit of the Credit Customer's request. SPP anticipates that it will respond to the Credit Customer's request within a reasonable period of time, generally within ten (10) Business Days after receiving all information that is required for an ongoing review as required in this Article.

# ARTICLE FOUR

## Creditworthiness and Total Credit Limit

**4.1 Creditworthiness Overview.** SPP will establish a Total Potential Exposure for each Credit Customer based on the Credit Customer's estimated cumulative financial obligation arising under the Tariff or otherwise to SPP, excluding Transmission Congestion Rights activity, as provided in Article 5. The Total Potential Exposure is the amount that the Credit Customer must support with credit. Transmission Congestion Rights activity must be supported with Financial Security as provided in Article 5A. The credit will consist of a combination of the Unsecured Credit Allowance and Financial Security, or either of them. SPP will determine the Credit Customer's Unsecured Credit Allowance based upon the Composite Credit Score. The Composite Credit Score, as defined herein, is a determination of financial strength and creditworthiness, based upon the Credit Assessment. Where Credit Customers are Affiliates of each other, an aggregate Unsecured Credit Allowance will be established for the Affiliates, as provided below. If the Credit Customer's Unsecured Credit Allowance is less than its Total Potential Exposure, the Credit Customer will be required either to establish additional credit in the amount of the difference by posting Financial Security or to decrease its Total Potential Exposure. A Credit Customer's total credit with SPP, consisting of the Unsecured Credit Allowance and any Financial Security, is the Credit Customer's Total Credit Limit. A Credit Customer may provide additional Financial Security at any time to increase or maintain its Total Credit Limit, for example, in order to increase its Total Potential Exposure or to compensate for a reduction in its Unsecured Credit Allowance.

**4.2 Composite Credit Score.** The "Composite Credit Score" is the numerical result of SPP's scoring process based upon various quantitative and qualitative predictors of creditworthiness as set forth in this Section. The results are scaled from one (1) to six (6) with one (1) being the strongest score and six (6) being the weakest. Key factors in the scoring process include financial ratios, years in business, and Credit Ratings. SPP will apply all measures used to determine Composite Credit Scores in a consistent manner. The respective models SPP will use to determine the Composite Credit Score for Large Company Credit Customers, Small Company Credit Customers, and Not-For-Profit Credit Customers are set forth in this Section.

**4.2.1 Large Company Credit Scoring.** The Large Company Credit Customer model will be utilized for Credit Customers with net fixed assets equal to or in excess of $250 million ("Large Company Credit Customers" or "Large Company"). The Large Company Credit Score will be comprised of a Quantitative Score and a Qualitative Score. Each score is then weighted as shown below to build a Composite Credit Score.

| **Large Company Analysis** | **Weight** |
|---|---|
| Quantitative Score | 70% |
| Qualitative Score | 30% |

**4.2.1.1** **Quantitative Score.** The Quantitative Score is based on the financial ratios below. These measures will be calculated for each Large-Company Credit Customer and compared with benchmarks to assign a score of one (1) to six (6) for each measure. A score of one (1) indicates that the Credit Customer has a strong financial health with regard to the measure, while a score of six (6) indicates poor financial health with regard to the measure. The following measures are used:

a. Current Ratio—Current Assets/Current Liabilities

b. EBIT Interest Coverage—(Interest Expense + Income Taxes + Net Income) / Interest Expense

c. Total Debt to Total Capitalization ("TD/TC")—(Long Term Debt + Current Portion + Other Short Term Borrowings) / (Total Debt + Preferred Equity + Common Equity)

d. Funds from Operations ("FFO") to Total Debt—(Cash from Operating Activities - Changes in Operating Assets and Liabilities) / (Long Term Debt + Current Portion + Other Short Term Borrowings)

The measures are then assessed as follows to calculate the total Quantitative Score:

| Scale | Current | EBIT Interest | TD/TC | FFO to Total Debt |
|---|---|---|---|---|
| 1 | >1.34 | >4.99 | <.30 | >.350 |
| 2 | 1.15 – 1.34 | 3.50 – 4.99 | .30 - .39 | .271 - .350 |
| 3 | 1.00 – 1.14 | 2.50 – 3.49 | .40 - .49 | .181 - .270 |
| 4 | 0.85 – 0.99 | 2.00 – 2.49 | .50 - .59 | .120 - .180 |
| 5 | 0.70 – 0.84 | 1.25 – 1.99 | .60 - .69 | .070 - .119 |
| 6 | <0.70 | <1.25 | >.69 | <.070 |

The measures are weighted as follows:

| Large Company Financial Ratios | Weight |
|---|---|
| Current Ratio | 10% |
| EBIT Interest Coverage | 25% |
| Total Debt to Total Capitalization | 25% |
| FFO to Total Debt | 40% |
| | 100% |

If one or more ratios cannot be calculated due to insufficient data to calculate the ratio, the weight that would have been assigned to

that ratio or ratios will be allocated equally among the remaining ratios.

**4.2.1.2 Qualitative Score.** The Qualitative Score, also on a scale of one (1) to six (6), will assess non-financial measure information about a Credit Customer's creditworthiness. A score of one (1) indicates that the Credit Customer has strong qualitative measures, while a score of six (6) indicates poor qualitative measures. The qualitative analysis will take into account a variety of information, but at a minimum will include the assessment of the following characteristics:

-Management
-Regional / Commodity Diversity
-Physical Liquidity
-Financial Liquidity
-Quality of Equity
-Volatility of Earnings
-Regulation/Rates
-Senior Unsecured Debt Rating
-SPP Payment Record
-Risk Procedures

**4.2.1.3 Composite Credit Score.** The Composite Credit Score is the weighted average of the Quantitative Score and the Qualitative Score. To illustrate, assume the following:

Large Company Qualitative Score = 4.0

Large Company Financial Measures:

| | **Value** | **Score** | **Weight** |
|---|---|---|---|
| Current Ratio | .82 | 5 | 10% |
| EBIT Interest Coverage | 2.08 | 4 | 25% |
| Total Debt to Total Capitalization | .63 | 5 | 25% |
| FFO to Total Debt | .17 | 4 | 40% |

Large Company Quantitative Score =
(5 x 10%) + (4 x 25%) + (5 x 25%) + (4 x 40%) = 4.35

Large Company Credit Score = (4.35 x 70%) + (4 x 30%) = 4.25

**4.2.2 Small Company Credit Scoring.** The Small Company model will be utilized for Credit Customers with net fixed assets less than $250 million ("Small Company Credit Customers" or "Small Company"). The Small Company Composite Credit

Score will be comprised of a Quantitative Score and a Qualitative Score. Each score is then weighted as shown below to build a Composite Credit Score.

| **Small Company Analysis** | **Weight** |
|---|---|
| Quantitative Score | 70% |
| Qualitative Score | 30% |

**4.2.2.1 Quantitative Score.** The Quantitative Score is based on the financial ratios below. These measures will be calculated for each Small Company Credit Customer and compared with benchmarks to assign a score of one (1) to six (6) for each measure. A score of one (1) indicates that the Credit Customer has a strong financial health with regard to the measure, while a score of six (6) indicates poor financial health with regard to the measure. The following measures are used:

a. Current Ratio—Current Assets/Current Liabilities

b. EBIT Interest Coverage—(Interest Expense + Income Taxes + Net Income) / Interest Expense

c. Total Liabilities to Total Net Worth ("TL/TNW")—(Total Liabilities) / (Total Equity-Intangibles-Treasury Stock)

d. Funds from Operations ("FFO") to Total Debt—(Cash from Operating Activities - Changes in Operating Assets and Liabilities) / (Long Term Debt + Current Portion + Other Short Term Borrowings)

e. Return on Assets ("ROA")—Net Income / Total Assets

The values are then assessed as follows to calculate the total Quantitative Score:

| **Scale** | **Current** | **EBIT Interest** | **TL/TNW** | **FFO to Total Debt** | **ROA** |
|---|---|---|---|---|---|
| 1 | >2.50 | >4.99 | <0.40 | >.350 | >.120 |
| 2 | 1.75 – 2.50 | 3.50 – 4.99 | 0.40 - 0.70 | .271-.350 | .100 - .120 |
| 3 | 1.40 – 1.74 | 2.50 – 3.49 | 0.71 – 1.49 | .181 - .270 | .075 - .099 |
| 4 | 1.15 – 1.39 | 2.00 – 2.49 | 1.50 – 2.25 | .120 - .18 | .045 - .074 |
| 5 | 1.00 – 1.14 | 1.25 – 1.99 | 2.26 – 4.00 | .070 - .119 | .015 - .044 |
| 6 | <1.00 | <1.25 | >4.00 | <.070 | <.015 |

The measures are weighted as follows:

| **Small Company Financial Ratios** | **Weight** |
|---|---|
| Current Ratio | 25% |
| EBIT Interest Coverage | 10% |
| Total Liabilities / Total Net Worth | 25% |

| | |
|---|---|
| FFO to Total Debt | 15% |
| ROA | 25% |
| | 100% |

If one or more ratios cannot be calculated due to insufficient data to calculate the ratio, the weight that would have been assigned to that ratio or ratios will be allocated equally among the remaining ratios.

**4.2.2.2** **Qualitative Score.** The Qualitative Score, also on a scale of one (1) to six (6), will assess non-financial measure information about a Credit Customer's creditworthiness. A score of one (1) indicates that the Credit Customer has strong qualitative measures, while a score of six (6) indicates poor qualitative measures. The qualitative analysis will take into account a variety of information, but at a minimum will include the assessment of the following characteristics:

-Management
-Regional / Commodity Diversity
-Physical Liquidity
-Financial Liquidity
-Quality of Equity
-Volatility of Earnings
-Regulation/Rates
-Peer Comparison using SIC codes
-Senior Unsecured Debt Rating
-SPP Payment Record

**4.2.2.3** **Composite Credit Score.** The Composite Credit Score is the weighted average of the Quantitative Score and the Qualitative Score. To illustrate, assume the following:

Small Company Qualitative Score = 4

Small Company Financial Measures:

| | **Value** | **Score** | **Weight** |
|---|---|---|---|
| Current Ratio | 1.10 | 5 | 25% |
| EBIT Interest Coverage | 1855.00 | 1 | 10% |
| Total Liabilities / Total Net Worth | 2.47 | 5 | 25% |
| FFO to Total Debt | 0.03 | 6 | 15% |
| ROA | 0.02 | 5 | 25% |

Small Company Quantitative Score =
(5 x 25%) + (1 x 10%) + (5 x 25%) + (6 x 15%) + (5 x 25%) = 4.75

Small Company Credit Score =
(4.75 x 70%) + (4 x 30%) = 4.53

**4.2.3 Not-For-Profit Credit Scoring.** The Not-For-Profit model will be utilized for Credit Customers who are not structured to generate profits for investors ("Not-For-Profit Credit Customers" or "Not-For-Profit"), including electric cooperatives, municipalities, and government agencies. The Not-For-Profit Composite Credit Score will be comprised of a Quantitative Score and a Qualitative Score. The lower of the Composite Credit Score calculated using two alternative weights for the Quantitative Score and the Qualitative Score as shown below shall be used in determining the allocation of the Not-For-Profit Credit Customer's Unsecured Credit Allowance.

| Not For Profit Credit Customer Analysis | Weight | |
|---|---|---|
| | Alternative 1 | Alternative 2 |
| Quantitative Score | 40% | 50% |
| Qualitative Score | 60% | 50% |

**4.2.3.1 Quantitative Score.** The Quantitative Score is based on the financial ratios below. These measures will be calculated for each Not-For-Profit Credit Customer and compared with benchmarks to assign a score of one (1) to six (6) for each measure. A score of one (1) indicates that the Credit Customer has a strong financial health with regard to the measure, while a score of six (6) indicates poor financial health with regard to the measure. The following measures, or their substantive equivalents for not-for-profit entities, are used:

a. Current Ratio ("CR")—Current Assets / Current Liabilities

b. Debt Service Coverage ("DSC")—(Operating Income + Interest Expense + Depreciation + Interest Income + Cash Portion of Capital Credits - Onetime Charges)/(Interest Expense + Debt Amortization)

c. Times Interest Earned Ratio ("TIER")—(Interest Expense + Patronage Capital or Margins or Changes in Net Assets) / (Interest Expense)

d. Total Debt to Total Capitalization ("TD/TC")—(Long Term Debt + Current Portion + Other Short Term Borrowings) / (Total Debt + Preferred Equity + Common Equity). Members' Equity could also be called Net Assets or Patronage Capital.

The values are then assessed as follows to calculate the total Quantitative Score:

Not-For-Profit Credit Customer Model Ratio Scales

| Scale | CR | DSC | TIER | TD/TC |
|---|---|---|---|---|
| 1 | >1.34 | >1.99 | >2.00 | <.50 |
| 2 | 1.15 – 1.34 | 1.50 – 1.99 | 1.50 – 2.00 | .51 - .74 |
| 3 | 1.00 – 1.14 | 1.00 – 1.49 | 1.00 – 1.49 | .75 - .85 |
| 4 | 0.85 – 0.99 | 0.80 – 0.99 | 0.80 – 0.99 | .86 - .93 |
| 5 | 0.70 – 0.84 | 0.60 – 0.79 | 0.50 – 0.79 | .94 - .99 |
| 6 | <0.70 | <0.60 | <0.50 | >.99 |

The measures are weighted as follows:

| Not-For-Profit Credit Customer Financial Ratios | Weight |
|---|---|
| Current Ratio | 15% |
| Debt Service Coverage | 35% |
| Times Interest Earned Ratio | 20% |
| Total Debt / Total Capitalization | 30% |
| | 100% |

If one or more ratios cannot be calculated due to insufficient data to calculate the ratio, the weight that would have been assigned to that ratio or ratios will be allocated equally among the remaining ratios.

**4.2.3.2** **Qualitative Score.** The Qualitative Score, also on a scale of one (1) to six (6), will assess non-financial measure information about a Credit Customer's creditworthiness. A score of one (1) indicates that the Credit Customer has strong qualitative measures, while a score of six (6) indicates poor qualitative measures. The qualitative analysis will take into account a variety of information, but at a minimum will include the assessment of the following characteristics:

-Regulation/Rates
-Terms of wholesale power contracts
-Customer count served
-Power supply portfolio (e.g., contracts, assets, etc)
-Management
-Ability to access short-term capital
-Senior Unsecured Debt Rating
-SPP Payment Record

**4.2.3.3** **Composite Credit Score**. The Composite Credit Score is the weighted average of the Quantitative Score and the Qualitative Score. To illustrate, assume the following:
Not-For-Profit Qualitative Score = 2

Not-For-Profit Financial Measures:

| | Value | Score | Weight |
|---|---|---|---|
| Current Ratio | 1.42 | 1 | 15% |
| Debt Service Coverage | 1.17 | 3 | 35% |
| Times Interest Earned Ratio | 0.73 | 5 | 20% |
| Total Debt / Total Capitalization | 1.50 | 6 | 30% |

Not-For-Profit Quantitative Score =
(1 x 15%) + (3 x 35%) + (5 x 20%) + (6 x 30%) = 4.00

Not-For-Profit Credit Score =
(4.00 x 40%) + (2.0 x 60%) = 2.80 using Alternative 1, or;

(4.00 x 50%) + (2.0 x 50%) = 3.00 using Alternative 2.

The lower Composite Credit Score resulting from utilizing the two alternatives is 2.80, so it will be the Composite Credit Score used in allocating this Not-For-Profit Credit Customer's Unsecured Credit Allowance as described in Section 4.3 below.

**4.3 Unsecured Credit Allowance.**

The Composite Credit Score is converted into an "Unsecured Credit Allowance," which is a percentage of Tangible Net Worth. (Tangible Net Worth = Total Equity – Intangibles – Treasury Stock). The Composite Credit Score is a numeric value on a scale of one (1) to six (6) with one (1) indicating stronger creditworthiness and six (6) indicating weaker creditworthiness. The conversion into an Unsecured Credit Allowance is based on the percentage values stated in Table 1.

**Table 1**

| Composite Credit Score | % Tangible Net Worth Small Company Model | % Tangible Net Worth Large Company Model | % Tangible Net Worth Not For Profit Model |
|---|---|---|---|
| 1.00 - 1.99 | 5.00% | 5.00% | 7.500% |
| 2.00 - 2.99 | 3.00% | 3.00% | 4.500% |
| 3.00 - 3.59 | 2.00% | 2.00% | 3.000% |
| 3.60 - 4.39 | 0.75% | 0.75% | 1.125% |
| 4.40 - 4.99 | 0.25% | 0.25% | 0.375% |
| 5.00 - 6.00 | 0% | 0% | 0.000% |

To illustrate, a Large Company Credit Customer with a Composite Credit Score of 4.36 and Tangible Net Worth of $501,468,000 would have a suggested Unsecured Credit Allowance calculated as follows:

Unsecured Credit Allowance = Table 1 Percentage x Tangible Net Worth

= 0.75% x $501,468,000

= $3,761,010

**4.3.1 Revenue Bond Adjustment to Tangible Net Worth Value for Power Supply Agents.** For Not-For-Profit Credit Customers that issue revenue bonds solely in support of their role as power supply agent for not-for-profit electric distribution utilities and meet: (a) the disclosure requirements in: (i) Section 3.1.3 of this Credit Policy and (ii) Section 3.2.5 of this Credit Policy; and (b) have a revenue bond rating or revenue bond ratings equal to or better than Baa1 issued by Moody's Investor Services or BBB+ issued by Standard & Poor's, the calculation of the suggested Unsecured Credit Allowance shall be based on an adjusted value for Tangible Net Worth. The adjusted value for Tangible Net Worth shall include the outstanding balance of revenue bonds as of the date of the calculation.

To illustrate, if the Not-For-Profit Credit Customer met all of the disclosure requirements for power supply agents, had a Tangible Net Worth of $2,000,000, and had $8,000,000 principal amount of revenue bonds outstanding, the adjusted Tangible Net Worth to be used in computing the suggested Unsecured Credit Allowance would be $10,000,000 (the sum of the adjusted Tangible Net Worth and the principal amount of revenue bonds outstanding as of the date of the calculation).

**4.3.2 Maximum and Minimum Unsecured Credit Allowances.** Notwithstanding the calculation under Section 4.3:

**4.3.2.1** No Credit Customer shall have an Unsecured Credit Allowance in excess of $50 million; and

**4.3.2.2** On the condition that a Not-For-Profit provides all required Credit Information and executes all documents required under this Credit Policy, and subject to the Default provisions of this Credit Policy, a Not-For-Profit Credit Customer shall have a minimum Unsecured Credit Allowance in the amount of $250 thousand.

**4.3.3 Guaranty.** In the event that the Credit Customer has a Guaranty, the Unsecured Credit Allowance will be based on the Credit Assessments of the Credit Customer and the Guarantor.

**4.3.4 Unsecured Credit Allowance for Affiliates.**

**4.3.4.1 Determination of Creditworthiness of Combined Affiliates.** If two or more Credit Customers are Affiliates, and each is granted an Unsecured Credit Allowance and a corresponding Total Credit Limit, SPP will consider the overall creditworthiness of the Affiliated Credit Customers when determining the Unsecured Credit Allowances in order not to grant more unsecured credit than the overall group of affiliated entities could support. SPP will work with Affiliated Credit Customers to allocate the total Unsecured Credit Allowance among the Affiliates while assuring that no individual Credit Customer, nor common guarantor, exceeds the Unsecured Credit Allowance appropriate for its credit strength. A $50 million maximum Unsecured Credit Allowance shall apply to all Affiliates as though the Affiliates are a single Credit Customer.

**Example:** Credit Customers A and B each have a $10.0 million Guaranty from their common parent, a holding company with an Unsecured Credit Allowance calculation of $12.0 million. SPP may limit the Unsecured Credit Allowance for each Credit Customer to $6.0 million, so the total Unsecured Credit Allowance does not exceed the corporate total of $12.0 million.

**4.3.4.2 Guaranty.** If the Guaranty is applicable to Affiliates (i.e., more than one Credit Customer), then the Unsecured Credit Allowance of the Guarantor shall be allocated among such Affiliates and the applicable allocation shall be utilized in determining each Affiliated Credit Customer's Unsecured Credit Allowance.

**4.3.5 Continuous Right to Modify.** SPP has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be reasonably necessary to support the Credit Customer's ability to pay for Transmission Service and any market services SPP may provide. If the modification results in a reduction or revocation of Unsecured Credit Allowance and the reduction or revocation results in the need to provide Financial Security, then the rights and duties of SPP and the Credit Customer shall be as set forth in Section 3.2.2.

**4.4 Financial Security Requirement.** If a Credit Customer (i) is denied an Unsecured Credit Allowance, or (ii) is granted an Unsecured Credit Allowance that is below its Total Potential Exposure calculated pursuant to Article 5, then the Credit Customer may submit Financial Security to cover or exceed the difference in the amount of the Unsecured Credit Allowance granted to the Credit Customer and the amount of its Total Potential Exposure. A Credit Customer electing to satisfy the alternative criteria for market participation specified in Section 3.1.1.8.2(e) and whose anticipated or actual market activity, as determined in Article Five and Article Five A, exceeds One Hundred Thousand Dollars ($100,000) in Market Exposure and/or Total TCR Credit Requirement

shall provide Financial Security that is twice the amount calculated to satisfy its Financial Security Requirement pursuant to this Section 4.4. Any Credit Customer may provide Financial Security in lieu of or in addition to the Unsecured Credit Allowance it was granted. Upon the Credit Customer's request, SPP shall provide a written explanation of how it determined the amount of required Financial Security for that Credit Customer. A Credit Customer also is required to submit Financial Security to cover or exceed its Total TCR Credit Requirement pursuant to Section 5A.8.

**4.5 Total Credit Limit.** The "Total Credit Limit" is the amount of any Unsecured Credit Allowance approved by SPP for the Credit Customer, plus the amount of any Financial Security the Credit Customer has provided to SPP. SPP shall determine the Total Credit Limit for each Credit Customer. Upon the Credit Customer's request, SPP shall provide a written explanation of how it determined the Unsecured Credit Allowance and the amount of required Financial Security for that Credit Customer. SPP will respond to the Credit Customer's request within five (5) Business Days.

# ARTICLE FOUR A

## Virtual Energy Bids and Virtual Energy Offers

### 4A.1 Overview.

**4A.1.1** Virtual Energy Bids and Virtual Energy Offers create potential exposure of non-payment, and therefore, have a credit requirement. SPP does not require the Credit Customer to segregate, allocate, or reserve a portion of its Total Credit Limit to support its Virtual Energy Bids and Virtual Energy Offers in the Day-Ahead Market. However, SPP analyzes the Credit Customer's Virtual Energy Bids and Virtual Energy Offers to determine if the Credit Customer has credit available to support its Virtual Energy Bids and Virtual Energy Offers at the time the Bids or Offers are submitted. Only the Virtual Energy Bids and Virtual Energy Offers that the Credit Customer has credit available to support will be credit approved for the Day-Ahead Market.

**4A.1.2** In its analysis, SPP will calculate the Estimated Virtual Exposure ("EVE") based on the Credit Customer's Virtual Energy Bids and Virtual Energy Offers. Using the EVE, SPP will determine if the Credit Customer has available credit to support its Virtual Energy Bids and Virtual Energy Offers. After the close of the Day-Ahead Market for an Operating Day, the credit requirement associated with the Credit Customer's cleared Virtual Energy Bids and Virtual Energy Offers will be adjusted to reflect the actual megawatts that cleared.

**4A.1.3** The total EVE for a Credit Customer includes both (i) the calculation of EVE for Virtual Energy Bids and Virtual Energy Offers prior to the close of the Day-Ahead Market; and (ii) the EVE calculations post Day-Ahead Market clearing updated to reflect the actual cleared Virtual Energy Bids and Virtual Energy Offers.

**4A.1.4** This Article addresses the calculation of the EVE and the credit requirements associated with the submission of Virtual Energy Bids and Virtual Energy Offers in the Day-Ahead Market and the Virtual Energy Bids and Virtual Energy Offers that clear in the Day-Ahead Market.

**4A.2 Calculation of Estimated Virtual Exposure (EVE) Prior to the Close of the Day-Ahead Market for an Operating Day.** When a Virtual Energy Bid or Virtual Energy Offer is submitted, SPP will calculate the EVE using reference prices for the Virtual Energy Bid or Virtual Energy Offer and the maximum megawatts submitted. If multiple Virtual Energy Bids and Virtual Energy Offers are submitted in a single submission, the EVE will be calculated for the single submission as a whole. If a Virtual Energy Bid or Virtual Energy Offer contains multiple hours, all of the hours will be included in the EVE calculation. The EVE is calculated for the submittal of Virtual Energy Bids and Virtual Energy Offers. In the event that both a Virtual Energy Bid and Virtual Energy Offer are submitted in the same submission for the same node and same operating hour, the one with the higher dollar value will be used in the EVE calculation for that submission.

**4A.2.1** For a given Virtual Energy Bid the Virtual Energy Bid EVE is the sum of (i) the product of the Virtual Energy Bid reference price for the Settlement Location of the Virtual Energy Bid times the maximum megawatt value of the submitted Bid curve plus (ii) the virtual transaction fee. For a given Virtual Energy Offer the Virtual Energy Offer EVE is the sum of (i) the product of the Virtual Energy Offer reference price for the Settlement Location of the Virtual Energy Offer times the maximum megawatt value of the submitted Offer curve plus (ii) the virtual transaction fee.

**4A.2.1.1** If a Market Participant submits both a Virtual Energy Bid and a Virtual Energy Offer at the same location for the same hour, only the Virtual Energy Bid or Virtual Energy Offer with the greater EVE is included in the calculation of the EVE for the submission.

**4A.2.1.2** The EVE for a single submission of Virtual Energy Bids and Virtual Energy Offers is equal to the sum of the hourly Virtual Energy Bid EVEs for each Virtual Energy Bid in the submission and the sum of the hourly Virtual Energy Offer EVEs in the submission, with the adjustment described in 4A.2.1.1 if both a Virtual Energy Bid and Virtual Energy Offer are received for the same location and hour. If Credit Customer cancels a Virtual Energy Bid or Virtual Energy Offer prior to the close of the Day-Ahead Market for the Operating Day for which it is submitted, the EVE associated with the canceled portion of the submission is removed from the calculation of the EVE for the submission.

**4A.2.1.3** The Virtual Energy Bid reference price is based on the difference between the Day-Ahead Locational Marginal Prices and the Real-Time Locational Marginal Prices in the prior year, at each node. The Virtual Energy Bid reference price for a given day is the 97$^{th}$ percentile hourly difference from the same quarter in the previous year. For virtual transactions occurring in the first quarter of 2022, the calculation of the Virtual Energy Bid reference price will not include the hourly differences from the operating hours in February 12, 2021 through February 19, 2021.

**4A.2.1.4** The Virtual Energy Offer reference price is based on the difference between the Real-Time Locational Marginal Price and the Day-Ahead Locational Marginal Price in the prior year, at each node. The Virtual Energy Offer reference price for a given day is the 97$^{th}$ percentile hourly difference from the same quarter in the previous year. For virtual transactions occurring in the first quarter of 2022, the calculation of the Virtual Energy Offer reference price will not include the hourly differences from the operating hours in February 12, 2021 through February 19, 2021.

**4A.2.1.5 Calculation of Virtual Energy Bid and Virtual Energy Offer Reference Prices During the Initial Year of the Integrated Marketplace.** During the initial year of the Integrated Marketplace, prior to the accumulation of complete Real-Time and Day-Ahead Locational Marginal Price data sufficient to calculate the Virtual Energy Bid and Virtual Energy Offer references prices pursuant to sections 4A.2.1.3 and 4A.2.1.4, SPP shall use data representative of the expected Day-Ahead and Real-Time Market results based on simulations of the Day-Ahead Market or other available information.

**4A.2.1.6 Calculation of Virtual Energy Bid and Virtual Energy Offer Reference Prices for New Settlement Locations.** When a new Settlement Location is created and until actual Virtual Energy Bid and Virtual Energy Offer reference prices can be calculated pursuant to section 4A.2.1.3 and 4A.2.1.4 for that Settlement Location, SPP will use the system average virtual reference price. The system average virtual reference price for a given quarter is the mean of all of the Virtual Energy Bid and Virtual Energy Offer reference prices for that quarter.

## 4A.3 Determination of Credit Approved Virtual Energy Bids and Virtual Energy Offers.

**4A.3.1** If the EVE for a submission of Virtual Energy Bids and Virtual Energy Offers is less than the Credit Customer's available credit, which is equal to the Credit Customer's Total Credit Limit less its Total Potential Exposure, then the submission is credit approved. Credit approved Virtual Energy Bids and Virtual Energy Offers, unless withdrawn will be included in the Day-Ahead Market.

**4A.3.2** If the EVE for a submission of Virtual Energy Bids and Virtual Energy Offers is greater than the Credit Customer's available credit, which is equal to the Credit Customer's Total Credit Limit less its Total Potential Exposure, then the submission will be rejected. Rejected Virtual Energy Bids and Virtual Energy Offers will not be included in the Day-Ahead Market and will not affect the Total Potential Exposure calculation.

**4A.3.3** Modifications to Virtual Energy Bids and Virtual Energy Offers prior to the close of the Day-Ahead Market for the Operating Day for which they were submitted will be evaluated using the same procedures. Modifications are evaluated based on their net credit impact. The EVE for the modified Virtual Energy Bids and Virtual Energy Offers submission will be revised to incorporate the modifications to the submission.

**4A.3.3** The EVE for credit approved Virtual Energy Bids and Virtual Energy Offers submissions that have not yet settled or cleared in the Day-Ahead Market is

included in the Total Potential Exposure calculation as set forth in Article 5. Therefore, the determination of whether a Virtual Energy Bid and Virtual Energy Offer submission is credit approved will take into account the credit requirements for previously determined credit approved Virtual Energy Bids and Virtual Energy Offers.

**4A.3.4** If a Credit Customer cancels a credit approved Virtual Energy Bid or Virtual Energy Offer submission prior to the close of the Day-Ahead Market for the Operating Day for which it is submitted, that Virtual Energy Bid or Virtual Energy Offer will no longer have a credit requirement associated with it and its EVE will be zero.

**4A.4 Updated EVE Calculations Post Day-Ahead Market Clearing.** After clearing of the Day-Ahead Market for an Operating Day, the EVEs for credit approved Virtual Energy Bids and Virtual Energy Offers shall be updated to replace the maximum megawatts with the actual megawatts that cleared. If there are Virtual Energy Bids and Virtual Energy Offers that cleared at the same location, the megawatt amounts will be netted in the updated EVE calculation.

# ARTICLE FIVE

## Calculation of Total Potential Exposure

**5.1 Overview.** The Total Potential Exposure is a calculated value applied to assure that the Credit Customer engages in activities within its Total Credit Limit. The Total Potential Exposure is based on the Credit Customer's estimated cumulative financial obligation under the Tariff or otherwise to SPP, excluding TCR activity. Potential Exposure to non-payment is calculated separately for each applicable category of service and then summed together to obtain the amount of Total Potential Exposure. This Article addresses the calculation and use of the value for Total Potential Exposure. As explained in Article 5A, only Financial Security may be used for credit requirements associated with TCR activity.

**5.2 Calculation of Total Potential Exposure for a Credit Customer.** A Credit Customer's Total Potential Exposure shall be the sum of the potential exposure to non-payment for market transactions and Transmission Service transactions billed pursuant to the Tariff. Because only Financial Security may be used to satisfy the credit requirements associated with TCR activity, TCR activity is not included in the Total Potential Exposure determination, but is reflected in the determination of whether there is a Total Potential Exposure Violation.

**5.2.1 Market Exposure ("ME").** Potential exposure to non-payment associated with market transactions in the Integrated Marketplace is calculated under the following formula:

ME = IMSC + CMSC + MEMERT + MEMEDA + EVE

IMSC = Invoiced Market Settlement Charges (all Real-Time Balancing Market and Day-Ahead Market, including virtual transaction activity, charges or credits that have been invoiced but not yet paid).

CMSC = Calculated Market Settlement Charges (all Real-Time Balancing Market and Day-Ahead Market, including virtual transactions, daily settlement activity, including charges or credits, that has been calculated but not yet invoiced).

MEMERT = Maximum Estimated Market Exposure for Real-Time Balancing Market activity shall be the greater of:

(a) The average of the last three hundred sixty five (365) days of daily Real Time Balancing Market settlement activity (or if settlement activity occurred for a lesser period, the average settlement activity during such lesser period), or

(b) The average of the last seven (7) days of daily Real-Time Balancing Market settlement activity (or if settlement activity occurred for a lesser period, the average settlement activity during such lesser period).

Once the greater value is determined that value is multiplied by the number of days remaining in the Potential Exposure Window. Inasmuch as the Potential Exposure Window refers to "days before service can be terminated," the time period for purposes of calculating the MEMERT does not include additional time for service termination.

MEMEDA = Maximum Estimated Market Exposure for Day-Ahead Market activity shall be the greater of:

(a) The average of the last three hundred sixty five (365) days of most recently calculated Settlement Statements for Day-Ahead Market activity (or if settlement activity occurred for a lesser period, the average settlement activity during such lesser period), or

(b) The average of the seven (7) most recent Operating Days for which SPP has calculated either (i) updated estimated Day-Ahead Market activity results calculated four days after the Operating Day; or (ii) initial Settlement Statements for Day Ahead Market activity (or if updated estimated activity results or settlement activity occurred for a lesser period, the average updated estimated activity and settlement activity resulting during such lesser period). The initial Settlement Statements are created at the end of the 7th calendar day following the Operating Day. As initial Settlement Statements become available such statements will be used instead of the updated estimated activity results calculated four days after the Operating Day.

For the time period prior to commencement of the Day-Ahead Market for which there are no calculated initial Settlement Statements for Day-Ahead Market activity for use in the determination of the MEMEDA for a Credit Customer, SPP shall use data representative of the expected Day-Ahead Market activity for the Credit Customer based on simulations of the Day-Ahead Market or other available information.

Once the greater value is determined that value is multiplied by the number of days remaining in the Potential Exposure Window. Inasmuch as the Potential Exposure Window refers to "days before service can be terminated," the time period for purposes of calculating the MEMEDA does not include additional time for service termination.

EVE = Estimated Virtual Exposure, calculated pursuant to Article 4A (for all credit approved Virtual Energy Bids and Virtual Energy Offers prior to the close of the Day-Ahead Market for an Operating Day or Days that have

not yet been settled and cleared Virtual Energy Bids and Virtual Energy Offers)

**5.2.2 Transmission Service Potential Exposure ("TSPE").** Potential exposure to non-payment associated with Transmission Service transactions is calculated under the following formula:

TSPE = ITSC + CTSC + METE

ITSC = Invoiced Transmission Service Charges (all transmission service charges or credits that have been invoiced but not yet been paid).

CTSC = Calculated Transmission Service Charges (transmission service charges or credits that have been calculated but not yet invoiced).

METE = Maximum Estimated Transmission Exposure (an estimate of the charges for the remainder of the Potential Exposure Window). METE will be calculated as follows:

METE will be the value of all charges based on reserved transmission capacity for each confirmed Transmission Service reservation for the period beginning on the day following the latest date included in the CTSC calculation and ending on the TSPE calculation date, plus the value of all charges for confirmed reservations for the number of days which when added to the number of days included in the ITSC and the CTSC would total 50 days. The number of days included in the ITSC is the number of days of transmission service included in an unpaid invoice. If there are no unpaid invoices, the number of days included in the ITSC would be zero. The number of days included in the CTSC are the days for which the transmission service charges or credits have been calculated, but not yet invoiced.

METE for Network Service reservations will be calculated by taking the highest monthly Network Service charge over the most recent twelve (12) month period (or, if Network Service has been taken for a shorter period, the period for which it was taken), divided by the number of days included in the month of the highest charge and multiplying the resulting amount by the number of days which when added to the number of days included in the ITSC and the CTSC would total 50 days. For this calculation, each Network Service charge is the amount of the Network Service invoice, less the amount of transmission revenue due to the invoiced Credit Customer for Network Service during the period covered by the applicable invoice

**5.2.3 Total Potential Exposure Calculation.** A Credit Customer's Total Potential Exposure ("TPE") shall be the sum of the potential exposure to non-payment for market transactions, excluding TCR transactions, and Transmission Service transactions billed pursuant to the Tariff and may be calculated using the formula:

**TPE = ME + TSPE**

## 5.3 Total Potential Exposure Violations.

**5.3.1 Transaction Limits.** At all times, the Credit Customer shall maintain additional Financial Security equal to or greater than the Total TCR Credit Requirement, calculated pursuant to section 5A.8. Also at all times, the Credit Customer shall maintain its Total Potential Exposure to a value equal to or less than its Total Credit Limit excluding any Financial Security required for TCR activity. A "Total Potential Exposure Violation" occurs when either or both (i) a Credit Customer's Total Potential Exposure equals or exceeds its Total Credit Limit excluding any Financial Security required for TCR activity; or (ii) a Credit Customer's Total TCR Credit Requirement exceeds the Credit Customer's Financial Security excluded from the Total Credit Limit. SPP will regularly monitor each Credit Customer's use of services and associated financial obligations. If a Credit Customer's Total Potential Exposure equals or exceeds ninety percent (90%) of its Total Credit Limit, SPP shall promptly give notice to the Credit Customer (excluding any Financial Security required for TCR activity pursuant to Article 5A). Failure by SPP to give this notice shall not relieve the Credit Customer of its duties under this Section.

**5.3.2 Cure of Total Potential Exposure Violation.** A Credit Customer shall cure a Total Potential Exposure Violation by: (i) payment to SPP of invoiced amounts to reduce the Credit Customer's Total Potential Exposure, and/or (ii) provision of Financial Security in an amount sufficient to increase the Credit Customer's Total Credit Limit, such that after making such payments of invoiced amounts and/or providing such Financial Security, the Credit Customer's Total Potential Exposure will not exceed its Total Credit Limit; and/or (iii) provision of Financial Security in an amount sufficient to satisfy the Total TCR Credit Requirement as provided in Article 5A. The Credit Customer shall have two (2) Business Days from receipt of notice from SPP to cure the violation. SPP, in its sole discretion, may determine to treat any amount tendered under (i) as an increase of Financial Security under (ii) and not as a payment to SPP.

**5.3.3 Failure to Cure Total Potential Exposure Violation.** A failure to cure a Total Potential Exposure Violation as required under Section 5.3.2 is a Default. In the event of such a Default, SPP has all rights under section 7 of the Tariff or section 10.5 of Attachment AE and all other rights and remedies in accordance with applicable law. Without prejudice to other remedies, a Credit Customer that fails timely to cure a Total Potential Exposure Violation shall be suspended from requesting any future services, including all Transmission Service and market services SPP may provide, unless and until the Credit Customer's Total Potential Exposure Violation is cured.

**5.4. Excess Financial Security.** In the event a Credit Customer has provided additional Financial Security under Section 5.3.2 to address a Total Potential Exposure Violation, and the Credit Customer's outstanding invoiced amounts subsequently return to levels

preceding that violation such that the total amount of Financial Security exceeds the amount required under this Credit Policy, the Credit Customer may request return of the excess Financial Security and SPP shall comply with the request within two (2) Business Days; provided, that if SPP determines to review the Credit Assessment for the Credit Customer due to the violation, it shall not be required to respond to the request, including return of any excess Financial Security, until two (2) Business Days after completing the new Credit Assessment.

# ARTICLE FIVE A

## Transmission Congestion Rights (TCRs)

### 5A.1 Overview.

**5A.1.1** Transmission Congestion Rights create potential exposure of non-payment, and therefore, have a credit requirement. SPP will establish a Total TCR Credit Requirement for each Credit Customer holding TCRs or participating in a TCR Auction. A Credit Customer may satisfy its Total TCR Credit Requirement by providing Financial Security. Unsecured Credit is not available to support a Credit Customer's holding of TCRs or activity in TCR Auctions. Additionally, SPP's prior approval is required for a Credit Customer to acquire or transfer TCRs through bilateral transactions.

**5A.1.2** To establish the credit requirement associated with TCRs, SPP analyzes: (i) the TCRs the Credit Customer holds (including TCRs held via self-conversion from ARRs); (ii) the Credit Customer's Bids and Offers for TCRs in the TCR Auctions; (iii) TCR payments or charges for which settlement has been calculated but not yet invoiced; and (iv) TCR payments or charges for which an invoice has been issued but payment has not occurred.

(a) SPP calculates the potential exposure associated with the full portfolio of TCRs that are held by the Credit Customer including TCRs obtained from LTCRs and ILTCRs.

(b) SPP evaluates individually each TCR Bid in the TCR Auctions to ensure that the Credit Customer has sufficient Financial Security to cover the credit requirements to purchase and hold the TCR. Only the TCR Bids for which the Credit Customer has sufficient Financial Security will be credit approved for consideration in the TCR Auction.

(c) SPP evaluates individually each TCR Offer in the TCR Auctions to ensure that the Credit Customer has sufficient Financial Security to cover any credit requirements associated with the Offer and the credit requirements for the retained TCR portfolio that would result if the TCR Offer clears in the TCR Auction. Only the TCR Offers for which the Credit Customer has sufficient Financial Security will be credit approved for consideration in the TCR Auction.

(d) Additionally, SPP analyzes the credit requirements associated with TCRs that are the subject of a proposed bilateral transfer prior to providing approval of such transfers. SPP approval of a bilateral

transfer for TCRs is required for such bilateral transfers to be completed.

**5A.1.3** As part of the determination of the credit requirement associated with TCRs, SPP calculates the Estimated TCR Exposure (ETCRE), which is an estimate of the potential value of the TCR over the life of the TCR. In the case of a TCR associated with a LTCR or ILTCR, the life of the TCR shall be considered one year. It will be calculated for all TCRs the Credit Customer holds, the Credit Customer's TCR Bids and TCR Offers, proposed TCR bilateral transfers, and TCRs acquired through ARR self-conversion. SPP will determine the credit requirement associated with TCRs and whether the Credit Customer has available Financial Security to support its TCR activity. After the close of a TCR Auction and on an ongoing basis, SPP will update the Credit Customer's Total TCR Credit Requirement associated with TCRs to reflect the actual TCRs the Credit Customer holds and TCR Auction results, including the costs to acquire or sell TCRs in a TCR Auction.

**5A.1.4** This Article addresses the calculation of the Total TCR Credit Requirement associated with TCRs, including the ETCRE calculations for the TCRs the Credit Customer holds and the Credit Customer's Bids and Offers for TCRs in the TCR Auctions and the acquisition and disposal costs of the TCR in the TCR Auctions; as well as the TCR payments or charges for which settlement has been calculated but not yet invoiced; and the TCR payments or charges for which an invoice has been issued but payment has not occurred. This Article also addresses the determination whether a Credit Customer has sufficient Financial Security available for the Credit Customer's proposed TCR Auction activity or proposed bilateral transfers of TCRs.

**5A.2 Calculation of Estimated TCR Exposure (ETCRE) for TCRs that a Credit Customer Holds (ETCRE Hold).** SPP will calculate the ETCRE Hold, which is an estimate of the potential value (positive or negative) of the TCR contract for the term of the TCR, for TCRs that a Credit Customer holds. A negative ETCRE Hold means SPP estimates that the potential value of the TCR will result in a payment by the Credit Customer. A positive ETCRE Hold means SPP estimates that the potential value of the TCR will result in a payment to the Credit Customer. The ETCRE Hold calculation is determined for each TCR on an individual basis. ETCRE Hold is the product of the TCR Final Reference Price times the TCR megawatts. SPP will calculate the TCR Final Reference Price for each TCR based on the difference of historical Day-Ahead Market Marginal Congestion Cost (MCC) between the TCR source and TCR sink.

**5A.2.1 TCR Final Reference Price.** For a given source and sink combination and with respect to time (season or month) and class (on-peak and off-peak), the TCR Final Reference Price has two components: (i) a TCR Mean Price; and (ii) a TCR

Stress Test Price. The Final Reference Price is the TCR Mean Price *minus* the TCR Stress Test Price.

**5A.2.1.1** Both the TCR Mean Price and TCR Stress Test Price are determined using the Day-Ahead Market Marginal Congestion Component (MCC) prices from the prior two years. Each year of the prior two year period will be weighted, with the more recent year receiving a 75% weighting and the more distant year receiving a 25% weighting. The MCC prices used in the calculations for a TCR match the definition of the TCR with respect to time (season or month) and class (on-peak and off-peak). Historical MCC prices to be used for the more recent year will only be used if the specific time period (season or month) has been completed, i.e. no partial period MCC prices will be used to calculate Final Reference Prices.

**5A.2.1.1.1** A TCR Final Reference Price determination is used in the calculations for ETCRE Hold, ETCRE Bid, and ETCRE Offer calculations. For each such calculation, the prior two year period used in the calculation is measured from the time of the calculation. ETCRE Hold calculations will be updated to reflect updated prior two year periods for a given TCR as MCC prices are completed for a season or month that previously was not included in the prior two year period.

**5A.2.1.2** The TCR Mean Price is the sum of 75% of the mean of the hourly Day-Ahead Market MCC difference calculated as the sink MCC minus the source MCC for the more recent year in the prior two year period plus 25% of the mean of the hourly Day-Ahead Market MCC difference calculated as the sink MCC minus the source MCC for the more distant year in the prior two year period.

**5A.2.1.3** The TCR Stress Test Price calculation differs for TCRs with positive and negative Mean Prices. For a TCR with a negative TCR Mean Price, the TCR Stress Test Price is the $90^{th}$ percentile of the opposite flow value (i.e. source MCC minus sink MCC) in the prior two year period. For a TCR with a positive TCR Mean Price, the TCR Stress Test Price is the $75^{th}$ percentile of the opposite flow value (i.e. source MCC minus sink MCC) in the prior two year period. The TCR Stress Test Price has a minimum value of zero and thus can never increase the TCR Final Reference Price.

**5A.2.2 Calculation of TCR Final Reference Price during the Initial Two-Years of the Integrated Marketplace.** Prior to the accumulation of complete MCC data sufficient to calculate the TCR Final Reference Price pursuant to Section 5A.2.1, to calculate both the Mean Price and Stress Test Price, to the extent complete MCC price data for the applicable prior two year period is not available, SPP will use the applicable historical energy imbalance service price differences.

**5A.2.3 Calculation of TCR Final Reference Price for New Settlement Locations.** When a new Settlement Location is created, SPP will use a proxy price based on the system average Day-Ahead Market MCC to calculate the TCR Mean Price and TCR Stress Test Price for the new Settlement Location. The system average Day-Ahead Market MCC for each defined TCR is the mean of the hourly Day-Ahead Market MCC for all Settlement Locations for which a Day-Ahead Market MCC exists for each hour in the prior two year period for a defined TCR. Based on a two year weighted average approach, the proxy will be blended with actual data after the first year.

**5A.3 TCR Portfolio Credit Requirement.** The Financial Security required for a Credit Customer's TCR portfolio is the TCR Portfolio Credit Requirement and is one component of the Total TCR Credit Requirement. The TCR Portfolio Credit Requirement is the lesser of (a) the sum of (i) the sum of the ETCRE Hold values for each TCR in the Credit Customer's TCR portfolio; (ii) the portion of the cost to acquire each TCR in a TCR Auction that has not yet been settled; and (iii) the disposal cost for TCR Offers that clear a TCR Auction that has not yet been settled, or (b) the Minimum TCR Collateral Requirement.

**5A.3.1** The sum of the ETCRE Hold values for each TCR in the Credit Customer's TCR portfolio used in the calculation of the TCR Portfolio Credit Requirement is equal to the net sum of the ETCRE Hold values for each TCR in the Credit Customer's TCR portfolio, with individual positive and negative ETCRE Hold values netted, for a time period greater than the last settled operating day with the most negative net sum of ETCRE Hold values of the Credit Customer's TCR portfolio. For a TCR with a term longer than a month, the ETCRE Hold for each month of the TCR is equal to the total ETCRE Hold for the TCR divided by the number of months of the term of the TCR. SPP calculates the ETCRE Hold each day for which at least one TCR in the portfolio is valid.

**5A.3.2** The portion of the acquisition cost to acquire each TCR in a TCR Auction that has not yet been settled includes the amounts that the Credit Customer is required to pay for TCRs it acquires in a TCR Auction, that have not yet been settled, and does not include amounts that may be owed to a Credit Customer to acquire a TCR. For TCRs acquired through self-converted ARRs, the acquisition cost is zero. For TCRs acquired through a bilateral transfer the acquisition cost is zero for the buyer because the acquisition cost remains the responsibility of the participant who originally acquired the TCR in a TCR Auction.

**5A.3.3** The portion of the disposal cost for each TCR Offer that clears a TCR Auction that has not yet been settled is the portion of a Credit Customer's loss associated with the difference between the Offer price and the original Auction Clearing Price for the TCR that is the subject of the TCR Offer. For TCRs acquired pursuant to a bilateral transfer that are the subject of a TCR Offer, zero will be used for the Auction Clearing Price for this calculation.

**5A.3.4** Except in the case of ARRs self-converted to TCRs, only negative TCR Portfolio Credit Requirements are included in the Total TCR Credit Requirement. If the TCR Portfolio Credit Requirement is a positive value it does not diminish the Financial Security requirement for TCRs and zero will be used for the TCR Portfolio Credit Requirement in the calculation of the Total TCR Credit Requirement.

**5A.3.5** Both positive and negative TCR values for ARRs self-converted to TCRs in a TCR Auction will be included in the Credit Customer's Total TCR Credit Requirement. Ninety percent (90%) of the positive and one hundred percent (100%) of the negative TCR values for ARRs self-converted will be netted and the netted value used in establishing the credit requirement.

**5A.3.6 Minimum TCR Collateral Requirement** means the total megawatt hours owned by the Credit Customer multiplied by $(0.10) to establish a minimum portfolio Financial Security requirement.

**5A.4 Calculation of ETCRE Bid.** SPP evaluates the Bids for TCRs to ensure that the Credit Customer has sufficient Financial Security to cover any Financial Security requirements to purchase and hold the TCR. The ETCRE Bid calculates the Financial Security requirements for each Bid. When a TCR Bid is submitted, SPP will calculate the ETCRE Bid for the Bid, which is the lesser of (a) the minimum sum of (i) the ETCRE Segment and (ii) the TCR Segment Cost, for the segments in the Bid, or (b) the Minimum Segment Hold. SPP calculates the ETCRE Segment for each megawatt point on the submitted Bid curve, and the TCR Segment Cost for each megawatt point on the submitted Bid curve, and the Minimum Segment Hold for the maximum megawatt on the submitted Bid curve. For each segment, SPP calculates the sum of (i) the ETCRE Segment and (ii) the TCR Segment Cost.

**5A.4.1 ETCRE Segment.** In evaluating TCR Bids, SPP calculates the ETCRE Segment for each megawatt point on the submitted Bid curve. The ETCRE Segment can be positive or negative. It is the potential value of holding the TCR in the Bid. It is calculated in the same manner as the ETCRE Hold, using the Final Reference Price, and the TCR Bid megawatts.

**5A.4.2 TCR Segment Cost.** In evaluating TCR Bids, SPP estimates the TCR acquisition cost by calculating the TCR Segment Cost for each megawatt point on the submitted Bid curve by multiplying the Bid price for that megawatt point times the megawatts for that point on the submitted Bid curve. The TCR Segment Cost

is the potential cost for the Credit Customer to acquire any megawatt point on the submitted Bid segment. For TCRs with negative acquisition costs, e.g., if the Bid curve has a negative Bid price, the TCR Segment Cost will be zero. For a TCR resulting from an ARR self-conversion, the TCR Segment Cost also will be zero.

**5A.4.3 Minimum Segment Hold** means the maximum megawatt point on the submitted TCR Bid curve multiplied by $(0.10) multiplied by the number of hours in the TCR product. The Minimum Segment Hold will always be negative.

**5A.4.4** If multiple TCR Bids and Offers are included in a single submission, the Credit Customer must have sufficient Financial Security to cover all of the Bids and Offers in the submission. The Financial Security requirement for a single submission is the sum of the negative ETCRE Bid and ETCRE Offer for the Bids and Offers in the submission without any netting of the individual ETCRE Bid or ETCRE Offer for the TCR Bids and Offers that are included in the submission.

**5A.5 Calculation of ETCRE Offer.** SPP evaluates the Offers for TCRs to ensure that the Credit Customer has sufficient Financial Security to cover any Financial Security requirements resulting if the TCR is no longer held and potential losses resulting from the sale. The ETCRE Offer calculates the Financial Security requirement for each Offer. When a TCR Offer is submitted, SPP will calculate the ETCRE Offer for the Offer which is the lesser of (a) the minimum sum of (i) the ETCRE Offer Segment; and (ii) the TCR Offer Segment Cost, for the segments in the Offer, or (b) the Minimum Offer Segment. SPP calculates the ETCRE Offer Segment for each megawatt point on the submitted Offer curve, and the Minimum Offer Segment for the maximum megawatt on the submitted Offer curve. For each segment, SPP calculates the sum of (i) the ETCRE Offer Segment, and (ii) the TCR Offer Segment Cost.

**5A.5.1 ETCRE Offer Segment.** In evaluating TCR Offers, SPP calculates the ETCRE Offer Segment for each megawatt point on the submitted Offer curve. It is the potential value of disposing of an existing TCR in the Offer. It is calculated in the same manner as the ETCRE Hold, using the Final Reference Price and the TCR Offer megawatts. If the calculated ETCRE Offer Segment is positive, SPP sets the ETCRE Offer to zero.

**5A.5.2 TCR Offer Segment Cost.** In evaluating TCR Offers, SPP estimates the TCR disposal cost by calculating the TCR Offer Segment Cost for each megawatt point on the submitted Offer curve by multiplying the Offer price for that megawatt point times the megawatts for that point on the submitted Offer curve. The TCR Offer Segment Cost is the potential cost for the Credit Customer to dispose of any megawatt point on the submitted Offer segment. If the TCR was originally acquired from an ARR self-schedule or pursuant to a bilateral transfer, zero is used for the original Auction Clearing Price. If the calculated ETCRE Offer Segment Cost is positive SPP sets the ETCRE Offer to zero.

**5A.5.3** Minimum Offer Segment means the maximum megawatt point on the submitted TCR Offer curve multiplied by $(0.10) multiplied by the number of hours in the TCR product. The Minimum Offer Segment will always be negative.

**5A.5.4** If multiple TCR Bids and Offers are included in a single submission, the Credit Customer must have sufficient Financial Security to cover all of the Bids and Offers in the submission. The Financial Security requirement for a single submission is the sum of the negative ETCRE Bid and ETCRE Offer for the Bids and Offers in the submission without any netting of the individual ETCRE Bid or ETCRE Offer for the TCR Bids and Offers that are included in the submission.

**5A.6 Determination of Credit Approved TCR Bids and Offers and Rejection of TCR Bids and Offers which are Credit Disapproved.**

**5A.6.1** If the sum of the ETCRE Bid and ETCRE Offer for all TCRs (other than TCRs self-converted from ARRs) included in a single submission of Bids and Offers for a TCR Auction, calculated pursuant to sections 5A.4 and 5A.5, without netting, is less than the Credit Customer's available amount of Financial Security, then the submission is credit approved for inclusion in the TCR Auction.

**5A.6.2** If the sum of the ETCRE Bid and ETCRE Offer for all TCRs (other than TCRs self-converted from ARRs) included in a single submission of Bids and Offers for a TCR Auction, calculated pursuant to sections 5A.4 and 5A.5, without netting, is greater than the Credit Customer's available Financial Security, then the entire submission is credit disapproved and the Bids and Offers will not be included in the TCR Auction.

**5A.6.3** If the sum of the ETCRE Bid and ETCRE Offer for all TCRs included in a single submission of ARR self-conversions for a TCR Auction, calculated pursuant to sections 5A.4 and 5A.5, with netting as described in Section 5A.3.5 of this Attachment X, is less than the Credit Customer's available amount of Financial Security, then the submission is credit approved for inclusion in the TCR Auction.

**5A.6.4** If the sum of the ETCRE Bid and ETCRE Offer for all TCRs included in a single submission of ARR self-conversions for a TCR Auction, calculated pursuant to sections 5A.4 and 5A.5, with netting as described in Section 5A.3.5 of this Attachment X, is greater than the Credit Customer's available Financial Security, then the entire submission is credit deficient and the ARR self-conversion will not be included in the TCR Auction unless satisfactory alternate credit arrangements are made.

**5A.7 Updated ETCRE Calculation Post TCR Auction.** After the clearing of a TCR Auction, the TCR Portfolio Credit Requirement will be updated to reflect the TCRs awarded in the TCR Auction, including the acquisition cost for TCR Bids that cleared the TCR Auction and the disposal cost for TCR Offers that cleared the TCR Auction. For TCR Bids, the TCR acquisition cost is calculated as the product of the Auction Clearing

Price times the awarded megawatts. For TCR Offers, the TCR disposal cost is calculated as the product of the Auction Clearing Price times the megawatts sold. The ETCRE Hold portion of the TCR Portfolio Credit Requirement will be updated to reflect the actual TCRs in the portfolio.

**5A.8 Total TCR Credit Requirement.** The total Financial Security requirement associated with the Credit Customer's holding of TCRs and participating in the TCR Auctions is the Total TCR Credit Requirement. The Total TCR Credit Requirement for a Credit Customers is the sum of (i) the TCR Portfolio Credit Requirement for the Credit Customer's TCR portfolio, reflecting all of the TCRs held by the Credit Customer, calculated pursuant to section 5A.3; (ii) the Financial Security required for the Credit Customer's participation in a TCR Auction, determined by the credit approved ETCRE Bid, calculated pursuant to section 5A.4, and ETCRE Offer, calculated pursuant to section 5A.5, for a TCR Auction that has not yet occurred; (iii) all TCR charges or credits that have been invoiced but not yet paid; and (iv) TCR charges or credits that have been calculated but not yet invoiced.

Total TCR Credit Requirement =
TCR Portfolio Credit Requirement + ETCRE Bid + ETCRE Offer + (ITCRC + CTCRC)

Where,

TCR Portfolio Credit Requirement is calculated pursuant to section 5A.3.

ETCRE Bid is the sum of the ETCRE Bid amounts for the Credit Customer's credit approved Bids for an auction that has not yet occurred, as calculated pursuant to section 5A.4, without netting ETCRE Bid or ETCRE Offers in a submission.

ETCRE Offer is the sum of the ETCRE Offer amounts for the Credit Customer's credit approved Offers for an auction that has not yet occurred, as calculated pursuant to section 5A.5, without netting ETCRE Bid or ETCRE Offers in a submission.

ITCRC is the Invoiced TCR Charges (all TCR charges or credits that have been invoiced but not yet paid). If the sum of ITCRC and CTCRC for a Credit Customer is negative, then zero will be included for the sum of ITCRC and CTCRC in the calculation of the Total TCR Credit Requirement.

CTCRC is the Calculated TCR Charges (TCR charges or credits that have been calculated but not yet invoiced). If the sum of ITCRC and CTCRC for a Credit Customer is negative, then zero will be included for the sum of ITCRC and CTCRC in the calculation of the Total TCR Credit Requirement.

**5A.8.1** If a Credit Customer's available Financial Security is less than its Total TCR Credit Requirement, then the Credit Customer shall be required to provide additional Financial Security within two (2) Business Days from receipt of notice

of such violation. Failure to provide such Financial Security is a Default under this Credit Policy.

**5A.9 Transfer of TCRs.** If a Credit Customer proposes to sell or acquire TCRs through a bilateral transfer with another Credit Customer, SPP will evaluate the effect of the proposed transfer on the Total TCR Credit Requirement of each party to the proposed bilateral transfer and determine if both the buyer and the seller have sufficient Financial Security for the bilateral transfer to occur. SPP approval of such bilateral transfers, based on whether both the buyer and seller have provided sufficient Financial Security to support the transfer, is required prior to such transfers.

**5A.9.1** For the seller in a bilateral transfer, SPP calculates the impact of the proposed transfer on the TCR Portfolio Credit Requirement that would result from the removal of the TCRs that are the subject of the proposed bilateral transfer from the TCR portfolio of the Credit Customer that is the seller in the bilateral transfer.

**5A.9.2** For the buyer in a bilateral transfer, SPP calculates the impact of the proposed transfer on the TCR Portfolio Credit Requirement that would result from the addition of the TCRs that are the subject of the proposed bilateral transfer from the TCR portfolio of the Credit Customer that is the buyer in the bilateral transfer.

**5A.9.3** If multiple TCRs are included in a single proposed bilateral transfer, both parties to the bilateral transfer must have sufficient Financial Security for the transfer of all of the TCRs in the proposed transfer.

**5A.9.4** SPP, in its sole discretion, may approve bilateral transfers if a Credit Customer does not have sufficient Financial Security to support the transfer, but the transfer would result in a reduction in Total TCR Credit Requirement for that Credit Customer.

**5A.9.5** The bilateral TCR transfer price is not included in SPP's evaluation of a bilateral transfer of TCRs. After an approved bilateral transfer of TCRs is completed, each Credit Customer's Total TCR Credit Requirement is updated.

**5A.10 Return of TCR Financial Security.** A Credit Customer may request that SPP return any Financial Security no longer required to hold TCRs or participate in TCR Auctions if it is not needed to support other market services. SPP may limit the frequency of such requested Financial Security returns, provided that Financial Security returns will be made by SPP at least once per month, if requested by a Credit Customer.

# ARTICLE SIX

## Guarantees

**6.1 Guaranty.** A Guaranty approved by SPP transfers to the Credit Customer a portion of the Guarantor's creditworthiness and thereby increases the Credit Customer's Total Credit Limit. Unlike an Irrevocable Letter of Credit or Surety Bond, a Guaranty is not Financial Security. A Guaranty that is backed by Financial Security will have the same impact upon the Total Credit Limit as Financial Security. A Guaranty that is not backed by Financial Security is unsecured and will be considered unsecured credit in the determination of the Unsecured Credit Allowance.

**6.2 Approval Process.** SPP will determine whether to approve a Guaranty based upon the creditworthiness of the proposed Guarantor as though it were a Credit Customer under this Credit Policy. All Credit Information required under this Credit Policy with respect to a Credit Customer must be submitted initially for the proposed Guarantor and regularly thereafter. SPP will evaluate the Credit Information and determine any Unsecured Credit Allowance and the Total Credit Limit for the Credit Customer beneficiary of the proposed Guaranty. SPP shall have the right to revise the Unsecured Credit Allowance and Total Credit Limit from time to time based upon continued assessment of the Credit Information of the Guarantor.

**6.3 Requirements for Guaranty.** A Credit Customer can utilize a Guaranty if all of the following conditions are satisfied:

**6.3.1 Guarantor's Satisfaction of Financial Standards under this Credit Policy.** A Guarantor is subject to the same financial review procedures as a Credit Customer. A Guarantor will be eligible to provide a Guaranty to the extent, if any, of the Guarantor's creditworthiness under this Credit Policy.

**6.3.2 The Form and Substance of the Guaranty Acceptable to SPP.** Appendix "D" of this Credit Policy is a form of Guaranty. The Guaranty must:

**6.3.2.1** Be duly authorized by the Guarantor and signed by an officer of the Guarantor

**6.3.2.2** State an effective period, or provide for automatic renewal or other basis for periodicity subject to cancellation on no less than sixty (60) days notice and provided that in all events the Guaranty is effective for all obligations of the Credit Customer undertaken prior to cancellation.

**6.3.2.3** Include certification of the corporate secretary that the execution, delivery, and performance of the Guaranty have been duly authorized;

**6.3.2.4** Certify that the Corporate Guaranty is not in violation of other undertakings or requirements applicable to the Guarantor, and enforceable against the Guarantor in accordance with its terms;

**6.3.2.5** Obligate the Guarantor to submit Credit Information on an ongoing basis as required under this Credit Policy;

**6.3.2.6** Incorporate default provisions, including default provisions referred to in Section 6.3.4;

**6.3.2.7** Secure, in combination with other forms of Financial Security, all obligations of the Credit Customer under or in connection with this Tariff and/or other Agreements; and

**6.3.2.8** Be supported by adequate consideration and be otherwise binding as a matter of law.

**6.3.2.9** Include as an attachment thereto the resolution(s) of the board of directors or other governing body of the Guarantor authorizing the Corporate Guaranty.

**6.3.3** Reserved for Future Use

**6.3.4 Default.** Any breach of the Guaranty by the Guarantor or the requirements of the Guarantor under this Credit Policy shall be deemed a Default of this Credit Policy and a default under the Tariff by the Guarantor and the Affiliates whose obligations are supported by the Guaranty. The following also shall be a Default of this Credit Policy and a default under the Tariff: (i) the Guaranty expires or terminates (other than in accordance with its terms or upon the written consent of SPP); (ii) the Guarantor disaffirms, disclaims, repudiates, rejects or challenges the validity of all or any part of the Guaranty; or (iii) the Guaranty or any material provision of the Guaranty ceases to be in full force and effect (other than in accordance with its terms or upon the written consent of SPP).

**6.4 Guaranty for Affiliates.** A single Guaranty may support the Total Credit Limits of Affiliates. With respect to such a Guaranty, the sum value of the Unsecured Credit Allowance of all such Affiliates and the Guarantor shall not exceed the lesser of:

(i) the approved Unsecured Credit Allowance for the Guarantor based on SPP's financial review of Guarantor; or

(ii) $50 million.

If a Guaranty is utilized to establish an Unsecured Credit Allowance for a Credit Customer, the value of the Guaranty shall be no greater than the lesser of:

(i) The credit limit imposed in the Guaranty; or

(ii) The portion of the Unsecured Credit Allowance calculated for the Guarantor that is allocated to such Credit Customer in SPP's sole discretion; provided that the Unsecured Credit Allowance calculated for the Guarantor may not exceed $50 million; or

(iii) $50 million.

**6.5 Guarantees for Not for Profit Credit Customers.** SPP shall allow other guarantees for Not for Profit Credit Customers so long as any guarantees for such customer satisfy the requirements of Section 6.3. The form in Attachment D shall be used (subject to modifications to reflect the not for profit nature of the customer and the structure of the guarantee). An example of a permissible guarantee would be individual cities guaranteeing the payments by a municipal energy entity.

**6.6 Costs.** The Credit Customer shall bear all costs of obtaining and maintaining the Guaranty.

**6.7 Withdrawal.** A Credit Customer or the Guarantor may request the withdrawal of the Guaranty by written request to SPP. A Guaranty may be withdrawn and/or terminated only upon SPP's written approval. SPP will not approve withdrawal or termination of a Guaranty unless and until:

(i) alternate Financial Security acceptable to SPP has been provided; or

(ii) all financial obligations of a Credit Customer under the Agreements have been irrevocably satisfied in full, all Service Agreements have been terminated, and the Credit Customer is no longer a Credit Customer.

## ARTICLE SEVEN

## Financial Security

**7.1 Acceptable Forms of Financial Security.** Financial Security may be a Cash Deposit, an Irrevocable Letter of Credit, a Surety Bond or, for a Credit Customer that is a Federal Power Marketing Agency, a letter as specified in Section 7.1.4 of this Article. These forms of Financial Security may be submitted separately or in combination to equal the full amount of any required or provided Financial Security. In addition, SPP requires the execution of a Credit and Security Agreement (with respect to Cash Deposit, Irrevocable Letter of Credit, and/or Surety Bond).

**7.1.2 Cash Deposits.** A Cash Deposit will be Financial Security in accordance with this Section.

**7.1.2.1 Deposit and Related Agreements.** The initial Cash Deposit must be accompanied by execution and delivery of a Credit and Security Agreement in the form attached to this Credit Policy as Appendix "B." Under the Credit and Security Agreement, the Credit Customer shall grant to SPP a first priority security interest in and to any and all Cash Deposits, cash collateral, and deposit accounts held or controlled by SPP then existing or thereafter opened, and any and all proceeds of such collateral, including, without limitation, the cash and interest deposited therein. This security interest secures the prompt payment when due of any and all obligations of the Credit Customer under or in connection with the Tariff, and/or any and all other Agreements. SPP may amend the Credit and Security Agreement from time to time, either for general applicability or on an individual basis. The Credit Customer will accept such amendment and, upon request, execute an amendatory document.

**7.1.2.2 Segregated Account.** The Cash Deposit will be placed in a segregated, interest bearing account in SPP's name and held within the sole control of SPP solely to secure the payment of the Credit Customer's obligations to SPP and subject to the terms and conditions of the Credit and Security Agreement. All interest earned will accrue to the benefit of the Credit Customer, will be added to the segregated account, and will be deemed additional Cash Deposit; provided, that all such accrued and unpaid interest that has not been applied to satisfy the Credit Customer's obligations will be released and paid to the Credit Customer quarterly, and further provided, that SPP shall not be obligated to pay any interest to the Credit Customer or release any amount from the segregated account during any uncured Default. Interest will be calculated per section 7.3 of the Tariff.

**7.1.2.3** **Use of Cash Deposit.** In the event a Credit Customer fails to make a payment timely to SPP, SPP may apply the Cash Deposit as necessary to satisfy the deficit. In such event, within three (3) Business Days, the Credit Customer must replenish the Cash Deposit in an amount equal to SPP's draw or in such other amount as SPP may require under this Credit Policy and failure to replenish shall be a Default under this Credit Policy. SPP's application of the Cash Deposit hereunder shall not cure the Default due to the Credit Customer's failure to make timely payment until and unless the Cash Deposit is timely replenished or other Financial Security is provided under Section 7.1.2.4.

**7.1.2.4** **Replacement of Cash Deposit.** A Credit Customer may replace any part of a Cash Deposit with other Financial Security acceptable to SPP under this Credit Policy.

**7.1.3 Irrevocable Letter of Credit.** An Irrevocable Letter of Credit will be Financial Security in accordance with this Section.

**7.1.3.1** **Form, Requirements, and Related Agreement.** Appendix "C" of this Credit Policy is an acceptable form of an Irrevocable Letter of Credit. SPP may amend the form of Irrevocable Letter of Credit from time to time, either for general applicability or on a case-by-case basis, and the Credit Customer will accept such amendment and, upon request, execute an amendatory document. SPP may accept an Irrevocable Letter of Credit, in its sole discretion, in revised form. Upon the Credit Customer's request, SPP shall provide a written explanation of why SPP did not accept that Credit Customer's proposed variation to the form of Irrevocable Letter of Credit set forth in Appendix "C" of this Credit Policy. The Credit Customer must execute the Credit and Security Agreement with respect to the Irrevocable Letter of Credit. Under the Credit and Security Agreement, the Credit Customer grants SPP a first priority security interest in and to any and all proceeds of any and all Irrevocable Letters of Credit then existing or thereafter issued with SPP as Beneficiary and the Credit Customer as Account Party under the Irrevocable Letter of Credit, including, without limitation, the cash issued upon a draw thereon. This security interest secures the prompt payment when due of any and all obligations of the Credit Customer to SPP, provided that the grant of a security interest shall not diminish SPP's rights to apply draws on the Irrevocable Letter of Credit to pay any and all amounts due. SPP may amend the Credit and Security Agreement from time to time, either for general applicability or on an

individual basis. The Credit Customer will accept such amendment and, upon request, execute an amendatory document.

**7.1.3.2** **Ratings of Issuing Financial Institution.** At the time of issuance and at all times the Irrevocable Letter of Credit is outstanding, the issuer must be a financial institution organized under the laws of the United States or any state of the United States or the District of Columbia or a branch or agency of a foreign commercial bank located in the United States, with a minimum corporate debt rating of an "A-" by S&P, "A3" by Moody's, "A-" by Fitch or an equivalent short-term debt rating by any of these agencies. SPP may accept an Irrevocable Letter of Credit from a financial institution that does not meet the debt rating requirements, provided that the Irrevocable Letter of Credit has a confirmation of third-party support (as governed by the Uniform Customs and Practice for Documentary Credits – International Chamber of Commerce Publication No. 500, Effective January 1, 1994 "UCP500" as stated in Article 9 Section B), in a form acceptable to SPP, from a financial institution that does meet or exceed the debt rating requirements stated in this Section. If after the Irrevocable Letter of Credit has been issued, the rating for the corporate debt of the financial institution is less than "A-" by S&P, "A3" by Moody's or "A-" by Fitch, SPP may give the Credit Customer notice to submit substitute Financial Security no later than three (3) Business Days after the notice.

**7.1.3.3** **Costs.** The applicable Credit Customer shall bear all costs of providing and maintaining the Irrevocable Letter of Credit.

**7.1.3.4** **Substitution of Irrevocable Letter of Credit.** The Credit Customer may replace an Irrevocable Letter of Credit with a substitute Irrevocable Letter of Credit or other Financial Security in form and amount acceptable to SPP. SPP will return the initial Irrevocable Letter of Credit upon receipt of an effective and acceptable substitute.

**7.1.3.5** **Term and Renewal.** The Irrevocable Letter of Credit must automatically renew unless the issuing financial institution provides a notice to SPP at least ninety (90) days prior to its expiration date stating its decision not to renew the Irrevocable Letter of Credit. If the Irrevocable Letter of Credit is not renewed, at least ninety (90) days prior to its stated expiration date (a "Non-Renewal Event"), the Credit Customer must submit substitute Financial Security acceptable to SPP, in SPP's sole discretion, no later than eighty-seven (87) days prior to the stated expiration date.

**7.1.3.6 Use of Irrevocable Letter of Credit.** In the event a Credit Customer fails to make any timely payment to SPP, SPP may draw upon the Irrevocable Letter of Credit as necessary to satisfy any and all amounts due from the Credit Customer pursuant to the Agreements. In such event, within three (3) Business Days, the Credit Customer must replenish the Irrevocable Letter of Credit or provide SPP with other Financial Security in an amount equal to the draw or in such other amount as SPP may require under this Credit Policy, and failure to satisfy this requirement shall be a Default under this Credit Policy. In the event of such failure to make timely payment, and in addition to any other remedies available to SPP, SPP may draw down the entire Irrevocable Letter of Credit and hold the proceeds in an unsegregated account and apply such proceeds to amounts owed by the Credit Customer to SPP pursuant to the Agreements. The foregoing sentence notwithstanding, upon the Credit Customer's written notice of request, SPP will treat as a Cash Deposit the proceeds of a draw over and above amounts currently due and unpaid and transfer same to a segregated account in accordance with such treatment, provided that the Credit Customer has executed a Credit and Security Agreement.

**7.1.4 Federal Power Marketing Agency Letter.** A form of letter as described in this Section will be Financial Security for a Federal Power Marketing Agency as that type of entity is defined in Article Two of this Attachment X.

Credit Customers that are Federal Power Marketing Agencies may provide Financial Security in the form of a letter, executed by an officer of the Federal Power Marketing Agency, that: (1) attests that the Federal Power Marketing Agency is lawfully authorized to participate in the SPP TCR market and that any debt the Federal Power Marketing Agency incurs due to its participation in the TCR market is a debt of the United States; (2) identifies the current year's appropriations for the Federal Power Marketing Agency from the United States Congress; and (3) verifies that the amount of the current year's appropriations for the Federal Power Marketing Agency from the United States Congress meets or exceeds the amount required to satisfy the credit requirements set forth in this Credit Policy.

**7.1.5 Surety Bond.** A Surety Bond will be Financial Security in accordance with this Section.

**7.1.5.1 Form, Requirements, and Related Agreement.** Appendix "F" of this Credit Policy is an acceptable form of a Surety Bond. SPP may amend the form of Surety Bond from time to time, either for

general applicability or on a case-by-case basis, and the Credit Customer will accept such amendment and, upon request, execute an amendatory document. SPP may accept a Surety Bond, in its sole discretion, in revised form. Upon the Credit Customer's request, SPP shall provide a written explanation of why SPP did not accept that Credit Customer's proposed variation to the form of Surety Bond set forth in Appendix "F" of this Credit Policy. The Credit Customer must execute the Credit and Security Agreement with respect to the Surety Bond. Under the Credit and Security Agreement, the Credit Customer grants SPP a first priority security interest in and to any and all proceeds of any and all Surety Bond then existing or thereafter issued with SPP as beneficiary and the Credit Customer as principal under the Surety Bond, including, without limitation, the cash issued upon a draw thereon. This security interest secures the prompt payment when due of any and all obligations of the Credit Customer to SPP, provided that the grant of a security interest shall not diminish SPP's rights to apply draws on the Surety Bond to pay any and all amounts due. SPP may amend the Credit and Security Agreement from time to time, either for general applicability or on an individual basis. The Credit Customer will accept such amendment and, upon request, execute an amendatory document.

**7.1.5.2** **Ratings of Issuing Surety.** At the time of issuance and at all times the Surety Bond is outstanding, the issuer must be a U.S. Treasury-listed surety with a certificate of authority from the insurance commissioner in each state in which the issuer conducts surety business, with a minimum financial strength rating of an "A" by A.M. Best. If after the Surety Bond has been issued, the financial strength rating of the surety is less than "A" by A.M. Best, SPP may give the Credit Customer notice to submit substitute Financial Security no later than three (3) Business Days after the notice.

**7.1.5.3** **Costs.** The applicable Credit Customer shall bear all costs of providing and maintaining the Surety Bond.

**7.1.5.4** **Substitution of Surety Bond.** The Credit Customer may replace a Surety Bond with a substitute Surety Bond or other Financial Security in form and amount acceptable to SPP. SPP will return the initial Surety Bond upon receipt of an effective and acceptable substitute.

**7.1.5.5** **Term and Renewal.** The surety may terminate the Surety Bond upon ninety (90) days written notice to SPP; *provided, however,* that: (i) the surety's liability hereunder shall survive such

termination and remain in full force and effect as to obligations incurred by Credit Customer during the term of the Surety Bond; and (ii) in the event that Credit Customer fails to provide an acceptable form of replacement Financial Security to SPP at least eighty seven (87) days prior to the termination of the Surety Bond, the surety shall, upon demand, without any notice other than such demand, and without any further action by SPP deliver a Cash Deposit to SPP not later than the next Business Day in the amount of the full remaining value of the Surety Bond as Financial Security for Credit Customer's obligations to SPP.

**7.1.5.6 Limits on Use of Surety Bonds.**

a) To be eligible to provide Surety Bonds on behalf of a Credit Customer the applicable surety must have a Tangible Net Worth of $1 billion or greater.

b) In no case shall SPP accept Surety Bonds with an aggregate value greater than $10 million dollars ($10,000,000) issued by any individual surety on behalf of an individual Credit Customer.

c) SPP shall not accept surety bonds with an aggregate value greater than $50 million dollars ($50,000,000) issued by any individual surety.

**7.1.5.7 Use of Surety Bond.** In the event a Credit Customer fails to make any timely payment to SPP, SPP may draw upon the Surety Bond as necessary to satisfy any and all amounts due from the Credit Customer pursuant to the Agreements. In such event, within three (3) Business Days, the Credit Customer must replenish the Surety Bond or provide SPP with other Financial Security in an amount equal to the draw or in such other amount as SPP may require under this Credit Policy, and failure to satisfy this requirement shall be a Default under this Credit Policy. In the event of such failure to make timely payment, and in addition to any other remedies available to SPP, SPP may draw down the entire Surety Bond and hold the proceeds in an unsegregated account and apply such proceeds to amounts owed by the Credit Customer to SPP pursuant to the Agreements. The foregoing sentence notwithstanding, upon the Credit Customer's written notice of request, SPP will treat as a Cash Deposit the proceeds of a draw over and above amounts currently due and unpaid and transfer same to a segregated account in accordance with such treatment, provided that the Credit Customer has executed a Credit and Security Agreement.

**7.2 Financial Security Defaults.** In addition to the breaches with respect to Financial Security identified in Section 7.1.2.3 (failure to replenish Cash Deposit), 7.1.3.6 (failure to replenish Irrevocable Letter of Credit), and 7.1.5.7 (failure to replenish a Surety Bond), any failure by an issuer of an Irrevocable Letter of Credit, or Surety Bond, or any breach of a Credit and Security Agreement shall be a Default under this Credit Policy and a default under the Tariff. A Default under this Credit Policy and a default under the Tariff shall also occur if: (i) the Financial Security expires or terminates (other than in accordance with its terms or upon the written consent of SPP); (ii) the person issuing the Financial Security disaffirms, disclaims, repudiates or rejects or challenges the validity of all or any part of the Financial Security; or (iii) the Financial Security or any material provision of the Financial Security ceases to be in full force and effect (other than in accordance with its terms or upon the written consent of SPP).

# ARTICLE EIGHT

## Default and Remedies

**8.1 Default.** Any of the following shall constitute an "Event of Default" under this Credit Policy by a Credit Customer:

**8.1.1** Failure to post any required Financial Security required under this Credit Policy in the time period specified;

**8.1.2** Reserved for Future Use;

**8.1.3** Failure to pay in full any amount payable under the Tariff, unless cured in accordance with Section 8.3 of this Credit Policy;

**8.1.4** A Credit Customer's involvement in financial difficulties as evidenced by: (i) its commencement of a voluntary case under Title 11 of the United States Code as from time to time in effect, or by its authorizing, by appropriate proceedings of its board of directors, general partners or other governing body, the commencement of such a voluntary case; (ii) its filing an answer or other pleading admitting or failing to deny the material allegations of a petition filed against it commencing an involuntary case under said Title 11, or seeking, consenting to or acquiescing in the relief therein provided, or by its failing to controvert timely the material allegations of any such petition; (iii) the entry of an order for relief in any involuntary case commenced under said Title 11; (iv) its seeking relief as a debtor under any applicable law, other than said Title 11, of any jurisdiction relating to the liquidation or reorganization of debtors or to modification or alteration of the rights of creditors, or by its consenting to or acquiescing in such relief; (v) the entry of an order by a court of competent jurisdiction (a) finding it to be bankrupt or insolvent, (b) ordering or approving its liquidation, reorganization or any modification or alteration of the rights of its creditors, or (c) assuming custody of, or appointing a receiver or other custodian for all or a substantial part of its property, and such entry or order shall not be vacated or stayed within ninety (90) days; (vi) the filing of a petition under Title 11 which shall not be vacated within ninety (90) days; or (vii) its making an assignment for the benefit of, or entering into a composition with, its creditors, or appointing or consenting to the appointment of a receiver or other custodian for all or a substantial part of its property.

**8.1.5** Commission of any other Default specified under this Credit Policy, including Defaults specified in Sections 3.2.2, 5.3.3, 6.3.4, 7.1.2.3., 7.1.3.6, 7.1.5.7, and 7.2.

**8.1.6** Except with respect to an event described in Sections 8.1.1 through 8.1.5, the failure to provide any of the Credit Information required under this Credit Policy in the time periods specified, and the failure to observe or perform any of the material terms or conditions or provisions set forth in this Agreement, and such

failure is not cured within two (2) Business Days after notice thereof from SPP. If such failure is a failure to provide any of the Credit Information required under this Credit Policy in the time periods specified, and the failure cannot reasonably be cured within such period, and if the Credit Customer has commenced and is diligently pursuing such cure and provides SPP with adequate assurance of due performance to protect SPP against loss arising from the failure to perform, the Credit Customer may request in writing stating the reasons for the delay and obtain an additional five (5) Business Days if the Credit Customer is a Large Company or a Small Company and ten (10) Business Days if the Credit Customer is a Not-For-Profit after the written notice of Default, as shall be necessary for the Credit Customer to cure the failure with all due diligence.

**8.2 Notice of Financial Difficulties**. Immediately upon the occurrence of an Event of Default as set forth in Section 8.1.4, the Credit Customer shall provide notice to SPP and a copy of any pleadings, orders, petitions, agreements or other document initiating or filed in connection with such Event of Default.

**8.3 Remedies for Default.** Upon the first occurrence of a customer default as described in Section 7.4 of the Tariff or an Event of Default (except as defined in Section 8.1.4 of this Credit Policy) within a twelve month period, SPP will take no action to suspend any Unsecured Credit Allowance as long as the default is remedied within the specified cure period. Should the first occurrence not be remedied within the specified cure period SPP will suspend any Unsecured Credit Allowance for ninety (90) calendar days. Upon the second customer default or Event of Default within a twelve (12) month period, SPP will suspend any Unsecured Credit Allowance for ninety (90) calendar days. The suspension will occur even if one or both occurrences were remedied within the specified cure period. SPP may, except to the extent such remedy is limited in this Credit Policy, exercise any rights or remedies it may have at law or in equity, including but not limited to bringing suit or otherwise initiating proceedings for monetary damages, injunctive relief, specific performance, and relief available under the Federal Power Act. If the Event of Default has not been cured by the Credit Customer within two (2) Business Days or as otherwise outlined under Section 8.1.6 after the Credit Customer's receipt of notice thereof, or, in the case of failure to pay in full amounts payable under Section 7 of the Tariff, within two (2) Business Days after the Transmission Customer's receipt of notice thereof, except as may be precluded under applicable law, SPP may terminate all of the Credit Customer's rights under this Credit Policy. Such termination shall not affect any liability of the Credit Customer incurred before and existing as of such termination. In addition, and without prejudice to any other remedies, SPP reserves all rights to terminate service in accordance with the Tariff and applicable law.

Upon the first occurrence of an Event of Default as defined in Section 8.1.4 of this Credit Policy, SPP will immediately suspend the Credit Customer's Unsecured Credit Allowance and may, at SPP's sole discretion, terminate all of the Credit Customer's rights under this Credit Policy and/or terminate service in accordance with the Tariff and applicable law. Any such termination shall not affect any liability that the Credit Customer incurred prior to and as of such termination. Upon the first occurrence of an Event of Default as defined in Section 8.1.4 of this Credit Policy, SPP also may order the Credit Customer to post additional collateral, cease one or more market transactions, or

take other measures to protect SPP and other Market Participants from the Credit Customer's Default.

# ARTICLE NINE

## Notice

**9.1 Designation of Credit Contact.** Each Credit Customer shall in writing designate a management level official as the person responsible for the Credit Customer's credit-related matters under this Credit Policy ("Credit Contact"), which designation may be changed from time to time in writing, together with contact information including fax, e-mail, and courier delivery address. SPP will seek to effect delivery of notices under the Credit Policy to the Credit Contact in the first instance; however, if delivery to the Credit Contact fails, then SPP may effect delivery to any officer, executive, or manager of the Credit Customer.

**9.2 Notices to SPP.** Any notice or request made by SPP shall be given in writing, by fax, email, hand delivery, reputable overnight courier, or first-class mail, to the Credit Customer's Credit Contact. Notice to SPP shall be addressed to:

Southwest Power Pool, Inc.
Credit and Risk Management Department
201 Worthen Drive
Little Rock, AR 72223-4936

## Appendix "A"

## Credit Application Form

### Credit Customer Identification

1.1 Name of the Company as identified in its certificate of formation / incorporation

_____

1.2 Date of formation / incorporation of the Company

_____

1.3 Registration / file number with the applicable Secretary of State's Office

_____

1.4 Please indicate all unique Company identifiers.

| | |
|---|---|
| Company Ticker Symbol | |
| Market Cap | |
| Federal Tax ID Number | |
| NERC Acronym | |
| SIC Code | |
| DUNS Number | |

1.5 Address of the registered office of the Company

| | |
|---|---|
| Country | |
| Address | |
| Post Code | |
| City | |
| Phone | |
| Website | |

1.6 Address of the trading office(s) of the Company

| | |
|---|---|
| Country | |
| Address | |
| Post Code | |
| City | |
| Phone | |
| Website | |

1.7 Please list any affiliated companies, including subsidiary companies of which your Company owns greater than 10%, that participate in SPP's markets or any other Independent System Operator or Regional Transmission Operator (ISO/RTO) markets.

| Subsidiaries and Affiliates | ISO / RTO |
|---|---|
| | |
| | |
| | |
| | |

1.8 What is the main business of your Company (as stated in the Company's certificate of incorporation, limited liability company agreement, partnership agreement or other applicable corporate governing documents)?

_____

1.9 Please include a copy of your Company's Articles of Incorporation, Articles of Organization or similar documents.

## Board, Shareholder, and Management Information

2.1 Please list board members (if applicable).

| Full Name | Business Mailing Address |
|---|---|
| | |
| | |
| | |
| | |
| | |

2.2 Please list any legal representatives (executive officers such as CEO, CFO, CRO, etc.) authorized to sign an agreement with SPP on behalf of the Company.

| Full name | Authorized to sign? | Business Mailing Address | Tenure with Company |
|---|---|---|---|
| | ☐ alone<br>☐ jointly | | |
| | ☐ alone<br>☐ jointly | | |
| | ☐ alone<br>☐ jointly | | |

2.3 Please state your Company's shareholders/owners and indicate their respective share or ownership percentage (>10%).

| Full name | Percentage | Business Mailing Address |
|---|---|---|
| | | |
| | | |
| | | |

2.4 Please provide the following information for each individual, if any, who, directly or indirectly, through any contract, arrangement, understanding, relationship or otherwise, owns 25% or more of the equity interests of the Company.

| Full name | Business Mailing Address |
|---|---|
| | |
| | |
| | |

2.5 Please list the persons responsible, respectively, for payment of invoices, compliance, credit, trading activity and questions about this form.

| Full name | Business Mailing Address | Contact details (business e-mail address and business phone number) |
|---|---|---|
| Payments: | | |
| Compliance: | | |
| Credit: | | |
| Trading: | | |
| Questions about this form: | | |

## SPP Market Participation

3.1 Please indicate which of SPP's products your Company transacts or intends to transact and include an estimate of the annual volumes by product (in MWh).

| | |
|---|---|
| Real-Time Energy | |
| Day-Ahead Energy | |
| Virtual Energy | |
| Transmission Congestion Rights | |
| Transmission Service | |

3.2 Please list forms of credit your Company intends to utilize to support trading exposure.

| | |
|---|---|
| Cash (See Section 7.1.2 and Appendix B) | |
| Irrevocable Letter of Credit (See Section 7.1.3 and Appendices B and C) | List Bank Counterparty |
| Corporate Guarantee (See Section 3.1.3, Article Six, and Appendix D) | List Potential Guarantor |
| Surety Bond (See Section 7.1.5 and Appendices B and F) | List Issuing Surety |

3.3 List your Company's financial auditors and their addresses.

_____

3.4 Please provide audited financial statements for the Company for the last three years, including any current third-party credit ratings.

_____

3.5 List all amounts held for collateral with any ISO/RTO as recorded in total assets of your Company's latest audited financial statements.

_____

**Loss Contingencies and Judgments**

4.1 Has your Company (or an Affiliate), in the last five years: a) consented to the appointment of, or was taken in possession by, a receiver, trustee, custodian or liquidator of a substantial part of its assets, b) filed a bankruptcy petition in any bankruptcy court proceeding, c) answered, consented, or sought relief under any bankruptcy or similar law or failed to obtain a dismissal of an involuntary petition, d) admitted in writing its inability to pay its debts when due, e) made a general assignment for the benefit of creditors, f) been the subject of an involuntary proceeding seeking to adjudicate the Company (or affiliate) bankrupt or insolvent, g) sought reorganization, arrangement, adjustment, or composition of it or its debt under any law relating to bankruptcy, insolvency, or reorganization or relief of debtors?

_____

4.2 If yes to any question in 4.1, please provide a description of proceedings including applicable docket or case numbers.

_____

4.3 Has your Company (or one or more of its affiliates), in the last five years, been found in violation of SEC, OCC, FERC, or CFTC requirements or any other federal or state regulation or law regarding energy commodities? Additionally, if not found in violation of such regulations and/or laws, has your Company (or its affiliates) settled allegations of violation with the applicable regulatory authority and/or paid fines related to activity in energy commodities?
If yes to any question in 4.3, please provide a description of proceedings including applicable docket or case numbers.

_____

4.4 Has your Company ever failed to cure an unpaid invoice from any RTO/ISO in the last 5 years, or been found to be in default by an RTO/ISO, or been either suspended or expelled (i.e., had its participation revoked) from an ISO/RTO?
If yes to any question in 4.4, please provide an explanation of the situation, its outcome, and all other relevant factors associated with the event (including applicable docket or case numbers).

_____

**Signatures**

The undersigned is duly authorized to declare and does hereby declare in good faith that all information, answers and documents provided with this Questionnaire are true, correct and authentic and that no relevant information is omitted.

| Place | Date | Print Name:<br>Title: |
|---|---|---|
| Signature | | |

Subscribed and sworn before me _____, a notary public of the State of _____, in and for the County of _____, this __ day of _____, 20_____.

_____

(Notary Public Signature)
My commission expires:__/__/__

## Additional Not-For-Profit Questions

**Additional sheets may be added to fully answer the following questions.**

1. **Does your company have the ability to set its own rates? If yes, please attach any documentation that will show that ability.**

2. **What are the terms and expiration dates of your company's wholesale power contracts?**

3. **How many customers do you serve directly? When considering your five largest customers that you directly serve, what percentage of your load do they represent?**

4. **Please describe your power supply portfolio and how it is used to meet your load. What percent of your load is secured by asset ownership or purchase power contracts? Are these assets or contracts long-term in nature? What are the expiration dates of your contracts? What is the fuel mix of your power supply portfolio? Do you engage in risk management activities? If so, please provide a brief summary of such activities.**

5. **How long has the present management team been in place? Please discuss their experience with the present firm and any previous experience.**

6. **Discuss your ability to access lines of credit from financial institutions.**

7. **Please discuss any other factors you want to have considered by SPP when assessing creditworthiness. If there are items concerning your financials that need explanation, please provide the explanation here.** If your company receives capital credits, please provide the associated cash portion of such capital credits, as well as the information needed to compute such an amount from your most recent audited financials.

## Appendix "B" Credit and Security Agreement

This Credit and Security Agreement is effective as of the _____ day of _____, 20__, by and between _____ ("Company") and Southwest Power Pool, Inc. ("SPP").

### Recitals

WHEREAS, SPP offers certain services, including certain transmission services, market services and other services as set out in the _____ Tariff of SPP, as may be amended and supplemented from time to time and together with all replacements and substitutes thereto (collectively, the "Tariff");

WHEREAS, SPP maintains a Credit Policy (which is Attachment **X** to the Tariff, as the same may be amended from time to time) in order to determine, on a case by case basis, the level of unsecured credit available to each customer who takes services under the Tariff and the form and amount of financial assurance to be required by each customer, if any;

WHEREAS, in the event Company provides financial assurance to SPP in the form of Cash Deposit, an Irrevocable Letter of Credit, a Surety Bond, or, for a Credit Customer that is a Federal Power Marketing Agency, a letter as specified in Section 7.1.4 of Attachment X, SPP requires Company, in accordance with the terms of its Credit Policy as filed and accepted by FERC, to execute this Credit and Security Agreement in order to assure the strength of SPP's security interest in such Cash Deposit, Federal Power Marketing Agency Letter, Irrevocable Letter of Credit, or Surety Bond;

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged by each of the parties hereto, Company and SPP hereby agree as follows:

(1) The "Liabilities" as used in this Credit and Security Agreement means all of the financial obligations of the Company under the Tariff and/or any and all agreements entered into, under, pursuant to, or in connection with the Tariff (including, without limitation, the SPP Credit Policy) and any and all other agreements to which SPP and the Company are parties (collectively, the "Agreements").

(2) As security for the payment and performance of the Liabilities, SPP shall have, and the Company hereby grants to SPP, a continuing security interest in the following collateral (as indicated below) (the "Collateral"): all of the Company's right, title, and interest in any and all cash, cash collateral, Cash Deposits and deposit accounts of the Company held or controlled by SPP, including accounts designated "for the benefit of" Company, that either (i) are or contain proceeds from any draw upon any Irrevocable Letter of Credit or Surety Bond naming SPP as beneficiary to the extent that SPP determines in its sole discretion to treat such payments as cash collateral, and without prejudice to SPP's right to treat draws as payments to SPP of any and all amounts due to SPP from the Company , or (ii) are or contain cash submitted by the Company as collateral or security, however created or evidenced, whether now existing or hereafter owned, acquired, created, used or arising, including all products and proceeds of the foregoing, any and all renewals, extensions, replacements, modifications, additions, and substitutions of the foregoing and all rights, remedies, claims and demands under or in connection with each of the foregoing.

(3) All Collateral held or controlled by SPP after the date of this Credit and Security Agreement shall be free of any lien, security interest or encumbrance, except for liens, security interests or encumbrances in favor of SPP, and the Company agrees not to grant any security interest or permit any lien or encumbrance to arise in any of the Collateral except for security interests, liens and encumbrances in favor of SPP without the prior written consent of SPP.

(4) The Company agrees to do such reasonable acts and things and deliver or cause to be delivered such other documents as SPP may reasonably deem necessary to establish and maintain a valid perfected security interest in the Collateral (free of all other liens and claims except those of SPP) to secure the payment and performance of the Liabilities and to defend title to the Collateral against any person claiming any interest therein adverse to SPP. The Company authorizes SPP to file a financing statement or statements on its behalf in those public offices deemed advisable or necessary by SPP to protect the security interest of the Company herein granted. If permitted by law, the Company agrees that a carbon, photographic or other reproduction of this Credit and Security Agreement or of a financing statement may be filed as a financing statement.

(5) Subject to the Tariff, upon the occurrence of any Default and at any time thereafter, SPP shall have all rights and remedies available at law or in equity including, without limitation, the rights and remedies of a secured party under the Arkansas Uniform Commercial Code, as in effect from time to time, including, without limitation, the right to retain and/or take possession of the Collateral. SPP may in its discretion transfer any property constituting Collateral into its own name or that of its nominee and receive the income thereon and hold the same as security for the Liabilities or apply it on amounts due on Liabilities.

(6) Until such time as SPP exercises its remedies upon a Default, all income, earnings and profits with respect to the Collateral shall be reported for state and federal income tax purposes as attributable to the Company and not SPP. Company hereby instructs SPP (and any other person authorized to report taxable income distributions) to issue, or cause to be issued, IRS Form 1099 indicating the Company as the recipient of such income, earnings and profits.

(7) Whenever possible each provision of this Credit and Security Agreement shall be interpreted in such a manner as to be effective and valid under applicable law, but if any provision of this Credit and Security Agreement shall be prohibited by or invalid under applicable law, such provision shall be ineffective only to the extent of such prohibition without invalidating the remainder of such provision or the remaining provisions of this Credit and Security Agreement. The Company recognizes that SPP has relied on this Credit and Security Agreement in extending credit to the Company and agrees that such reliance by SPP shall be sufficient consideration for this Credit and Security Agreement.

(8) The Company maintains any and all rights under Section 206 of the Federal Power Act it may have with regard to this Credit and Security Agreement or its implementation.

This Credit and Security Agreement shall be construed and enforced in accordance with, and governed by, the laws of the State of Arkansas (without giving effect to the principles of conflicts of laws thereof).

_____
Company Name

_____
Authorized Signature

_____
Print Name

_____
Title

**SOUTHWEST POWER POOL, INC.**
By:

_____
Authorized Signature

_____
Print Name

_____
Title

## Appendix "C" Form of Irrevocable Standby Letter of Credit

**Irrevocable Standby Letter of Credit No. _____**
**Issued: [Date]**
**Expires at our counter (unless evergreen): [Date]**

Ladies and Gentlemen:

We do hereby issue this Irrevocable Non-Transferable Standby Letter of Credit No. _____ by order of, for the account of and on behalf of _____ ("Account Party") and in favor of Southwest Power Pool, Inc. ("Beneficiary" or "SPP") ("Letter of Credit").

This Letter of Credit is irrevocable and is issued, presentable and payable and we guaranty to the Beneficiary of this Letter of Credit that drafts drawn under and in compliance with the terms of this Letter of Credit will be honored on presentation and surrender of certain documents pursuant to the terms of this Letter of Credit.

This Letter of Credit is available in one or more drafts and may be drawn hereunder for the account of Account Party up to an aggregate amount not exceeding $ _____ .00 (United States Dollars _____ and 00/100).

This Letter of Credit is drawn against by presentation to us at our office located at the following address:

_____
_____

of a drawing certificate: (i) Signed by an officer or authorized agent of the Beneficiary; (ii) dated the date of presentation; and (iii) containing one (1) of the following statements:

1. "The undersigned hereby certifies to _____ ("Issuer"), with reference to its Irrevocable Non-Transferable Standby Letter of Credit No. _____, dated _____, issued on behalf of _____ ("Account Party") and in favor of Southwest Power Pool, Inc. ("Beneficiary") that said Account Party has failed to make a payment in accordance with the terms and provisions of one or more of the following, as applicable: SPP's Tariff, as may be amended and supplemented from time to time, together with all replacements and substitutes (the "Tariff"), any and all agreements

entered into by Account Party under, pursuant to, or in connection with the Tariff and any and all agreements to which Account Party and SPP are parties, as such agreements may be amended and supplemented from time to time, whether now or hereafter executed, and any replacements or substitutions thereof, (collectively, the "Agreements"). The Beneficiary hereby draws upon the Letter of Credit in an amount equal to $ _____ (United States Dollars _____ and 00/100)"; or

2. "As of the close of business on _____, 20__ (fill in date which is less than eighty-seven (87) days before the expiration date of the Letter of Credit), Account Party has failed to renew, replace or amend the Letter of Credit in a manner acceptable to Beneficiary." The Beneficiary hereby draws upon the Letter of Credit in an amount equal to $_____ (United States Dollars _____ and 00/100)"; or

3. "As of the close of business on _____, 20__ (fill in date which is more than three (3) Business Days after the Beneficiary has requested that Account Party replace the Letter of Credit because the Issuer's corporate debt is rated less than "A-" by S&P, "A3" by Moody's, "A-" by Duff & Phelps, or "A-" by Fitch), Account Party has failed to replace the Letter of Credit in a manner acceptable to Beneficiary." The Beneficiary hereby draws upon the Letter of Credit in an amount equal to $_____ (United States Dollars _____ and 00/100)".

Beneficiary shall have the right, in the event of a draw pursuant to subparagraph (2) or (3) of the immediately preceding paragraph, to draw down the entire face value of the Letter of Credit.

If presentation of any drawing certificate is made on a business day and such presentations made on or before 10:00 a.m._____ Time, ("Issuer") shall satisfy such drawing request on the same business day. If the drawing certificate is received after 10:00 a.m._____ Time, ("Issuer") will satisfy such drawing request on the next business day.

It is a condition of this Letter of Credit that it will be automatically extended without amendment for one year from the expiration date hereof, or any future expiration date, unless at least 90 days prior to any expiration date we notify you by registered mail or overnight courier that we elect not to consider this Letter of Credit extended for any such period.

This Letter of Credit may be terminated upon Beneficiary's receipt of full payment from the Account Party and Issuer's receipt of a written release from the Beneficiary releasing the Issuer from its obligations under this Letter of Credit.

Disbursements under the Letter of Credit shall be in accordance with the following terms and conditions:

1. The amount, which may be drawn by the Beneficiary under this Letter of Credit, shall be automatically reduced by the amount of any drawings hereunder.

2. All commissions and charges will be borne by the Account Party.

3. This Letter of Credit may not be transferred or assigned by the Issuer.

4. This Letter of Credit is irrevocable.

5. Except when the amount of this Letter of Credit is increased this Letter of Credit may not be amended, changed or modified without the express written consent of the Beneficiary and the Issuer. Such consent may be delivered by electronic means including electronic mail to - _____.

6. This Letter of Credit shall be governed by the International Standby Practices Publication No. 590 of the International Chamber of Commerce, including any amendments, modifications or revisions thereof (the "ISP"), except to the extent that terms hereof are inconsistent with the provisions of the ISP, in which case the terms of the Letter of Credit shall govern. This Letter of Credit shall be governed by the internal laws of the state of Arkansas to the extent that the terms of the ISP are not applicable; provided that, in the event of any conflict between the ISP and such Arkansas laws, the ISP shall control.

_____ _____

[Authorized Signature] [Date]

Name: _____

Title:_____

## Appendix "D" Guaranty Form

## GUARANTY AGREEMENT

This Guaranty Agreement (the "Guaranty") is made by _____ ("Guarantor"), a _____ corporation, in favor of Southwest Power Pool, Inc. ("Creditor"), an Arkansas nonprofit corporation.

WHEREAS, one or more direct or indirect subsidiaries of the Guarantor (each referred to individually as "Debtor" and collectively as "Debtors") and the Creditor are parties to certain agreements pursuant to, or in connection with, the Creditor's Open Access Transmission Tariff, whether now existing or hereafter arising in accordance with their respective terms (each referred to individually as "Agreement" and collectively as "Agreements");

WHEREAS, Guarantor is the direct or indirect parent of the Debtor, will receive substantial and direct benefits from the extensions of credit contemplated by the Agreements and has agreed to enter into this Guaranty to provide assurance for the performance of Debtor's obligations in connection with the Agreements and to induce the Creditor to enter into the Agreements; and

WHEREAS, the execution and delivery of this Guaranty is a condition to Creditor's further performance of its obligations under the terms of the Agreements;

NOW, THEREFORE, in consideration of the promises and other good and valuable consideration, the adequacy, receipt and sufficiency of which are hereby acknowledged, Guarantor hereby agrees as follows:

1. **Guaranty.** Guarantor hereby unconditionally and absolutely guarantees the punctual payment as and when due of Debtor's payment obligations arising under any Agreement, as such Agreement may be amended or modified from time to time, together with any interest thereon (collectively, the "Guaranteed Obligations"). Guarantor's obligations and liability under this Guaranty shall be limited to payment obligations only and Guarantor shall have no obligation otherwise to perform under any Agreement, including, without limitation, to sell, deliver, purchase, receive, or transmit any electrical energy product or service.

2. **Guaranty Absolute.** The liability of Guarantor under this Guaranty shall be absolute and unconditional irrespective of:

   (a) any lack of validity or enforceability of or defect or deficiency in any Agreement or any other documents executed in connection with any Agreement;

   (b) any modification, extension or waiver of any of the terms of any Agreement;

   (c) any change in the time, manner, terms or place of payment of or in any other term of, all or any of the Guaranteed Obligations, or any other amendment or waiver of

or any consent to departure from any Agreement or any other agreement or instrument executed in connection therewith;

(d) any sale, exchange, release or non-perfection of any property standing as security for the liabilities hereby guaranteed, or any liabilities incurred directly or indirectly hereunder or any setoff against any of said liabilities, or any release or amendment or waiver of or consent to departure from this Guaranty or any other guaranty, for all or any of the Guaranteed Obligations;

(e) except as to applicable statutes of limitation, failure, omission, delay, waiver or refusal by Creditor to exercise, in whole or in part, any right or remedy held by Creditor with respect to any Agreement or any transaction under any Agreement;

(f) any change in the existence, structure or ownership of Guarantor or any Debtor, or any insolvency, bankruptcy, reorganization or other similar proceeding affecting any Debtor or its assets; or

(g) any other circumstance that might otherwise constitute a defense available to, or a discharge of, any Debtor or any other individual, partnership, joint venture, corporation, association, trust or other enterprise that is a party to any Agreement, or any other agreement or instrument (including any guarantor) in respect of the Guaranteed Obligations, other than payment in full of the Guaranteed Obligations.

The obligations of the Guarantor hereunder are several from any Debtor or any other person, and are primary obligations concerning which the Guarantor is the principal obligor. There are no conditions precedent to the enforcement of this Guaranty, except as expressly contained herein. It shall not be necessary for Creditor, in order to enforce payment by Guarantor under this Guaranty, to show any proof of any Debtor's default, to exhaust its remedies against any Debtor, any other guarantor, or any other person liable for the payment or performance of the Guaranteed Obligations. Creditor shall not be required to mitigate damages or take any other action to reduce, collect, or enforce the Guaranteed Obligations.

This Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment of any of the Guaranteed Obligations are annulled, set aside, invalidated, declared to be fraudulent or preferential, rescinded or must otherwise be returned, refunded or repaid by Creditor upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of Debtor or any other guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, Debtor or any other guarantor or any substantial part of its property or otherwise, all as though such payment or payments had not been made.

3. **Waiver.** This is a guaranty of payment and not of collection. Guarantor hereby waives:

(a) notice of acceptance of this Guaranty, of the creation or existence of any of the Guaranteed Obligations and of any action by Creditor in reliance hereon or in connection herewith;

(b) notice of the entry into any Agreement between any Debtor and the Creditor and of any amendments, supplements or modifications thereto; or any waiver of consent under any Agreement, including waivers of the payment and performance of the obligations thereunder;

(c) notice of any increase, reduction or rearrangement of any Debtor's obligations under any Agreement or any extension of time for the payment of any sums due and payable to the Creditor under any Agreement;

(d) except as expressly set forth herein, presentment, demand for payment, notice of dishonor or nonpayment, protest and notice of protest or any other notice of any other kind with respect to the Guaranteed Obligations; and

(e) any requirement that suit be brought against, or any other action by Creditor be taken against, or any notice of default or other notice be given to, or any demand be made on, Debtor or any other person, or that any other action be taken or not taken as a condition to Guarantor's liability for the Guaranteed Obligations under this Guaranty or as a condition to the enforcement of this Guaranty against Guarantor.

4. **Expenses.** Notwithstanding and in addition to the limit on Guarantor's liability hereunder set forth in Section 1, Guarantor agrees to pay on demand any and all costs, including reasonable legal fees and expenses, and other expenses incurred by Creditor in enforcing Guarantor's payment obligations under this Guaranty; provided that the Guarantor shall not be liable for any expenses of Creditor if no payment under this Guaranty is due.

5. **Subrogation.** Guarantor shall be subrogated to all rights of Creditor against the Debtors in respect of any amounts paid by Guarantor pursuant to this Guaranty, provided that Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise (including, without limitation, any statutory rights of subrogation under Section 509 of the Bankruptcy Code, 11 U.S.C. § 509, or otherwise), reimbursement, exoneration, contribution, indemnification, or any right to participate in any claim or remedy of the Creditor against any Debtor or any collateral which the Creditor now has or acquires, until all of the Guaranteed Obligations shall have been irrevocably paid to Creditor in full. If any amount shall be paid to the Guarantor on account of such subrogation rights at any time when all the Guaranteed Obligations shall not have been paid in full, such amount shall be held in trust for the benefit of Creditor and shall forthwith be paid to Creditor to be applied to the Guaranteed Obligations. If (a) the Guarantor shall perform and shall make payment to Creditor of all or any part of the Guaranteed Obligations and (b) all the Guaranteed Obligations shall have been paid in full, Creditor shall, at the Guarantor's request, execute and deliver to

the Guarantor appropriate documents necessary to evidence the transfer by subrogation to the Guarantor of any interest in the Guaranteed Obligations resulting from such payment by Guarantor.

6. **Setoff.** The Creditor is hereby authorized at any time, to the fullest extent permitted by law, to set off and apply any deposits (general or special, time or demand, provisional or final) and other indebtedness owing by the Creditor to or for the account of Guarantor against any and all of the obligations of Guarantor under this Guaranty, irrespective of whether or not the Creditor shall have made any demand under this Guaranty or such Agreement and although such obligations may be contingent and unmatured. The Creditor agrees promptly to notify Guarantor after any such set-off and application made by the Creditor provided that the failure to give such notice shall not affect the validity of such set-off and application.

7. **Notices.** All demands, notices and other communications provided for hereunder shall, unless otherwise specifically provided herein, (a) be in writing addressed to the party receiving the notice at the address set forth below or at such other address as may be designated by written notice, from time to time, to the other party, and (b) be effective upon delivery, when mailed by U.S. mail, registered or certified, return receipt requested, postage prepaid, by express courier with traceable receipt, by facsimile, or personally delivered. Notices shall be sent to the following addresses:

If to Creditor:
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
Attention: Credit and Risk Management Department

If to Guarantor:

_____
_____
_____
_____

8. **Demand and Payment.** Any demand by Creditor for payment hereunder shall be in writing, signed by a duly authorized officer of Creditor and delivered to the Guarantor pursuant to Section 7 hereof, and shall (a) reference this Guaranty, (b) specifically identify the Debtor, the Guaranteed Obligations to be paid and the amount of such Guaranteed Obligations, and (c) set forth payment instructions. There are no other requirements of notice, presentment or demand. Guarantor shall pay, or cause to be paid, such Guaranteed Obligations within two (2) business days of receipt of such demand.

9. **No Waiver; Remedies.** Except as to applicable statutes of limitation, no failure on the part of Creditor to exercise, and no delay in exercising, any right hereunder shall operate as a waiver thereof, nor shall any single or partial exercise of any right hereunder preclude any other or further exercise thereof or the exercise of any other right. The

remedies herein provided are cumulative and not exclusive of any remedies provided by law.

10. **Term; Termination.** This Guaranty shall continue in full force and effect for the term of the Agreements. Notwithstanding the foregoing, this Guaranty may be terminated at any time by the Guarantor by providing at least sixty (60) days' prior written notice to Creditor; provided, however, upon termination hereof, Guarantor agrees that the obligations and liabilities hereunder shall continue in full force and effect with respect to any obligations incurred prior to the termination date, and any fees and costs of enforcement in connection herewith.

11. **Assignment; Successors and Assigns.** Creditor may, upon notice to Guarantor, assign its rights hereunder without the consent of Guarantor. Guarantor may assign its rights hereunder with the prior written consent of Creditor, which consent shall not be unreasonably withheld. Subject to the foregoing, this Guaranty shall be binding upon and inure to the benefit of the parties hereto and their respective successors, permitted assigns, and legal representatives.

12. **Amendments, Etc.** A written amendment executed by the Guarantor only may (a) increase the guaranty limit specified in Section 1 and/or (b) extend the termination date of this Guaranty. No other amendment of this Guaranty shall be effective unless in writing and signed by Guarantor and Creditor. No waiver of any provision of this Guaranty nor consent to any departure by Guarantor therefrom shall in any event be effective unless such waiver shall be in writing and signed by Creditor. Any such waiver shall be effective only in the specific instance and for the specific purpose for which it was given.

13. **Captions.** The captions in this Guaranty have been inserted for convenience only and shall be given no substantive meaning or significance whatsoever in construing the terms and provisions of this Guaranty.

14. **Representation and Warranties.**

The Guarantor represents and warrants as follows:

(a) the Guarantor is duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty. This representation is evidenced by a copy of the resolution(s) of the board of directors or other governing body of the Guarantor authorizing this Guaranty, which is attached to and made a part of this Guaranty;

(b) the execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets;

(c) this Guaranty is not in violation of other undertakings or requirements applicable to Guarantor, and is enforceable against the Guarantor in accordance with these terms;

(d) this Guaranty constitutes the legal, valid and binding obligation of the Guarantor enforceable against Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other laws of general applicability relating to or affecting Creditor's rights and to general equity principles; and

(e) the audited financial statements of Guarantor for the most recent fiscal year and the unaudited financial statements of Guarantor for the most recent quarter (the "Financial Statements"), heretofore delivered to Creditor or filed with the United States Securities Exchange Commission by Guarantor present fairly the financial condition and results of operations of Guarantor and its consolidated subsidiaries as of the dates and for the period specified therein in conformity with United States generally accepted accounting principles, and, except as otherwise expressly stated therein, consistently applied. Except as expressly stated to Creditor in writing, there has been no Material Adverse Change in the financial condition of Guarantor and its consolidated subsidiaries since the dates of the Financial Statements.

15. **Limitation by Law.** All rights, remedies and powers provided in this Guaranty may be exercised only to the extent that the exercise thereof does not violate any applicable provision of law, and all the provisions of this Guaranty are intended to be subject to all applicable mandatory provisions of law that may be controlling and to be limited to the extent necessary so that they will not render this Guaranty invalid, unenforceable, in whole or in part, or not entitled to be recorded, registered or filed under the provisions of any applicable law.

**16. GOVERNING LAW; SUBMISSION TO EXCLUSIVE JURISDICTION. THIS GUARANTY SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF ARKANSAS AND ANY APPLICABLE FEDERAL LAW. TO THE EXTENT PERMITTED BY APPLICABLE LAW, THE PARTIES HERETO HEREBY SUBMIT TO THE EXCLUSIVE JURISDICTION OF ANY ARKANSAS STATE COURT SITTING IN PULASKI COUNTY, ARKANSAS, OR THE UNITED STATES DISTRICT COURT FOR THE EASTERN DISTRICT OF ARKANSAS, FOR THE PURPOSES OF ALL LEGAL PROCEEDINGS ARISING OUT OF OR RELATING TO THIS GUARANTY OR THE TRANSACTIONS CONTEMPLATED HEREBY. THE PARTIES HEREBY WAIVE ANY OBJECTION TO VENUE IN PULASKI COUNTY, ARKANSAS, AND ANY OBJECTION TO ANY ACTION OR PROCEEDING ON THE BASIS OF FORUM NON CONVENIENS.**

IN WITNESS WHEREOF, Guarantor has caused this Guaranty to be duly executed and delivered by its duly authorized officer effective as of this ___ day of _____, _____ ("Effective Date").

**[GUARANTOR]**

By:_____
Name:_____
Title:_____

## Appendix "E" Annual Minimum Market Participation Criteria and Risk Management Certification Form

### SPP ANNUAL MINIMUM MARKET PARTICIPATION CRITERIA – RISK MANAGEMENT CERTIFICATION FORM

I, _____, a duly authorized officer of _____ ("Market Participant"), understanding that Southwest Power Pool, Inc. ("SPP") is relying on this certification as evidence supporting SPP's determination that Market Participant meets the risk management and minimum market participation requirements as set forth in Attachment X to SPP's Open Access Transmission Tariff ("Tariff"), hereby certify that I have full authority to certify and represent on behalf of Market Participant and further certify and represent as follows:

1. Training. Employees or agents transacting in markets or services provided pursuant to the Tariff on behalf of the Market Participant have received, or will receive, applicable training with regard to their participation under the Tariff as a condition of being authorized to transact on behalf of Market Participant. As used in this representation, training is deemed 'applicable' where it is commensurate and proportional in sophistication, scope and frequency to the volume of transactions and the nature and extent of the risk taken by the Market Participant.

2. Risk Management. Market Participant maintains current written risk management policies and procedures that address those risks that could materially affect Market Participant's ability to pay its SPP invoices when due, including, but not limited to, credit risks, liquidity risks and market risks.

3. Operational Capabilities. Market Participant has available appropriate personnel resources, operating procedures, and technical abilities to promptly and effectively respond to SPP communications and directions related to, but not limited to, settlements, billing, credit requirements and other financial matters.

4. Minimum Participation Criteria. Market Participant meets or exceeds the minimum market participation criteria, including capitalization requirements, as specified in Section 3.1.1.8 of Attachment X of the Tariff. The Market Participant shall submit audited financial statements for the most recent fiscal year to demonstrate minimum Tangible Net Worth or minimum total assets, or provide a report produced by a Rating Agency to establish its Credit Rating as specified in Section 3.1.1.8.2. In the event the Market Participant is unable to meet at least one of these minimum financial requirements, the Market Participant shall maintain with SPP the amount of Financial Security required by Section 3.1.1.8.2(e) of Attachment X to the Tariff.

Date: _____

_____

(Signature)

Print Name: _____

Title: _____

Subscribed and sworn before me _____, a notary public of the State of _____, in and for the County of _____, this __ day of _____, 20___.

_____

(Notary Public Signature)

My commission expires: _____/_____/_____

# Appendix "F" FORM OF SURETY BOND

Surety Bond No._____

THIS SURETY BOND is issued on **[date]** by **[full legal name of surety]** ("Surety") on behalf of **[full legal name of SPP customer]** ("Principal"), and in favor of Southwest Power Pool, Inc. ("SPP"). Capitalized terms used and not otherwise defined herein shall have the meaning ascribed to those terms in SPP's Open Access Transmission Tariff ("OATT").

**WHEREAS**, Principal seeks to satisfy credit or security requirements established in the OATT; and

**WHEREAS**, Surety is U.S. Treasury-listed with a minimum "A" rating from A.M. Best and has agreed, in exchange for compensation provided by Principal, to provide this Surety Bond on behalf of Principal in accordance with SPP's credit requirements;

**NOW, THEREFORE,** in consideration of the mutual promises and covenants herein contained, Surety hereby agrees and covenants as follows:

1. Amount of Bond. Surety unconditionally and irrevocably agrees to pay SPP amounts not to exceed an aggregate of **[amount]**, in accordance with the terms of this Surety Bond.

2. Payment Upon Demand. Surety shall pay such amount as specified by SPP upon receipt of a demand for payment notice ("Demand for Payment Notice"). Such Demand for Payment Notice shall be: (i) signed by an officer or authorized agent of SPP, (ii) dated the date of presentation, and (iii) be in the form as set forth in Exhibit A, Exhibit B, or Exhibit C, as applicable.

3. Validation. SPP may demand payment pursuant to this Surety Bond without prior demonstration of the validity of the demand.

4. Multiple Draws. SPP may demand multiple payments pursuant to this Surety Bond; *provided, however*, that the total amount of Surety's obligation hereunder shall not exceed an aggregate of **[amount]**.

5. Time and Form of Payment. Surety shall pay amounts owed pursuant to this Surety Bond in full not later than the first business day following receipt of SPP's written demand for payment to the account designated therein.

6. Obligations Unconditional. This Surety Bond is not conditioned upon SPP first attempting to collect payment, resorting to any other means of security or collateral, or pursuing any other remedies it may have. The obligations of Surety hereunder are independent of the obligations of Principal, and SPP may bring an action against Surety without bringing an action against Principal. SPP may from time to time, without notice or demand, and without affecting Surety's liability hereunder, take and hold other security for Principal's obligations to SPP and exchange, waive, release, or apply such security as SPP deems appropriate in its sole discretion.

Surety's liability under this Surety Bond is not conditioned upon the validity or enforceability of Principal's obligations to SPP.

7. Term of Surety Bond. The term of this Surety Bond shall begin on the date of its issuance, as set forth above, and shall continue in full force and effect until all amounts owed by Principal pursuant to the Agreements, as that term is defined in the OATT, are paid in full, including any amounts owed as a result of true-ups or other corrections to previous settlements; *provided, however,* that Surety may terminate this Surety Bond as provided in Paragraph 8, below.

8. Termination. Surety may terminate this Surety Bond upon ninety (90) days written notice to SPP; *provided, however,* that: (i) Surety's liability hereunder shall survive such termination and remain in full force and effect as to obligations incurred by Principal during the term of this Surety Bond; and (ii) in the event that Principal fails to provide an acceptable form of replacement Financial Security to SPP at least eighty seven (87) days prior to the termination of this Surety Bond, Surety shall, upon demand, without any notice other than such demand, and without any further action by SPP deliver Cash Deposit to SPP not later than the next Business Day in the amount of the full remaining value of this Surety Bond as security for Principal's obligations to SPP. A Cash Deposit provided to SPP by Surety and not applied by SPP to satisfy unpaid obligations of Principal shall be returned to Surety at such time as: (i) Principal provides adequate replacement Financial Security to SPP or (ii) all amounts owed by Principal to SPP are paid in full, including amounts owed as a result of true-ups or other corrections to previous settlements.

9. Principal Pays Bond Costs. Principal shall pay all commissions and charges for this Surety Bond. Principal's failure to pay any such charges shall not be grounds for termination of this Surety Bond, except as provided in Paragraph 8, above.

10. Expenses. Surety shall pay all reasonable costs incurred by SPP in the enforcement of this Surety Bond, including attorney fees and expenses. Surety's obligation to pay such costs shall be in addition to other amounts owed pursuant to this Surety Bond and shall not be limited by the maximum stated amount of this Surety Bond.

11. Communications. Demands, notices, and other communications shall be deemed effective when received, shall be in writing, and shall be delivered by courier with receipt of delivery or by registered mail, certified mail, or facsimile to the following addresses:

a. If to Surety:

**[Surety notice address]**

b. If to SPP:

Attn: Credit and Risk Management Department
Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936

c. If to Principal:

**[Principal notice address]**

Surety, SPP, or Principal may change the address provided for receipt of communications pursuant to this Surety Bond by providing written notice to the other parties.

12. Representations and Warranties. Surety represents and warrants to SPP that:

a. Surety has the legal power to execute and deliver this Surety Bond and to perform in accordance with its terms. All necessary actions have been taken to authorize the execution and delivery of this Surety Bond and performance in accordance with its terms. This Surety Bond is a legal, valid, and binding obligation of Surety.

b. There is no action or proceeding pending or, to Surety's knowledge, threatened before any court, arbitrator, or governmental agency that may materially adversely affect Surety's ability to perform its obligations under this Surety Bond.

c. There is no fact that Surety has not disclosed in writing to SPP of which Surety is aware or which Surety can reasonably foresee that would materially adversely affect Surety or the ability of Surety to perform its obligations hereunder.

13. Assignment. SPP may assign its rights under this Surety Bond without in any way diminishing Surety's obligations hereunder. Surety shall not be permitted to assign or transfer its rights under this Surety Bond without prior written consent of SPP.

14. Amendment and Waiver. The terms and provisions of this Surety Bond may not be amended or waived except in a writing signed by SPP and Surety. Election not to exercise, failure to exercise, or delay in exercising any rights under this Surety Bond shall in no way operate as a waiver of any rights of SPP under this Surety Bond.

15. Entire Agreement. This Surety Bond embodies the entire agreement between Surety and SPP with respect to the matters set forth herein and supersedes all prior such agreements.

16. Severability. Should any provision of this Surety Bond be determined by a court of competent jurisdiction to be unenforceable, all of the other provisions shall remain effective.

17. Choice of Law; Jurisdiction; Venue; and Service of Process. This Surety Bond shall be governed by the laws of the State of Arkansas without regard to conflict of laws principles. Surety irrevocably submits to the jurisdiction of any Arkansas court or any United States court sitting in Arkansas over any action or proceeding arising out of or relating to this Surety Bond and irrevocably agrees that all claims in such action or proceeding may be heard and determined

by such court. Surety agrees that a final judgment in any such action or proceeding shall be conclusive and may be enforced in other jurisdictions by suit on the judgment or in any other manner provided by law. Surety waives any objection to venue on the basis of forum non conveniens. Surety irrevocably consents to the service of process in any action or proceeding by the mailing of copies of such process to Surety at its address set forth herein. Nothing herein shall affect the right of SPP to bring any action or proceeding against Surety or its property in the courts of any other jurisdictions.

18. Waiver of Jury Trial. SURETY IRREVOCABLY, VOLUNTARILY, AND WITH ADVICE OF COUNSEL WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN ANY ACTION ARISING IN CONNECTION WITH THIS SURETY BOND.

IN WITNESS WHEREOF, Surety has executed and delivered this Surety Bond this **[date]**.

**[Full Legal Name of Surety]**

By:_____

Name:
Title:

# EXHIBIT A

(Form of Demand for Payment Notice – Principal Failure to Make Payment)

[**Date**][1]

[**Name and Address of Surety**][2]

*Re: Surety Bond No. _____*
*Demand for Payment*

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"), with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of SPP customer**] ("Principal") and in favor of Southwest Power Pool, Inc. ("SPP") that Principal has failed to make payment in accordance with the terms of the Agreements as defined in SPP's OATT. SPP hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**Wiring Instructions**]

Southwest Power Pool, Inc.

By: _____[3]

Name: _____

Title: _____

_____

[1] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[2] This will be the address of the Surety as set forth in the Surety Bond.
[3] The undersigned must be an officer or authorized agent of SPP.

# EXHIBIT B

(Form of Demand for Payment Notice – Principal Failure to Provide Acceptable Security)

[**Date**][4]

[**Name and Address of Surety**][5]

*Re: Surety Bond No. _____*
*Demand for Payment*

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"),with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of SPP customer**] ("Principal") and in favor of Southwest Power Pool, Inc. ("SPP") that as of the close of business on [**date**] **[date less than eighty-seven (87) days before the expiration of the Surety Bond]**,[6] Principal has failed to renew, replace, or amend this Surety Bond in satisfaction of the credit requirements established pursuant to SPP's OATT. SPP hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**Wiring Instructions**]

Southwest Power Pool, Inc.

By: _____[7]

Name: _____

Title: _____

_____

[4] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[5] This will be the address of the Surety as set forth in the Surety Bond.
[6] Insert date less than eighty-seven (87) days prior to expiration of the Surety Bond.

[7] The undersigned must be an officer or authorized agent of SPP.

## EXHIBIT C

(Form of Demand for Payment Notice – Surety Rating Downgrade)

[**Date**] [8]

[**Name and Address of Surety**] [9]

*Re: Surety Bond No. _____*
*Demand for Payment*

To the above named Surety:

The undersigned hereby certifies to [**full legal name of surety**] ("Surety"),with reference to its Surety Bond No. [**bond number**], dated [**execution date of Surety Bond**], issued on behalf of [**full legal name of SPP customer**] ("Principal") and in favor of Southwest Power Pool, Inc. ("SPP") that as of the close of business on [**date**] **[date more than three (3) business days after SPP has requested that Principal replace the Surety Bond because the Surety's rating by A.M. Best is less than "A"]**, Principal has failed to replace this Surety Bond in a manner acceptable to SPP. SPP hereby demands payment in the amount of $ [**amount**] in accordance with the following instructions.

[**Wiring Instructions**]

Southwest Power Pool, Inc.

By: _____ [10]

Name: _____

Title: _____

_____

[8] The date of the Demand for Payment Notice must be the date for which presentation of the Notice is made.
[9] This will be the address of the Surety as set forth in the Surety Bond.
[10] The undersigned must be an officer or authorized agent of SPP.

# ATTACHMENT Y
# TRANSMISSION OWNER DESIGNATION PROCESS

# I. OVERVIEW OF TRANSMISSION OWNER DESIGNATION PROCESS

1) As determined in accordance with Section I.2 of this Attachment Y, the Transmission Provider shall designate a Transmission Owner in accordance with the process set forth in Section III of this Attachment Y for transmission facilities approved for construction by the Transmission Provider after January 1, 2015 that meet all of the following criteria:

   a) Transmission facilities that are: ITP Upgrades, Network Upgrades required pursuant to the study results under Attachment AQ of this Tariff, high priority upgrades, Generator Retirement Upgrades, or Interregional Projects;

   b) Transmission facilities with a nominal operating voltage of greater than 100 kV;

   c) Transmission facilities that are not a Rebuild of an existing facility;

   d) Transmission facilities that do not alter a Transmission Owner's use and control of its existing right of way under relevant laws or regulations;

   e) Transmission facilities located where the selection of a Transmission Owner pursuant to Section III of this Attachment Y does not violate relevant law where the transmission facility is to be built;

   f) Transmission projects that do not require both a Rebuild of existing facilities and new transmission facilities; and

   g) Transmission facilities that are not a Local Transmission Facility.

2) For transmission projects involving both a Rebuild of existing facilities and the construction of new transmission facilities, the Transmission Provider shall designate the Transmission Owner(s) as follows:

a. If 80% or more of the total cost of a project consists of the Rebuild of existing facilities, then the Transmission Provider shall designate the Transmission Owner(s) for the project in accordance with Section IV of this Attachment Y; or

b. Otherwise, the Transmission Provider shall divide the project into two or more segments based upon whether that portion of the project is a Rebuild of existing facilities or new facilities. For those segments that are Rebuilds of existing facilities, the Transmission Provider shall designate the Transmission Owner(s) in accordance with Section IV of this Attachment Y. For those segments that are new facilities, the Transmission Provider shall designate the Transmission Owner(s) in accordance with Section III of this Attachment Y.

3) For any upgrade meeting the specifications listed in Section I.1 of this Attachment Y, the Transmission Provider may designate the Transmission Owner(s) in accordance with Section IV of this Attachment Y if such upgrade is required to be in service within 3 years or less to address an identified reliability violation ("Short-Term Reliability Project"). To have a transmission project approved as a Short-Term Reliability Project, the Transmission Provider shall:

a) Separately identify and post an explanation of the reliability violations and system conditions for which there is a time-sensitive need, in sufficient detail to allow stakeholders to understand the need and why it is time sensitive.

b) Provide to stakeholders and post on its website a full and supported written description explaining:

i. The decision to designate the Transmission Owner pursuant to Section IV of this Attachment Y, including an explanation of other transmission or non-transmission options that the Transmission Provider considered but concluded would not sufficiently address the immediate reliability need; and

ii. The circumstances that generated the immediate reliability need and an explanation of why that immediate reliability need was not identified earlier.

c) Permit stakeholders thirty (30) days to provide comments in response to the description required under Section I.3.b of this Attachment Y and make such comments publicly available.

d) Maintain and post a list of prior year designations of Short-Term Reliability Projects. The list must include the Short-Term Reliability Project's need date and the date that the DTO actually energized the project. Such list must be filed with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year.

e) Obtain approval by the SPP Board of Directors.

4) No project may receive an NTC as the result of a 20-Year Assessment.

5) For any upgrade not defined in Section I.1 or Section I.4, or does not meet the requirements of Sections I.2 or I.3 of this Attachment Y, the Transmission Provider shall designate the Transmission Owner(s) in accordance with the process set forth in Section IV of this Attachment Y.

6) The designation from the Transmission Provider shall be provided pursuant to Section V of this Attachment Y.

7) The Transmission Provider shall track all projects that are approved for construction in accordance with Section VI of this Attachment Y.

## II. DEFINITIONS

The terms used in this Attachment Y shall have the meanings as defined in this Section II or as otherwise defined in this Tariff.

**Applicant:** An entity that has submitted an application to the Transmission Provider to be a Qualified RFP Participant.

**Competitive Upgrades:** Those upgrades defined in Section I.1 of this Attachment Y or an upgrade for which the Transmission Provider must select a replacement Transmission Owner pursuant to Section IV.3 of this Attachment Y.

**Competitive Upgrade Participant ("CU Participant"):** An entity that has signed or will sign the SPP Membership Agreement as a Transmission Owner that proposes to participate in a Competitive Upgrade but that will not be the DTO for the Competitive Upgrade.

**Guaranty:** This term shall have the meaning given in Attachment X of this Tariff.

**Guarantor:** This term shall have the meaning given in Attachment X of this Tariff.

**Industry Expert Panel:** The panel of industry experts designated by the Oversight Committee to review and evaluate proposals submitted in response to any Request for Proposals in the Transmission Owner Selection Process.

**Local Transmission Facility:** A transmission facility that is located solely within a single Zone and has all of its costs allocated to such Zone.

**Not-For-Profit:** This term shall have the meaning given in Attachment X of this Tariff.

**Qualified RFP Participant ("QRP"):** An entity that has been determined by the Transmission Provider to satisfy the qualification criteria set forth in Section III.1 of this Attachment Y.

**Rebuild:** Shall mean, for purposes of this Attachment Y, a transmission facility that is an improvement to, addition to, or replacement of part of, an existing transmission facility.

**Request for Proposals ("RFP"):** For purposes of this Attachment Y, a request issued by the Transmission Provider for proposals from QRPs to construct, own, operate, and maintain a Competitive Upgrade.

**RFP Proposal:** A proposal submitted by one or more QRPs in response to a Request for Proposals issued by the Transmission Provider for a Competitive Upgrade.

**RFP Respondent:** Each QRP involved in the submission of an RFP Proposal that proposes to be the DTO for all or part of a Competitive Upgrade.

**Transmission Owner Selection Process:** The process of determining the Transmission Owner for Competitive Upgrades pursuant to Section III.2 of this Attachment Y.

# III. TRANSMISSION OWNER SELECTION PROCESS FOR COMPETITIVE UPGRADES

## 1) Application and Qualification Process

### a) Application

Any entity that desires to participate in the Transmission Owner Selection Process outlined in this Section III must submit an application and supporting materials to demonstrate that it satisfies the qualification criteria set forth in this Section III. The Transmission Provider will evaluate the Applicant's application and supporting materials to determine whether the Applicant satisfies the qualification criteria to be a QRP and participate in the Transmission Owner Selection Process in accordance with the timeline set out in Section III.1(c) of this Attachment Y.

i) Any entity wishing to participate in the Transmission Owner Selection Process, whether a current Transmission Owner or another entity, must submit an application to the Transmission Provider in the form provided on the Transmission Provider's website. The initial application must be received no later than June 30 of the year prior to the calendar year in which the Applicant wishes to begin participation in the Transmission Owner Selection Process. The Applicant shall submit an application fee with its application equal to the amount of the SPP annual membership fee. If the Applicant is a Member of SPP and is current in payment of its annual membership fee, then no application fee shall be required. The amount of the application fee shall be posted on the Transmission Provider's website as part of the application form.

### b) Qualification Criteria

An Applicant must demonstrate that it meets the following qualification criteria:

i) SPP Membership Criterion

An Applicant must be a Transmission Owner or be willing to sign the SPP Membership Agreement as a Transmission Owner if the Applicant is selected as part of the Transmission Owner Selection Process.

ii) Financial Criteria

An Applicant must demonstrate that it meets one of the following financial criteria:

(1) A senior unsecured investment grade rating or an issuer rating of BBB- or equivalent from a "nationally recognized statistical rating organization" as defined in Attachment X of this Tariff. If an Applicant maintains a rating from all three approved nationally recognized statistical rating organizations, it must maintain at least two ratings in the investment grade range. If an Applicant maintains a rating from two of the approved nationally recognized statistical rating organizations, it must maintain at least one of those ratings in the investment grade range.

(2) If the Applicant does not satisfy the requirement set forth in (1) above, the Applicant may submit to the Transmission Provider a Guaranty from its parent or affiliated organization that possesses an investment grade rating or an issuer rating of BBB- or equivalent from a "nationally

recognized statistical rating organization" as defined in Attachment X of this Tariff. A Guaranty obligates the Guarantor to satisfy the obligations of the guarantee entity. Parent Guaranties are acceptable where the Applicant is a subsidiary, joint venture, or affiliate of the parent Guarantor. The Guaranty may be cancelled at any time that the Applicant establishes an investment grade rating as discussed in Section III.1(b)(ii)(1) of this Attachment Y. The Guaranty will be in a form consistent with Appendix D of Attachment X of this Tariff and must satisfy the following requirements:

(a) Be duly authorized by the Guarantor and signed by an officer of the Guarantor;

(b) State a minimum effective period of five (5) years, or provide for automatic renewal subject to cancellation with no less than sixty (60) days notice, provided that in all events the Guaranty is effective for all obligations of the Applicant undertaken prior to cancellation;

(c) Include a certification by the corporate secretary of the Guarantor that the execution, delivery, and performance of the Guaranty have been duly authorized;

(d) Certify that the Guaranty does not violate other undertakings or requirements applicable to the Guarantor and is

enforceable against the Guarantor in accordance with its terms;

(e) Obligate the guarantor to submit a representation letter annually indicating any material changes from the information provided in the Applicant's application related to the Guarantor and Guaranty, and representing that the Guarantor continues to satisfy the financial criteria;

(f) Secure all obligations of the Applicant under or in connection with this Tariff and other agreements with the Transmission Provider;

(g) Be supported by adequate consideration and be otherwise binding as a matter of law; and

(h) Include as an attachment a resolution of the board of directors or other governing body of the Guarantor authorizing the Guaranty.

(3) If the Applicant does not satisfy the requirements set forth in (1) or (2) above, the Applicant may submit to the Transmission Provider a formal letter of reference from a commercial bank evidencing an existing line of credit from commercial banks (or access to an existing line of credit through Inter-company agreements with a Parent or Affiliate), or bonding indication letter from an insurance or surety company either of which indicate a willingness to extend credit to the Applicant in an amount of at least

$25,000,000 (for bank) or willingness to provide a surety bond in the amount of at least $25,000,000 (for an insurance or surety company). Commercial bank reference letters acceptable to the Transmission Provider must be issued by a financial institution organized under the laws of the United States or any state of the United States or the District of Columbia or a branch or agency of a foreign commercial bank located in the United States, with a minimum corporate debt rating of A- or equivalent from a "nationally recognized statistical rating organization" as defined in Attachment X of this Tariff and total assets of at least $10 billion. Bonding indication letters acceptable to the Transmission Provider must be issued by an insurance or surety company with a minimum financial strength rating of A- and a minimum financial size category of X from the A.M. Best Company.

(4) If the Applicant is a municipality, a cooperative, or other Not-For-Profit entity, the Applicant may satisfy the financial criteria requirement by providing evidence of direct rate-setting authority or taxing authority. The Applicant must possess this authority and cannot rely on an affiliation with another entity that possesses rate-setting or taxing authority.

iii) Managerial Criteria

An application must show that the Applicant has requisite expertise by describing its capability, experience, and process to address the following areas:

(1) Transmission Project Development

(a) engineering, permitting, environmental, equipment and material procurement, project management (including cost control, scope, and schedule management), construction, commissioning of new facilities, new or emerging technologies; and

(b) routing, surveying, rights-of-way, eminent domain, and real estate acquisition, including process for obtaining easements.

(2) Internal safety program, contractor safety program, safety performance record and program execution.

(3) Transmission Operations: control center operations, NERC compliance process and compliance history, registration or the ability to register for compliance with applicable NERC Reliability Standards, storm/outage response and restoration plan, record of past reliability performance, statement of which entity will be operating completed transmission facilities, staffing, equipment, and crew training.

(4) Transmission Maintenance: staffing and crew training, transmission facility and equipment maintenance, record of past maintenance performance, NERC compliance process and history, statement of which entity will be performing maintenance on completed transmission facilities.

(5) Ability to comply with Good Utility Practice, SPP Criteria, and industry standards.

(6) Ability to comply with or demonstration of how the Applicant plans to be able to comply with NERC Reliability Standards.

(7) Any other relevant project development experience that the Applicant believes may demonstrate its expertise in the above areas.

An Applicant can demonstrate that it meets the managerial criteria either on its own or by relying on one or more entities to satisfy any of the managerial criteria ("Alternate Qualifying Entity (ies)"). If the Applicant seeks to satisfy the managerial criteria in whole or in part by relying on one or more Alternate Qualifying Entity(ies), the Applicant must submit: materials demonstrating to the Transmission Provider's satisfaction that the Alternate Qualifying Entity(ies) meet(s) the managerial criteria for which the Applicant is relying upon the Alternate Qualifying Entity(ies) to satisfy.

**c) Determination of Qualifications**

i) Upon receiving an application, the Transmission Provider shall review the application to determine whether the Applicant satisfies the qualification criteria set forth in Section III.1(b) of this Attachment Y. The Transmission Provider shall notify each Applicant of its determination no later than September 30 of the year in which the application was submitted.

ii) If the Transmission Provider determines that the Applicant fails to satisfy one or more of the qualification criteria, the Transmission Provider shall inform the Applicant of such deficiency(ies), and the Applicant shall be allowed to cure any deficiency(ies) within thirty (30) calendar days of notice from the Transmission Provider by providing any additional information that the Applicant believes cures the deficiency(ies). The Transmission Provider shall review the information provided by the Applicant and render a final determination of whether the Applicant satisfies the qualification criteria within forty-five (45) calendar days of the Transmission Provider's receipt of the additional information. If, after attempting to cure the deficiency(ies), the Applicant still has not satisfied the qualification criteria, the Applicant shall be disqualified from the Transmission Owner Selection Process for the following year.

iii) Upon the Transmission Provider's determination that an Applicant satisfies the qualification criteria, the Transmission Provider shall notify the Applicant that it has been determined to be a QRP and can participate in the Transmission Owner Selection Process effective January 1 of the following calendar year. By December 31 of each year, the Transmission Provider shall post on its website a list of all QRPs that are eligible to participate in the following calendar year for any Competitive Upgrade.

**d) Annual Recertification Process and Reporting Requirements**

i) By June 30 of each year, each QRP must submit to the Transmission Provider a letter signed by an authorized officer of the QRP certifying that the QRP continues to meet the current

qualification criteria or indicating any material changes to the information provided in its application. The QRP shall pay an annual certification fee equal to the amount of the SPP annual membership fee. If the QRP is a Member of SPP and is current in payment of its annual membership fee, then no certification fee will be required.

ii) If at any time there is a material change to the information provided in its application, a QRP shall be required to inform the Transmission Provider within seven (7) calendar days of such change so that the Transmission Provider may determine whether the QRP continues to satisfy the qualification criteria. Upon notification of any such change, the Transmission Provider shall have the option to: (a) determine that the change does not affect the QRP's status; (b) suspend the QRP's eligibility to participate in the Transmission Owner Selection Process until the QRP has cured any deficiency in its qualifications to the Transmission Provider's satisfaction; (c) allow the QRP to continue to participate in the Transmission Owner Selection Process for a limited time period, as specified by the Transmission Provider, while the QRP cures the deficiency to the Transmission Provider's satisfaction; or (d) terminate the QRP status in accordance with Section III.1(e) of this Attachment Y.

**e) Termination of QRP Status**

The Transmission Provider may terminate a QRP's status if the QRP: (1) fails to submit its annual certification letter; (2) fails to pay the applicable fee as required by Section III.1(d) of this Attachment Y; (3) experiences a change in its qualifications and the Transmission Provider determines that it may no longer be a QRP; or (4) informs the Transmission Provider that

it no longer desires to be a QRP; or (5) fails to notify the Transmission Provider of a change to the information provided in its application in accordance with Section III.1(d) of this Attachment Y. In the event the Transmission Provider terminates a QRP's status based on any of the aforementioned criteria, the Transmission Provider will provide the QRP notice of termination to be effective immediately.

**f) Dispute Resolution**

If the Applicant or QRP ("Affected Party") disagrees with the Transmission Provider's determination regarding its qualifications under Section III.1 of this Attachment Y, the Affected Party may initiate dispute resolution procedures. Any such dispute shall first be referred to a designated senior representative of the Transmission Provider and a senior representative of the Affected Party for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) calendar days (or such other period upon which the Transmission Provider and the Affected Party may agree) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth in Sections 12.2 through 12.5 of this Tariff.

**2) Transmission Owner Selection Process**

Once a Competitive Upgrade has been approved by the SPP Board of Directors, the Transmission Provider shall issue a Request for Proposals ("RFP") for the Competitive Upgrade as specified in this Section III of Attachment Y. RFP Proposals may be sponsored by one or more entities. If an RFP Proposal involves more than one sponsoring entity, at least one of the sponsoring entities must be a QRP. RFP Proposals with more than

one sponsoring entity shall comply with all of the requirements set forth in Section III.2(a) of this Attachment Y that are applicable to such entity (whether an RFP Respondent or a CU Participant); otherwise the RFP Proposal shall be deemed incomplete and the Transmission Provider shall follow the process for incomplete RFP Proposals set forth in Section III.2(e)(iv) of this Attachment Y.

**a) RFP Proposals Involving More Than One Entity**

i) Joint RFP Proposal

(1) An RFP Proposal may be submitted jointly by more than one QRP ("Joint RFP Proposal") for the purposes of identifying more than one DTO for a Competitive Upgrade.

(2) Each RFP Respondent for a Joint RFP Proposal must be a QRP at the time that the Joint RFP Proposal is submitted and at all times during the Transmission Owner Selection Process during which the Joint RFP Proposal is pending. If at any time during the Transmission Owner Selection Process set forth in this Section III one or more of the RFP Respondents involved in the submission of a Joint RFP Proposal ceases to be a QRP, the Joint RFP Proposal shall be disqualified from further consideration.

ii) Multi-Owner RFP Proposal

(1) An RFP Proposal or a Joint RFP Proposal may include one or more CU Participants ("Multi-Owner RFP Proposal"). A Multi-Owner RFP Proposal must include at least one QRP that will serve as the RFP Respondent and the DTO for the Competitive Upgrade if the Multi-Owner RFP Proposal is selected by the Transmission Provider.

(2) Except as provided in Sections III.2(c)(vi), (vii), (xi), and (xvii) and Sections III.2(g)(iii)(4) and (5) of this Attachment Y, in reviewing a Multi-Owner RFP Proposal, the Transmission Provider shall evaluate only the capabilities of the QRP(s) that will serve as the DTO(s) for the Competitive Upgrade.

(3) A Multi-Owner RFP Proposal that identifies more than one proposed DTO shall also be classified as a Joint RFP Proposal and shall satisfy all RFP requirements applicable to Joint RFP Proposals.

iii) For purposes of this Attachment Y, any reference to an RFP Proposal shall also include a Joint RFP Proposal and a Multi-Owner RFP Proposal, and any reference to an RFP Respondent shall mean the QRPs involved in the submission of a Joint RFP Proposal or a Multi-Owner RFP Proposal both individually and collectively.

**b) Industry Expert Panel**

i) On an annual basis, the Oversight Committee or its successor shall identify a pool of candidates to serve as industry experts on one or more Industry Expert Panel(s) ("IEP") to evaluate proposals that are submitted in response to any RFP issued by the Transmission Provider pursuant to this Section III of Attachment Y. IEP candidates shall have documented expertise on file with the Transmission Provider in one or more of the following areas: (1) electric transmission engineering design; (2) electric transmission project management and construction; (3) electric transmission operations; (4) electric transmission rate design and analysis; and (5) electric transmission finance.

ii) Each industry expert must disclose to the Oversight Committee any affiliation with any SPP stakeholder or any QRP. In the event an affiliation exists, the Oversight Committee will evaluate whether the affiliation may adversely impact an industry expert's ability to independently evaluate RFP Proposals, and the Oversight Committee may disqualify that industry expert.

iii) The Oversight Committee shall present its recommended pool of IEP candidates to the SPP Board of Directors for approval. The name and qualifications of each recommended candidate shall be posted on the Transmission Provider's website prior to SPP Board of Directors approval.

iv) The Oversight Committee shall create an IEP from the IEP candidate pool to evaluate proposals resulting from the RFPs. The IEP shall consist of three (3) to five (5) industry experts such that the IEP will have expertise in all five (5) areas listed in Section III.2(b)(i) of this Attachment Y. The Oversight Committee may create additional IEPs. Each IEP member must sign a confidentiality agreement prior to participating in the Transmission Owner Selection Process.

v) If a member of a designated IEP becomes affiliated with a stakeholder or QRP, the IEP member shall immediately notify the Transmission Provider and the Oversight Committee. The Oversight Committee shall evaluate whether any affiliation between a member of a designated IEP and a stakeholder or QRP may adversely impact the IEP member's ability to independently evaluate RFP Proposals reviewed by that IEP. In such event, the Oversight Committee may remove the IEP member from that IEP.

If necessary, the Oversight Committee may designate a replacement IEP member from the IEP candidate pool.

vi) The Transmission Provider shall facilitate the IEP's efforts to develop recommendations to the SPP Board of Directors. The IEP will evaluate all aspects of each proposal submitted for its review. Once all evaluations are complete, the IEP will develop a single recommendation for the SPP Board of Directors consisting of its recommended RFP Proposal and an alternate RFP Proposal for each Competitive Upgrade.

**c) Request for Proposals**

The Transmission Provider shall issue an RFP for each Competitive Upgrade, which shall contain information including, but not limited to:

i) An overview of the purpose for the RFP including the need for the Competitive Upgrade, regulatory context and authority, and other necessary information.

ii) The minimum RFP Proposal submission requirements.

iii) Minimum design specifications.

iv) The date regulatory approvals are required to be completed as determined by the Transmission Provider.

v) Identification of information that will not be treated as confidential shall be in the RFP.

vi) A requirement that the RFP Proposal provide the following information specific to the Competitive Upgrade:

(1) financial information, including but not limited to demonstration of financing (including a reasonable contingency); detailed engineering and construction cost estimate; itemized revenue requirement calculations for each RFP Respondent and CU Participant that proposes to have revenue requirements under this Tariff; and financial and business plans, including the nature of any FERC incentives any RFP Respondent or CU Participant intends to request;

(2) engineering information, including but not limited to engineering design of the project and technical requirements;

(3) construction information, including but not limited to anticipated project timeline including timeline for all necessary regulatory approvals, equipment acquisition, description of applicable rights-of-way and real estate acquisition, description of routing, description of permitting, description of outage clearance(s), and identification of the party responsible for construction;

(4) operations and maintenance information, including but not limited to demonstration of operations, statement of which entity will be operating and maintaining the transmission facility, storm and outage response plan, maintenance plan, staffing, equipment, crew training, and record of past maintenance and outage restoration performance;

(5) safety information, including but not limited to identification of the internal safety program, contractor safety program, and safety performance record;

(6) for a Multi-Owner RFP Proposal, such information with respect to CU Participants as is required for evaluation of the RFP Proposal under the criteria set forth in Sections III.2(c)(vi)(2) - (5) of this Attachment Y given the proposed percentage share of ownership or interest in the Competitive Upgrade by each RFP Respondent and CU Participant; and

(7) identification of information in the RFP Proposal that the RFP Respondent considers to be confidential.

vii) A requirement that the RFP Proposal demonstrate that each RFP Respondent (and, in the case of a Multi-Owner RFP Proposal, the CU Participants as set forth below) possesses the necessary financial strength by providing one of the following:

(1) demonstration that each RFP Respondent continues to satisfy the financial criteria set forth in Section III.1(b)(ii)(1) or (2) of this Attachment Y and that the Competitive Upgrade does not exceed 30% of the total capitalization of the RFP Respondent or its parent Guarantor;

(2) demonstration of conclusive evidence of the ability to obtain a performance bond in an amount equal to the total cost of the Competitive Upgrade, including financing costs

and a 20% contingency, from an insurance or surety company with an A.M. Best "Financial Strength Rating" of Superior (A++, A+) or Excellent (A, A-) and an adjusted "Policy Holder Surplus" of $500,000,000 or more; or

(3) demonstration of conclusive evidence of the ability to obtain a letter of credit in an amount equal to the total cost of the Competitive Upgrade, including financing costs and a 20% contingency, from a financial institution that satisfies the requirements set forth in Attachment X Section 7.1.3.2 of this Tariff.

For purposes of this requirement, "conclusive evidence" shall mean a letter from a bonding agent or bank indicating approval of or willingness to provide the required performance bond or letter of credit to the RFP Respondent.

In the case of a Joint RFP Proposal, the financial obligations shall be met by each RFP Respondent based upon the portion of the facility to be owned and operated by each RFP Respondent. In the case of a Multi-Owner RFP Proposal, the financial obligations can either be met by the identified RFP Respondents or by a combination of RFP Respondents and CU Participants based upon the proposed share of ownership of or interest in the Competitive Upgrade. In either case, such allocation of ownership or interest and each RFP Respondent's and/or CU Participant's share of financial responsibility shall be set forth in detail in the RFP Proposal.

viii) Information exchange requirements including but not limited to, identification of data required to be provided to the Transmission

Provider in accordance with NERC reliability standards and CEII requirements.

ix) A description of the proposal evaluation procedure, including the statement of proposal evaluation methodology and criteria for acceptable proposals.

x) A requirement that the each RFP Respondent agrees to pay, as outlined in Section III.2(f) of this Attachment Y: (1) a deposit for each RFP Proposal submitted for the RFP Proposal's share of the Transmission Provider's costs to administer the Transmission Owner Selection Process; and (2) any additional costs that are assessed after the completion of the Transmission Owner Selection Process.

xi) A requirement that each RFP Respondent, and in the case of a Multi-Owner RFP Proposal, each CU Participant, disclose any credit rating changes, bankruptcies, dissolutions, mergers, or acquisitions within the past five (5) years of the RFP Respondent or CU Participant or its parent, controlling shareholder, or entity providing a Guaranty pursuant to Section III.1(b)(ii)(2) of this Attachment Y.

xii) A requirement that each RFP Respondent provide its Internal Revenue Service Tax Identification Number.

xiii) A requirement that the RFP Respondent declare whether it may seek to assign the Competitive Upgrade to an Affiliate pursuant to Section III.2(e)(xi) of this Attachment Y if selected as the DTO for the Competitive Upgrade, along with a description of such Affiliate.

xiv) A requirement that a Joint RFP Proposal:

(1) Clearly and specifically identify each RFP Respondent's respective roles and responsibilities (as well as each RFP Respondent's respective percentage of responsibility) for finance, construction, ownership, operation, maintenance, and restoration of the Competitive Upgrade in such a manner that one hundred (100) percent of the responsibilities for the Competitive Upgrade are identified;

(2) Specify each RFP Respondent's qualifications and responsibilities for satisfying the requirements set forth in Sections III.2(c)(vi) and III.2(c)(vii) of this Attachment Y; and

(3) Provide as part of the Joint RFP Proposal submission any agreements between or among the RFP Respondents governing the division of roles and responsibilities.

xv) A requirement that each RFP Respondent participating in a Joint RFP Proposal acknowledges and agrees that:

(1) Each RFP Respondent shall be jointly and severally liable for all aspects of finance and construction of the Competitive Upgrade, such that, if the Joint RFP Proposal is selected by the Transmission Provider, the other RFP Respondent(s) shall be liable for the defaulting RFP Respondent's(s') obligations in the event that one or more RFP Respondent(s) defaults on its obligations; or

(2) In the event that each RFP Respondent does not agree to be jointly and severally liable as set forth in Section III.2(c)(xv)(1) of this Attachment Y, if the Joint RFP Proposal is selected by the Transmission Provider, the Transmission Provider shall reevaluate the entire Competitive Upgrade pursuant to Section III.2(h) of this Attachment Y if one or more RFP Respondent(s) defaults on its obligations with respect to the Competitive Upgrade.

xvi) A requirement that a Joint RFP Proposal identify a single point of contact for the Joint RFP Proposal, who will represent all RFP Respondents in any communications with the IEP or the Transmission Provider with respect to the Joint RFP Proposal.

xvii) A requirement that each Multi-Owner RFP Proposal shall provide sufficient detail to enable a thorough evaluation of the RFP Proposal including information regarding:

(1) the identity of each RFP Respondent and CU Participant;

(2) any division of ownership of or interest in the Competitive Upgrade;

(3) any agreements between or among the RFP Respondents and CU Participants regarding the ownership of or interest in the Competitive Upgrade sufficient to establish the ability of the RFP Respondent(s) to perform the obligations of a DTO; and

(4) the timing of any such transfer of ownership or interest.

xviii) A requirement that the RFP Respondent acknowledges and agrees that notwithstanding any defaults of any CU Participant on its obligations under any participation agreements, the RFP Respondent is responsible for all aspects of the Competitive Upgrade. Further, if the Multi-Owner RFP Proposal is also a Joint RFP Proposal, the proposal must specify which RFP Respondent will be responsible for any CU Participant default.

xix) A requirement that:

(1) Each RFP Respondent agree to execute the SPP Membership Agreement as a Transmission Owner if the RFP Proposal is selected by the Transmission Provider, if it has not already done so; and

(2) Each CU Participant in a Multi-Owner RFP Proposal shall agree in writing to execute the SPP Membership Agreement as a Transmission Owner at such time that the entity is first eligible to execute the Membership Agreement as a Transmission Owner, if it has not already done so.

xx) Subject to any modifications resulting from Attachment Y, Section VIII.3(b), the deadline for all RFP Proposal submissions shall be one hundred eighty (180) calendar days from the date the RFP is issued ("RFP Response Window"). The Transmission Provider may reduce the RFP Response Window to no less than ninety (90) days based on, but not limited to, the Competitive Upgrade's need date or scope. If the final day of the RFP Response Window falls on a weekend or a holiday recognized by the Transmission

Provider, the due date for RFP Proposals shall be the next Business Day.

In the event that the Transmission Provider determines the need for a re-evaluation of a Competitive Upgrade in accordance with Section VIII of this Attachment Y, the SPP Board of Directors may suspend the Transmission Owner Selection Process for that RFP as necessary for that Competitive Upgrade pending a final determination by the SPP Board of Directors of the re-evaluation. Notice of a suspension shall be sent to all QRPs within three (3) Business Days.

**d) Industry Expert Panel Direction to Respondents Document**

i) The IEP shall draft and the Transmission Provider shall issue IEP formal guidance to respondents no later than forty-five (45) calendar days after the RFP issuance.

ii) The IEP formal guidance to respondents shall be intended to improve Transmission Owner Selection Process efficiency by providing evaluation clarity not provided in the RFP.

iii) The IEP formal guidance to respondents shall include, but not be limited to:

(1) Summary of the project for which the RFP was issued;

(2) Key criteria considered in each evaluation category including a quantitative indication of scoring emphasis on these key criteria; and

(3) Any other information the IEP determines relevant to their evaluation.

**e) RFP Process and Timeline**

i) The Transmission Provider shall issue each RFP by or before the later of: (1) thirty (30) calendar days after approval of the Competitive Upgrade by the SPP Board of Directors; or (2) eighteen (18) months prior to the date that anticipated financial expenditure is needed for a Competitive Upgrade. The RFP shall be issued only to QRPs.

ii) Each RFP Respondent shall submit a complete proposal in response to the RFP within the RFP Response Window as defined in Section III.2(c)(xx) of this Attachment Y.

iii) The Transmission Provider shall not disclose any information contained in any RFP Proposal, except to the IEP, until the issuance of the IEP reports in accordance with Section III.2(e)(vi)(2) of this Attachment Y.

iv) Upon receipt of an RFP Proposal, the Transmission Provider shall immediately review the proposal for completeness, and shall promptly notify the RFP Respondent if the RFP Proposal is incomplete. The RFP Respondent(s) may submit information in order to complete the proposal if such submittal is made within the RFP Response Window. Any RFP Respondent that fails to submit a complete RFP Proposal within the RFP Response Window will be deemed to have waived its right to respond to the RFP, the RFP Proposal shall be disqualified from further consideration, and the Transmission Provider shall refund a portion of the Transmission Owner Selection Process deposit in accordance with Section III.2(f) of this Attachment Y.

v) If the Transmission Provider does not receive any complete proposals in response to an RFP, the Transmission Provider shall

inform the SPP Board of Directors and shall select the DTO in accordance with the process set forth in Section IV of this Attachment Y. If all of the RFP proposals for a Competitive Upgrade include cost estimates that exceed the cost estimate determined by the Transmission Provider at the time the Competitive Upgrade was approved for construction by thirty (30) percent or more, the Transmission Provider shall inform the SPP Board of Directors, and the SPP Board of Directors shall decide whether to proceed with the IEP review of the RFP responses, or whether to withdraw the RFP and reevaluate the Competitive Upgrade. If the SPP Board of Directors withdraws the RFP, each RFP Proposal shall be entitled to a partial refund of its Transmission Owner Selection Process deposit as set forth in Section III.2(f)(iv) of this Attachment Y.

vi) Upon the closing of the RFP Response Window, the Transmission Provider shall provide the RFP Proposals to the IEP. The IEP shall review, score, and rank all RFP Proposals and submit its recommendation to the SPP Board of Directors based upon selection criteria outlined in Section III.2(g) of this Attachment Y. The identity of RFP Respondents that submitted the RFP Proposals shall not be disclosed to the SPP Board of Directors as part of the IEP's recommendation. The IEP's recommendation shall be submitted to the Transmission Provider within ninety (90) calendar days of the initiation of the IEP's review ("Review Period").

(1) During its review, the IEP may initiate communication with RFP Respondents to obtain answers to any additional questions about proposals, and any such communications shall be documented by the IEP. Lobbying of the IEP by, or on behalf of, any RFP Respondent or CU Participant is

prohibited, and may result in the Transmission Provider disqualifying the RFP Respondent and the RFP Proposal from the RFP process. The IEP shall score and rank each RFP Proposal in a non-discriminatory manner based upon the information supplied in the RFP Proposal and information, if any, obtained during the Review Period.

(2) The IEP shall compile an internal report for the Transmission Provider detailing the process, data, results of its deliberations, and its recommended RFP Proposal and an alternate RFP Proposal for each Competitive Upgrade. The Transmission Provider shall be responsible for producing two redacted versions of the internal report, a Board of Directors report and a public report. The Board of Directors report shall exclude the names of the RFP Respondents. The public report shall exclude the names of RFP Respondents and any confidential information obtained during the Transmission Owner Selection Process. No later than twenty-one (21) calendar days prior to the SPP Board of Directors meeting during which the SPP Board of Directors will consider the IEP recommendation, the public report shall be posted on the Transmission Provider's website and the Board of Directors report shall be provided to the SPP Board of Directors.

vii) Except as provided in Sections III.2(e)(vii)(a) and III.2(e)(vii)(b) of this Attachment Y, the SPP Board of Directors shall select an RFP Proposal ("Selected RFP Proposal") and an alternate RFP Proposal for each Competitive Upgrade based primarily on the information provided by the IEP. The Transmission Provider shall notify each RFP Respondent that was involved in the submission

of the Selected RFP Proposal that it has been chosen by the SPP Board of Directors to become the DTO for the Competitive Upgrade ("Selected RFP Respondent(s)") by issuing an NTC(s) for the Competitive Upgrade pursuant to Section V of this Attachment Y. For a Joint RFP Proposal, each NTC shall specify the applicable roles and obligations of each Selected RFP Respondent based on the information provided in the Selected RFP Proposal. To become the DTO(s) for the Competitive Upgrade, each Selected RFP Respondent must, within seven (7) calendar days of receiving such notice: (1) sign any necessary agreement(s) to assume all of the responsibilities of a Transmission Owner related to the Competitive Upgrade pursuant to the SPP Membership Agreement and this Tariff; (2) submit to the Transmission Provider a deposit in accordance with Section III.2(e)(xii) of this Attachment Y; and (3) provide written notification to the Transmission Provider that it accepts the NTC. For a Joint RFP Proposal, each Selected RFP Respondent must fulfill these requirements within seven (7) calendar days.

a. If the Board of Directors accepts the IEP's recommendation, pursuant to Section III.2(g)(i) of this Attachment Y, resulting in all RFP Proposals being eliminated from consideration due to a low score in any evaluation category, the DTO for the Competitive Upgrade will be identified as follows:

    1. If the Competitive Upgrade qualifies under Section I.3 of this Attachment Y, the DTO will be identified as set forth in Section I.3 of this Attachment Y.

2. If the Competitive Upgrade does not meet the conditions set forth in Section III.2(e)(vii)(a)(1) of this Attachment Y, the Transmission Provider shall reevaluate the Competitive Upgrade to determine what action to take, including: (a) resubmission of the Competitive Upgrade for DTO selection under Section III of this Attachment Y; (b) modification of the Competitive Upgrade and resubmission of the Competitive Upgrade for DTO selection under Section III of this Attachment Y; or (c) cancellation of the Competitive Upgrade.

b. If a Competitive Upgrade was previously resubmitted, pursuant to Section III.2(e)(vii)(a) of this Attachment Y, for selection of a DTO under Section III of this Attachment Y and no DTO was selected, the Transmission Provider will identify the DTO pursuant to Section IV of this Attachment Y.

viii) A Selected RFP Respondent shall be deemed to have waived its right to become the DTO if, within seven (7) calendar days of receiving such notice, the Selected RFP Respondent: (1) does not respond to such notice from the Transmission Provider; (2) notifies the Transmission Provider that it is no longer willing to become the Transmission Owner for the Competitive Upgrade; (3) fails to sign the necessary agreement(s); (4) fails to provide a deposit in accordance with Section III.2(e)(xii) of this Attachment Y; or (5) fails to provide written notification to the Transmission Provider that it accepts the NTC. For Joint RFP Proposals, if one or more of the Selected RFP Respondents fails to fulfill these requirements within seven (7) calendar days, all Selected RFP Respondents for

the Joint RFP Proposal shall be deemed to have waived their rights. In the event that one or more Selected RFP Respondents has been deemed to have waived its rights, the Transmission Provider shall notify the SPP Board of Directors.

ix) If a Selected RFP Respondent has waived its rights pursuant to Section III.2(e)(viii) of this Attachment Y, the Transmission Provider shall notify each RFP Respondent involved in the submission of the alternate RFP Proposal that it has been chosen by the SPP Board of Directors to become the DTO for the Competitive Upgrade, and the Transmission Provider shall issue an NTC(s) for the Competitive Upgrade pursuant to Section V of this Attachment Y. For a Joint RFP Proposal, each NTC shall specify the applicable roles and obligations of each RFP Respondent that submitted the alternate RFP Proposal, based on the information provided in the alternate RFP Proposal. To become the DTO(s) for the Competitive Upgrade, each RFP Respondent that submitted the alternate RFP Proposal must, within seven (7) calendar days of receiving such notice: (1) sign any necessary agreement(s) to assume all of the responsibilities of a Transmission Owner related to the Competitive Upgrade pursuant to the SPP Membership Agreement and this Tariff; (2) submit to the Transmission Provider a deposit in accordance with Section III.2(e)(xii) of this Attachment Y; and (3) provide written notification to the Transmission Provider that it accepts the NTC. For a Joint RFP Proposal, each RFP Respondent that submitted the alternate RFP Proposal must fulfill these requirements within seven (7) calendar days.

x) An RFP Respondent that submitted the alternate RFP Proposal shall be deemed to have waived its right to become the DTO if,

within seven (7) calendar days of receiving such notice, the RFP Respondent that submitted the alternate RFP Proposal: (1) does not respond to such notice from the Transmission Provider; (2) notifies the Transmission Provider that it is no longer willing to become the Transmission Owner for the Competitive Upgrade; (3) fails to sign the necessary agreement(s); (4) fails to provide a deposit in accordance with Section III.2(e)(xii) of this Attachment Y; or (5) fails to provide written notification to the Transmission Provider that it accepts the NTC. For Joint RFP Proposals, if one or more of the RFP Respondents for the alternate Joint RFP Proposal fails to fulfill these requirements within seven (7) calendar days, all RFP Respondents for the alternate Joint RFP Proposal shall be deemed to have waived their rights to become a DTO. In the event that an RFP Respondent for the alternate RFP Proposal has been deemed to have waived its rights, the Transmission Provider shall notify the SPP Board of Directors, and the Transmission Provider shall determine the DTO in accordance with the process set forth in Section IV of this Attachment Y.

xi) A DTO for a Competitive Upgrade cannot assign the Competitive Upgrade to another entity, except to an Affiliate of the DTO subject to requirements set forth in Section VII of this Attachment Y. The Transmission Provider's selection of an RFP Proposal that includes a declaration of intent to assign as the Selected RFP Proposal does not constitute Transmission Provider approval of the assignment.

xii) When accepting the responsibilities of being a DTO for a Competitive Upgrade, the Selected RFP Respondent(s) shall provide the following to the Transmission Provider:

(1) a cash deposit representing 2% of the estimated cost of the Selected RFP Proposal; and

(2) a firm capital commitment acceptable to the Transmission Provider that is sufficient to complete the Competitive Upgrade, including one of the following:

a. A binding commitment letter from lenders and/or equity providers;

b. Cash held in escrow;

c. A performance and payment bond;

d. Surety bond;

e. Existing balance sheet liquidity; or

f. Demonstrated history of ability to obtain adequate capital to support the project.

The cash deposit shall be held in escrow by the Transmission Provider. Upon reaching the 50% completion milestone of the Competitive Upgrade, as determined by the Transmission Provider, the Transmission Provider shall refund the deposit, plus any interest the deposit accrued while in escrow, to the DTO(s). If the DTO(s) fail(s) to reach the 50% completion milestone of the Competitive Upgrade in accordance with Section III.2(h) of this Attachment Y, then the DTO(s) shall forfeit the deposit and any

accrued interest. The Transmission Provider shall then select a new DTO in accordance with Section III.2(h) and apply the deposit and accrued interest to reduce the final cost of the Competitive Upgrade. If the Transmission Provider cancels the Competitive Upgrade through no fault of the DTO(s), then the Transmission Provider shall refund the deposit and accrued interest to the DTO(s).

xiii) A DTO for a Competitive Upgrade that resulted from a Multi-Owner RFP Proposal may convey an interest in the Competitive Upgrade to a CU Participant identified in the Multi-Owner RFP Proposal in a manner consistent with and on no less favorable terms than those specified in the Multi-Owner RFP Proposal; however, such DTO may not assign its responsibilities as the DTO as part of such conveyance.

**f) Transmission Owner Selection Process Deposit and Cost Calculation**

i) Each RFP Proposal shall pay its share of the Transmission Provider's total cost incurred to administer the Transmission Owner Selection Process for each Competitive Upgrade, as calculated pursuant to this Section III.2(f). At the time of submission of each RFP Proposal, each RFP Respondent (or for a Joint RFP Proposal, the RFP Respondents collectively) shall submit a Transmission Owner Selection Process deposit for each RFP Proposal, which shall be determined as follows (based on the value of the Competitive Upgrade as identified in the SPP Transmission Expansion Plan approved by the SPP Board of Directors):

Small Project (less than $10 million): $10,000 deposit

Medium Project
(between $10 million and $100 million): $25,000 deposit

Large Project (greater than $100 million): $50,000 deposit

The Transmission Provider shall hold each RFP Proposal's Transmission Owner Selection Process deposit in a segregated interest-bearing account in the name(s) of the RFP Respondent(s) tied to the RFP Respondent's(s') Internal Revenue Service Tax Identification Number(s).

ii) The Transmission Provider shall determine the actual Transmission Owner Selection Process costs at the completion of the process, and all RFP Respondents will make additional payments or obtain refunds based on the reconciliation of Transmission Owner Selection Process deposits collected and actual Transmission Owner Selection Process costs. The Transmission Owner Selection Process costs shall include the Transmission Provider's staff and administrative costs associated with administering the Transmission Owner Selection Process for the Competitive Upgrade and all costs associated with administering the IEP process for the Competitive Upgrade, including the identification, recruiting, hiring, and retention of industry experts to serve on the IEP(s). The costs shall be allocated to each RFP Proposal on a pro-rata share basis, calculated by taking the total Transmission Owner Selection Process costs for each Competitive Upgrade and dividing by the number of RFP Proposals submitted for that Competitive Upgrade. The Transmission Provider shall refund any unused deposit amounts with interest earned on such deposits.

iii) If an RFP proposal is disqualified from further consideration pursuant to Section III.2(e)(iv) of this Attachment Y, the Transmission Provider shall refund to the RFP Respondent that submitted the disqualified RFP Proposal ninety (90) percent of its Transmission Owner Selection Process deposit and such disqualified RFP Proposal shall not be subject to the true-up adjustment calculated by the Transmission Provider in accordance with Section III.2(f)(ii) of this Attachment Y.

iv) If the SPP Board of Directors withdraws an RFP pursuant to Section III.2(e)(v) of this Attachment Y, the Transmission Provider shall refund to each RFP Proposal submitted in response to the withdrawn RFP ninety (90) percent of its Transmission Owner Selection Process deposit.

**g) Transmission Owner Selection Criteria and Scoring**

i) The IEP will develop a final score for each RFP Proposal and provide its recommended RFP Proposal and an alternate RFP Proposal to the SPP Board of Directors for each Competitive Upgrade. The IEP will incorporate DPP incentive points into their scoring process for development of recommended and alternate proposals. The IEP evaluation and recommendation shall not be administered in an unduly discriminatory manner. The RFP Proposal with the highest total score may not always be recommended. The IEP may recommend that any RFP Proposal be eliminated from consideration due to a low score in any individual evaluation category.

ii) The IEP may award up to one thousand (1000) base points for each RFP Proposal. The IEP will establish a scoring methodology that is consistently applied across all evaluation categories. Additional details on each evaluation category are provided in the Transmission Provider's business practices. An additional one hundred (100) points shall be available to provide an incentive for stakeholders to share their ideas and expertise to promote innovation and creativity in the transmission planning process.

iii) **Base Points:** The evaluation categories and maximum base points for each category are listed below.

(1) Engineering Design (Reliability/Quality/General Design), 200 points: Measures the quality of the design, material, technology, and life expectancy of the Competitive Upgrade. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Type of construction (wood, steel, design loading, etc.);
(b) Losses (design efficiency);
(c) Estimated life of construction; and
(d) Reliability/quality metrics.

(2) Project Management (Construction Project Management), 200 points: Measures an RFP Respondent's expertise in implementing construction projects similar in scope to the Competitive Upgrade that is the subject of the RFP. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Environmental;
(b) Rights-of-way acquisition;
(c) Procurement;
(d) Project scope;
(e) Project development schedule (including obtaining necessary regulatory approvals);
(f) Construction;
(g) Commissioning;
(h) Timeframe to construct; and
(i) Experience/track record.

(3) Operations (Operations/Maintenance/Safety), 250 points: Measures safety and capability of an RFP Respondent to operate, maintain, and restore a transmission facility. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Control center operations (staffing, etc.);
(b) Storm/outage response plan;
(c) Reliability metrics;
(d) Restoration experience/performance;
(e) Maintenance staffing/training;
(f) Maintenance plans;
(g) Equipment;
(h) Maintenance performance/expertise;
(i) NERC compliance-process/history;
(j) Internal safety program;
(k) Contractor safety program; and
(l) Safety performance record (program execution).

(4) Rate Analysis (Cost to Customer), 225 points: Measures an RFP Respondent's and, if applicable, a CU Participant's cost to construct, own, operate, and maintain the Competitive Upgrade over a forty (40) year period. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Estimated total cost of project;
(b) Financing costs;
(c) FERC incentives;
(d) Revenue requirements;
(e) Lifetime cost of the project to customers;
(f) Return on equity;
(g) The quantitative cost impact of material on hand, assets on hand, rights-of-way ownership, control, or acquisition; and
(h) Cost certainty guarantee.

(5) Finance (Financial Viability and Creditworthiness), 125 points: Measures an RFP Respondent's and, if applicable, a CU Participant's ability to obtain financing for the Competitive Upgrade. Criteria considered in this evaluation category shall include, but not be limited to:

(a) Evidence of financing;
(b) Material conditions;
(c) Financial/business plan;
(d) Pro forma financial statements;
(e) Expected financial leverage;
(f) Debt covenants;
(g) Projected liquidity;

(h) Dividend policy; and

(i) Cash flow analysis

iv) **Incentive Points:** Each RFP Respondent or CU Participant that submitted a detailed project proposal ("DPP") in accordance with Attachment O Section III.6 of this Tariff that was selected and approved for construction as a Competitive Upgrade shall receive one hundred (100) incentive points in the Transmission Owner Selection Process for that Competitive Upgrade, which shall be added to the total base points awarded by the IEP. To demonstrate eligibility for the incentive points, the RFP Respondent must document in its RFP Proposal that it or one of the CU Participants participating in a Multi-Owner RFP Proposal submitted a DPP for that Competitive Upgrade. The eligibility for the incentive points may only be awarded to the RFP Proposal if the DPP was submitted during the Integrated Transmission Planning Assessment from which the Competitive Upgrade was approved. The Transmission Provider shall confirm such eligibility in accordance with Attachment O Section III.6 of this Tariff and inform the IEP. An RFP Proposal will be entitled to no more than one hundred (100) incentive points regardless of how many entities involved in the submission of the RFP Proposal may individually be eligible for incentive points.

**h) Failure of a Transmission Owner to Complete the Competitive Upgrade**

(i) If, after accepting the NTC, a DTO cannot or is unwilling to complete the Competitive Upgrade as directed by the Transmission Provider (the "Defaulting DTO"), the Transmission Provider shall evaluate the status of the Competitive Upgrade and may designate

a new DTO for the Competitive Upgrade in accordance with Section V.4 of this Attachment Y, except as provided in Section III.2(h)(ii) of this Attachment Y for Joint RFP Proposals. If the Transmission Provider has determined that there is sufficient time for the Transmission Owner Selection Process to be completed and the Competitive Upgrade placed in service prior to the required need date as determined by the Transmission Provider, the process described in Section III of this Attachment Y shall be used to designate another entity to become the DTO for the Competitive Upgrade. If sufficient time is not available, the Transmission Provider shall designate a new DTO for the Competitive Upgrade in accordance with Section IV of this Attachment Y.

(ii) If the Competitive Upgrade was the result of a Joint RFP Proposal and the DTOs agreed to be jointly and severally liable for the Competitive Upgrade pursuant to Section III.2(c)(xv)(1) of this Attachment Y, the Transmission Provider shall issue a modified NTC to each DTO that is not the Defaulting DTO, specifying each DTO's responsibility to fulfill the obligations of the Defaulting DTO. If each of the DTOs involved in the submission of a Joint RFP Proposal did not agree to be jointly and severally liable pursuant to Section III.2(c)(xv)(1) of this Attachment Y, the Transmission Provider shall follow the process set forth in Section III.2(h)(i) of this Attachment Y.

## IV. INCUMBENT TRANSMISSION OWNER DESIGNATION PROCESS

1) If a project forms a connection with facilities of a single Transmission Owner, that Transmission Owner shall be selected to be the DTO. If a project forms a connection with facilities owned by multiple Transmission Owners, the applicable Transmission Owners shall be selected to be the DTOs. If there is more than one Transmission Owner selected to construct a project, the DTOs will agree among themselves which part of the project will be provided by each entity. If the DTOs cannot come to a mutual agreement regarding the assignment and ownership of the project, the Transmission Provider will facilitate their discussion. Each DTO will receive an NTC, in accordance with Section V of this Attachment Y, for each project or segment of a project that the DTO is responsible to construct.

2) In order to maintain its right to construct a project, the DTO shall respond within ninety (90) days after the receipt of the NTC with a written commitment to construct the project as specified in the NTC or a proposal for a different project schedule and/or alternative specifications in its written commitment to construct ("DTO's proposal"). The Transmission Provider shall respond to the DTO's proposal within ten (10) days of its receipt of the proposal. If the Transmission Provider accepts the DTO's proposal, the NTC will be modified according to the accepted proposal, and the DTO shall construct the project in accordance with the modified NTC. If the Transmission Provider rejects the DTO's proposal, the DTO's proposal shall not be deemed an acceptable written commitment to construct the project. However, the Transmission Provider's rejection of such proposal shall not preclude a DTO from providing a written commitment to construct the project after such rejection, provided the subsequent written commitment to construct the project is made within the ninety (90) day time period after the issuance of the NTC.

3) If a DTO does not provide an acceptable written commitment to construct within the ninety (90) day period, the Transmission Provider shall select a replacement Transmission Owner in accordance with Section III of this Attachment Y.

4) At any time after accepting an NTC, a DTO that was designated under this Section IV of Attachment Y may assign a project by arranging for another entity to build and own all or part of the project in its place subject to the conditions set forth in Section VII of this Attachment Y.

5) Nothing in this Section IV shall relieve a Transmission Owner of its obligations specified in Section VI.3 of Attachment O of this Tariff, Section V.4 of Attachment Y of this Tariff, and Section 3.3(a) of the SPP Membership Agreement.

## V. NOTIFICATION TO CONSTRUCT PROCESS

1) Once a Transmission Owner is selected to construct a project through Section III or Section IV of this Attachment Y, the Transmission Provider shall issue an NTC for project(s) for which financial commitment is required prior to the approval of the next annual SPP Transmission Expansion Plan report. At the discretion of the SPP Board of Directors, the Transmission Provider may issue an NTC to the appropriate Transmission Owner to begin implementation of other such approved or required transmission project(s) for which financial commitment is not required prior to approval of the next annual SPP Transmission Expansion Plan report.

2) The Transmission Provider shall issue an NTC to each entity selected to become the DTO for each transmission project. The NTC shall include, but not be limited to: (1) the specifications of the project required by the Transmission Provider, and (2) a reasonable project schedule, including a project need date.

3) Request for refined cost estimate

   a) The Transmission Provider may issue an NTC that requires a refined cost estimate within a stated timeframe defined in the NTC. Such NTC shall direct the entity selected to become the DTO only to perform detailed engineering and cost studies. In complying with this NTC, the DTO shall be authorized to expend only those funds necessary to perform such studies. The entity selected to become the DTO shall provide to the Transmission Provider a written commitment that it: (1) accepts the obligation to construct the transmission facility subject to issuance of an NTC authorizing construction in accordance with Section III or Section IV of this Attachment Y; and (2) will provide the Transmission Provider a refined cost estimate within the Transmission Provider's stated timeframe or state its inability to provide the refined cost estimate in the stated timeframe.

   b) The Transmission Provider shall compare the refined cost estimate to the project cost estimate approved by the SPP Board of Directors. If the refined cost estimate falls within bandwidth of the approved project cost estimate, the Transmission Provider shall issue an NTC authorizing construction and setting the refined cost estimate as the baseline cost for cost tracking purposes pursuant to Section VI of this Attachment Y. The bandwidth shall be defined by the Transmission Provider and stated in the Transmission Provider's business practices.

   c) If the refined cost estimate falls outside of the bandwidth defined by the Transmission Provider, the Transmission Provider shall re-evaluate the project using the refined cost estimate and provide a recommendation to the SPP Board of Directors at its next scheduled quarterly meeting. The

Transmission Provider's recommendation could be, but is not limited to, one of the following actions:

(i) Accept the refined cost estimate;
(ii) Modify the project;
(iii) Replace the project with an alternative solution; or
(iv) Cancel the project.

The SPP Board of Directors shall determine the action to be taken regarding the transmission project. If the SPP Board of Directors determines to proceed with the project, the Transmission Provider shall issue an NTC authorizing construction and setting the refined cost estimate of the project as the baseline cost. If the SPP Board of Directors determines not to proceed with the project, the DTO shall be notified that the project has been cancelled and the DTO is eligible to pursue recovery of its study costs in accordance with Section VIII of Attachment J of this Tariff.

4) Any Transmission Owner that has accepted an NTC in accordance with this Tariff shall use due diligence to meet the terms contained in the NTC. If at any time the Transmission Owner cannot meet one or more of the terms agreed to in the NTC or cannot meet the regulatory approval need date set forth in the RFP for a Competitive Upgrade if applicable, it shall notify the Transmission Provider in a timely manner. The Transmission Owner may suggest changes to the NTC and present the reasons why the changes should be approved. The Transmission Provider shall review the proposed changes and determine a course of action to propose to the SPP Board of Directors, including, but not limited to:

a) Accept changes negotiated with the Transmission Owner;
b) Withdraw the NTC and issue an NTC for the same project to another entity that shall be determined in accordance with this Attachment Y;
c) Withdraw the NTC and replace the project with an alternative solution; or
d) Withdraw the NTC and cancel the project.

The SPP Board of Directors shall determine the action to be taken regarding the project.

## VI. PROJECT TRACKING PROCESS

Costs and schedules related to all projects approved for construction under the Tariff shall be tracked by the Transmission Provider

1) Upon the acceptance of an NTC by a DTO, other than an NTC issued for refined cost estimation, the baseline cost of the project will be set. The baseline cost shall be the estimated cost of the project as agreed to between the DTO and the Transmission Provider at the time such NTC was accepted.

2) The DTO shall submit updates of the estimated costs and schedules to the Transmission Provider on at least a quarterly basis in a standard format and method defined by the Transmission Provider.

3) If at any time the cost projection varies from the estimated baseline cost by more than the bandwidth defined by the Transmission Provider in its business practices, the Transmission Provider shall investigate the reason for the change in cost and report to the SPP Board of Directors the reason for the change in cost and its recommendation on whether to accept the change in cost and reset the baseline cost. The SPP Board of Directors shall make the final determination as to the action that will be taken up to and including the cancellation of the project and withdrawal of the NTC.

4) If at any time the project schedule significantly changes, the Transmission Provider shall investigate the reason for the change and may take action in accordance with Section V.4 of this Attachment Y. Factors that the Transmission Provider shall consider in determining whether a project schedule delay is significant shall include, but not be limited to, the need date, construction time, necessity for long-lead equipment, and permitting schedules.

## VII. ASSIGNMENT OF NOTIFICATION TO CONSTRUCT

1) At any time after accepting an NTC, a DTO that was designated under Section IV of this Attachment Y may assign the NTC for a project by arranging for another entity to build and own all or part of the project in its place subject to the following conditions:

   a) Prior to starting its construction activity, the entity must have obtained all state regulatory authority necessary to construct, own, and operate transmission facilities within the state(s) where the project is located;

   b) The entity meets the financial requirements of the Transmission Provider as specified in Section III.1(b)(ii) of this Attachment Y;

   c) The entity has signed or is capable and willing to sign the SPP Membership Agreement as a Transmission Owner; and

   d) The entity meets such other qualifications as specified in Section III.1(b) of this Attachment Y.

2) Subject to the limitations set forth in Section III.2(e)(xi) of this Attachment Y, at any time after accepting an NTC, a DTO that was designated to construct a Competitive Upgrade pursuant to Section III of this Attachment Y may be permitted to assign the NTC for the Competitive Upgrade to an Affiliate, provided that the following conditions are met (no other assignments by a DTO designated under Section III of this Attachment Y shall be permitted):

   a) The DTO declared in its RFP Proposal its intent to seek to assign the Competitive Upgrade to an Affiliate in accordance with Section III.2(c)(xiii) of this Attachment Y;

   b) The Affiliate shall be formed prior to approval of any such assignment;

c) The Affiliate has provided express written agreement that it will be bound by all aspects of the RFP Proposal and the NTC, including but not limited to being bound by the annual transmission revenue requirement set forth in the RFP proposal or a lesser annual transmission revenue requirement;

d) The Affiliate meets all of the qualification criteria and follows the process specified in Section III.1 of this Attachment Y;

e) The Affiliate has signed or is capable and willing to sign the SPP Membership Agreement as a Transmission Owner; and

f) Prior to starting its construction activity, the Affiliate must have obtained all state regulatory authority necessary to construct, own, and operate transmission facilities within the state(s) where the project is located.

To the extent applicable, the DTO may request that the Transmission Provider rely on information provided pursuant to Section III.2 of this Attachment Y in evaluating the proposed assignment. If at any time, any of these conditions ceases to be satisfied, the Transmission Provider may withdraw the NTC and reevaluate the Competitive Upgrade pursuant to Section V.4 of this Attachment Y. The Affiliate will immediately become eligible to accept the NTC and become the DTO for the Competitive Upgrade upon: (1) the Transmission Provider's determination that the Affiliate satisfies the criteria set forth in Section III.1 of this Attachment Y and the conditions set forth in this Section VII; (2) approval of the assignment by the SPP Board of Directors; and (3) the Affiliate's execution of the SPP Membership Agreement as a Transmission Owner. The Affiliate will become a QRP eligible to participate in the Transmission Owner Selection Process in accordance with the timeline set forth Section III.1.

3) Any assignment pursuant to this Section VII of this Attachment Y shall be subject to the approval of the SPP Board of Directors, which consent shall not be unreasonably withheld, conditioned, or delayed.

4) Nothing in this Section VII shall relieve a Transmission Owner of its obligations specified in Section VI.3 of Attachment O of this Tariff, Section V.4 of Attachment Y of this Tariff, and Section 3.3(a) of the SPP Membership Agreement.

## VIII. COMPETITIVE UPGRADE RE-EVALUATION PROCESS

1) In the event that material changes occur that may cause a Competitive Upgrade to be re-evaluated, in accordance with this Section VIII of this Attachment Y, the Transmission Provider may re-evaluate the need for the Competitive Upgrade at any time prior to the close of RFP Response Window.

   A request for a Competitive Upgrade re-evaluation may be submitted by any stakeholder via the SPP Request Management System and must present the basis for the request including, at a minimum, the initial parameters, the revised values for those parameters, and the substance, reasoning, and the sources of such revised values in addition to all analysis supporting the request. The request must be complete enough for the Transmission Provider to determine whether the request is valid and whether a re-evaluation is necessary. Material changes that could cause a Competitive Upgrade to be re-evaluated include but are not limited to:

   a. Changes in load;

   b. Changes in generation; or

   c. Modeling error

2) Within three (3) Business Days of receiving a request for re-evaluation of a Competitive Upgrade, the Transmission Provider will post notice of the request on its website and will provide email notice to QRPs. The publicly posted notice shall serve as the basis for the re-evaluation request and shall include all non-confidential information submitted by the requesting entity. Information deemed confidential by the requesting entity will be made available, subject to the execution of the applicable confidentiality agreement, using the secure, password protected web-based workspace used for sharing confidential planning information as required by Section VII of Attachment O of this Tariff.

   The Transmission Provider will then notify the SPP Board of Directors of the request and provide a recommendation as to whether a re-evaluation should be performed. If the Transmission Provider recommends that the Competitive Upgrade be re-evaluated:

a. the Transmission Provider will also include the recommended parameters for the re-evaluation, schedule for completion, and planning models to be used.

b. the Transmission Provider may also provide a recommendation on whether it is necessary to suspend the Transmission Owner Selection Process consistent with Section III.2(c)(xx) of this Attachment Y. If the SPP Board of Directors approves a suspension of the Transmission Owner Selection Process, the length of such suspension shall be specified by the SPP Board of Directors and the RFP Response Window will be extended by the duration of the approved suspension.

3) If the SPP Board of Directors approves a recommendation to re-evaluate a Competitive Upgrade, the Transmission Provider will perform the re-evaluation analysis to determine if material changes have occurred that necessitate the withdrawal of the Competitive Upgrade. The Transmission Provider will inform the SPP Board of Directors of the results of the re-evaluation analysis and provide a recommendation as to whether the Competitive Upgrade should be withdrawn.

a. If the SPP Board of Directors determines that the Competitive Upgrade should be withdrawn, the Transmission Provider will withdraw any applicable RFP and the Transmission Owner Selection Process for that withdrawn Competitive Upgrade will be terminated. Notice of the withdrawn Competitive Upgrade shall be sent to all QRPs.

b. If the SPP Board of Directors determines that the Competitive Upgrade should not be withdrawn, then the Transmission Owner Selection Process shall continue or be re-instated if it was suspended. SPP will provide a notice of the new RFP Response Deadline on spp.org and will provide email notice to QRPs.

4) If the Transmission Provider withdraws the RFP pursuant to Section VIII.3(a) of this Attachment Y, the Transmission Provider shall refund to each RFP Proposal submitted in response to the withdrawn RFP its Transmission Owner Selection Process deposit provided in accordance with Section III.2(f)(i) of this Attachment Y.

# ATTACHMENT Z1
# AGGREGATE TRANSMISSION SERVICE STUDY PROCEDURES AND COST ALLOCATION AND RECOVERY FOR SERVICE UPGRADES

## I. Introduction

This attachment describes the process used to evaluate long-term transmission service requests using an Aggregate Transmission Service Study process. The Transmission Provider will combine all long-term point-to-point and long-term designated network resource requests received during a specified period of time into a single Aggregate Transmission Service Study. Using this Aggregate Transmission Service Study process, the Transmission Provider will combine all requests received during an open season to develop a more efficient expansion of the transmission system that provides the necessary ATC to accommodate all such requests at the minimum total cost. For the purposes of this Attachment Z1, all Transmission Owners that are not taking Network Integration Transmission Service under this Tariff will be treated the same as Transmission Customers taking Network Integration Transmission Service under this Tariff. This attachment also details cost allocation and cost recovery for Service Upgrades, for directly assigned costs that are in excess of the Safe Harbor Cost Limit for Service Upgrades associated with new or changed Designated Resources and cost recovery for Network Upgrades associated with generator interconnections.

## II. Open Season

The Aggregate Transmission Service Study process commences with the initiation of an open season. The open season shall be six (6) months in duration. During the open season period, Eligible Customers may make requests for long-term transmission service that starts no earlier than six (6) months after the close of the open season. Eligible Customers may submit and withdraw requests during the open season without any obligation. In order for an Eligible Customer's request for Long-Term Firm Point-To-Point Transmission Service or Network Integration Transmission Service of one year or longer to be included in the Aggregate Facilities Study, the Eligible Customer must satisfy the following requirements:

A. For Eligible Customers requesting Long-Term Firm Point-To-Point Transmission Service, a Completed Application that includes all of the information specified under Sections 17.2 and 17.3 of this Tariff, or Section 17.8 of this Tariff if applicable, and an executed Aggregate Facilities Study Agreement ("AFSA") must be submitted on the Transmission Provider's OASIS prior to the end of the open season. Timing requirements for distribution of the AFSA by the Transmission Provider to the Eligible Customer shall be in accordance with Section III of this Attachment Z1; or

B. For Eligible Customers requesting Network Integration Transmission Service of one year or longer, a Completed Application that includes all of the information specified under Section 29.2 of this Tariff and an executed AFSA must be submitted on the Transmission Provider's OASIS prior to the end of the open season. Timing requirements for distribution of the AFSA by the Transmission Provider to the Eligible Customer shall be in accordance Section III of this Attachment Z1.

Existing long-term firm service customers who desire to exercise a reservation priority under Section 2.2 of this Tariff shall do so pursuant to the terms of Section 2.2.

## III. Aggregate Transmission Service Study Process

### A. Aggregate Facilities Study Agreement

1. All Eligible Customers that submitted a Completed Application for transmission service during the open season specified in Section II of this Attachment Z1 must submit an AFSA to the Transmission Provider prior to the close of the open season. The AFSA shall be available on the Transmission Provider's OASIS. By executing the AFSA, the Eligible Customer agrees to reimburse the Transmission Provider and any affected Transmission Owner(s) for its share of costs for any required Aggregate Facilities Study(ies) as described in this Section III.
2. If the Eligible Customer elects not to execute the AFSA, its transmission service request and Application shall be deemed withdrawn and its security, pursuant to this Tariff, shall be returned with accrued interest, if any.
3. The AFSA shall require the Eligible Customer to specify the following conditions under which the Eligible Customer is willing to accept the requested transmission service ("Study Completion Conditions"):
    a. the maximum amount of Directly Assigned Upgrade Costs the Eligible Customer will accept;
    b. the maximum amount of third party upgrade costs the Eligible Customer will accept;
    c. the deferred start date the Eligible Customer will accept for the transmission service;
    d. whether the Eligible Customer is willing to pay for redispatch costs and the length of duration for redispatch that is acceptable; and
    e. the maximum amount of letter of credit requirements acceptable.

    The Eligible Customer may elect to specify a single combined maximum amount for both the Directly Assigned Upgrade Costs and third party upgrade costs rather than the separate amounts specified in sections (a) and (b) immediately above.
4. By executing the AFSA, the Eligible Customer agrees to take the transmission service requested in accordance with Section III.C.8 of this Attachment Z1 if the Study Completion Conditions specified in its AFSA are met upon the completion of the Aggregate Facilities Study except as provided in Section III.D of this Attachment Z1.

5. Changes to an Eligible Customer's request in OASIS will not be permitted following the close of the open season and withdrawal of an OASIS request after that date will not relieve an Eligible Customer of any obligations specified in Section III.A.4 of this Attachment Z1.

**B. Study Costs**

1. Upon execution of the AFSA, the Eligible Customer shall submit a deposit to the Transmission Provider for each transmission service request. The deposit shall be an amount equal to the greater of $100 per MW of requested transmission capacity or $5,000. The requested transmission capacity used to calculate the deposit shall be the maximum amount of transmission capacity requested over the term of the transmission service request. If the Transmission Provider has not received the Eligible Customer's deposit prior to the close of the open season, the Eligible Customer's transmission service request shall be deemed withdrawn.
2. All Eligible Customers entering an Aggregate Facilities Study shall be responsible for the cost of the Aggregate Facilities Study. The cost of the Aggregate Facilities Study will be prorated among the Eligible Customers based on the maximum requested transmission capacity. If an Eligible Customer's cost for the Aggregate Facilities Study is less than the deposit, the Transmission Provider shall refund any remaining deposit with accrued interest, if any. If an Eligible Customer's cost for the Aggregate Facilities Study is greater than the deposit, the Eligible Customer shall be responsible for any cost in excess of its deposit. The amount billed for the Aggregate Facilities Study by the Transmission Provider shall not exceed the actual cost of the study.
3. In performing an Aggregate Facilities Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customers will not pay a charge for such existing studies; however, the Eligible Customers will be responsible for paying costs associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customers' requests for service on the Transmission System.

**C. Aggregate Facilities Study**

1. The Transmission Provider shall commence the Aggregate Facilities Study upon the close of an open season. The Transmission Provider will use due diligence to complete the required Aggregate Facilities Study within one hundred sixty-five (165) days for all Eligible Customers' requests with executed AFSAs. The Transmission Provider shall coordinate with the affected Transmission Owner(s) to complete the Aggregate Facilities Study. If the Transmission Provider is unable to complete the Aggregate Facilities Study within one hundred sixty-five (165) days, the Transmission Provider shall notify the Eligible Customer(s) and provide an estimate of the time needed to reach a final determination along with an explanation of the reason(s) that additional time is required to complete the study.
2. The Transmission Provider shall post the results of the first iteration of the Aggregate Facilities Study on the Transmission Provider's OASIS and notify all Eligible Customers in the study. Within fifteen (15) days of such posting, the Eligible Customer may request a waiver of costs in excess of the Safe Harbor Cost Limit in accordance with Attachment J. Within five (5) Business Days of the posting, any Eligible Customer with one or more Study Completion Conditions that were not met in the first iteration of the Aggregate Facilities Study may adjust its Study Completion Conditions in its AFSA to accommodate the results of the Aggregate Facilities Study. Failure by an Eligible Customer to adjust any of its Study Completion Conditions that were not met in the first iteration of the Aggregate Facilities Study shall result in the Eligible Customer's request being withdrawn from the Aggregate Facilities Study. If all Study Completion Conditions are met in the first iteration of the Aggregate Facilities Study, the Transmission Provider shall deem the Aggregate Facilities Study complete.
3. Following the receipt of any modified Study Completion Conditions, the Transmission Provider shall perform additional iterations of the Aggregate Facilities Study, as necessary. At the completion of each iteration, if one or more of an Eligible Customer's Study Completion Conditions are not met, the Transmission Provider shall remove such Eligible Customer's request from the Aggregate Facilities Study. For any Eligible Customer's request removed from the Aggregate Facilities Study by the Transmission Provider as a result of not

meeting such Eligible Customer's Study Completion Conditions, the Transmission Provider shall refuse that Eligible Customer's request in OASIS. For the Eligible Customers' requests remaining in the Aggregate Facilities Study, the Transmission Provider shall conduct an additional iteration, if necessary.

4. For each Aggregate Facilities Study, the Transmission Provider shall identify system constraints and, in conjunction with the applicable Transmission Owner(s), determine any upgrades required to reliably provide the requested transmission service for the study group in a manner that minimizes the overall costs for the study group. In identifying the required upgrades, the Transmission Provider shall perform a regional review to determine if alternative solutions would reduce overall cost to customers and incorporate such solutions as appropriate.
5. The power flow models used for an Aggregate Facilities Study shall be developed for each season for the period from the earliest start of service to the latest end of service for the applicable requests. The models will include all other applicable existing reservations having equal or greater queue priority including potential renewals of existing service having a reservation priority pursuant to Section 2.2 of this Tariff.
6. The Transmission Provider shall recognize constraints due to contractually limited facilities and allocate available capacity on a first come first served basis on the contractual constraint only.
7. The Transmission Provider shall deem the Aggregate Facilities Study complete when all remaining Eligible Customers' Study Completion Conditions have been met. The Transmission Provider will finalize the solutions for the Aggregate Facilities Study and the cost estimates for upgrades necessary to provide the requested transmission service.
8. At the completion of the Aggregate Facilities Study, the Transmission Provider shall determine the allocation of estimated cost to provide the transmission service for each request. The Transmission Provider shall issue Service Agreements to all Eligible Customers remaining in the Aggregate Facilities Study, except those Eligible Customers with third party impacts subject to Section

III.D below. Upon receipt of the Service Agreement, the Eligible Customer shall have thirty (30) days to execute the Service Agreement or request the filing of an unexecuted Service Agreement. The Transmission Provider shall file an unexecuted Service Agreement with the Commission for any Eligible Customer failing within thirty (30) days to execute the Service Agreement or request the Service Agreement be filed unexecuted.

9. For those upgrades requiring the issuance of a Notification to Construct, the Eligible Customer must provide to the Transmission Provider security in an amount equal to the full amount of the upgrade's estimated engineering and construction cost allocated to the customer for cost recovery within thirty (30) days of confirmation of an Eligible Customer's OASIS request. The Transmission Provider may waive this security requirement, or release any security the Eligible Customer has provided to the Transmission Provider, if the Transmission Owner advises the Transmission Provider that the Eligible Customer has independently provided to the Transmission Owner sufficient security for the upgrade and the Transmission Owner agrees to not seek recovery from the Transmission Provider in connection with any non-payment by the Eligible Customer associated with the upgrade. The Transmission Provider may, at its sole discretion, waive the requirement to provide such security until the beginning of the quarter when the building Transmission Owner first incurs financial obligations for the upgrade. The amount of the security may increase or decrease each year thereafter based upon the total amount of financial obligations, plus an estimate of the increase or decrease in financial obligations that will be incurred in the next 12 months. The Eligible Customer may reduce the amount of security each year by the amount of revenue paid the previous year by the Eligible Customer related to the cost allocated to it for cost recovery.

10. If security is required, the Eligible Customer shall provide the Transmission Provider with a letter of credit as specified in Appendix C to Attachment X of this Tariff, or other acceptable forms of security equivalent to only those costs of new facilities or upgrades that are allocated to the Eligible Customer for cost recovery. Other acceptable forms of security are:

- Cash;
- Surety bond issued by an insurer and acceptable to the Transmission Provider; or
- Guaranty in a form consistent with Appendix D of Attachment X of the Tariff.

**D. Third Party Impacts**

1. An Eligible Customer's request with any identified third party impact(s) shall be resolved in accordance with Section 21 of this Tariff.
2. For any Eligible Customer's request in a completed Aggregate Facilities Study meeting the Study Completion Conditions but with identified third party impact(s) where the Eligible Customer has not reached an agreement with the third party in accordance with Section 21 of this Tariff, the Eligible Customer has until the start date of its requested transmission service or one (1) year after completion of the Aggregate Facilities Study, whichever is sooner, to complete such negotiations or request the Service Agreement be filed unexecuted at the Commission to resolve the third party issue(s). The Transmission Provider may grant a 90 day extension for completion of such negotations, at the request of the Eligible Customer. If an extension is granted, the start date of the requested transmission service will be deferred if necessary. If the Eligible Customer has not notified the Transmission Provider of a successful conclusion to the negotiation with the third party by the deadline described above, the Transmission Provider shall deem the transmission service request to be terminated and withdrawn and the Eligible Customer will be subject to a make-whole payment in accordance with Section III.D.4. The calculation of the Eligible Customer's make-whole payment shall include any impacts to subsequent completed Aggregate Facilities Studies.
3. If the Eligible Customer notifies the Transmission Provider of the successful conclusion of the negotiation with the third party by the deadline described in Section III.D.2, the Tranmission Provider shall issue a Service Agreement to the Eligible Customer. The Eligible Customer shall have thirty (30) days to execute the Service Agreement or request the filing of an unexecuted Service Agreement and to provide the required security in accordance with Section III.C. The

Transmission Provider shall file an unexecuted Service Agreement with the Commission if the Eligible Customer fails within thirty (30) days to execute the Service Agreement or request the Service Agreement be filed unexecuted.

4. If any Eligible Customer is required to pay a make-whole payment in accordance with Section III.D.2, the make-whole payment amount shall be calculated by the Transmission Provider. To calculate the make-whole payment amount, the Transmission Provider shall first reallocate total upgrade costs for the remaining confirmed transmission service requests in accordance with the provisions of Section IV of this Attachment Z1; however, the Directly Assigned Upgrade Cost assigned to each remaining confirmed transmission service request shall not increase as a result of the reallocation. The make-whole payment assigned to a withdrawn Eligible Customer's request shall be any reallocated upgrade costs that are in excess of the sum of (i) the Directly Assigned Upgrade Costs and (ii) the amounts included in rates, for any remaining confirmed transmission service request(s). If there is more than one withdrawn Eligible Customer's request, the make-whole payment, if any, shall be assigned to the withdrawing Eligible Customers based upon the impact of the withdrawal of each withdrawn Eligible Customer's request on those upgrades for which the Directly Assigned Upgrade Costs increased for the confirmed transmission service requests, thereby resulting in the make-whole payment. Upgrade costs for facilities only required by the withdrawn Eligible Customer's request(s) shall not be included as part of the calculation of the make-whole payment. An Eligible Customer required to pay a make-whole payment shall enter into a Sponsored Upgrade Agreement with the Transmission Provider in accordance with Attachment J of this Tariff and will be eligible for compensation in accordance with Attachment Z2 of this Tariff.

## E. Additional Waiver Criteria

In addition to the requirements listed in Section III.C.2 of this Attachment Z1, the Eligible Customer may simultaneously submit an identical transmission service request in the then-open season of the Aggregate Facilities Study concurrently with the submittal of a request for waiver of the costs in excess of the Safe Harbor Cost Limit. Any waiver of costs granted by

the SPP Board of Directors will be applied to costs allocated to the identical request during evaluation in the Aggregate Facilities Study. Alternatively, a waiver of costs granted by the SPP Board of Directors may be applied to the original request for service, but only if the original request continues to remain viable in the Aggregate Facilities Study pursuant to the process in this Attachment Z1. In no case will a waiver of costs granted by the SPP Board of Directors be applied to both the original request for service and an identical request for service.

## IV. Cost Allocation for Service Upgrades

The cost of Service Upgrades shall be allocated in accordance with this Section.

a. For the purpose of determining the cost responsibility for each transmission service request, all upgrades required to provide transmission service for all transmission service reservations included in an Aggregate Facilities Study shall be included in an Aggregate Cost Allocation Assessment. The cost of each transmission upgrade component will be allocated to each customer in the aggregation group on a pro-rata impact basis as provided in paragraph b. With regard to the cost allocation, the Transmission Provider shall review all upgrades and determine the earliest date that each upgrade is required to be in-service in order to provide the requested transmission service. This date is the Date Upgrade Needed. The cost of a facility upgrade shall be allocated to all customers in the aggregate group whose reservation period begins after the Date Upgrade Needed or extends past the Date Upgrade Needed, whether or not an interim redispatch option is available. If the Date Upgrade Needed for the upgrade is after completion of service, no cost will be allocated to the customer for the upgrade under consideration.

All requests that have a positive impact on the upgrade and for which the service has not been completed prior to the Date Upgrade Needed for such upgrade, shall be allocated costs for the upgrade; and the Transmission Provider shall review these requests in order to determine the amortization period for the facility. For this determination, the start date of the amortization period shall be the expected in-service date of the facility. The end date for the amortization period shall be the end of the term of the request that ends at the latest point in time as adjusted for deferral of any requests.

In the event the expected in-service date of the upgrade is after the Date Upgrade Needed, the customers whose requests span a portion of the time between the Date Upgrade Needed and the expected in-service date may:

1. Defer the start of the request until the expected in-service date of the upgrade; or
2. Request interim redispatch, if available.

If the customer selects the interim redispatch option, the Transmission Provider will evaluate curtailment of existing confirmed service or interim redispatch of units to provide service prior to completion of any allocated network upgrades. The Transmission Provider will determine whether a feasible redispatch solution exists to relieve the incremental MW impact on the limiting facilities. This redispatch option will be used to allow the customer to begin transmission service based on an earlier start date than the deferred date. Redispatch services shall be provided in accordance with Attachment K of this Tariff.

b. An allocation of the cost of each facility upgrade to each request shall be determined on a pro-rata basis for the positive incremental power flow impacts of the requested service on such upgraded facility in proportion to the total of all incremental impacts on such upgraded facility. For each upgraded facility identified, the average incremental power flow impact of each request in the aggregate study shall be determined using each summer model available for the aggregate study period, after the Date Upgrade Needed of such upgraded facility. Each impact amount shall be determined by first establishing a set of initial seasonal base cases that excludes flows associated with all requests included in the Aggregate Facilities Study. Then each request will be added to the models and the change in flow across such upgraded facility shall be determined for each request included in the Aggregate Facilities Study. The cost of an upgrade allocated to each request shall be proportional to the average positive incremental impact of each request on such facility divided by the total average positive incremental impact of all requests included in the Aggregate Facilities Study on such upgraded facility. The cost of each upgrade shall be allocated to requests independently. Incremental flows having a negative impact on an upgraded facility shall be ignored.

c. After concluding the above cost allocations to each reservation in the aggregate group, the Transmission Provider shall determine the charges for each request by using the levelized monthly revenue requirement associated with the transmission service requested by each customer in the aggregate group. This levelized monthly revenue requirement is determined by calculating the present worth of the revenue requirements associated with the upgrades as allocated to each customer in the aggregate group and then calculating an appropriate monthly amount for each customer in the aggregate group for each respective reservation.

## V. Cost Recovery for Service Upgrades

a. The cost of Service Upgrades shall be recovered in accordance with this Section. For Point-to-Point Service, the levelized monthly revenue requirement derived from the cost allocation process shall be compared to the charge applicable for each request under the transmission access charges of Schedule 7, Sections 1 and 7; and each customer shall be required to pay the higher of the total monthly transmission access charges or the monthly revenue requirement associated with the directly assigned portion of the Service Upgrade, if any. For Network Integration Transmission Service, the charge shall be a direct assignment charge pursuant to Schedule 9, Section 4; and each customer will be required to pay the monthly revenue requirement associated with the directly assigned portion of the Service Upgrade, if any, in addition to the total monthly transmission access charges applicable under Schedule 9, Sections 1 and 6. Cost recovery from a customer of the revenue requirement for the directly assigned portion of a Service Upgrade allocated to such customer will be accomplished over the duration of the customer's transmission service request.

b. For Service Upgrades associated with Designated Resources, to the extent a waiver is not granted pursuant to Section III of Attachment J, the cost in excess of the Safe Harbor Cost Limit of Service Upgrades associated with Designated Resources shall be recovered in accordance with this Section V. Transmission Customers paying the above charges will be eligible for compensation in accordance with Attachment Z2 of this Tariff.

c. The following process shall be used to allocate Directly Assigned Upgrade Costs in order to minimize the number of new Network Upgrades created out of an Aggregate Transmission Service Study that are eligible for compensation under Attachment Z2 ("Z2 Eligible Upgrade") of this Tariff.

1. Identify each Network Upgrade that is ineligible for one hundred percent (100%) base plan funding and will become a Z2 Eligible Upgrade and each existing Z2 Eligible Upgrade that is impacted by any transmission service request in the Aggregate Transmission Service Study.

2. Any Directly Assigned Upgrade Costs associated with a transmission service request shall be allocated to the Z2 Eligible Upgrade(s) identified in accordance with Section V.c.1 of this Attachment Z1 up to the maximum amount of upgrade costs allocated to the transmission service request for such Z2 Eligible Upgrade(s).

3. Any Directly Assigned Upgrade Costs associated with a transmission service request that are not allocated in accordance with Section V.c.2 of this Attachment Z1 shall be allocated to the upgrades associated with that transmission service request so as to: i) minimize the number of new Z2 Eligible Upgrades arising from the Aggregate Transmission Service Study; and ii) when possible, allocate any remaining Directly Assigned Upgrade Costs to the Network Upgrade(s) required by that request which is affected by the most transmission service requests.

## VI. Cost Recovery for Network Upgrades Associated with Generation Interconnection

Each Generation Interconnection Customer shall be required to pay for the Network Upgrades associated with a generation interconnection in accordance with the terms of its interconnection agreement.

Generation Interconnection Customers will be eligible for compensation in accordance with Attachment Z2 of this Tariff for the Network Upgrades associated with generation interconnection service funded by the Generation Interconnection Customer.

# ATTACHMENT Z2
# COMPENSATION FOR UPGRADE SPONSORS

Sections I, II and III of this Attachment Z2 shall be applicable only to those Network Upgrades with an agreement authorizing construction of the upgrade that is executed on or before July 1, 2020. If such authorizing agreement is filed with the Commission unexecuted, then the applicable date is the effective date granted by the Commission in an order accepting the agreement. An Upgrade Sponsor for such a Network Upgrade is eligible to receive revenues from revenue crediting to the extent provided in Sections I, II, and III of this Attachment Z2 unless the Upgrade Sponsor selects and qualifies for candidate ILTCRs in accordance with Section IV of this Attachment Z2. For all Network Upgrades with an agreement authorizing construction of the upgrade with an execution date, or effective date granted by the Commission if filed unexecuted, after July 1, 2020 and for which an Upgrade Sponsor incurs Directly Assigned Upgrade Costs, any compensation of the Upgrade Sponsor shall be available only through candidate ILTCRs in accordance with Section IV of this Attachment Z2 and such upgrades shall not be Creditable Upgrades.

## I. Creditable Upgrades

A. A Network Upgrade meeting the conditions of the foregoing paragraph for applicability of Sections I, II, and III of this Attachment Z2 and which was paid for, in whole or part, through revenues collected from a Transmission Customer, Network Customer, or Generation Interconnection Customer through Directly Assigned Upgrade Costs shall be considered a Creditable Upgrade where the Upgrade Sponsor is eligible to receive revenue credits in accordance with Section II of this Attachment Z2. A Network Upgrade that does not increase the power-flow capacity of a circuit on the Transmission System, as represented in the planning model, shall not be considered a Creditable Upgrade if the execution date of the agreement requiring construction of the Network Upgrade is on or after February 1, 2018. Such agreement requiring construction of the Network Upgrade shall include a Generator Interconnection Agreement, Interim Generator Interconnection Agreement, Service Agreement for Network Integration Transmission Service, Service Agreement for Firm Point-To-Point Transmission Service, or Agreement for Sponsored Upgrade, and shall include a list of those upgrades associated with the agreement that are eligible for credits in accordance

with Section II of this Attachment Z2. If the agreement is filed unexecuted with the Commission, the effective date accepted by the Commission shall be applied rather than an execution date in determining whether a Network Upgrade that does not increase power-flow capacity is considered a Creditable Upgrade.

B. A Sponsored Upgrade is not automatically a Creditable Upgrade nor is it automatically eligible to receive revenue credits since Sponsored Upgrades are not built to satisfy a need identified by the Transmission Provider. For a Sponsored Upgrade to become a Creditable Upgrade, the Transmission Provider must determine that the Sponsored Upgrade is needed as part of the Transmission System. At the time the Sponsored Upgrade becomes a Creditable Upgrade, the Transmission Provider shall determine the direction of flow which caused the Creditable Upgrade to be needed and the capability in the opposite direction.

C. A Creditable Upgrade shall cease being a Creditable Upgrade when: (1) the facility is permanently removed from service, (2) all the Upgrade Sponsors have been fully compensated, or (3) the costs have been fully included in rates in accordance with Section III of this Attachment Z2.

## II. Revenue Crediting

An Upgrade Sponsor shall be eligible to receive revenue credits in accordance with this Attachment Z2. The Directly Assigned Upgrade Costs are recoverable, with interest calculated in accordance with 18 CFR §35.19a(a)(2), from new transmission service using the facility as defined below until the amount owed the Upgrade Sponsor is zero. The provisions of this Attachment Z2 are applicable to Transmission Owners subject to the provisions of Section 39.1 of this Tariff.

### A. New Point-To-Point Transmission Service:

Revenues from new Long-Term Firm Point-To-Point Transmission Service that could not be provided but for the Creditable Upgrade(s) will be used, in whole or in part, for crediting purposes. For each new reservation for Long-Term Firm Point-To-Point Transmission Service that could not be provided but for one or more Creditable Upgrades, made after (i) the commitment for such Creditable Upgrade by an Upgrade Sponsor or (ii) the request causing the need for such Creditable Upgrade, with service commencing after or extending beyond the date the Creditable Upgrade is completed, the Upgrade Sponsor for each affected Creditable Upgrade shall receive a portion of the transmission service charge equal to the positive response factor of such new reservation on the Creditable Upgrade times the portion of the new reservation capacity that could not be provided but for the Creditable Upgrade times the rate applicable to such new reservation. For crediting purposes, the Transmission Provider shall perform a one-time calculation of the response factor of such new reservation on the Creditable Upgrade. This allocation from new service shall continue until the Upgrade Sponsor has been fully compensated. Revenue credits will be paid to Upgrade Sponsors in accordance with Section II.D of this Attachment Z2. Short-Term Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service granted on or after February 1, 2018 shall not be used to pay revenue credits under this Section II.A. Short-Term Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service granted

prior to February 1, 2018 shall continue to be used to pay revenue credits under this Section II.A for the duration of term of that service.

**B. New Network Integration Transmission Service and Service to Transmission Owners Taking Service Under Non-Rate Terms and Conditions:**

Revenue for credits will be provided from (i) new Long-Term Network Integration Transmission Service, and (ii) new transmission service taken under the non-rate terms and conditions of this Tariff by Transmission Owners subject to Section 39.1 of this Tariff, that could not be provided but for one or more Creditable Upgrades to accommodate designation of new Network Loads or Transmission Owner's(s') loads, new Designated Resources or increases in the designation of existing Designated Resources above previously designated levels. Revenue credits shall be determined based upon the subsequent incremental use of each affected Creditable Upgrade for such new or increased Network Load or Transmission Owner load or Network Resource.

The annual revenue credit amount to be paid monthly by a Network Customer, or included in rates, for each such new or increased use of a Creditable Upgrade shall be the product of the total annual revenue requirement associated with the Creditable Upgrade and the ratio of the incremental impact placed on the Creditable Upgrade by each such new or increased use to the total of the incremental impacts placed on the Creditable Upgrade by all currently and previously identified incremental Network Integration Transmission Service and Long-Term Firm Point-To-Point Transmission Service uses of the Creditable Upgrade.

For the calculation of such revenue credits to be given to an Upgrade Sponsor for subsequent use of a Creditable Upgrade, the incremental use assigned to such Upgrade Sponsor shall be the capacity of the Creditable Upgrade minus all currently and previously identified incremental Network Integration Transmission Service and Long-Term Firm Point-To-Point Transmission Service uses. The

cost of such revenue credit amount shall be paid by the Network Customer making such new or increased use of the Creditable Upgrade, or included in rates pursuant to the Base Plan and Balanced Portfolio funding formulas in Attachment J, in addition to all other applicable charges under this Tariff. Revenue credits will be paid to Upgrade Sponsors in accordance with Section II.D of this Attachment Z2.

**C. Power Controlling Devices:**

**1. New Network Integration Transmission Service:**

Revenue credits will be provided for new Long-Term Network Integration Transmission Service using the device in either direction to accommodate designation of new Network Loads, new Designated Resources or increases in the designation of existing Designated Resources above previously designated levels. Revenue credits shall be determined based upon the subsequent additional incremental use of the device by any such new or increased use.

The annual revenue credit amount to be paid monthly by a Network Customer, or included in rates, for each such new or increased use of a Creditable Upgrade shall be the product of the annual revenue requirement associated with the device and the ratio of the incremental impact placed on the device by each such new or increased use to the total of the incremental impacts placed on the device by all currently and previously identified incremental Network Integration Transmission Service and Long-Term Firm Point-To-Point Transmission Service uses of the device in both directions.

For the calculation of such revenue credits to be given to an Upgrade Sponsor for subsequent use of the device, the incremental use assigned to such Upgrade Sponsor shall be the capacity of the device in both directions minus all currently and previously identified incremental Network Integration Transmission Service and Long-Term Firm Point-To-Point Transmission Service uses of the device in both directions. The

cost of such revenue credit amount shall be paid by the Network Customer making such new or increased use of the device, or included in rates pursuant to the Base Plan and Balanced Portfolio funding formulas in Attachment J, in addition to all other applicable charges under this Tariff. Revenue credits will be paid to Upgrade Sponsors in accordance with Section II.D of this Attachment Z2.

**2. New Point-To-Point Transmission Service:**

Crediting for Long-Term Firm Point-To-Point Transmission Service using the power controlling device in either direction shall be a portion of the transmission service charge equal to the positive response factor of such new reservation on the device times the new reservation capacity times the rate applicable to such new reservation less any revenue credits applicable to other Network Upgrades on the transmission path. For service granted prior to February 1, 2018, crediting for Short-Term Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service using the device in either direction shall be the percent usage of the total revenue received by the Transmission Provider that is not required for other transmission funding obligations. Short-Term Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service granted on or after February 1, 2018 shall not be used to pay revenue credits under this Section II.C.2. Short-Term Firm Point-To-Point Transmission Service and Non-Firm Point-To-Point Transmission Service granted prior to February 1, 2018 shall continue to be used to pay revenue credits under this Section II.C.2 for the duration of term of that service. Revenue credits will be paid to Upgrade Sponsors in accordance with Section II.D of this Attachment Z2.

**D. Distribution of Revenue Credits**

1. For use of Creditable Upgrades which are also Service Upgrades, such revenue credits shall be given to the original Upgrade Sponsor and to all

previously identified Upgrade Sponsors from incremental Network Integration Transmission Service and Long-Term Firm Point-To-Point Transmission Service uses, including prior incremental Network Integration Transmission Service uses that resulted in the obligation to pay revenue credits. The grant of such revenue credits shall be in proportion to the fraction of the annual revenue requirement associated with the Creditable Upgrade for which each Upgrade Sponsor is responsible, net of any revenue credits previously applied.

2. For use of Sponsored Upgrades that qualify as Creditable Upgrades, such revenue credits shall be given first to the Project Sponsor from new transmission service using the Creditable Upgrade until the revenue credit due to the Project Sponsor for that Creditable Upgrade is zero. Then such revenue credits shall be given to all Upgrade Sponsor(s) of the Creditable Upgrade. The grant of such revenue credits shall be in proportion to the fraction of the annual revenue requirement associated with the Creditable Upgrade for which each Upgrade Sponsor is responsible, net of any revenue credits previously applied.

3. For use of Creditable Upgrades associated with a Generator Interconnection Agreement, revenue credits from new transmission service using the Creditable Upgrade shall be given first to the Generation Interconnection Customer(s) associated with the Creditable Upgrade until the revenue credit due is zero. Then such revenue credits shall be given to all other Upgrade Sponsors of the Creditable Upgrade. The grant of such revenue credits shall be in proportion to the fraction of the annual revenue requirement associated with the Creditable Upgrade for which each Upgrade Sponsor is responsible, net of any revenue credits previously applied.

## III. Future Roll-In

When a facility upgrade being paid for pursuant to the provisions of Attachment Z1 to this Tariff is rolled into the revenue requirements used for the development of generally applicable transmission service rates, the Transmission Owner that constructed the facility upgrade shall pay the remaining balance of each customer's unrecovered payments described in Sections VI.A and VI.B of Attachment Z1 that are applicable to that facility upgrade. All customers who have upgraded facilities and have remaining balances subject to cost recovery pursuant to Section VI of Attachment Z1, shall be paid in full. The customer shall continue to pay the charges specified in the customer's transmission service agreement for the transmission service initially reserved.

## IV. Incremental LTCRs

A. In order for candidate ILTCRs to be awarded to an Upgrade Sponsor with Directly Assigned Upgrade Costs for a Network Upgrade, the Upgrade Sponsor and Transmission Provider shall be responsible for the following:

a) Prior to execution of an agreement committing the Upgrade Sponsor to Directly Assigned Upgrade Costs for a Network Upgrade, or prior to the date of any Commission order accepting such agreement if filed unexecuted, the Upgrade Sponsor must request that up to three source-to-sink paths be evaluated by the Transmission Provider to determine the amount of incremental ATC created on these paths as a result of the portion of the upgrade associated with the Directly Assigned Upgrade Cost.

b) The Transmission Provider shall determine the minimum increase in ATC on each of the requested paths over a ten-year period and communicate the MW results to the Upgrade Sponsor. The Upgrade Sponsor may then decide to select one of the requested paths on which candidate ILTCRs are desired and the minimum increase in ATC on that selected path shall be equal to the candidate ILTCRs on that path. Such selection shall be documented in the applicable executed agreements as specified under Section V of Attachment J of this Tariff.

c) The Transmission Provider will consider all awarded ILTCRs in all planning studies on a going forward basis once the Upgrade Sponsor executes the applicable agreements, or the Commission accepts an agreement filed unexecuted, as specified under Attachment J of this Tariff.

d) The Transmission Provider's costs associated with studies for potential ILTCRs shall be the responsibility of the Upgrade Sponsor requesting such studies.

B. When one or more Transmission Customers request to receive candidate ILTCRs for a Service Upgrade which was funded in whole or in part through

Directly Assigned Upgrade Costs, the Transmission Provider will allocate the available candidate ILTCRs to each Transmission Customer in the same proportion as each Transmission Customer's pro-rata share of the total cost of the upgrade allocated in accordance with Section IV of Attachment Z1 of this Tariff.

If multiple Transmission Customers fund a Service Upgrade through Directly Assigned Upgrade Costs, each Transmission Customer may choose a different source-to-sink path for the candidate ILTCR and each Transmission Customer's candidate ILTCR allocation will be in proportion to the total cost of the upgrade.

# ATTACHMENT AA
# RESOURCE ADEQUACY

## 1.0 Overview

Maintaining appropriate planning reserves ensures that the Transmission Provider will have sufficient capacity to serve the SPP Balancing Authority Area's peak demand. This Attachment AA requires a Load Responsible Entity to maintain capacity required to meet its load and planning reserve obligations. Additionally, this Attachment AA provides the obligations and responsibilities of the Transmission Provider, Market Participants, Load Responsible Entities, and Generator Owners with regard to load and planning reserves.

## 2.0 Definitions

Terms defined herein shall only be applicable to this Attachment AA.

**Asset Owner**
As defined in Attachment AE of this Tariff.

**Behind-The-Meter Generation**
As defined in Attachment AE of this Tariff.

**Deficiency Payment**
A payment by a Market Participant when one or more of its LREs has not met the Resource Adequacy Requirement as calculated in accordance with Section 14.2 of this Attachment AA.

**Deliverable Capacity**
The accredited capacity of a Resource that is determined to be deliverable in either a Summer Season or a Winter Season Deliverability Study.

**Demand Response Resource**
As defined in Attachment AE of this Tariff.

**Demand Response Program**
Measurable load reduction program(s) capable of being controlled or dispatched by a Load Responsible Entity, a Market Participant, or the Transmission Provider.

**Firm Capacity**
The accredited capacity of commercially operable generating units, or portions of generating units, adjusted to reflect purchases and sales of capacity with another party, and that is deliverable with firm transmission service to the LRE’s load.

**Firm Power**

Power purchases and sales deliverable with firm transmission service to serve the LRE's load with capacity, energy, and planning reserves, that must be continuously available in a manner comparable to power delivered to native load customers.

**Generator Owner**

The Asset Owner of a Resource.

**Jointly Owned Unit**

As defined in Attachment AE of this Tariff.

**Load Responsible Entity ("LRE")**

An Asset Owner with registered load in the Integrated Marketplace.

**Market Participant**

As defined in Attachment AE of this Tariff.

**Net Peak Demand**

The forecasted Peak Demand less the a) projected impacts of a Demand Response Program and b) adjusted to reflect the contract amount of Firm Power with another entity as specified in Section 8.2 of this Attachment AA.

**Non-Controllable and Non-Dispatchable Behind-The-Meter Generation**

Behind-The-Meter Generation resources that are non-controllable and non-dispatchable by the Transmission Provider, Market Participant, or the LRE.

**Non-Controllable and Non-Dispatchable Demand Response Programs**

Demand Response Programs that are non-controllable and non-dispatchable by the Transmission Provider, Market Participant, or the LRE.

**Peak Demand**

The highest demand including a) transmission losses for energy, b) the projected impacts of Non-Controllable and Non-Dispatchable Behind-The-Meter Generation, and c) the projected impacts of Non-Controllable and Non-Dispatchable Demand Response Programs measured over a one clock hour period.

**Resource**

As defined in Attachment AE of this Tariff.

***Seasonal Net Peak Load***

*The actual demand including a) transmission losses for energy, b) the impacts of Non-Controllable and Non-Dispatchable Behind-The-Meter Generation, c) the impacts of Non-Controllable and Non-Dispatchable Demand Response Programs, and d) the impacts of Demand Response Programs measured over a one clock hour period during either the Summer Season or Winter Season.*

**Summer Season**

June 1st through September 30th of each year.

**Winter Season**

December 1st through March 31st of each year.

**Workbook**

An electronic tool provided by the Transmission Provider which is used by an LRE or Generator Owner to submit information to the Transmission Provider for the purposes of administering this Attachment AA.

## 3.0 Roles and Responsibilities

### 3.1 Generator Owner and Load Responsible Entity

Except as provided in Section 3.1(1) of this Attachment AA, the roles and responsibilities of the LRE and Generator Owner are separate and distinct from the other under this Attachment AA. An entity may be an LRE, a Generator Owner, or both. For an entity that is both an LRE and Generator Owner, the Transmission Provider shall recognize the rights, roles, and responsibilities as separate and distinct functions.

(1) An LRE that is also a Generator Owner shall access its Workbook pursuant to the provisions of Section 9.3(b) of this Attachment AA but shall be considered an LRE for Workbook reporting purposes, and all excess capacity of the Generator Owner shall be considered LRE Excess Capacity for purposes of Resource Adequacy Assurance as described in Section 14.0 of this Attachment AA.

### 3.2 Market Participant and Load Responsible Entity

(1) An LRE may be a Market Participant or can engage a third party Market Participant to represent it. If an LRE refuses to either (a) become a Market Participant or (b) engage a third party Market Participant to represent it, the Transmission Provider shall file an unexecuted Market Participant Agreement with the Commission pursuant to Section 2.2(6) of Attachment AE of this Tariff.

(2) A Market Participant that represents an LRE under Attachment AH of this Tariff is the entity responsible under this Attachment AA to ensure the LRE's compliance with the Resource Adequacy Requirement.

(3) The relationship between a Market Participant and its LRE, as established in the submission of the Workbook on February 15th, will be considered fixed for the upcoming Summer Season for enforcement of the Resource Adequacy Requirement.

(4) The Market Participant is responsible to ensure its LRE(s) provides the necessary data to allow the Transmission Provider to verify its LRE(s)' compliance with the Resource Adequacy Requirement.

(5) An LRE shall submit all necessary data to the Transmission Provider either directly or through the LRE's Market Participant.

(6) A Market Participant may aggregate the forecasted Peak Demand of multiple LREs whose load assets are served by a common set of Designated Resources or a Firm Power transaction between the LREs. In such case, the Market Participant shall be considered the LRE for the aggregated demand and, for purposes of compliance with this Attachment AA, the Market Participant's forecasted Peak Demand shall be used to calculate a single Resource Adequacy Requirement for the aggregated load assets.

(7) The Market Participant is responsible for any Deficiency Payment(s) incurred by the LRE(s) it represents.

### 3.3 Procedures for Assignment of Market Participant Obligations

(1) A Market Participant may assign its duties, obligations and responsibilities for an LRE under this Attachment AA, but only to another Market Participant. A non-Market Participant must become a Market Participant prior to accepting an assignment.

(2) Assignor Market Participant shall be responsible to negotiate and contract with another Market Participant for the assignment of its duties, obligations, and responsibilities with respect to the LRE. A valid assignment must be in writing, bilaterally executed by both parties, and the assignee Market Participant shall affirmatively accept the duties, obligations, and responsibilities of the assignor Market Participant under this Attachment AA.

(3) Assignor Market Participant shall provide copies of the assignment to the Transmission Provider prior to February 15th of each calendar year. In the event the demonstration of such assignment does not occur prior to February 15th of each calendar year, the Transmission Provider shall not be required to accept the assignment for the upcoming Summer Season.

(4) A valid assignment by the assignor Market Participant under this Attachment AA does not affect the assignor Market Participant's status as a Market Participant or other rights and obligations it may have under other provisions of this Tariff.

(5) Except as otherwise provided in Sections 3.3(6), 3.3(7), and 3.3(8) of this Attachment AA, upon demonstration of a valid assignment, Transmission Provider will accept the transfer of the LRE to the assignee Market Participant, and enforce the provisions of Attachment AA against the assignee Market Participant, without recourse against the assignor Market Participant.

(6) Either party may serve the Transmission Provider with written notice of the assignment's termination. The Transmission Provider will recognize the assignment's termination if the notice contains a written acknowledgement by both parties that the assignment has been terminated. Upon termination of the assignment, the duties, obligations, and responsibilities of the Market Participant for the transferred LRE under Attachment AA of the Tariff shall immediately revert back to assignor Market Participant, unless a replacement assignment that meets the requirements of this section is provided to the Transmission Provider.

(7) Nothing in the Transmission Provider's acceptance of the assignment shall be construed to create or give rise to any liability on the part of the Transmission Provider and the parties to the assignment expressly waive any claims that may arise in their favor against the Transmission Provider, except as specifically may be provided in the Tariff. The Transmission Provider shall be held harmless by the by parties for any breach of the assignment or dispute between the parties with regards to the assignment, and such dispute shall not delay or cancel the financial responsibilities of the assignee Market Participant under this Attachment AA. Any dispute between the Transmission Provider and either party may be subject to the dispute resolution provisions of Section 12 of the Tariff.

(8) The Transmission Provider shall not be responsible for the actions of any party, or have any affirmative duties assigned to the Transmission Provider under the assignment. The Transmission Provider's recognition of the assignment shall not be construed as Transmission Provider's acceptance of the provisions of the assignment that may conflict with the Tariff or the Transmission Provider's administration of the Tariff, and specifically, the application of this Attachment AA against the assignee Market Participant, or upon termination of the assignment, the assignor Market Participant. In the event there exists a conflict

between a term of the assignment and this Tariff, the provisions of this Tariff shall control.

## 4.0 Planning Reserve Margin

The Planning Reserve Margin ("PRM") shall be set in the SPP Planning Criteria. Determination of the PRM will be supported by a probabilistic Loss of Load Expectation ("LOLE") Study, which will analyze the ability of the Transmission Provider to reliably serve the SPP Balancing Authority Area's forecasted Peak Demand. The LOLE Study will be performed by the Transmission Provider on a biennial basis, or more often as determined by the Transmission Provider. The Transmission Provider, with input from the stakeholders, shall develop the inputs and assumptions to be used for the LOLE Study. The Transmission Provider will study the PRM such that the LOLE for the applicable planning year does not exceed one (1) day in ten (10) years, or 0.1 day per year. At a minimum, the PRM shall be determined using probabilistic methods by altering capacity through the application of generator forced outages and forecasted demand through the application of load uncertainty to ensure the LOLE does not exceed 0.1 day per year. The Transmission Provider shall post the final results of the LOLE Study.

## 5.0 Summer Season Resource Adequacy Requirement

**5.1** The Resource Adequacy Requirement is equal to the LRE's Summer Season Net Peak Demand plus its Summer Season Net Peak Demand multiplied by the PRM.

(1) The LRE is responsible to meet the Resource Adequacy Requirement for the Summer Season and failure to comply shall result in a Deficiency Payment as calculated in accordance with Section 14.2 of this Attachment AA.

**5.2** The Deliverable Capacity or Firm Capacity utilized by an LRE to meet the Resource Adequacy Requirement may not be included in the Deliverable Capacity or Firm Capacity utilized by another LRE to meet the Resource Adequacy Requirement. Deliverable Capacity or Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Deliverable Capacity or Firm Capacity for compliance with the Resource Adequacy Requirement.

**5.3** If an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the Resource Adequacy Requirement contained in this Attachment AA is not intended to affect an LRE's obligation to maintain distinct and separate amounts of Resources to cover its applicable planning reserve obligation for its load located external to the SPP Balancing Authority Area. Load and Resources that are pseudo-tied or dynamically scheduled into the SPP Balancing Authority Area shall be considered internal for purposes of determining the Resource Adequacy Requirement.

## 6.0 Winter Season Obligation

**6.1** The Winter Season Obligation is equal to the LRE's Winter Season Net Peak Demand plus its Winter Season Net Peak Demand multiplied by the PRM.

**6.2** The Deliverable Capacity or Firm Capacity utilized by an LRE to meet the Winter Season Obligation may not be utilized by another LRE to meet the Winter Season Obligation. Deliverable Capacity or Firm Capacity that is contracted to other entities shall not be available to the LRE that is transferring the Deliverable Capacity or Firm Capacity for compliance with the Winter Season Obligation.

**6.3** If an LRE serves load both internal and external to the SPP Balancing Authority Area, compliance with the Winter Season Obligation contained in this Attachment AA is not intended to affect an LRE's obligation to maintain distinct and separate amounts of Resources to cover its applicable planning reserve obligation for its load located external to the SPP Balancing Authority Area. Load and Resources that are pseudo-tied or dynamically scheduled into the SPP Balancing Authority Area shall be considered internal for purposes of determining the Winter Season Obligation.

## 7.0 Qualification of Deliverable Capacity, Firm Capacity, Firm Power, Demand Response Programs, and Behind-The-Meter Generation

**7.1** As part of the annual Workbook submission, an LRE or Generator Owner with Deliverable Capacity from resources internal to the SPP Balancing Authority Area shall qualify such capacity by: (a) registering the Resource in the Integrated Marketplace; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; and (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria.

**7.2** As part of the annual Workbook submission, an LRE or Generator Owner with Firm Capacity from a resource(s) internal to the SPP Balancing Authority Area shall qualify such capacity by: (a) demonstrating the resource(s) is (i) registered in the Integrated Marketplace or (ii) listed as a Designated Resource in the Network Integration Transmission Service Agreement; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria; and (d) demonstrating that there is firm transmission service from the internal resource(s) to the LRE's load.

**7.3** As part of the annual Workbook submission, an LRE or Generator Owner with Firm Capacity from a resource(s) external to the SPP Balancing Authority Area shall qualify such capacity by: (a) demonstrating ownership or contractual rights; (b) submitting, or causing to be submitted, to the Transmission Provider the current operational test results per the requirements of the Balancing Authority where the resource(s) is located; (c) demonstrating that there is firm transmission service from the external resource(s) to the LRE's load; and (d) attesting that any external capacity being identified is not otherwise being used as capacity in any other Balancing Authority Area or in another resource adequacy construct.

**7.4** As part of the annual Workbook submission, an LRE with Firm Power from a resource(s) internal to the SPP Balancing Authority Area shall qualify those purchases or sales by: (a) demonstrating the resource(s) is (i) registered in the Integrated Marketplace or (ii) listed as a Designated Resource in the Network Integration Transmission Service Agreement; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria; and (d) demonstrating that there is firm transmission service from the internal resource(s) to the LRE's load.

**7.5** As part of the annual Workbook submission, an LRE with Firm Power from a resource(s) external to the SPP Balancing Authority Area shall qualify those purchases or sales by: (a) demonstrating ownership or contractual rights; (b) submitting, or causing to be submitted, to the Transmission Provider the current operational test results per the requirements of the Balancing Authority where the resource(s) is located; (c) demonstrating that there is firm transmission service from the external resource(s) to the LRE's load; (d) demonstrating that the capacity includes planning reserves; and (e) attesting that any external capacity being identified is not otherwise being used as capacity in any other Balancing Authority Area or in another resource adequacy construct.

**7.6** As part of the annual Workbook submission, an LRE shall qualify a Demand Response Program by: (a) submitting, or causing to be submitted, to the Transmission Provider the appropriate reporting and documentation requirements in accordance with the SPP Business Practices; (b) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (c) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria.

**7.7** As part of the annual Workbook submission, an LRE claiming Firm Capacity from Behind-The-Meter Generation less than 10 MW internal to the SPP Balancing Authority Area shall qualify such generation by: (a) being controlled or dispatched by an Load Responsible Entity or Market Participant; (b) submitting, or causing to be submitted, to the Transmission Provider the appropriate reporting and documentation requirements in accordance with the SPP Business Practices; (c) submitting, or causing to be submitted, to the Transmission Provider the current Operational Test results as performed in accordance with the SPP Planning Criteria; (d) submitting, or causing to be submitted, to the Transmission Provider the current Capability Test results as performed in accordance with the SPP Planning Criteria; and (e) demonstrating that there is firm delivery from the internal resource(s) to the LRE's load.

**7.8** A resource qualified in accordance with Section 7.1, 7.2, 7.4, or 7.7 of this Attachment AA shall have its accredited capacity determined in accordance with SPP Planning Criteria and SPP Business Practices.

**7.8.1** Qualified resources shall be capable of supplying their accredited capacity for a minimum of four (4) continuous hours.

**7.8.2** The requirement set forth in Section 7.8.1 shall not apply to run-of-the-river hydroelectric, wind, or solar resources. Qualified run-of-the-river hydroelectric, wind, or solar resources shall be capable of supplying their accredited capacity based on historical performance in accordance with the SPP Planning Criteria and SPP Business Practices.

**7.9** A Demand Response Program qualified in accordance with Section 7.6 of this Attachment AA shall be capable of maintaining an LRE's level of net peak demand achieved by the highest level of projected load reduction during four consecutive hours.

**7.10** The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information received pursuant to Section 7 of this Attachment AA when such information is so designated as "confidential" and if such designation is

reasonable, except to the extent required by this Tariff, by regulatory or judicial order, by law or statute.

## 8.0 Qualification and Verification of Power Purchase Agreements

**8.1** An LRE or Generator Owner shall provide the Transmission Provider a copy of the power purchase agreement(s) to enable the Transmission Provider to verify the Deliverable Capacity, Firm Capacity, or Firm Power and to confirm compliance with this Attachment AA. On a prospective basis, the LRE or Generator Owner shall only submit a copy of a new or modified agreement(s).

(1) Any redacted versions of a power purchase agreement submitted by an LRE or Generator Owner shall contain sufficient information to allow the Transmission Provider to verify compliance with the Resource Adequacy Requirement.

(2) An LRE or Generator Owner with a power purchase agreement that does not identify the specific resource(s) shall identify each resource that is available or partially available through an attestation supporting the power purchase agreement.

**8.2** When the purchaser and seller are both LREs, a power purchase agreement that qualifies as Firm Power shall result in a Net Peak Demand adjustment of the obligation for capacity and planning reserves from the purchaser to the seller. The purchaser shall deduct the purchased contract amount from its Net Peak Demand and the seller shall add the amount to its Net Peak Demand. The responsibility to maintain the Resource Adequacy Requirement and the Winter Season Obligation shall transfer from the purchaser to the seller.

**8.3** When the seller is not an LRE, a power purchase agreement that qualifies as Firm Power shall not result in a Net Peak Demand adjustment and the purchaser will remain responsible for the Resource Adequacy Requirement and Winter Season Obligation for load served by the agreement. The purchaser shall not deduct the purchased contract amount from its Net Peak Demand; however, the purchaser may reflect as Firm Capacity the contract amount of the agreement plus the purchaser's PRM multiplied by the contract amount. Firm transmission service is only required for the contract amount.

**8.4** When the purchaser is not an LRE, a power purchase agreement that qualifies as Firm Power shall result in a Firm Capacity transaction for load served by the agreement. The seller, who is an LRE, shall not include the purchased contract amount in its Net Peak Demand; however, the seller shall reflect as Firm Capacity the contract amount of the agreement plus the seller's PRM multiplied by the contract amount. Firm transmission service is only required for the contract amount.

**8.5** A power purchase agreement executed prior to July 1, 2018 will continue to be defined and qualified as Firm Power if it does not include provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure (as defined in Section 10.1 of this Tariff) or uncured defaults. All other power purchase agreements must specifically meet the definition of Firm Power.

**8.6** An LRE may arrange for short-term capacity to provide a part of its Firm Capacity or short-term Firm Power to reduce a portion of its Summer Season Net Peak Demand or Winter Season Net Peak Demand, subject to the following provisions:

(1) Such short-term capacity or short-term Firm Power shall be available for a minimum of four consecutive months, starting either June 1st or December 1st;

(2) The amount of short-term Firm Capacity or short-term Firm Power purchased in aggregate shall not exceed 25% of an LRE's applicable Net Peak Demand; and

(3) If the seller under a short-term Firm Power agreement is not an LRE, then the purchaser under the short-term Firm Power agreement will remain responsible for any Resource Adequacy Requirement or Winter Season Obligation for load served under the short-term Firm Power agreement.

**8.7** The Transmission Provider shall make all reasonable efforts to preserve the confidentiality of information received pursuant to Section 8 of this Attachment AA when such information is so designated as "confidential" and if such designation is reasonable, except to the extent required by this Tariff, by regulatory or judicial order, by law or statute.

## 9.0 Resource Adequacy Timeline

The Resource Adequacy process is performed annually beginning on July 1st of each year. For any prescribed date that falls on a weekend or holiday, the date of performance shall be the next business day.

(1) On July 1st of each year the Transmission Provider shall post the following on the SPP website and distribute via email distribution list:

(a) Notification of the commencement of the process; and

(b) A timeline indicating when the Market Participant, LRE, and Generator Owner are required to meet their respective obligations.

(2) By October 1st of each year the Transmission Provider will perform the Deliverability Study for the upcoming Summer Season.

(3) On October 1st of each year the Transmission Provider shall post and provide notice via email distribution list:

(a) The following on the SPP website:

(i) The unpopulated Workbook;

(ii) Instructions for completing the Workbook; and

(iii) The deadline to submit the Workbook.

(b) The following on a secure website:

(i) A Workbook populated with the results of the Summer Season Deliverability Study for each individual Generator Owner.

*(ii) A Workbook populated with the results of the Effective Load Carrying Capability Study for each individual Load Responsible Entity and Generator Owner.*

(4) The Transmission Provider shall not modify the unpopulated Workbook after December 31st of each year. Any modification to the unpopulated Workbook by

the Transmission Provider after the initial October 1st posting shall be posted on the SPP website and distributed via email distribution list.

(5) By February 15th of each year, each Market Participant and participating Generator Owner will ensure the Transmission Provider is provided with a Workbook.

(6) No later than five (5) calendar days after February 15th, the Transmission Provider shall provide notice to all Market Participants, LREs, and Generator Owners that have not submitted a Workbook by the deadline. Such notice shall include the communication that the Market Participant may be subject to a Deficiency Payment if such deficiency is not cured. A Market Participant, LRE, or Generator Owner that receives such notice shall have ten (10) calendar days to submit its Workbook. Failure to provide a Workbook within the ten (10) calendar days after notification shall result in the Transmission Provider disclosing a listing of the entities that have not submitted a Workbook to the Supply Adequacy Working Group, which will provide a report to the Markets and Operations Policy Committee.

(7) No later than April 1st of each year, the Transmission Provider will review the information in the Workbook to determine whether each LRE meets the Resource Adequacy Requirement. The Transmission Provider will notify the Market Participant and the LRE if the LRE has not met the Resource Adequacy Requirement.

(8) By April 1st of each year the Transmission Provider will perform the Deliverability Study for the upcoming Winter Season.

(9) By April 1st of each year the Transmission Provider shall post and provide notice via email distribution list:

(a) The following on a secure website:

i) A Workbook populated with the results of the Winter Season Deliverability Study for each individual Generator Owner.

(10) By May 15th of each year, an LRE or Generator Owner shall update its Workbook to reflect purchases and sales that occurred after the initial submission.

(11) By May 15th of each year, an LRE must demonstrate it has cured any deficiency in compliance with the Resource Adequacy Requirement.

(12) No later than June 15th of each year, the Transmission Provider shall post its final report on the status of each LRE's compliance with the Resource Adequacy Requirement for the upcoming Summer Season and whether the respective Market Participant is subject to the Deficiency Payment.

(13) On or before June 30th of each year, and after the posting of the final report, the Transmission Provider shall calculate and assess the Deficiency Payment in accordance with the provisions contained in Sections 14.2 and 14.3, respectively, of this Attachment AA.

## 10.0 Deliverability Study

**10.1** The Transmission Provider shall perform a Deliverability Study for the Summer Season and a Deliverability Study for the Winter Season every year. Each Deliverability Study will evaluate the deliverability to the SPP Balancing Authority Area of each Resource registered in the Integrated Marketplace and not whether such Resources are deliverable to specific delivery points or SPP Zones. Each Deliverability Study will result in a determination of each Resource's seasonal capacity that is deliverable to the SPP Balancing Authority Area. The results of the Summer Season Deliverability Study shall be valid for the upcoming Summer Season and the subsequent Summer Season. The results of the Winter Season Deliverability Study shall be valid for the upcoming Winter Season and the subsequent Winter Season.

**10.2** The Transmission Provider will utilize its current transmission planning models to perform the Summer Season Deliverability Study and the Winter Season Deliverability Study. The Transmission Provider will begin each Deliverability Study with the initial assumption that any Resource generating in the planning model is automatically deliverable to the SPP Balancing Authority Area for the dispatched output. A Resource's total capacity equals the generating unit's maximum output of MWs. For multiple generating units at one site, the total capacity for the site is the sum of maximum MWs of all generating units. A transfer level equal to the difference between the Resource's maximum MW capacity and the amount dispatched in the planning model is determined for each Resource. Each transfer will consist of at least one Resource or may consist of multiple Resources grouped together, as specified in either the Summer Season Deliverability Study or the Winter Season Deliverability Study scope. A First Contingency Incremental Transfer Capability ("FCITC") analysis of each transfer will be performed to determine the deliverability of the Resource. Transmission Facilities 100 kV and above will be included in the FCITC analysis. A three percent (3%) transfer distribution factor threshold will be used to analyze constraints impacted by the transfer.

**10.3** The Summer Season Deliverability Study and the Winter Season Deliverability Study results for each Generator Owner's Resource shall consist of the total Resource's deliverability of MW amounts. Each Generator Owner of a Jointly Owned Unit will coordinate to determine the MW deliverability amounts for its share of a Jointly Owned Unit.

**10.4** The amount of Deliverable Capacity of any Resource available for purchase to meet the PRM portion of the Resource Adequacy Requirement or Winter Season Obligation shall equal the lesser of: a) the Resource's accredited capacity less the MW amount of capacity that has been committed to meet i) Firm Capacity and ii) a sale to another entity; or b) the amount of a Resource's total deliverable MWs less the MW amount of capacity that has been committed to meet i) Firm Capacity and ii) a sale to another entity, as determined from the Generator Owner's Workbook.

**10.5** A Generator Owner that does not submit a Workbook that contains the amount of generation capacity available through each Deliverability Study shall be deemed to have no Deliverable Capacity and shall not be entitled to receive any revenue distributions collected from Deficiency Payments.

**10.6** Demand Response Resource(s) classified as Demand Response Program(s) shall not be a) eligible to be used as Deliverable Capacity and b) available for purchase to satisfy the PRM portion of the Resource Adequacy Requirement or the Winter Season Obligation.

**10.7** A power purchase agreement to satisfy the PRM portion of the Resource Adequacy Requirement or Winter Season Obligation based on the most recent Summer Season or Winter Season Deliverability Study may only rely on the results of such study for no longer than the upcoming Summer Season or Winter Season and the subsequent Summer Season or Winter Season.

(1) Deliverable Capacity purchases by an LRE to satisfy the PRM portion of the Resource Adequacy Requirement or Winter Season Obligation will not require firm transmission service to support the capacity. Deliverable Capacity purchases

shall not entitle a Market Participant to receive Auction Revenue Rights under Attachment AE of the Tariff.

(2) Deliverable Capacity purchases shall not be utilized to serve any portion of the LRE's Summer Season Net Peak Demand or Winter Season Net Peak Demand. If the LRE's power purchase agreement to satisfy the PRM portion of the Resource Adequacy Requirement or Winter Season Obligation also includes capacity needed to serve any portion of its Summer Season Net Peak Demand or Winter Season Net Peak Demand, the LRE must secure firm transmission service for such capacity to serve any portion of its Summer Season Net Peak Demand or Winter Season Net Peak Demand.

## 11.0 Workbook

**11.1** The Generator Owner's Workbook will contain, but is not limited to, the following information:

(1) Capacity sales to another entity; and

(2) Uncommitted Deliverable Capacity available to meet the PRM.

**11.2** The LRE's Workbook will contain, but is not limited to, the following information:

(1) The LRE's Summer Season Net Peak Demand;

(2) Firm Capacity owned by the LRE;

(3) Purchases and sales for Deliverable Capacity:

(4) Purchases and sales for Firm Capacity;

(5) Purchases and sales for Firm Power; and

(6) Uncommitted Deliverable Capacity available to meet the PRM.

**11.3** The LRE's Workbook shall be subject to the following provisions:

(1) A Workbook will be used to qualify the LRE's compliance with the Resource Adequacy Requirement for the upcoming Summer Season. Absent a calculation error or otherwise incorrect information, an LRE that demonstrates compliance with the requirements of Section 5.0 of this Attachment AA is considered to have met its Resource Adequacy Requirement, subject to any subsequently reported sales. An LRE shall update its Workbook by May 15th to correct calculation errors or incorrect information.

(2) A Workbook may include any Resources, provided the Resource's capacity is expected to be available during June 15th through September 15th. After February 15th, if the expected availability of a Resource changes to unavailable during June 15th through September 15th, the Resource will be considered as available for purposes of meeting the Resource Adequacy Requirement.

(3) Resources contained in the Workbook that are identified by February 15th to be unavailable during part or all of the period from June 15th through September

15th will not count as capacity for purposes of meeting the LRE's compliance with the Resource Adequacy Requirement. Should a Resource that is initially identified to be unavailable during part or all of the period from June 15th through September 15th but subsequently becomes available and the LRE updates its Workbook by May 15th, such Resource will count as capacity for purposes of meeting the Resource Adequacy Requirement.

## 12.0 Post-Season Analysis

The Transmission Provider shall conduct a post-Summer Season analysis to compare the LRE's actual Summer Season Net Peak Demand versus the LRE's planning forecast. The analysis would be used to evaluate, at a minimum, LRE's planning forecast consistency and develop further improvements for the resource adequacy process. The Transmission Provider will take the results to the Supply Adequacy Working Group for review who may refer cases of potential discrepancies to the Markets and Operations Policy Committee for further investigation and action, if necessary.

## 13.0 Cost of New Entry

The Cost of New Entry ("CONE") value shall be 85.61 $/kw-yr. The CONE value shall be reviewed on or before November 1st of each year by the Transmission Provider and any changes shall be filed with the Commission. The Transmission Provider shall post the Commission-approved CONE for the next Summer Season on the SPP website within ten (10) calendar days of Commission approval.

The Transmission Provider's calculation of the CONE for the SPP Balancing Authority Area shall be based on publicly available information (e.g., information provided by the Energy Information Administration) relevant to the estimated annual capital and fixed operating costs of a hypothetical natural gas-fired peaking facility. The Transmission Provider shall consider factors, including, but not limited to: (1) physical factors (such as, the type of generating resource that could reasonably be constructed to provide Firm Capacity in the SPP Balancing Authority Area, costs associated with locating the Resource within the SPP Balancing Authority Area); (2) financial factors (such as, the hypothetical debt/equity ratio for the Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE value, the Transmission Provider shall not consider the anticipated net revenue from the sale of capacity, energy or Ancillary Services.

## 14.0 Resource Adequacy Assurance

### 14.1 Variables

The variables used in the calculations are as follows:

(1) Generator Owner Excess Capacity

The available Deliverable Capacity above the committed capacity of Generator Owner Resource(s) as reflected in its completed Workbook.

(2) LRE Deficient Capacity

Resource Adequacy Requirement less the sum of Deliverable Capacity and Firm Capacity, or zero if the sum of Deliverable Capacity and Firm Capacity is greater than or equal to the Resource Adequacy Requirement.

(3) LRE Excess Capacity

Deliverable Capacity and Firm Capacity less Resource Adequacy Requirement, or zero if the Deliverable Capacity and Firm Capacity is less than or equal to the Resource Adequacy Requirement.

(4) SPP Balancing Authority Area Planning Reserve

[(The sum of all LREs' Deliverable Capacity and Firm Capacity less the sum of all LREs' Summer Season Net Peak Demand) plus the sum of all Generator Owner Excess Capacity] divided by the sum of all LREs' Summer Season Net Peak Demand.

### 14.2 Deficiency Payment

(1) Deficiency Payment =

LRE Deficient Capacity * CONE * CONE FACTOR

Where the CONE FACTOR shall be:

(a) 125% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 8%; or

(b) 150% when the SPP Balancing Authority Area Planning Reserve is greater than or equal to the PRM plus 3%, but less than the PRM plus 8%; or

(c) 200% when the SPP Balancing Authority Area Planning Reserve is less than the PRM plus 3%.

(2) An LRE that resolves its capacity deficiency for the purpose of meeting the Resource Adequacy Requirement by May 15th of the applicable year will be considered compliant.

(3) An LRE that fails to obtain sufficient capacity to meet the Resource Adequacy Requirement by May 15th of the applicable year, or fails to correct its Workbook by May 15th of the applicable year, will be considered deficient for the upcoming Summer Season. The responsible Market Participant shall be subject to the Deficiency Payment and such payment shall not relieve the LRE's obligation to comply with the Resource Adequacy Requirement.

(4) A Market Participant, or its LRE, that does not submit the Workbook to the Transmission Provider by May 15th of the applicable year will be considered one hundred percent (100%) deficient and in violation of the Resource Adequacy Requirement for the upcoming Summer Season and shall subject the responsible Market Participant to the Deficiency Payment for the entire Resource Adequacy Requirement. To calculate the LRE Deficient Capacity, the Transmission Provider shall set the Deliverable Capacity and Firm Capacity to zero and utilize the previous year's Summer Season Peak Demand.

## 14.3 Billing Procedure

On an annual basis, the Transmission Provider shall calculate the Deficiency Payment amounts to be assessed against a Market Participant pursuant to Section 14.2 of this Attachment AA. On or before June 30th of the applicable calendar year, the Transmission Provider shall submit an invoice to the Market Participant as a charge for the Deficiency Payment amount. The invoice shall be paid by the Market Participant within seven (7) calendar days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider. In the event of a dispute between the Transmission Provider and the Market Participant related to the calculation and assessment of a

Deficiency Payment, the Market Participant shall pay the amount in dispute, and the Transmission Provider shall deposit into an escrow account the portion of the invoice in dispute, pending resolution of such dispute.

### 14.4 Revenue Distribution

Revenues from Deficiency Payments collected by the Transmission Provider shall be distributed to Market Participant(s) for its LRE(s) with LRE Excess Capacity or Generator Owner(s) with Generator Owner Excess Capacity on a *pro rata* basis according to the following:

(1) In the event that the sum of all LRE Excess Capacity is greater than or equal to the sum of LRE Deficient Capacity then:

LRE revenue =
(individual LRE Excess Capacity / sum of all LRE Excess Capacity) * sum of the Deficiency Payment(s)

(2) In the event that the sum of all LRE Excess Capacity is less than the sum of LRE Deficient Capacity, then the allocation of revenues shall be distributed according to the following steps:

(a) LRE revenue =

[(individual LRE Excess Capacity / sum of LRE Deficient Capacity) * sum of the Deficiency Payment(s)]; and

(b) Any remaining revenues not allocated pursuant to Section 14.4(2)(a) of this Attachment AA will be allocated to Generator Owner(s) in accordance with each Generator Owner's submitted completed Workbook in the following manner:

(i) In the event that the sum of all LRE Excess Capacity and all Generation Owner Excess Capacity is greater than or equal to the sum of Deficient Planning Reserve(s) then:

Generator Owner revenue =

[[(sum of LRE Deficient Capacity – sum of all LRE Excess Capacity) / sum of LRE Deficient Capacity] * (individual Generator Owner Excess Capacity / sum of all Generator Owner Excess Capacity) * sum of Deficiency Payment(s)]; or

(ii) In the event that the sum of all LRE Excess Capacity and all Generator Owner Excess Capacity is less than the sum of Deficient Planning Reserve(s) then:

(a) Generator Owner revenue =

[(individual Generator Owner Excess Capacity / sum of LRE Deficient Capacity) * sum of Deficiency Payment(s)]; and

(b) All remaining revenue not allocated in Section 14.4(2)(b)(ii)(a) of this Attachment AA will be allocated to each LRE that has met its Resource Adequacy Requirement on a load ratio share based on Summer Season Net Peak Demand:

LRE revenue =
[(sum of LRE Deficient Capacity – sum of all LRE Excess Capacity – sum of all Generator Owner Excess Capacity) / sum of LRE Deficient Capacity] * (individual LRE Summer Season Net Peak Demand / sum of LRE Summer Season Net Peak Demand(s) that have met the Resource Adequacy Requirement) * sum of Deficiency Payment(s)

(3) The Transmission Provider shall not be liable to an LRE for any revenues collected and distributed pursuant to this Attachment AA, or for damages arising out of or relating to any act or omission, performance, or failure to perform of a Market Participant with respect to such revenues or distribution thereof. It is the responsibility of each Market Participant to distribute such revenues that it receives pursuant to Section 14.4 of this Attachment AA to its eligible LREs.

## 14.5 Dispute Resolution

All disputes under this Attachment AA shall be subject to the dispute resolution procedures contained in Section 12 of this Tariff.

# ATTACHMENT AB
# GENERATOR RETIREMENT PROCESS

**1.0 Introduction:** When it becomes necessary or desirable for a Generator Owner to retire a Resource, the provisions of this Attachment AB shall apply. For the purposes of this attachment, the retirement of a Resource is defined as the permanent removal and de-registration of a Resource from the Integrated Marketplace. This attachment does not apply to requests for generating facility replacement as defined in Attachment V of this Tariff.

**2.0 Submission of Study Requests for Resource Retirements:** The Generator Owner shall make a request to study the retirement of a Resource by submitting notification to the Transmission Provider no less than one year from the expected retirement date. This request shall include the Resource name, the expected retirement date, and other relevant information specified in Addendum 1 to Attachment AB. Upon notification, the Transmission Provider will also inform the SPP Market Monitor of the anticipated Resource retirement.

**3.0 Studies:** The Transmission Provider shall conduct all necessary studies associated with the retirement of a Resource. Such studies shall be conducted at Generator Owner's expense pursuant to the provisions of this section.

**3.1 Resource Retirement Screening Assessment:** Upon receipt of the request to study a Resource retirement, the Transmission Provider shall perform a preliminary screening assessment of the impact of the expected Resource retirement on the Transmission System. The Transmission Provider shall respond within 30 calendar days of receipt of such request with results of a screening assessment determining if technical analysis is required prior to the Resource retiring. If technical analysis not required by the Transmission Provider, the Generator Owner may submit its retirement notice in accordance with the SPP Market Protocols at any time.

**3.2 Transmission System Study:** If further technical analysis is required, the Generator Owner must execute a Resource Retirement Study ("RRS") Agreement to proceed with such study and provide a study deposit of $10,000, within 30 Calendar Days of notification. If the Generator Owner fails to return an executed RRS Agreement within 30 Calendar Days along with the required deposit, the request will be deemed withdrawn.

The Transmission Provider will make a good faith effort complete the study ahead of the retirement date of the Resource. The Transmission Provider and Generator Owner will resolve issues associated with the timeframe of the study and retirement date of the Resource in accordance with Good Utility Practice.

The RRS Agreement shall commit the Generator Owner to pay the Transmission Provider the actual cost to complete the study. Upon receipt of the executed RRS Agreement and deposit, the Transmission Provider shall begin an assessment of the impact of the expected Resource retirement. During the RRS, the Transmission Provider shall assess the impacts on the Transmission System caused by the removal of a Resource using power flow, transient stability, and short circuit analyses, as appropriate. For all requests for which the Transmission Provider finds no reliability impact on the Transmission System, the RRS

will be considered complete. Undesignation and de-registration of the Resource will be required pursuant to Section 4.0 of this Attachment AB. For requests where the Transmission Provider identifies a reliability impact on the Transmission System, a long-term solution may be necessary.

Transmission Provider shall issue a study report to the Generator Owner upon completion of the RRS. If Transmission Provider is unable to complete such study in the allotted time, Transmission Provider shall provide an explanation to the Generator Owner regarding the cause(s) of such delay and a revised completion date and study cost estimate.

**3.3 Confidentiality:** The Transmission Provider will keep the information included in the retirement study request and any supporting information confidential. While analyzing the effects of the retirement on the Transmission System, additional parties including SPP Members and non-Members may be needed to participate in the scope development or mitigation development efforts described in Business Practice 7800. Those entities who participate in such efforts shall have an executed non-disclosure agreement (NDA) on file with SPP. All information and analysis communicated through such processes shall be treated as confidential until posting of the results of the Generator Retirement Process as provided in Section 3.4.

**3.4 Resource Retirement Study Completion:** Prior to inclusion of a Generator Retirement Upgrade in the SPP Transmission Expansion Plan, Transmission Provider will post the supporting RRS report publicly on SPP's website. The Generator Owner shall reimburse Transmission Provider for the unpaid cost of the RRS if the cost of the RRS exceeds the deposit. Transmission Provider shall refund to the Generator Owner any portion of the deposit that exceeds the cost of the RRS with interest earned, if any.

**3.5 Generator Retirement Upgrades:** If the Transmission Provider determines that one or more Network Upgrade(s) is necessary to address reliability impacts to the Transmission System caused by the retirement of a Resource, the Transmission Provider shall make a recommendation to the SPP Board of Directors for approval of the Generator

Retirement Upgrade(s). If a Generator Retirement Upgrade is approved for construction by the SPP Board of Directors, the Transmission Provider will issue all NTC/NTC-Cs in accordance with Attachment Y of this Tariff.

**3.6 Withdrawal of Study Request:** During the course of a RRS, the Generator Owner may withdraw its request for study of retirement of a Resource. The Generator Owner remains responsible for the study costs incurred up to the date of the withdrawal of the request.

**4.0 Resource Undesignation and De-registration:** The applicable Market Participant and all applicable Transmission Customer(s) or Network Customer(s) are responsible to take the necessary actions such that, effective no later than the retirement date, the Resource is not registered under Attachment AE and is not a Designated Resource.

## Addendum 1 to Attachment AB

Pursuant to the Resource Retirement Process in Attachment AB of the Tariff, notice is hereby provided on _____ (date of notice) to the Transmission Provider that Generator Owner requests the study of retirement of a Resource registered in the Integrated Marketplace.

Responses marked with an asterisk (*) are required. Supply all details that are known or projected.

## Resource Retirement Study Request

1) Description of Resource*
   a) Resource name*
   b) Expected retirement date(s)*
   c) Market Participant
   d) Transmission Customer
   e) Reason for the retirement (e.g., age or limited run time) *
   f) Related transmission service agreement*
   g) Bus Number and Unit ID*
2) Other pertinent information

**Requestor Contact:**

Name: _____

Title: _____

Mailing Address: _____

Email Address: _____

Voice Phone No.: _____

By: _____

(Representative of Generator Owner)

Title: _____

Date: _____

# ATTACHMENT AC
# SHORT-TERM SERVICE – SYSTEM IMPACT STUDY PROCESS

1. Short-Term Service Request and Initial Validation

A request for Short-Term Service may be submitted by an Eligible Customer on the Transmission Provider's OASIS in the following increments: Daily, Weekly, and Monthly. Upon receipt of the Eligible Customer's request for Short-Term Service the Transmission Provider will evaluate the request in accordance with the provisions of Attachment C of this Tariff to determine whether sufficient transmission capacity exists to satisfy the request. A Short-Term Service request that passes such initial validation will be accepted by the Transmission Provider within the timeframes provided in Attachment P of this Tariff.

## 2. Requests that Fail Initial Validation

### 2.1 System Impact Study Option

This Reservation Processing Method for Short-Term Firm Transmission Service will be used to process short-term firm requests upon notification by Customer requesting the service. Short-Term Service requests that do not pass initial validation will be processed in accordance with Section 3 of this Attachment AC of this Tariff if requested by the Eligible Customer. Such requests shall be made by the Eligible Customer only by including the following statement in the customer comment field of such reservation: "exercise System Impact Study option" in accordance with the provisions of Section 19.2 of this Tariff. Entry of this comment constitutes Customer's agreement to pay for all System Impact Studies necessary to support the evaluation of this service.

### 2.2 Counteroffer

Short-Term Service requests that do not pass initial validation and where the Eligible Customer does not exercise the System Impact Study option shall be reviewed by the Transmission Provider to determine if partial service can be offered. If partial service can be offered the Transmission Provider shall counteroffer the available transmission capacity to the Eligible Customer.

# 3. System Impact Study Process

## 3.1 Initial Feasibility Analysis

For Short-Term Service requests that do not pass initial validation and where the Eligible Customer has exercised the System Impact Study option, the Transmission Provider shall conduct an analysis of the feasibility of such request at no cost to the Eligible Customer. Such request shall be deemed feasible if: (1) the number of internal flowgate constraints is three or less; and (2) the Available Flowgate Capacity required is either (i) less than the TRM Value minus the transmission capacity used by other requests granted pursuant to these procedures or (ii) less than fifteen percent of the Available Flowgate Capacity minus the transmission capacity used by other requests granted pursuant to these procedures. Upon conclusion of the feasibility analysis, the Eligible Customer will be notified of the results of the analysis and if the request is deemed to be feasible. For Short-Term Service requests that are deemed infeasible, the Transmission Provider shall counteroffer partial service to the extent it is available; if partial service is not available the Transmission Provider will refuse the request.

## 3.2 Notification and Request for System Impact Study

Upon notification by the Transmission Provider that the request is feasible, the Eligible Customer shall notify the Transmission Provider of its election to continue with the System Impact Study. If the Eligible Customer elects to terminate the System Impact Study, the Transmission Provider shall counteroffer partial service to the extent it is available; if partial service is not available the Transmission Provider will refuse the request.

## 3.3 System Impact Study

If the Eligible Customer elects to move forward with the System Impact Study, the Transmission Provider will perform a System Impact Study in accordance with the provisions of Attachment D of this Tariff.

## 4. Acceptance and Confirmation of Short-Term Service Request Subject to Redispatch

If the System Impact Study determines that redispatch options will permit the Transmission Provider to accept the request, the Transmission Provider will respond in accordance with the times specified on Addendum 1 to this Attachment AC. If the Eligible Customer confirms the request, any redispatch costs incurred to relieve a system constraint to be charged to the Eligible Customer shall be collected and paid as part of the Energy and Operating Reserve Market settlement procedures described under Attachment AE of this Tariff and through the limitations on Auction Revenue Rights pursuant to the terms of Section 13.5 of this Tariff.

## 5. Processing of Short-Term Service Requests that Fail the System Impact Study

For Short-Term Service requests that fail the System Impact Study, the Transmission Provider shall counteroffer partial service to the extent it is available; if partial service is not available the Transmission Provider will refuse the request.

**Addendum 1 to Attachment AC**

## Time Frames for Short-Term System Impact Studies

| Term | Eligible Customer Responds to Feasibility Analysis | SPP Studies and Post System Impact Study | Eligible Customer Confirms Request | Customer Meets Requirements (Reservation Pending)[1] |
|---|---|---|---|---|
| Monthly | 1 Business Day | 10 Business Days | 7 Business Days | 4 Days |
| Weekly | 4 Business Hours | 3 Business Days | 3 Business Days | 2 Days |
| Multi-Day (up to 1 week) | 2 Business Hours | 2 Business Days | 2 Business Days | 24 Hours |
| Daily | 2 Business Hours | 2 Business Days | 2 Business Days | 2 Hours |
| Daily (Day Prior) | 1 Business Hour | 1 Business Day | 1 Business Day | 2 Hours |

**Note:** Business Hour: One Hour between 8 AM through 5 PM, Central Prevailing Time, during one business day.
Business Day: Monday through Friday, except NERC Holidays.

[1] Pending Reservation is a reservation that would be accepted if the reservation in System Impact Study were to be refused. This situation demands a shorter time frame.

# ATTACHMENT AD

## Tariff Administration between Southwestern Power Administration and Southwest Power Pool, Inc.

The following articles and exhibits reflect the currently effective terms and conditions within the contract between Southwest Power Pool, Inc. ("SPP"), acting in its capacity as a Regional Transmission Organization ("RTO"), and Southwestern Power Administration ("Southwestern"), such contract being referred to in this Attachment AD as "Agreement" or "the Agreement."

## ARTICLE I

## GENERAL PROVISIONS

Section 1. Services Provided By SPP. (a) During the Term of the Agreement, SPP shall provide Southwestern all of the following services: administration of Southwestern's Open Access Transmission Tariff ("Southwestern's Tariff"); Scheduling Services as specified in Section 11 of this Article I; Operating Reserve Sharing as specified in Section 10 of this Article I; OASIS administration; reliability coordination; transmission planning; performance of transmission and generation interconnection studies; and performance of current and next day system studies as specified in Section 7 of this Article I. For the Term of the Agreement, Southwestern shall compensate SPP for these services by providing a total of $2,603,701.69 from revenues collected by SPP for transmission service provided by SPP pursuant to the SPP Open Access Transmission Tariff ("SPP's Tariff"), and which shall be invoiced in monthly increments by SPP as necessary to collect the entire amount due SPP identified herein; Provided, That, if such revenues are insufficient to collect the entire amount, any balance remaining at the end of the Agreement's Term due to SPP shall be forfeited.

(b) SPP, on behalf of Southwestern, shall administer Southwestern's Tariff for any new Transmission Transactions beginning February 1, 2007; Provided, That, application of the billing determinants of SPP's Tariff to and billing for new Transmission Transactions shall be according to Article II of this Attachment AD. SPP's Administration Charge shall be applied by SPP to Transmission Transactions administered by SPP as defined in Article II. The term "SPP's Administration Charge" as used herein shall be as defined in SPP's Tariff. The term "Transmission Transaction(s)" as used herein shall be defined as contract(s) or service agreement(s), or reservation(s) made thereunder, for the use of the transmission system for the movement of electric capacity or energy on either a firm or non-firm basis.

(c) For Transmission Transactions administered by SPP pursuant to Section 1(b) of this Article I, SPP shall determine whether there is Available Transfer Capability to allow the Transmission Transaction. The term "Available Transfer Capability" as used herein shall be defined as a measure of the transfer capability remaining in the Transmission System for further commercial activity over and above already committed uses. Available Transfer Capability will be determined pursuant to the provisions and procedures of the SPP Tariff and applicable North American Electric Reliability Corporation ("NERC") Reliability Standards. For any new Transmission Transactions, modifications to existing Transmission Transactions, and applicable generation interconnection requests, SPP shall perform all necessary tariff studies, including but not limited to feasibility, system impact, and facilities studies in accordance with SPP's Aggregate Transmission Study and Generation Interconnection study processes. SPP shall notify the requestor of SPP's approval or denial of the transmission service request.

(d) All transmission service requests for new service after February 1, 2007, shall be made on the SPP OASIS. SPP shall be shown as the transmission service provider on the tag for the schedules and SPP shall approve or deny such schedules. SPP shall decrement Available Transfer Capability by the amount of the approved reservation.

(e) SPP shall perform the accounting to determine the amount owed to Southwestern pursuant to the provisions of Article II and Article III of this Attachment AD. SPP's accounting shall be included on SPP's monthly invoice to Southwestern for such Transmission Transactions and shall include sufficient detail (including hourly accounting summaries if required by Southwestern) for Southwestern to verify accuracy in billing and revenue distribution for Transmission Transactions under Article II of this Attachment AD. Additionally, Southwestern shall have the right to audit SPP's records. SPP may, at its option, offer discounts for Transmission Transactions administered by SPP under Southwestern's Tariff; Provided, That, such Transmission Transactions are for service of less than one year and such discounts are commensurate with other discounts being offered by SPP for similar service. Prior to invoicing the customer(s) for Transmission Transactions under Article II of this Attachment AD, SPP shall provide Southwestern with a detailed summary of such transactions for review and verification.

(f) The parties recognize that Southwestern has existing transmission contracts that will continue to be administered by Southwestern. The parties also recognize that these existing contracts have Redirect Rights as dictated by applicable rate schedules. The term "Redirect Rights" as used herein shall be defined as rights to request a change in service specifications for the provision of transmission service on a firm or non-firm basis, including secondary transmission service, over points of receipt and points of delivery other than those specified in the contract or service agreement in amounts not to exceed the firm capacity reservation of such contract or service agreement. Upon receiving a request to redirect either the source and/or sink of such Transmission Transactions, SPP shall determine whether sufficient Available Transfer Capability exists to accommodate the redirect request and approve or deny the request as appropriate.

(g) Unless otherwise agreed in writing, compensation by Southwestern to SPP calculated pursuant to Section 1, Section 10(e), Section 14(n), and Section 14(o) of this Article I and Section 5(a) of Article II shall constitute Southwestern's full financial obligation to SPP. Furthermore, such compensation shall be made pursuant to the terms of this Attachment AD, which shall include separate invoices and payment schedules as applicable.

Section 2. Reimbursable Services. Upon mutual agreement by Southwestern and SPP, and in accordance with applicable laws and regulations, SPP and Southwestern may perform services for each other on a reimbursable basis. Such reimbursable services shall be evidenced by written agreement between Southwestern and SPP.

Section 3. Billing. SPP shall invoice Southwestern on a monthly basis. Payments due Southwestern by SPP shall be offset against payments due SPP by Southwestern with the resulting balance being paid by the party in whose favor such balance exists; Provided, That, transactions between Southwestern and SPP pursuant to Section 10 of this Article I shall be offset and invoiced separately from all other

transactions under this Attachment AD. Such net amount due shall be payable to the party owed or its assignee within 30 days of the date of such resulting invoice.

Section 4. Tariff Application. (a) The application of Southwestern's Tariff and SPP's Tariff to Transmission Transactions utilizing the System of Southwestern shall be as set forth in Article II and Article III of this Attachment AD. The term "System of Southwestern" as used herein shall be defined as the transmission and related facilities of Southwestern that are constructed or acquired by purchase or other agreement, as authorized under Section 5 of the Flood Control Act of 1944, and the transmission and related facilities of the U.S. Army Corps of Engineers ("Corps"). SPP and Southwestern may utilize each other's transmission facilities to implement service under the SPP Tariff and Southwestern's Tariff as set forth in this Attachment AD.

(b) In order to mitigate rate pancaking, SPP and Southwestern agree that only Southwestern's Tariff shall apply to Transmission Transactions made pursuant to Section 1(iii) and Section 1(iv) of Article II of this Attachment AD, and that only SPP's Tariff shall apply to Transmission Transactions made pursuant to Article III of this Attachment AD, for Transmission Transactions within the SPP Footprint; Provided, That, some of the billing determinants under the SPP Tariff shall apply to Transmission Transactions as specifically indicated in Article II; Provided Further, That existing Transmission Transactions made by SPP under SPP's Tariff prior to November 1, 2004, shall remain under SPP's Tariff for their terms.

(c) The term "SPP Footprint" as used in this Attachment AD shall be defined as the facilities committed for use under the SPP Tariff by those utilities executing an SPP Membership Agreement as a Transmission Owner and Southwestern's facilities pursuant to Article III of this Attachment AD. For the purposes of determining tariff application under Article III of this Attachment AD, the System of Southwestern shall be considered part of the SPP Footprint.

Section 5. Operating and Planning. (a) The parties shall comply with all mandatory Reliability Standards subject to enforcement by the Federal Energy Regulatory Commission (hereinafter "FERC") or the North American Electric Reliability Corporation (hereinafter "NERC"), SPP Regional Reliability Standards, and SPP Criteria as specified in Section 13 of this Article I for all Transmission Transactions under their respective tariffs as well as in the planning and operation of their transmission systems and balancing authority areas. Except as provided in Section 7 of this Article I, SPP is not, and shall not be considered, the Registered Entity on behalf of Southwestern for any other NERC Reliability Standard.

(b) Subject to the provisions set forth in this Section 5 and Section 20 of this Article I, SPP shall consider Southwestern part of the SPP Footprint for coordinating with neighboring regional organizations as appropriate, and documenting all transmission service requests, the disposition of such requests, and any supporting data required to support the decision with respect to such requests. Subject to the provisions set forth in this Section 5 and Section 20 of this Article I, SPP shall negotiate, in connection with SPP's Tariff as appropriate, to develop reciprocal service, equitable tariff application, compensation principles, and any related arrangements.

(c) The parties recognize and agree that the individual hydroelectric projects

owned by the Corps, from which Southwestern markets power and energy and provides reactive power and voltage support, are subject to the control and requirements of the Corps. Any operation of, and maintenance, modification, or addition to such Corps hydroelectric projects, including the funding of such activities, is subject to the requirements and express approval of the Corps.

(d) The parties also recognize and agree that Southwestern's transmission system is integrated at various locations through switchyard facilities owned and operated by the Corps. Any operation of, and maintenance, modification, or addition to such Corps facilities, including the funding of such activities, is subject to the requirements and express approval of the Corps.

(e) Southwestern shall communicate and coordinate with the Corps on any operation of, and maintenance, modification, or addition to the Corps facilities set forth in Section 5(c) and Section 5(d) of this Article I as requested by SPP; Provided, That, compliance with SPP's request shall be within the discretion of and subject to the approval of the Corps.

Section 6. Reservation Priority of Existing Transmission Transactions. Existing firm Transmission Transactions, including all ancillary services, provided by Southwestern under Section 1(i) and Section 1(ii) of Article II of this Attachment AD shall be recognized as firm by SPP. SPP recognizes that the use of transmission service over the System of Southwestern that is associated with Federal Power deliveries, for deliveries from resources other than Federal Power, shall be treated as a level NN-6 transmission service with regard to reservation priority. Notwithstanding the definition of "Federal Power-Southwestern" that may be contained in Part I of the SPP Tariff, the term "Federal Power" for the purposes of this Attachment AD only shall be defined as all power and energy generated at reservoir projects under the control of the Corps in the marketing area of Southwestern as well as power and energy delivered to Southwestern from other sources for the purpose of fulfilling Southwestern's contractual obligations for the sale of power and energy pursuant to Southwestern's Federal Power allocations.

Section 7. Reliability. (a) Subject to the provisions of this Attachment AD, Southwestern is in the SPP Reliability Coordinator Footprint and SPP shall be the NERC registered Reliability Coordinator for the facilities subject to SPP's Tariff administration and Southwestern's transmission facilities through which Transmission Transactions are administered by SPP pursuant to this Attachment AD. As the Reliability Coordinator, SPP shall be responsible to monitor reliability and for emergency response pursuant to related SPP Criteria, NERC and SPP Regional Reliability Standards, and the following requirements:

(i) SPP shall monitor real-time data to determine whether any balancing authority areas are experiencing generation capacity deficiencies. If a generation capacity deficiency event threatens the security of the facilities under SPP's administration, SPP shall be authorized to and shall direct the acquisition of generation capacity and, if that direction is not satisfied, the shedding of firm load in the deficient balancing authority area.

(ii) SPP is authorized to and shall direct the response to any

emergency, and Southwestern shall carry out the required emergency actions as directed by SPP (except in cases involving endangerment to the safety of employees or the public), including the shedding of firm load if required for regional security.

(iii) If, after the conclusion of an emergency condition, Southwestern disagrees with SPP's handling of the emergency, the parties will utilize the dispute resolution procedures of Section 19 of this Article I.

(b) In the event SPP requests the redispatch of hydroelectric generation owned and operated by the Corps and marketed by Southwestern, Southwestern shall coordinate its operations with the Corps to accommodate SPP's request to the extent allowed by the Corps. Southwestern shall not be obligated to accommodate any requests by SPP for market purposes or to make more transmission capacity available. Except in cases of immediate emergency, Southwestern will advise SPP of Southwestern's Replacement Cost in order to respond to SPP's request and SPP agrees to compensate Southwestern for such Replacement Cost in a manner approved by Southwestern if Southwestern responds to SPP's request. The term "Replacement Cost" as used herein shall be defined as Southwestern's cost to replace capacity and/or energy as a direct consequence of Southwestern's provision of redispatch requested by SPP. In the event of an immediate emergency and response by Southwestern, any compensation by SPP to Southwestern shall be in accordance with the standard practice of SPP's compensation to other generating entities.

(c) Southwestern is registered with NERC as a Transmission Operator ("TOP") and retains all compliance responsibility for applicable mandatory NERC Reliability Standards. The SPP RTO will support Southwestern by performing, on behalf of Southwestern, the following TOP functional activities:

(i) Seasonal, next-day, and current-day Bulk Electric System studies to determine System Operating Limits ("SOLs"), including both determining new limits and identifying potential exceedances of pre-defined SOLs;

(ii) Update of such Bulk Electric System studies as necessary to reflect current system conditions; and

(iii) Provision of the results of such Bulk Electric System studies to Southwestern.

(d) The information provided by SPP in accordance with Section 7(c) of this Article I shall allow Southwestern to verify that SPP's performance complies with applicable NERC Reliability Standard requirements, and SPP shall:

(i) Provide evidence of such compliance, at a minimum, upon request of Southwestern or applicable compliance Enforcement Authority. This may arise with respect to, but is not limited to, audits, compliance investigations, or other compliance monitoring activities and could include on-site visits to the SPP locations; and

(ii) Provide self-certifications, self-reports, or other information to the

applicable compliance Enforcement Authority, regarding tasks performed by SPP.

(e) For disputes regarding SPP's performance under Section 7(c) and 7(d) of this Article I, the parties will utilize the dispute resolution procedures of Section 19 of this Article I.

Section 8. Transmission Maintenance. Southwestern shall coordinate with SPP for approval of all planned maintenance of the transmission facilities owned by Southwestern consistent with SPP Criteria and the following requirements:

(i) Periodically, Southwestern shall provide SPP its planned maintenance schedule with the goal of producing a rolling one-year period of planned maintenance activity and shall provide SPP updates to its planned maintenance schedule. Southwestern shall notify SPP of the actual implementation of a planned maintenance schedule at least one week in advance of an outage.

(ii) SPP shall analyze such planned maintenance schedules submitted by Southwestern in conjunction with other work on the regional transmission grid to determine the impact of Southwestern's planned maintenance schedule on Available Transmission Capability, ancillary services, the reliability of the facilities administered by SPP pursuant to this Attachment AD and under SPP's purview as Reliability Coordinator, and the purview of neighboring Reliability Coordinators, and any other relevant effects.

(iii) SPP shall advise Southwestern if Southwestern's planned maintenance activity will have an adverse impact according to the following schedule:

(a) Within two (2) business days of receiving Southwestern's plan for maintenance and subsequent updates by Southwestern that are scheduled to occur within thirty (30) business days of Southwestern's submission of such plan to SPP; or

(b) Within ten (10) business days of receiving Southwestern's plan for maintenance and subsequent updates by Southwestern that are scheduled to occur beyond thirty (30) business days of Southwestern's submission of such plan to SPP.

(iv) If an adverse impact is revealed by SPP, Southwestern agrees to work with SPP to revise its maintenance schedule to mitigate the impact.

(v) SPP shall notify Southwestern of any request to change Southwestern's planned transmission maintenance outages that

have been previously approved by SPP if forced transmission outages or other circumstances compromise the integrity or reliability of the facilities administered by SPP. Subject to Federal statutes and regulations applicable to Southwestern, Southwestern will work with SPP to revise its maintenance schedules; Provided, That, SPP compensates Southwestern for any additional costs or impacts to accommodate the revised schedule change as determined by Southwestern. Such Federal statutory and regulatory requirements and cost impacts on Southwestern include but are not limited to the need to compensate a contractor for work delay or reschedule, and/or the need to utilize Congressional appropriations within established time frames and authorization. Such compensation shall be provided to Southwestern by SPP in advance of the rescheduled maintenance. The parties agree that such compensation shall be documented in the form of a separate agreement if required by Southwestern.

(vi) SPP shall coordinate with Southwestern and other transmission owners to the extent practicable to implement schedules for unplanned transmission maintenance when conditions endanger the safety of employees or the public, may result in damages to facilities, or may result in the unsatisfactory operation of Southwestern's transmission facilities or any other transmission system.

Section 9. Generation Maintenance and Switchyard Facilities Owned by the Corps. Subject to the provisions of Section 5(e) of this Article I, Southwestern shall coordinate with SPP for all planned maintenance of the generation facilities and switchyard facilities owned by the Corps, consistent with the following requirements:

(i) Periodically, Southwestern shall provide SPP the Corps' planned maintenance schedule for the Corps' generation and switchyard facilities with the goal of producing a rolling one-year period of planned maintenance activity. Southwestern shall coordinate with the Corps to update the Corps' planned maintenance schedule provided to SPP. Southwestern shall notify SPP of the actual implementation of a planned maintenance schedule at least one week in advance of an outage.

(ii) SPP shall analyze the Corps' planned maintenance schedule to determine its effect on Available Transfer Capability, ancillary services, the reliability of the facilities administered by SPP pursuant to this Attachment AD under SPP's purview as a Reliability Coordinator and under the purview of neighboring Reliability Coordinators, and any other relevant effects. SPP shall inform Southwestern if the Corps' maintenance schedule is expected to have an impact on reliability. If an adverse impact is revealed by SPP, Southwestern agrees to work with SPP and the Corps to revise the Corps' maintenance schedule to mitigate the

impact.

(iii) As part of its review process, SPP shall identify the Corps' maintenance schedules that limit Available Transfer Capability. Southwestern shall work with the Corps to identify opportunities and associated costs for rescheduling planned maintenance to maintain Available Transfer Capability. If the Corps agrees to change planned maintenance at the request of SPP and such change requires the Corps to incur additional costs, SPP shall provide compensation for such additional costs in the method and in such amount as required by the Corps. Generally any such compensation shall be in advance of the Corps changing the planned maintenance.

Section 10. Operating Reserve Sharing. (a) SPP shall provide necessary Operating Reserve Sharing services to facilitate Southwestern's participation in SPP's Operating Reserve Sharing Group (hereinafter "SPP RSG").

(b) Southwestern shall participate as a member of the SPP RSG pursuant to the SPP Reserve Sharing Group Operating Process, dated January 1, 2018. A copy of the SPP Reserve Sharing Group Operating Process dated January 1, 2018, is attached as Exhibit "1" and by this reference incorporated into this Attachment AD. In the event of a conflict between this Attachment AD and the SPP Reserve Sharing Group Operating Process in its current form and as may be modified by SPP, the provisions of the SPP Reserve Sharing Group Operating Process shall prevail.

(c) As soon as practicable, SPP will notify Southwestern of any changes to the SPP Reserve Sharing Group Operating Process and such changes shall subsequently be applicable to this Attachment AD within 60 calendar days of such notice. If Southwestern objects to any changes to the SPP Reserve Sharing Group Operating Process, Southwestern may terminate its participation in the SPP RSG upon 30 calendar days' written notification to SPP. Unilateral termination by Southwestern of participation in the SPP RSG shall not be considered a termination of this Attachment AD.

(d) The parties recognize and agree that Southwestern's activities under this Section 10 are limited to participation in the SPP RSG under the Integrated Marketplace, and that otherwise Southwestern shall not be considered a Market Participant unless agreed to by the parties in writing. The parties recognize and agree that Southwestern shall not engage, or otherwise participate in Integrated Marketplace transactions as a Market Participant that are not associated with the scheduling of Reserve Energy pursuant to this Section 10(d).

(e) Each party will provide Reserve Energy to the other party when required by the other party under this Section 10(e). The term "Reserve Energy" as used herein shall be defined as the difference between the actual energy production to serve load and the actual scheduled energy to serve load. Reserve Energy delivered to Southwestern from SPP will be subject to settlement in the SPP Real-Time Balancing Market. Charges and payments shall be calculated by SPP utilizing the Real-Time Reserve Sharing Group Amount charge type.

(i) The rate to be charged or credited to either party when supplying Reserve Energy pursuant to this Attachment AD shall be the greater of: (1) $100.00 US per MWh (hereinafter "$100/MWh"); or (2) the Locational Marginal Price (hereinafter "LMP"), calculated at the interface Settlement Location between SPP and Southwestern. All payment will be financial, and accounting for Reserve Energy will be in whole megawatt hours (hereinafter "MWh"). Charges shall be calculated in accordance with the settlement procedures specified in Attachment AK of the Tariff. As soon as practicable, SPP will notify Southwestern of any changes to Attachment AK of the Tariff and such changes shall subsequently be applicable to this Attachment AD within 60 calendar days of such notice. If Southwestern objects to any changes to Attachment AK of the Tariff, it may terminate its participation in the SPP RSG upon 30 calendar days' written notification to SPP. Unilateral termination by Southwestern of participation in the SPP RSG shall not be considered a termination of this Attachment AD.

(ii) For purposes of participation in the SPP RSG, the System of Southwestern shall be considered part of the SPP Footprint. Southwestern and SPP shall not be charged transmission service charges for utilizing the Parties' respective transmission facilities to serve export or import energy schedules between the Southwestern Balancing Authority Area and the SPP Balancing Authority Area.

Section 11. Scheduling Services. SPP shall provide Southwestern with electronic scheduling and tagging services in the same manner as those provided to SPP Members that are necessary to facilitate Southwestern's responsibilities under NERC Reliability Standards for assessing and communicating tag approvals and statuses. SPP shall provide Southwestern scheduling services including:

(i) Creating and uploading, as necessary, reserve sharing schedules that involve the parties' scheduling system(s), for Southwestern's use;

(ii) Creating, as necessary, loss payback schedules with Southwestern for those losses incurred under the SPP Tariff, and uploading those to the parties' scheduling system(s) for Southwestern's use;

(iii) Calculating the Net Scheduled Interchange ("NSI") for Southwestern based on all schedules with Southwestern contained in the parties' scheduling system(s), and periodically making updated NSI values available to Southwestern for incorporation in the Southwestern Area Control Error equation; and

(iv) Acting as the Interchange Coordinator for Southwestern, as that function is defined in the current NERC functional model. Southwestern shall comply with SPP's applicable scheduling

practices for all transactions required to be scheduled under the SPP Tariff and the transactions administered by SPP under the Southwestern Tariff.

Section 12. Information. The parties shall furnish to each other such information as is necessary to perform their respective obligations under this Attachment AD.

Section 13. SPP Criteria and Federal Requirements. (a) The term "SPP Criteria" as used herein shall mean the document named "SPP Operating Criteria, Revision 1.4," effective December 11, 2017, and the document named "SPP Planning Criteria, Revision 1.4," effective July 25, 2017, collectively attached as Exhibit "2" and by this reference incorporated into this Attachment AD. In the event of a conflict between the Agreement and Exhibit "2," the provisions of the Agreement shall control except as provided in Section 10 of Article I of this Attachment AD. Notwithstanding Section 10 of Article I of the Agreement, any changes to the SPP Criteria that SPP proposes to be applicable to this Attachment AD shall be evidenced by an executed amendment to the Agreement to include such modified SPP Criteria.

(b) Southwestern's performance of obligations under this Attachment AD shall be subject to and in accordance with all Federal statutes, regulations, and limitations of Southwestern's hydroelectric resources.

(c) Southwestern shall communicate and coordinate with the Corps on any request by SPP connected to the operation of, and maintenance, modification, or addition to the Corps' generation and transmission facilities to comply with SPP Criteria; Provided, That, compliance with SPP's Criteria involving Corps facilities shall be within the discretion of and subject to the approval of the Corps.

Section 14. Transmission Expansion, Interconnections, Modifications, and Additions. (a) It is recognized that SPP will, from time to time, evaluate potential expansion of the transmission facilities that are utilized to implement SPP's Tariff which, pursuant to this Attachment AD, also include the transmission facilities of Southwestern. SPP may recommend the upgrade of transmission facilities that involve Southwestern facilities and/or the upgrade/expansion of the transmission facilities of others that will improve existing service under Southwestern's contracts with its customers, facilitate service under Southwestern's Tariff as administered by SPP pursuant to this Attachment AD, or facilitate new or existing service under the SPP Tariff. Implementation of Southwestern's participation, if any, shall be evidenced by written agreement between Southwestern and SPP.

(b) Unless otherwise provided by Federal statute applicable to Southwestern, the purpose for Southwestern's participation in the SPP transmission planning processes shall be to meet Southwestern's compliance obligations for the NERC Reliability Standards related to transmission planning (including, but not limited to, transmission planning (TPL) Reliability Standards), to facilitate information exchange in compliance with NERC Modeling, Data, and Analysis ("MOD") Reliability Standards, and to provide data and information for SPP regional and interregional planning functions including the development of transmission planning models, transmission assessments, transmission expansion plans, studies for transmission service, generation interconnections, transmission interconnections, and flowgate determination. Southwestern further agrees to coordinate with SPP for (1) Southwestern's construction activities and (2) the identification of mutually beneficial solutions for transmission system planning

projects within SPP's regional and inter-regional planning processes, including but not limited to, associated local, regional, and economic transmission planning provisions included in both the SPP Tariff and Southwestern Tariff. The Agreement and the responsibilities identified in Section 14(b) of Article I of this Attachment AD shall constitute Southwestern's full and complete obligation in the SPP regional transmission planning process as a non-enrolled participating non-public utility transmission provider. However, Southwestern reserves the right to plan and construct modifications or additions to Southwestern's transmission facilities without the approval of SPP, and to approve or disapprove the requests by others to plan and construct such modifications or additions.

(c) Subject to statutes applicable to Southwestern, Southwestern agrees to coordinate its activities with SPP for construction of proposed Non-Federal Transmission Facilities and to seek SPP guidance on the impact of such construction to the bulk transmission system. The term "Non-Federal Transmission Facilities" as used herein shall be defined as transmission and related facilities not constructed or acquired by Southwestern pursuant to Section 5 of the Flood Control Act of 1944.

(d) No interconnections to Southwestern's transmission facilities shall be made without written contractual agreements between Southwestern and the interconnecting party which satisfy Southwestern's NEPA requirements and which establish the terms and conditions of the interconnection. Such agreements shall be made pursuant to Southwestern's then-current General Requirements for Interconnection as posted on Southwestern's Web site, or Southwestern's currently accepted Tariff provisions governing generation interconnections, whichever is applicable.

(e) For interconnecting non-Federal generation to the System of Southwestern, the provisions of the SPP Tariff shall be used for determining the feasibility and facility requirements of the SPP Footprint to accommodate the interconnection, excluding requirements for the facilities at the interconnection site, which will be determined by Southwestern.

(f) For transmission modifications identified through the SPP transmission planning process, Southwestern will review identified modifications and compare against Southwestern's 10-year construction plan. If the project or projects are included in Southwestern's construction plan, Southwestern will endeavor to construct such projects subject to the Federal statutes and regulations applicable to Southwestern, including budgetary authority from Congress. If the project or projects are not included in Southwestern's construction plan, Southwestern will take such project or projects into consideration in the development of subsequent construction plans. In instances when Southwestern is unable to complete construction and installation of an identified and agreed upon transmission modification by the in-service date identified by SPP, Southwestern will provide SPP an alternate schedule to accommodate available budgetary authority from Congress. Costs for projects constructed by Southwestern under this Section 14(f) shall be funded through Southwestern's budgetary authority. Notwithstanding provisions of this Section 14(f), Southwestern shall not be obligated to undertake projects that include voltage upgrades or conductor size increases that require Southwestern to replace its structures, without separate written agreement between Southwestern and SPP stipulating funding, cost allocation, and assignment of NERC compliance responsibilities for such upgrade(s).

(g) Funding of, construction of, and costs for transmission modifications associated with service agreements under Southwestern's Tariff will be determined by the then-effective provisions of Southwestern's Tariff.

(h) Costs for modifications to Southwestern transmission facilities required to accommodate new SPP Tariff transmission service in Southwestern's Zone shall be directly assigned to the requesting party of such transmission service (hereinafter "Requesting Party"). Each constructed modification funded pursuant to this Section 14(h) shall be evidenced by a separate written agreement among SPP, Southwestern, and the Requesting Party. Pursuant to such separate written agreement and prior to the commencement of construction activities, the Requesting Party shall provide Southwestern sufficient funds to construct such modifications required for the requested transmission service. To the extent the new transmission service results in an increase in revenues allocable to Southwestern and to the extent such revenues exist and continue to be distributed to Southwestern under this Attachment AD, SPP shall credit the Requesting Party each month from such increased revenues until (1) the Requesting Party is repaid the amount of funds provided to Southwestern to construct such modifications, plus monthly interest at one-twelfth of the U.S. Department of Treasury Annual Interest Rate Certification Table 9 – Power Marketing Administration percentage or (2) the agreement between SPP and the Requesting Party for such SPP Tariff transmission service terminates and is not renewed, whichever occurs earlier.

(i) Costs for modifications to SPP Transmission Owner transmission facilities required to accommodate new SPP Tariff transmission service in Southwestern's Zone shall be eligible for cost allocation through SPP's base plan funding mechanism; Provided, That, any costs allocable to Southwestern shall be provided for through and subject to Section 14(m) and Section 14(n) of this Article I.

(j) Costs for modifications to Southwestern transmission facilities required to accommodate new SPP Tariff transmission service not in Southwestern's Zone shall be directly assigned to the Requesting Party. Each constructed modification funded pursuant to this Section 14(j) shall be evidenced by a separate written agreement among SPP, Southwestern, and the Requesting Party. Pursuant to such separate written agreement and prior to the commencement of construction activities, the Requesting Party shall provide Southwestern sufficient funds to construct such modifications required for the requested transmission service. To the extent the new transmission service results in an increase in revenues allocable to Southwestern and to the extent such revenues exist and continue to be distributed to Southwestern under this Attachment AD, SPP shall credit the Requesting Party each month from such increased revenues until (1) the Requesting Party is repaid the amount of funds provided to Southwestern to construct such modifications, plus monthly interest at one-twelfth of the U.S. Department of Treasury Annual Interest Rate Certification Table 9 – Power Marketing Administration percentage or (2) the agreement between SPP and the Requesting Party for such SPP Tariff transmission service terminates and is not renewed, whichever occurs earlier.

(k) Costs for modifications to non-SPP transmission owner (hereinafter "Third Party") transmission facilities required to accommodate new SPP Tariff transmission service in Southwestern's Zone shall be addressed between the Requesting Party and the Third Party. The Requesting Party shall make arrangements with the Third

Party for construction of such requisite modifications. SPP shall determine when sufficient arrangements have been made with the Third Party for granting the Requesting Party's transmission service.

(l) Costs for modifications to Southwestern transmission facilities required to accommodate changes to existing SPP Tariff transmission service shall be directly assigned to the Requesting Party. Each constructed modification funded pursuant to this Section 14(l) shall be evidenced by a separate written agreement among SPP, Southwestern, and the Requesting Party. Pursuant to such separate written agreement and prior to the commencement of construction activities, the Requesting Party shall provide Southwestern sufficient funds to construct such modifications required for the requested changes to the existing transmission service. To the extent the modified transmission service results in an increase in revenues allocable to Southwestern and to the extent such revenues exist and continue to be distributed to Southwestern under this Attachment AD, SPP shall credit the Requesting Party each month from such increased revenues until (1) the Requesting Party is repaid the amount of funds provided to Southwestern to construct such modifications, plus monthly interest at one-twelfth of the U.S. Department of Treasury Annual Interest Rate Certification Table 9 – Power Marketing Administration percentage or (2) the agreement between SPP and the Requesting Party for such SPP Tariff transmission service terminates and is not renewed, whichever occurs earlier.

(m) The parties recognize that SPP has established a process to recover the cost of transmission expansion within the SPP Footprint. Southwestern desires to participate in that process pursuant to the provisions set forth in Section 14(n) of this Article I by contributing a portion of the revenues it receives from SPP for use of Southwestern's transmission system under the SPP Tariff.

(n) Subject to the provisions of this Attachment AD and Federal statutes and regulations applicable to Southwestern and for the period identified within this Section 14(n), Southwestern will contribute toward the SPP region-wide annual transmission revenue requirement (hereinafter "Region-wide ATRR") identified within the SPP Tariff Attachment H as the Region-wide ATRR. Southwestern's contribution to the SPP Region-wide ATRR for the Term shall be a total of $6,206,035 and shall be contributed by netting monthly increments from the monthly amount of revenues owed to Southwestern by SPP for the use of Federal transmission facilities for transmission service provided by SPP pursuant to SPP's Tariff, such monthly increments to be as necessary to collect the entire amount identified herein subject to Section 14(o) of this Article I.

(o) Southwestern's monthly contribution to SPP's Region-wide ATRR pursuant to Section 14(n) of this Article I is limited to the net monthly revenues provided by SPP that are owed to Southwestern pursuant to other provisions of this Attachment AD after the monthly amount owed by Southwestern to SPP pursuant to Section 1 of Article I is deducted and; Provided Further, That, if such revenues are insufficient to collect the entire amount identified herein, any balance remaining at the end of the Agreement's Term shall be forfeited. Such monthly contribution shall constitute Southwestern's full contribution to the SPP Region-wide ATRR pursuant to Section

14(n) of this Article I. Any future contribution shall be identified by the parties, concomitantly with the renewal date, if any, of this Attachment AD.

(p) As point-to-point and network transmission transactions specifically under Southwestern's Tariff or contracts expire or are terminated and transition to the SPP Tariff pursuant to Section 1(b) of Article II of this Attachment AD, the parties will negotiate in good faith any appropriate modifications to Southwestern's monthly contribution toward the SPP Region-wide ATRR. All revisions contemplated by this Section 14(p) are subject to written agreement between the parties.

(q) In the event that funds are not made available to Southwestern by Congress in accordance with Section 23 of this Article I, and new or upgraded facilities are required to Southwestern's transmission system to serve existing load, the transmission customer whose load may be impacted by the absence of such new or upgraded facilities may elect to provide in advance the necessary funds for such construction by Southwestern in accordance with a separate written agreement between the parties, and Southwestern's ability to accept such funds shall be subject to the authority granted to it by Congress and shall be in accordance with Section 23 of this Article I.

Section 15. Coordinating Committee. (a) The parties hereby establish a Coordinating Committee for the purposes of developing procedures for the implementation of the operating and technical requirements of this Attachment AD and any other matters referred to herein or necessary for implementation, administration, or operation of this Attachment AD.

(b) Southwestern and SPP shall each appoint two members to the Coordinating Committee.

(c) The Coordinating Committee shall meet at least semi-annually, or more often if necessary.

(d) Decisions of the Coordinating Committee must be unanimous to become effective for implementation under this Attachment AD.

(e) All procedures and decisions of the Coordinating Committee shall be in writing and must be executed as amendment(s) to the Agreement to become effective.

(f) Subject to consent of the Board of Directors and Membership of SPP, one of Southwestern's representatives on the Coordinating Committee shall have voting privileges as if a member of the SPP Membership.

Section 16. Protection from Liability. SPP agrees to provide Southwestern the same protection from liability for SPP's use of Southwestern's facilities under the SPP Tariff and from any actions or omissions done by Southwestern in compliance with the directives of SPP as SPP provides to other transmission owners and balancing authority areas.

Section 17. Southwestern's Balancing Authority Area. (a) SPP recognizes Southwestern as a NERC Balancing Authority. Southwestern's Balancing Authority Area shall be consistent with applicable NERC mandatory Reliability Standards and SPP Regional Reliability Standards and SPP Criteria subject to the provisions of Section 13 of

this Article I.

(b) Unless otherwise agreed in writing, Southwestern's Balancing Authority Area inadvertent with the Eastern Interconnection will be settled in kind using the NERC settlement methodology in place as of November 1, 2004, on a megawatt hour for megawatt hour basis.

Section 18. Services Provided by Southwestern. Services provided to SPP by Southwestern at the request of SPP, such as training services, shall be on a reimbursable basis with advance funding.

Section 19. Dispute Resolution. Any dispute arising out of or relating to this Attachment AD shall be referred to the Coordinating Committee representatives designated under Section 15 of this Article I for resolution on an informal basis as promptly as practicable. In the event the Coordinating Committee representatives are unable to resolve the dispute within fourteen (14) business days (or such other period as the parties may agree upon), each party shall, within seven (7) business days' written notice by either party, designate a senior officer with authority and responsibility to resolve the dispute and refer the dispute to them. If the senior officers do not agree upon a resolution of the dispute within fourteen (14) business days (or such other period as the parties may agree upon) after the dispute is referred to them, either party may further pursue informal resolution using alternative dispute resolution techniques, as provided in Section 12.1 of SPP's Tariff, except that the parties acknowledge Southwestern cannot submit a dispute to binding arbitration. If a dispute remains unresolved, the parties acknowledge that any action by or against Southwestern shall be initiated in a Federal court of competent jurisdiction.

Section 20. Federal Statutes. Southwestern's performance under this Attachment AD shall be subject to the provisions of this Section 20 and to Southwestern fulfilling its responsibilities and obligations under all Federal statutes and regulations applicable to Southwestern, including, but not limited to, Section 302(a)(1) of the Department of Energy Organization Act (42 U.S.C. 7152), Section 5 of the Flood Control Act of 1944 (16 U.S.C. 825s), Public Law 95-456 (16 U.S.C. 825s-3), Section 1232 of the Energy Policy Act of 2005 – Federal Participation in Transmission Organizations (42 U.S.C. 16431), the National Environmental Policy Act (hereinafter "NEPA"), the Anti-Deficiency Act (31 U.S.C. 1341), the Freedom of Information Act, and the Debt Collection Act (31 U.S.C. 3701) *et seq*. Nothing contained in this Section 20 shall be construed to require or obligate SPP to comply with such Federal laws or regulations or have such Federal laws or regulations apply to SPP by virtue of participating in the Agreement.

Section 21. Indemnification and Limitation of Liability. (a) SPP's obligation to indemnify Southwestern and SPP's limitation of liability shall be in accordance with the provisions of the SPP Tariff governing such indemnification and limitation of liability between SPP and Transmission Owners.

(b) Southwestern is liable only for negligence on the part of its officers and employees in accordance with the Federal Tort Claims Act, 28 U.S.C. §§ 1346(b), 1346(c), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

Section 22. Force Majeure. Neither party shall be in breach of this Attachment AD to the extent and during the period that such party's performance is made impracticable by any unanticipated cause or causes beyond such party's control, and without such party's fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor dispute, civil disturbance, act of the public enemy or terrorist acts, sabotage, war, act of war, insurrection, riot, epidemic, fire, earthquake, lightning, storm or flood, failure of water supply, explosion, breakage or accident to machinery or equipment or failure of facilities, or restraint by court of general jurisdiction. Upon the occurrence of an event considered by a party to constitute a *force majeure* event, such party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event; Provided, That, this Section 22 shall not require any party to settle any strike or labor dispute. A party claiming a *force majeure* event shall notify the other party in writing immediately, and in no event later than forty-eight (48) hours after the occurrence of the *force majeure* event. The foregoing notwithstanding, the occurrence of a cause under this Section 22 shall not excuse a party from making any payment otherwise required under this Attachment AD subject to Section 23 of this Article I.

Section 23. Availability of Funds to Southwestern. (a) This Attachment AD and all rights and obligations hereunder, and the expenditure of funds by Southwestern under the provisions hereof, are expressly conditioned and contingent upon the Congress making available (through direct appropriation, authorization of a revolving fund, the authority to borrow funds, or through such other means as it may provide) the necessary funds or the authority to accept funds from others to enable Southwestern to carry out the provisions of this Attachment AD, and, if such funds or authorities are not available, SPP hereby releases Southwestern from Southwestern's contractual obligations and from any and all liability for failure to perform and fulfill Southwestern's obligations under this Attachment AD as of the last day for which funds or authorities were available.

(b) No obligation contained herein for the future payment of money by Southwestern, or liability on the part of Southwestern for breach of any of the provisions contained herein, shall be binding upon or enforceable against Southwestern unless and until funds, as provided in Section 23(a) of this Article I, are available out of which such obligations or liability can be legally paid.

(c) Nothing in this Attachment AD may be considered to imply that Congress will, at a later date, appropriate funds sufficient to meet any deficiencies or obligations incurred under this Attachment AD.

Section 24. No Expansion of Jurisdiction, Waiver of Defenses, Liability for Penalties, or Inconsistent Obligations. By entering into the Agreement, Southwestern has not waived or conceded any defense it may have, including sovereign immunity, intergovernmental immunity, or lack of subject matter jurisdiction in any action against it by an Enforcement Authority, nor has Southwestern accepted any liability, responsibility, or obligation to pay any civil monetary penalties or fines to which it would not have been subject in the absence of the Agreement that may be imposed by an Enforcement Authority. The term "Enforcement Authority" as used herein, shall be defined as FERC, NERC as the Electric Reliability Organization (hereinafter "ERO"), or Regional Entities

with enforcement authority pursuant to a delegation from NERC as the ERO or FERC for the purpose of proposing and enforcing NERC Reliability Standards.

# ARTICLE II

## TRANSMISSION TRANSACTIONS UNDER SOUTHWESTERN'S TARIFF AND CONTRACTS

Section 1. Transmission Transactions. (a) Except as noted in Section 1(i), Section 1(ii), and Section 5 of this Article II, the following Transmission Transactions which use the System of Southwestern are specifically excluded from the provisions of the SPP Tariff, and Southwestern's Tariff or contracts shall apply to these Transmission Transactions:

(i) All Federal Power deliveries over the System of Southwestern. The SPP Tariff may apply to these Transmission Transactions once such transactions leave the System of Southwestern to receipt points within the SPP Footprint.

(ii) All existing transmission contracts executed between Southwestern and others prior to November 1, 2004, that are effective as of the date of this Attachment AD, regardless of terms or durations. The SPP Tariff may apply to these Transmission Transactions once such transactions leave the System of Southwestern to receipt points within the SPP Footprint.

(iii) All existing and new radial and looped metered loads, including those loads which may be connected to other transmission systems as well as to the System of Southwestern, that are served from the System of Southwestern. Transmission Transactions excluded from the SPP Tariff include, but are not limited to, those types of Transmission Transactions currently between Southwestern and the Grand River Dam Authority under Contract No. DE-PM75-98SW00380; between Southwestern and Arkansas Electric Cooperative, Inc. under Contract No. DE-PM75-97SW00366; between Southwestern and Nixa, Missouri, under Contracts Nos. DE-PM75-92SW00208 and DE-PM75-92SW00209; between Southwestern and Oklahoma Gas and Electric Company under Contract No. DE-PM75-02SW00470; and between Southwestern and Associated Electric Cooperative, Inc., under Contract Nos. DE-PM75SW00370 and DE-PM75-92SW00216.

(iv) All Transmission Transactions in which the source and sink are both directly connected to the System of Southwestern, regardless of terms and durations, except as provided for in Section 1(b) of this Article II.

(b) It shall be the intent of this Article II that once point-to-point and network transmission transactions specifically expire or are terminated, they shall be allowed to transition to the SPP Tariff; Provided, That, any contract service to metered loads or Network Service under Southwestern's Tariff that are converted to transmission service

under the SPP Tariff shall be considered in Southwestern's Zone.

(c) The term "Grandfathered Agreements" as used for the purposes of this Attachment AD, shall include the following:

(1) Existing or new contracts entered into by Southwestern on behalf of the United States for the use of transmission facilities of Southwestern that are constructed or acquired by purchase or other agreement, as authorized under Section 5 of the Flood Control Act of 1944, for the transmission of Federal Power; and

(2) Contracts executed before the Effective Date, regardless of term, entered into by Southwestern on behalf of the United States for the transmission of power or energy across transmission facilities owned and operated by Southwestern.

(d) Should the treatment of Grandfathered Agreements identified in the SPP Tariff conflict with the treatment provided by this Attachment AD, the provisions herein shall have precedence for the transactions subject to this Attachment AD.

Section 2. Pre-Existing Arrangements under the SPP Tariff. (a) Notwithstanding the provisions of Section 1 of this Article II, Southwestern shall allow SPP to utilize the System of Southwestern under the SPP Tariff for Transmission Transactions made under contracts between SPP and other parties executed prior to November 1, 2004, pursuant to Section 3 of Article IV of this Attachment AD.

(b) Section 1(iii) and Section 1(iv) of this Article II shall not apply to the service which City Utilities of Springfield, Missouri ("CU"), provides to itself (excluding the load of the City of Nixa, Missouri, that is served from the System of Southwestern) under SPP's Network Integration Transmission Service; Provided, That, CU has sufficient transmission capacity through facilities other than Southwestern's to import power to serve itself; and Provided Further, That, CU continues to be a Zone within the SPP Tariff. The term "Zone" as used herein shall be defined as the geographic area of the facilities of an SPP Transmission Owner or a specific combination of SPP Transmission Owners as listed in Schedules or Attachments to the SPP Tariff.

(c) The provisions of Section 2 of Article III of this Attachment AD shall apply to all pre-existing agreements, if any, under the SPP Tariff.

Section 3. Recognition of Settlement Case between AECI and GRDA. The parties recognize that as part of the American Arbitration Association Case, Settlement No. 711980016601 between KAMO Electric Cooperative, Inc. ("KAMO"), and the Grand River Dam Authority ("GRDA"), the Arbitrator declared that KAMO has the right to move its loads to the Associated Electric Cooperative, Inc. ("AECI"), balancing authority area. At the request of AECI, Southwestern may add the existing interconnections between Southwestern and KAMO at Southwestern's Weleetka and Keystone Switchyards as points-of-delivery for Federal power sold by Southwestern to AECI. SPP agrees to recognize such balancing authority area change and the change in points-of-delivery for Federal power.

Section 4. Recognition of Aggregated Load and Scheduling Needs. The parties recognize that Southwestern may integrate some or all of the loads served from the

System of Southwestern into an aggregated load and scheduling node(s). These loads include the net load behind the meters for: Jonesboro, Paragould, and Piggott, Arkansas; and Carthage, Kennett, Malden, and Poplar Bluff, Missouri. Transmission Transactions to the aggregated load and scheduling node(s) shall be made pursuant to Article II or Article III of this Attachment AD. All Transmission Transactions from the aggregated load and scheduling node(s) shall be made pursuant to the applicable provisions of Article II or Article III of this Attachment AD. Existing reservations and subsequent tagging shall be revised to reflect the aggregation. The parties further agree that such aggregated load and scheduling node(s) shall continue to be recognized in the event of termination or expiration of this Attachment AD.

Section 5. Application of the SPP Tariff Billing Determinants and Billing. The billing determinants of Southwestern's rates shall apply to the transactions listed under Sections 1 through 4 of this Article II except as follows:

(a) For long-term firm transmission (one year or longer) and network integration transmission service contracts executed between December 31, 2006, and January 31, 2009, that involve schedules for the delivery of non-Federal power to load served from the System of Southwestern, only the following billing determinants of the SPP Tariff shall apply: (i) Schedule 1 - Scheduling, System Control and Dispatch Service; (ii) Schedule 1-A - Tariff Administration Service; (iii) Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service; and (iv) Attachment M - Loss Compensation Procedure. With the exception of Schedule 1-A, SPP shall bill the transmission customer for such billing determinants of the SPP Tariff and apply the SPP Tariff revenue distribution methodology for the amounts received by SPP associated with such SPP billing determinants. Southwestern shall coordinate with SPP to calculate the appropriate Schedule 1-A charges, for which Southwestern shall invoice the customer and subsequently provide to SPP in accordance with Section 3 of Article I of this Attachment AD. All other portions of Southwestern's rates and Southwestern's Tariff provisions for transmission service, excluding the SPP Tariff billing determinants noted in this Section 5(a), shall apply to such transactions, and Southwestern shall bill the transmission customer for such portions and retain the revenue.

(b) Except as may be provided in Section 2 of Article III of this Attachment AD, none of the SPP Tariff provisions associated with the SPP imbalance market or any future market(s) administered by SPP shall apply to the Transmission Transactions addressed in this Article II.

# ARTICLE III

## TRANSMISSION TRANSACTIONS UNDER SPP'S TARIFF

Section 1. Transmission Transactions. (a) The following Transmission Transactions which use the System of Southwestern are specifically included under the SPP Tariff:

(i) Transmission service for all Transmission Transactions originating in the SPP Footprint and terminating outside of the SPP Footprint which utilize Southwestern facilities and to which Southwestern is not a party selling or purchasing power, and excluding transactions under Article II of this Attachment AD.

(ii) Transmission service for all Transmission Transactions originating outside the SPP Footprint and terminating in the SPP Footprint which utilize Southwestern facilities and to which Southwestern is not a party selling or purchasing power, and excluding transactions under Article II of this Attachment AD.

(iii) Transmission service for all Transmission Transactions originating outside the SPP Footprint and terminating outside the SPP Footprint which utilize Southwestern facilities and to which Southwestern is not a party selling or purchasing power, and excluding transactions under Article II of this Attachment AD.

(iv) Transmission service for all Transmission Transactions originating on the System of Southwestern to which Southwestern is not a party selling or purchasing power, and terminating to load not connected to the System of Southwestern but within the SPP Footprint. The SPP Tariff may apply to transactions in which Southwestern is the selling party once such transactions leave the System of Southwestern to receipt points within the SPP Footprint if transmission rights for the utilization of facilities within the SPP Footprint do not already exist.

(v) Transmission service for all Transmission Transactions originating in the SPP Footprint and terminating in the SPP Footprint which utilize Southwestern facilities to which Southwestern is not a party selling or purchasing power, and excluding transactions under Article II of this Attachment AD.

(vi) Transmission service for all Transmission Transactions originating on the System of Southwestern and terminating outside the SPP Footprint to which Southwestern is not a party selling or purchasing power, and excluding transactions under Article II of this Attachment AD.

(b) Subject to the provisions of Section 1(b) of Article II of this Attachment AD, all scheduled Transmission Transactions implemented under point-to-point transmission service contracts executed after January 31, 2009, and network integration

transmission service contracts executed on or after April 1, 2011, whose point of delivery is connected to the System of Southwestern or is otherwise considered to sink in the Southwestern Zone shall be under the SPP Tariff; Provided, That, allowing such transactions to be placed under the SPP Tariff shall not bind Southwestern to any obligations not contemplated in the Agreement; Provided Further, That, should any existing Southwestern transmission contract(s) convert to the SPP Tariff, or there is a modification of service under either the Southwestern contracts or SPP Tariff which results in a loss of revenues to Southwestern for a particular transaction, the parties agree that Southwestern shall reserve the right to assess an Interconnection Facilities Service Charge to recover all or a portion of such lost revenues.

Section 2. Southwestern's Internal Balancing Authority Area Customers, and the SPP Markets. (a) Notwithstanding the provisions of Section 1 of this Article III, and Section 2 of Article II of this Attachment AD, participation in the SPP Integrated Marketplace, or any future markets administrated by the SPP, by customers internal to Southwestern's balancing authority area must be recognized by and shall be subject to the terms and conditions of contractual arrangements between Southwestern and the participating customer which address the impacts to Southwestern operations and the hydroelectric system from which Southwestern markets power and energy. These contractual arrangements must be in place prior to such customer's participation in such SPP market system(s).

(b) Unless otherwise agreed in writing, SPP shall not apply, via settlements or any other mechanism, its existing and future market methodologies, protocols, etc., to: 1) Southwestern's Federal hydroelectric generating resource, or 2) loads inside Southwestern's balancing authority area that are not participating in SPP markets.

Section 3. Transmission Transactions Not Addressed. Any Transmission Transaction not specifically addressed in this Article III shall be considered excluded from the SPP Tariff.

Section 4. Compensation. SPP shall compensate Southwestern for SPP's use of Southwestern's facilities pursuant to this Article III under the terms and conditions set forth in the SPP Tariff. SPP compensation to Southwestern for losses and ancillary services shall be in accordance with the SPP Tariff.

Section 5. Reduction of Monthly Schedule 9 and Schedule 11 Charge in Southwestern's Zone. Effective April 1, 2018, and in accordance with Section 34.9 of the SPP Tariff, SPP shall begin application of a reduction of charges under Schedule 9 and Schedule 11 of the SPP Tariff for Southwestern customers taking Network Integration Transmission Service under the SPP Tariff where: (1) the point of delivery identified for deliveries of Federal Power-Southwestern is also a point of delivery identified in the Network Integration Service Agreement between the customer and SPP and (2) where said point of delivery is also physically connected to Southwestern's transmission facilities located in Southwestern's Zone (SPP pricing Zone 10). All other SPP Tariff charges, as applicable, shall be based on the total network load of the customer.

# ARTICLE IV

## TERM, TERMINATION OF AGREEMENT, AND NOTICES

Section 1. Term. The Agreement became effective on March 1, 2014, and shall expire by its own terms at midnight, June 30, 2023 (hereinafter "Term"). The parties may extend the Term of the Agreement by written amendment.

Section 2. Renegotiation. If any provision of the Agreement, or the application thereof to any person, entity, or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, or if a modification or condition to the Agreement is imposed by a regulatory authority exercising jurisdiction over the Agreement, then the parties shall endeavor in good faith to negotiate such amendment or amendments to the Agreement as will restore the relative benefits and obligations of the signatories under the Agreement immediately prior to such holding, modification, or condition. Substantive changes to the FERC regulations governing the relative tariffs, the NERC functional model, the NERC mandatory Reliability Standards, or any other law or regulation implicating the Agreement, or which substantively alters the obligations of either party shall be cause to renegotiate the Agreement under this section.

Section 3. Users Held Harmless. The parties agree that upon termination/expiration of the Agreement, customers taking service under either the SPP Tariff or Southwestern Tariff which involves facilities in the "SPP Footprint" as defined in Section 4(c) of Article I of this Attachment AD and where such service is under transmission contracts executed prior to such termination/expiration, shall continue to receive the same service for the remaining term of each such contract at the same rates, terms, and conditions as would have been applicable if such termination/expiration had not occurred. The parties agree to continue providing service to such transmission customers and to receive revenues in accordance with the terms of this Attachment AD, but no more in revenues for that service than if there had been no termination/expiration of the Agreement.

Exhibit 1- "SPP Reserve Sharing Group Operating Process," dated January 1, 2018.

Exhibit 2- "SPP Operating Criteria, Revision 1.4," effective December 11, 2017, and "SPP

Planning Criteria, Revision 1.4," effective July 25, 2017.

# Exhibit 1 to Attachment AD

# SPP Reserve Sharing Group Operating Process

**Effective: 1/1/2018**

## 1.1 Reserve Sharing Group Purpose

In the continuous operation of the electric power network, Operating Capacity is required to meet forecasted load, including an allowance for uncertainty, to provide protection against equipment failure and to provide adequate regulation of frequency and Balancing Authority Area tie line power flows. Operating Reserves are needed to regulate load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales.

This Operating Process establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group (RSG).

The primary purpose of this Operating Process is to ensure a high level of reliability in the SPP Reserve Sharing Group to assure that there are capacity resources available at all times that can be used quickly to relieve stress placed on the interconnected electric system during an Operating Reserve Contingency. Another purpose of this Operating Process is to efficiently utilize the operating reserve resources of the members of the SPP Reserve Sharing Group.

This Operating Process describes practices to be followed by all SPP Reserve Sharing Group members to ensure prompt response to Operating Reserve Contingencies. The methods prescribed by this Operating Process to jointly activate Contingency Reserve are intended to ensure that the combined area control error (ACE) of the SPP Reserve Sharing Group is quickly recovered by the Reserve Sharing Group while simultaneously scheduling assistance soon after an Operating Reserve Contingency.

The SPP Reserve Sharing Group is not a “Frequency Response Sharing Group’ or a “Regulation Reserve Sharing Group” as defined in the NERC Glossary of Terms.

## 1.2 Annual Maintenance of this Operating Process

Annually on or before September 1 of each year, SPP (as the reserve sharing group administrator) and each participating Balancing Authority will review this Operating Process. Each participating Balancing Authority shall provide SPP written confirmation of the results

of this review. The results of this review shall consist of either proposed changes or confirmation that this Operating Process is agreeable to the participating Balancing Authority.

SPP or any participating Balancing Authority may propose changes to this Operating Process as a part of this annual review or at any point prior to the next scheduled annual review. Proposed changes to this Operating Process by a participating Balancing Authority must be provided in writing to SPP. SPP, as the reserve sharing group administrator, may implement changes or decline to incorporate proposed changes by another participating Balancing Authority.

The SPP Balancing Authority Operating Committee will review and approve any proposed changes on behalf of the SPP Balancing Authority.

Annually on or before January 1 of each year, SPP shall issue an updated version of this Operating Process to all participating Balancing Authorities.

## 1.3 Definitions

Capitalized terms not otherwise defined herein shall have the definitions assigned by the NERC Glossary of Terms.

### 1.3.1 Assistance Period

Assistance Period is that time frame when any SPP Reserve Sharing Group member receives Contingency Reserve assistance from other SPP Reserve Sharing Group members. The Assistance Period will normally not exceed 60 minutes. The SPP Operating Reliability Working Group will set the ending time for Assistance Period and may change the length of the Assistance Period.

### 1.3.2 Assisting Areas

The Assisting Areas are defined as the other Balancing Authority Areas in the SPP Reserve Sharing Group, which are called upon to supply Contingency Reserves to the Contingency Area.

### 1.3.3 Balancing Authority Annual Contingency Reserve Requirement

A Balancing Authority member’s share of the total SPP Reserve Sharing Group Previous Calendar Year System Peak Responsibility. The Balancing Authority’s Annual Contingency Reserve Requirement Ratio shall be determined by dividing the Balancing Authority’s Previous Calendar Year System Peak Responsibility by the sum of all of the RSG member Balancing Authority’s Previous Calendar Year System Peak Responsibility.

### 1.3.4 Balancing Authority Daily Peak Load Obligation

Balancing Authority Annual Peak Load Obligation is the peak hour load plus Firm Power sales minus Firm Power purchases during the hour the SPP Reserve Sharing Group as a whole experiences its highest load.

### 1.3.5 Balancing Authority Minimum Daily Contingency Reserve Requirement

A Balancing Authority member's Contingency Reserve Requirement Ratio multiplied by the Reserve Sharing Group Total Contingency Reserve Requirement. Each Balancing Authority's Daily Contingency Reserve Requirement shall be rounded up to the next nearest whole MW and shall be no less than two (2) MW.

### 1.3.6 Contingency Area

The Contingency Area is defined as the Balancing Authority Area suffering an Operating Reserve Contingency.

### 1.3.7 Contingency Reserve

The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.

In addition to the NERC Glossary of Terms definition, Contingency Reserve will be defined as follows within the SPP RSG. Contingency Reserve is the sum of Operating Reserve - Spinning and Operating Reserve - Supplemental. At least half of the Contingency Reserve shall be Operating Reserve - Spinning.

### 1.3.8 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. Power purchased shall only be considered to be Firm Power if firm transmission service is in place to the load serving member for delivery of such power. Firm Power does not include "financially firm" power.

### 1.3.9 Most Severe Single Contingency

The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is

not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

### 1.3.10 Operating Capacity

Operating Capacity is the dispatchable capability claimed for any generating source, which will be used for supplying Operating Reserves. Operating Capacity shall include capacity purchases that can be used to supply the buyer's Operating Reserves minus capacity sales that cannot be used to supply the seller's Operating Reserves. Operating Capacity shall recognize any temporary de-ratings, proven loading rates, starting times and equipment limitations including transmission-operating limits. This capacity is not intended to be the tested seasonal net capability; instead it is the normal operating rating of a generator on a given day.

### 1.3.11 Operating Reserve

That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

In addition to the NERC Glossary of Terms definition, Operating Reserve will be defined as follows within the SPP RSG. Operating Reserve is the sum of Regulating Reserve and Contingency Reserve.

### 1.3.12 Operating Reserve - Spinning

The portion of Operating Reserve consisting of:

- Generation synchronized to the system and fully available to serve load within the Disturbance Recovery
  Period following the contingency event; or
- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

### 1.3.13 Operating Reserve - Supplemental

The portion of Operating Reserve consisting of:

- Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or

- Load fully removable from the system within the Disturbance Recovery Period following the contingency event.

Operating Reserve – Supplemental may consist of any or a combination of the following that is fully able to serve load within the Disturbance Recovery Period following the contingency event:

1) The amount of Operating Capacity connected to the bus that will not be realized by prime-mover governor action. The realization of this capacity may require the governor speed level to be reset.
2) That portion of fast starting generating capacity at rest, such as hydroelectric, combustion turbines, and internal combustion engines as prime movers that can be started and synchronized.
3) Operating Capacity that can be realized by increasing boiler steam pressure, by removing feedwater heaters from service, and/or by decreasing station power use.
4) Operating Capacity and contingency reserve, provided firm transmission has been purchased, being held available under contract by another Balancing Authority above its own operating reserve requirements and available on call.
5) Interruptible or curtailment of loads under contract.
6) Power deliveries that can be recovered provided a clear understanding exists between the transacting parties to avoid both parties crediting their respective operating reserves by this transaction.
7) Generating units operating in a synchronous condenser mode.
8) Interruptible pumping load on pumped hydro units.
9) Operating Capacity made available by voltage reduction. The voltage reduction shall be made on the distribution system and not on the transmission system.
10) Operating Capacity that can be fully applied from a change in the output of a High Voltage Direct Current terminal.

### 1.3.14 Operating Reserve Contingency

An Operating Reserve Contingency is defined as the sudden and complete loss of a generating unit, sudden partial loss of generating capacity, loss of a capacity purchase which a Balancing Authority is unable to replace, or Other Extreme Conditions.

### 1.3.15 Other Extreme Conditions

Other Extreme Conditions include but are not limited to the:

1) Interruption of firm transmission service, or

2) An inability to use prescheduled firm transmission service due to any type of congestion management, or

3) When a RSG member Balancing Authority requires assistance to prevent shedding firm load or Firm Power sales, or

4) When a RSG member Balancing Authority is unable to maintain its Operating Reserves.

### 1.3.16 Previous Calendar Year System Peak Responsibility

The sum of a Balancing Authority's load and firm interchange at the time of the SPP Reserve Sharing Group coincident peak from the previous calendar year as determined by SPP.

### 1.3.17 Regulating Reserve

An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.

### 1.3.18 Reserve Sharing Group

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of disturbance control performance, the areas become a Reserve Sharing Group.

### 1.3.19 Reserve Sharing Group Annual Contingency Reserve Requirement

The minimum amount of Contingency Reserve that must be collectively carried by the Balancing Authorities participating in the SPP Reserve Sharing Group at a given time.

## 1.4 Minimum Annual Daily Contingency Reserve Requirement

The Operating Reliability Working Group (ORWG) will set the Minimum Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a Minimum Daily Contingency Reserve, over and above any Regulating Reserves, equal to the generating capacity of the largest unit within the metered boundaries of any RSG member Balancing Authority plus one-half of the capacity of the next largest generating unit within the metered boundaries of any RSG member Balancing Authority. Generation capacity is considered to be added at the first injection of test power of the generator, regardless of commercial status.

If the SPP Reliability Coordinator foresees an operating condition in which reserves are inadequate to cover the Most Severe Single Contingency (MSSC), the SPP Reliability Coordinator has the authority to increase the total SPP Reserve Sharing Group Minimum Daily Contingency Reserve Requirement to the level necessary to cover the MSSC for the duration of the operating condition.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

Each day, by 7:00am, the SPP Reliability Coordinator will notify each member Balancing Authority of its Daily Contingency Reserve Requirement for the following operating day.

### 1.4.1 Minimum Annual Balancing Authority Contingency Reserve Requirement Share Calculation

A RSG member Balancing Authority's Minimum Annual Contingency Reserve Requirement is equal to a prorated amount of the total SPP Reserve Sharing Group Minimum Annual Contingency Reserve Requirement. The RSG member Balancing Authority's Minimum Annual Contingency Reserve Requirement shall be determined by dividing the Balancing Authority's Previous Calendar Year System Peak Responsibility by the sum of all of the RSG member Balancing Authority's Previous Calendar Year System Peak Responsibility and multiplying the resultant by the Reserve Sharing Group Annual Contingency Reserve Requirement. Each Balancing Authority's Annual Contingency Reserve Requirement shall be rounded up to the next nearest whole MW and shall be no less than two (2) MW.

A member Balancing Authority whose historical information used as the basis of the Minimum Annual Contingency Reserve Requirement has changed significantly due to extreme circumstances may apply to the ORWG for a temporary waiver of all or a portion of its Minimum Annual Contingency Reserve Requirement. For example, the BA may request such a waiver due to (i) the shifting of load from one BA to another or (ii) drought conditions for Balancing Authorities whose system Capacity is comprised of more than 75% hydro based generation resources. ORWG will review such requests and make a recommendation to be considered by the MOPC at its next regularly scheduled meeting.

### 1.4.2 Minimum Annual Contingency Reserve Requirement Review Process

By April 1 each year, each RSG member Balancing Authority will submit to the SPP Reliability Coordinator its Previous Calendar Year System Peak Responsibility. SPP will calculate the Reserve Sharing Group's Total Previous Calendar Year System Peak Responsibility and each member Balancing Authority's Annual Contingency Reserve

Requirement Ratio. The results of these calculations will be presented for review and approval by the OWRG to be made effective June 1 of each year.

## 1.5 Procedures

All SPP Reserve Sharing Group members shall participate in this procedure to jointly activate Contingency Reserve.

### 1.5.1 Normal Daily Operation

1) Each RSG Member Balancing Authority's Operating Reserve shall be distributed so as to ensure that it can be utilized without exceeding individual element ratings, transfer limitations, or a unit's capability to apply the reserve to meet the NERC DCS requirements.

2) Each RSG member Balancing Authority shall schedule Operating Capacity and firm obligations so its requirements for Operating Reserve are met at all times.

3) Energy associated with Operating Reserve - Supplemental, except Assistance Schedules, may be sold with the understanding that it is recallable to meet the NERC DCS requirements. The buyer shall therefore maintain resources to support the withdrawal of this energy in addition to meeting its Operating Reserve Requirement.
4) Generating capacity associated with the required Operating Reserve - Spinning shall not be sold unless allocated during an Assistance Period.
5) Each RSG member Balancing Authority may contract with another Balancing Authority to provide part or its entire Operating Reserve obligation, provided the Balancing Authority accepting this additional Operating Reserve obligation maintains the Operating Reserve obligation of both Balancing Authorities and the firm transmission service required to deliver Operating Reserve energy is obtained.
6) When a RSG member Balancing Authority foresees it will be unable to provide its Balancing Authority Minimum Daily Contingency Reserve Requirement with available resources because load is greater than anticipated, forced outages or other limitations, it shall obtain Operating Capacity and firm transmission service. Such capacity shall not be from another Balancing Authority's Balancing Authority Minimum Daily Contingency Reserve Requirement.

### 1.5.2 Contingency Operation

These procedures may be implemented immediately following the occurrence of an Operating Reserve Contingency of any type and magnitude, but are required to be implemented for Operating Reserve Contingencies as specified below.

1) A complete or partial loss of 200 MW magnitude or greater of a resource within any 60 second period, or

2) A loss of Operating Capacity resulting in the BA possessing less than its Balancing Authority Minimum

Daily Contingency Reserve Requirement, or,

3) Any "Other Extreme Conditions" event.

These procedures are to be implemented in a non-discriminatory manner.

1) Immediately following an Operating Reserve Contingency, the Contingency Area shall report the occurrence via the SPP Reserve Sharing System. This report shall contain a description of the contingency; the net MW lost due to the contingency and any MW amount of Contingency Reserve being carried on the contingency unit. For those generating units whose station auxiliaries do not decrease to essentially zero or increase after a unit trip, gross MWs lost shall be used instead of net MWs lost. The operating owner of jointly owned generating units shall be responsible for reporting outages and the MW amount lost by each owner.
2) Within the constraints described in this Operating Process, allocation magnitudes shall be determined and notices distributed to the members of the Reserve Sharing Group.
3) The Assistance Schedule becomes part of each Assisting Area's scheduled net interchange and shall therefore be reflected in its ACE. The schedule shall be implemented at a zero time ramp rate immediately following allocation notification. If obvious and significant errors exist in assistance schedules, the Contingency Area system operator shall dictate appropriate corrective action during the Contingency Period, and notify SPP.
4) Assisting Areas shall immediately acknowledge receipt of the allocation notice via the SPP Reserve Sharing System. If a Contingency Area fails to receive acknowledgment from an Assisting Area, the SPP Reliability Coordinator shall notify the Assisting Area of the assistance schedule.
5) The Contingency Area(s) and Assisting Areas shall provide the requested assistance within the requirements established in the Disturbance Recovery Criterion of the NERC Reliability Standards.
6) The Contingency Reserve Requirement of each Balancing Authority involved in the Assistance Period shall be updated to reflect the reduction of responsibility until the end of the Assistance Period.
7) All allocations shall be rounded to the nearest whole MW with a minimum of 2 MW and the smallest amount of energy to be allocated shall be one MWH.
8) After the contingency notification has been completed, the Contingency Area shall promptly make arrangements to replace the energy requirement created by the Operating Reserve Contingency (including its Contingency Reserve Allocation) prior to the end of the Assistance Period. The Contingency Area shall make a reasonable effort to purchase capacity and firm transmission service after utilization of its own resources.

9) If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, this becomes an Other Extreme Condition and shall be reported as a separate contingency.
10) For each reportable contingency (as defined per section 7.4.4), the Contingency Area and Assisting Areas will send to SPP upon request, an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data.
11) If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, this becomes an Other Extreme Condition and shall be reported as a separate contingency.
12) Each transmission provider shall immediately notify the SPP of the loss of transmission interconnection capability affecting its interchange transfer capability. The SPP shall update Group assignments for use during subsequent Assistance Periods. Each transmission provider is responsible for notifying the SPP once the contingency loss in the interchange transfer capability has been restored so that Group assignments can be updated.
13) For each reportable contingency (as defined by the Operating Reliability Working Group), the Contingency Area and Assisting Areas will send to SPP an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data. If electronic data is not available, this data will be supplied on the NERC required charts.

### 1.5.3 Subsequent Contingencies

In the event that a subsequent Operating Reserve Contingency occurs during a period when assistance is already in progress, the same procedures shall be followed to allocate responsibility for the additional Operating Reserve Contingency. Response to multiple Contingencies may be limited if the combined MW loss exceeds the Most Severe Single Contingency.

### 1.5.4 Assistance Reports

Energy and transmission service reports shall be issued following the Assistance Period. These reports shall be used as verification of associated energy schedules and transmission service reservations. The Operating Reliability Working Group shall distribute monthly summary reports of Other Extreme Conditions activity for use.

SPP Staff will report to NERC quarterly the performance of the SPP Reserve Sharing Group. Performance will be calculated based on the data that Balancing Authorities provide and any

additional data required for each reportable contingency. At a minimum, reportable contingencies will be of a magnitude between 80% and 100% of the capacity of the largest generating unit scheduled to be on-line within the SPP each day. The Operating Reliability Working Group may lower the 80% factor in order to better monitor the performance of the SPP Reserve Sharing Group.

### 1.5.5 Other Extreme Conditions Events

Other Extreme Conditions (OEC) Events may be requested by any Balancing Authority member of the SPP Reserve Sharing Group. OECs may be implemented for any of the following reasons, but shall be implemented when the requesting Balancing Authority has used all or a portion of its reserve obligation due to the event:

1) Loss of a Capacity Import Schedule;
2) Loss of Contingency Reserves;
3) Initial or additional assistance is required and no other mechanism is available within the confines of the
   SPP computer communication system.

Any SPP Reserve Sharing Group member not having their Balancing Authority Minimum Daily Contingency Reserve Requirement shall enter an Other Extreme Conditions for the amount of the deficiency. A NERC Energy Emergency Alert (EEA) may or may not be required. If the Balancing Authority determines an EEA must be issued, the Balancing Authority shall notify the Reliability Coordinator. If the OEC is requested along with an EEA, the Balancing Authority shall be prepared to demonstrate the emergency condition by taking the steps required by the EEA.

The SPP Reserve Sharing Group member submitting an Other Extreme Conditions event shall submit a written report to OECEEAReports@spp.org within 2 business days of the event. The written report will describe the operating conditions that precipitated the event. Other Extreme Conditions shall be investigated as required by the SPP Operating Reliability Working Group to ensure compliance with the SPP Reserve Sharing Group Operating Process and NERC Reliability Standards.

## 1.6 Compensation for Assistance

### 1.6.1 Energy Charge

The charge for energy assistance delivered by Assisting Areas under the application of this Operating Process shall be determined by interchange agreements between the members involved in the Reserve Sharing Group.

### 1.6.2 Accounting

All compensation for energy associated with the application of this Operating Process shall be handled by contractual agreements and standard accounting procedures being utilized by the SPP Reserve Sharing Group members.

### 1.6.3 Transmission Service

All compensation for transmission service shall be in accordance with the appropriate transmission service tariffs. The SPP staff shall be responsible for all billings for transmission service provided under the SPP Regional Transmission Tariff. The individual transmission provider shall be responsible for all billings under the transmission provider's transmission tariff. It shall be the SPP staff's responsibility to provide the required transmission service information to the transmission provider for all transmission service under an individual transmission provider's transmission tariff.

## 1.7 Responsibilities

### 1.7.1 Balancing Authorities

It shall be the responsibility of each Balancing Authority to observe the policies and procedures contained herein; maintaining Operating Reserve, ensuring connectivity to the SPP computer communications system, reporting daily information, identifying and reporting an Operating Reserve Contingency within its Balancing Authority Area, acknowledging schedules and supplying assistance to members of the SPP Reserve Sharing Group.

### 1.7.2 Operating Reliability Working Group

In order to review the adequacy in SPP Reserve Sharing Group, reports shall be compiled and distributed by SPP for review by SPP Reserve Sharing Group members and the Operating Reliability Working Group. These reports shall contain compliance information and a summary of Assistance Period events.

Exhibit 2 to Attachment AD

# Operating Criteria

## Revision 1.4

MAINTAINED BY

SPP Operating Reliability Working Group

PUBLISHED: 11/20/2015

LATEST REVISION: Effective 12/11/2017

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| | | **REVISIONS** |
| **Revision** | **Date** | **Description of Modification** |
| 0.a | 10/12/2010 | Initial draft |
| 1.0 | 11/20/2015 | Reflects the approval of RR117 and RR58_CRR014. |
| 1.1 | 4/1/2016 | Reflects the approval of RR98. |
| 1.2 | 10/3/2016 | Reflects the approval of RR113, RR146, RR159 Reflects |
| 1.3 | 4/27/2017 | the approval of RR134, RR168, RR195, RR213 Reflects |
| 1.4 | 12/11/2017 | the approval of RR240 |

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# 1. Glossary

# 2. Introduction

The Operating Criteria contained within this document serve to support the values and principles upon which SPP is formed. These criteria are reviewed and managed by the Organizational Group structure as described in the SPP Bylaws. Unless stated otherwise in the applicable section of this document, these Operating Criteria shall be reviewed by the Operating Reliability Working Group (ORWG) and any revisions to this document shall be performed pursuant to the approved Revision Request Process and submitted to the Markets and Operations Policy Committee (MOPC) for consideration of approval. The MOPC shall present applicable Revision Requests to the SPP Board of Directors for their review and approval as appropriate.

## 2.1 Purpose

The Operating Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the various SPP Operational and Operating Reliability Functions.

## 2.2 Document Relationship

The Operating Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the various SPP Operational and Operating Reliability Functions.

# 3. Operating Functions Overview

SPP's Operating Reliability Functions include: Reliability Coordination, Balancing Authority, Transmission Service Provider, and Reserve Sharing Group Administrator.

## 3.1 Reliability Coordination

Southwest Power Pool, Inc. is registered with the North American Electric Reliability Corporation (NERC) as a Reliability Coordinator (RC) for Transmission Operators (TOP's), Generator Operators (GOP's) and Balancing Authorities (BA's). An RC has the highest responsibility and authority to act and direct actions in accordance with relevant NERC Reliability Standards and other directives put forth from the NERC or the Federal Energy Regulatory Commission (FERC) to preserve the integrity of the Bulk Electric System.

## 3.2 Balancing Authority

SPP also functions as a registered Balancing Authority for selected TOP's and GOP's. A Balancing Authority is a responsibily entity that integrates resource plans ahead of time, maintains load-interchange-generation balancing within the Balancing Authority Area, and supports Interconnection Frequency in real time. SPP's Integrated Marketplace supports the Balancing Authority function of SPP.

## 3.3 Transmission Service Provider

SPP is also the Transmission Service Provider for the SPP Open Access Transmission Tariff. SPP administers the provisions of the Tariff and provides Transmission Service to Transmission Customers under the applicable transmission service agreements.

## 3.4 Reserve Sharing Group

SPP is registered with NERC as the Reserve Sharing Group (RSG). An RSG is a relationship established by contract between two or more BA's that collectively maintain, allocate, and supply Operating Reserves required for each member BA's use in recovering from contingencies within the group. The end result is that a lesser amount of Operating Reserves is maintained among the RSG members than would be required in the absence of the RSG. NERC Reliability

Standards set forth requirements for how the RSG functions and what objectives RSGs must meet to maintain Bulk Electric System reliability.

As the administrator of the SPP RSG, and in coordination with other participating BAs, SPP maintains the *SPP Reserve Sharing Group Operating Process* that establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the RSG. BAs participating in the SPP RSG shall meet the requirements set forth in the *SPP Reserve Sharing Group Operating Process*, which can be found on SPP.org at Documents-Governing.

# 4. Reliability Coordination

Continuous coordinated operation of the bulk electric system is essential to maintain reliable electric service to all customers. Reliability coordination procedures are established herein for sharing of operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the bulk electric system.

## 4.1 Responsibility and Authority

The Reliability Coordinator has the responsibility and authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise that authority to alleviate capacity and energy emergencies and coordinate restoration activities between individual Transmission Operators, The Reliability Coordinator also shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

### 4.1.1 Information and Data Exchange

#### 4.1.1.1 Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority

The SPP Reliability Coordinator and the SPP Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions, Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The SPP Reliability Coordinator and the SPP Balancing Authority shall distribute its data specification to entities that have data required by the SPP Reliability Coordinator's and the SPP Balancing Authority's analysis functions, Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The entities shall satisfy the requirements contained within the "Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority" (RDS). SPP shall be responsible for maintaining the RDS. The Operating Reliability Working Group (ORWG) shall be responsible for initially approving the RDS and reviewing and approving subsequent changes to the RDS. The Reliability Compliance Working Group (RCWG) shall provide formal comments on proposed changes to the RDS prior to ORWG review. SPP shall distribute this document directly to each applicable entity both upon the initial approval and the approval of subsequent changes within 30 days.

#### 4.1.1.2 SPP Sharing of Externally Provided Data

The SPP Reliability Coordinator shall obtain a current signed NERC Confidentiality Agreement from entities receiving data provided to SPP by an entity other than SPP ensuring that the confidentiality of the data be maintained as required by the NERC Confidentiality Agreement.

#### 4.1.1.3 Node Connectivity Requirement (Effective Until 1/1/2018)

SPP operates ICCP nodes at both the primary and disaster recovery (backup) sites. Both the primary and backup site ICCP servers feed real-time data to the primary and backup site Energy Management Systems. To ensure maximum availability of ICCP data required for operating reliability, the following connectivity requirements are required:

- SPP members are required to configure their ICCP servers to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.

- SPP will normally reference the same ICCP Object ID from both nodes when reading member data, thus imposing no additional maintenance workload upon the member companies.
- Members operating a backup site may choose to concurrently serve data from that site. In that instance, SPP will configure the SPP primary ICCP node to communicate with the member's primary site node and will configure the SPP backup site ICCP node to communicate with the member backup site node.
- SPP will configure the SPP backup site ICCP nodes to serve data to member sites using a separate and distinct ICCP Object ID in order to permit them to concurrently read operating reliability data from redundant nodes.

#### 4.1.1.4 Node Connectivity Requirement (Effective 1/1/2018)

SPP operates ICCP nodes at both the primary and backup sites. Both the primary and backup site ICCP node feed real-time data to their primary and backup site Energy Management Systems concurrently. To ensure maximum availability of ICCP data required for reliability, the following connectivity requirements are required for entities registered with NERC as a Generator Operator or Transmission Operator within the SPP Reliability Coordinator Area to be binding on January 1, 2018 or as otherwise consistent with waiver provisions outlined in the RDS:

- All Transmission Operators are required to configure their ICCP nodes to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.
- All Transmission Operators and Generator Operators are required to configure two ICCP nodes so that, in the event of a failure of their active ICCP node, their alternate ICCP node reconnects to SPP's ICCP nodes within 240 seconds.
    - If the TOP or GOP has a third party contract for their ICCP connections, then the third party should be able to reconnect within 240 seconds.
- All Generator Operators with more than 1500 MW of net aggregate generation or fifteen capacity resources in the SPP Balancing Authority Area are required to configure two ICCP nodes to read their Integrated Marketplace resource set point instructions from both SPP's primary and secondary ICCP nodes concurrently.

In the event of an outage on ICCP Nodes:

- Planned maintenance outages should comply with the Outage Scheduling Information of the RDS (Telemetering and Control System Status). For forced or unplanned outages, the TOP or GOP should contact SPP and follow the Outage Scheduling Information of the RDS (Telemetering and Control System Status).

### 4.1.2 Member Responsibilities

Transmission Operators shall determine System Operating Limits (SOLs), as defined by NERC, in conjunction with transmission owners. SOLs will be provided for facilities that comprise flowgates and any other facilities as determined by the Transmission Operator in conjunction with the transmission owners. The Transmission Operator shall inform the Reliability Coordinator of changes to any SOL as specified in Appendix OP-1 and notify the Reliability Coordinator of any SOL exceedances. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with the SOL Methodology in SPP Planning Criteria 7.3.

#### 4.1.2.1 Outage Reporting and Coordination

Each Transmission Operator, Generator Operator and Balancing Authority shall perform the functions specified in OP-2 Outage Coordination Methodology.

##### 4.1.2.1.1 Special Protection Systems

The Transmission Operator shall immediately inform the Reliability Coordinator of the status of any Special Protection System, that may have an inter-Balancing Authority, or inter- Transmission Operator impact, including any degradation or potential failure to operate as expected.

##### 4.1.2.1.2 Other Protection Systems

If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify the Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

##### 4.1.2.1.3 Fuel Supply

Balancing Authorities or Generator Operators, as appropriate, shall notify SPP of any generation derates resulting from Operational Flow Orders (OFOs) or Critical Notices or any other type of

fuel delivery constraint. The parties submitting the information shall indicate that the derate is a result of an OFO, Critical Notices, or fuel delivery constraint and indicate which pipeline(s) or delivery constraints are impacting them. Whenever an OFO, Critical Notices, or fuel delivery constraint causes an inability for the Generator Operator to meet its firm obligations, it must use the normal established communication protocols to notify its host Balancing Authority. Furthermore, Balancing Authorities shall notify the SPP Reliability Coordinator should it be necessary to request a NERC Energy Emergency Alert and/or a SPP Other Extreme Conditions as a result of the OFO or Critical Notice.

#### 4.1.2.2 Vegetation Management

This section of the SPP Criteria is applicable to all entities in the SPP Regional Entity footprint and the SPP Reliability Coordinator footprint.For the purpose of this Criteria and NERC Reliability Standard FAC-003, the SPP Regional Entity [SPP RE], the SPP Reliability Coordinator and the SPP Operating Reliability Working Group are collaborating to act as the Regional Reliability Organization [RRO] as identified in the Standard. NERC Reliability Standard FAC-003-1requires a vegetation management program for 'transmission lines operating at 200kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region' (applicable lines). For the purpose of implementing FAC-003-1 and proposed revisions to the FAC-003 standard, the SPP RC will designate the applicable facilities that are to be monitored for compliance to the standard in consultation with the SPP ORWG. The SPP Reliability Coordinator designates the following transmission lines as being subject to the FAC-003 standard:

(1) All transmission lines operating at 200kV and above; and
(2) All transmission lines, not included in 1. above that are listed as monitored or contingent elements of an Interconnection Reliability Operating Limit (IROL) flowgate as published in the *SPP IROL Relief Guides.*

The SPP Reliability Coordinator develops and identifies IROL flowgates on a continual basis to ensure reliability, However, IROL flowgate facilities will only be added to the applicable lines list annually to provide adequate time for Transmission Owners to incorporate those facilities into their Transmission Vegetation Management Plans. The SPP Reliability Coordinator will maintain the master list of the applicable transmission lines. The facilities identified will become applicable to the standard 12 months after being identified by the RC. The SPP RC is

responsible for communicating to the appropriate Transmission Owners those transmission lines designated as applicable transmission lines by the SPP RC and subject to compliance monitoring

and reporting of vegetation contacts as detailed in NERC Reliability Standard FAC-003. The Transmission Owner shall develop communications and notification protocols for the purposes of implementing changes to the applicable transmission line list and for reporting vegetation contacts to the SPP RE.

#### 4.1.2.3 Transmission Facility Ratings

Each Transmission Owner shall provide the SPP Reliability Coordinator with Normal and Emergency Ratings in accordance with the Transmission Owner's Facility Rating methodology. Emergency Ratings are helpful in real-time operations, providing system operators a specified time to implement mitigating actions before exceeding pre-contingent or post-contingent System Operating Limits. Transmission Owners shall provide the SPP Reliability Coordinator with the highest available Emergency Rating that provides sufficient time for system operators to take actions that are intended to keep actual loading within applicable limits. The SPP Reliability Coordinator will initiate mitigation procedures with the default assumption that the Emergency Ratings are associated with a finite time period of at least thirty minutes. For an Emergency Rating associated with a finite time period of less than thirty minutes, an approved operating guide must be on file with the SPP Reliability Coordinator. The operating guide must outline the steps that will be taken to reduce loading on the transmission facility within the finite time associated with the Emergency Rating.

### 4.1.3 Operating Reliability Working Group

The Operating Reliability Working Group shall be responsible for policy oversight of implementation and on-going reliability coordination processes and services as described in this Criteria. This working group shall make regular reports to the Markets and Operations Policy Committee.

### 4.1.4 SPP Staff

The SPP Staff shall be responsible for development and administration of reliability coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

### 4.1.5 Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following activities:

#### 4.1.5.1 Reliability Assessments

(1) Monitor the collection of real-time operating information, schedules and daily forecasts from Balancing Authorities as specified in Appendix OP-1.

(2) Develop and use operational models to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL exceedances, including overloaded transmission lines and transformers, voltage and stability limits, and determining the adequacy of operating reserve for the current operating day and the next day.

(3) Perform Day Ahead Contingency Analysis to assess the impact of any single transmission contingency 100kV and above while monitoring all facilities 100kV and above within the entire SPP RC Footprint and neighboring Balancing Authority Areas or Transmission Operators systems.

(4) Develop mitigation plans or operating guides for any potential interface, SOLs or IROLs found in the Day Ahead Contingency Analysis that is forecast to exceed 100% of the emergency rating of any facility 100kV and above or any pre-contingent bus voltages of +/- 5% and/or post-contingent bus voltages in excess of +/- 10%.

(5) During conditions where system reliability is threatened, notify and coordinate with affected Transmission Operators, Balancing Authorities, or Transmission Service Providers in determining appropriate control action.

(6) Perform voltage stability simulations for identified areas and paths with the potential for post contingent and real-time voltage stability issues. See Appendix OP-3.

(7) Sharing the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time.

#### 4.1.5.2 Operational Coordination

(1) Coordinate and grant permission for bulk transmission equipment maintenance.

(2) Coordinate pending generator maintenance.

(3) Manage the SPP Open Access Same-Time Information System (OASIS) node and Available Transfer Capability (ATC) calculation.

(4) Monitor the NERC Hot line and NERC Reliability Coordinator Information System (RCIS) and disseminating information.

(5) Initiating time error corrections (TEC).

(6) Initiating Geo-magnetic Disturbance (GMD) notifications and assist as needed in the development of any required response plans.

(7) in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, redispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs, and/or mitigate CPS or DCS exceedances.

#### 4.1.5.3 Monitoring

(1) Monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.

(2) Identifying sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.

(3) Monitor Special Protection Systems that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL exceedance) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

(4) Monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

(5) Coordinate bilateral inadvertent energy accounting and payback.

#### 4.1.5.4 Emergency Procedure Implementation

(1) Monitor and coordinate implementation of Operating Reserve Criteria.

(2) Monitor and coordinate implementation of Transmission Loading Relief and other

congestion management procedures.

(3) Monitor and coordinate implementation of Load Shedding and Restoration Criteria.
(4) Monitor and coordinate implementation of Black Start Criteria.
(5) Issue short supply advisories.
(6) Issue weather advisories.
(7) Evaluate actions taken to address an IROL or SOL exceedance and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

#### 4.1.5.5 Interregional Coordination

(1) Coordinate normal and emergency operations with other Reliability Coordinators.
(2) Authoritatively act on behalf of SPP Members to resolve interregional issues.

#### 4.1.5.6 Other Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following additional activities:

(1) Coordinate implementation of Black Start procedures as outlined in Criteria.
(2) Implement Transmission Loading Relief Procedures and other congestion management procedures as required.
(3) Administer the SPP Reserve Sharing Group.
(4) Provide reports to the ORWG of congestion management activities performed by the RC. These reports shall also be posted periodically.

#### 4.1.5.7 Reliability Coordinator Performance Standards

The SPP Reliability Coordinator shall have the following performance standards:

(1) The SPP Reliability Coordinator shall act in accordance with Good Utility Practice including NERC Standards and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice or NERC Standards, and shall allow SPP members to take any actions required by Good Utility Practice and NERC Standards.
(2) The SPP Reliability Coordinator shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency or NERC Standard.
(3) The SPP Reliability Coordinator shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Standards and SPP Criteria.

(4) The SPP Reliability Coordinator shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.
(5) The SPP Reliability Coordinator shall possess the applicable NERC Certification.
(6) The SPP Reliability Coordinator shall sign an appropriate standards of conduct document ensuring appropriate protection of competitively sensitive information.

# 5. Balancing Authority

# 6. Transmission Service Provider

# 8. Emergency Communication

Dependable communications are critical to maintaining the reliability of the Bulk Electric System. Accordingly, NERC has outlined necessary communication links in the reliability standards applying to Transmission Operators, Balancing Authorities, and Reliability Coordinators. It is vital that communication channels are functional and disturbances to the communication network should be addressed.

Key critical paths:

(1) Internal communications
(2) Between the Reliability Coordinator and its Transmission Operators and Balancing
(3) Authorities.
(4) With other Reliability Coordinators, Transmission Operators, and Balancing
(5) Authorities as necessary to maintain reliability.
(6) Where applicable, these facilities shall be redundant and diversely routed.

The communication paths should be verified periodically and an action plan should exist to maintain and recommend solutions to communication problems.

## 8.1 SPP Emergency Communication Network

The SPP Emergency Communication Network is comprised of Satellite Phones located at the SPP primary and backup control centers, control centers of each member Balancing Authority

and/or Transmission Operator. If loss of any primary communication facilities are encountered, the SPP Emergency Communication Network shall be used to exchange information. Therefore,

it is important for operators to be familiar and comfortable with the operation of the Satellite Phones. The Reliability Coordinator shall ensure proper training.

Balancing Authorities, Transmission Operators and Reliability Coordinators shall participate in weekly testing of the SPP Emergency Communication Network. Testing will ensure reliability and it will also give users practice on the system. The Reliability Coordinator shall initiate and monitor the SPP Satellite Phone testing.

During actual emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Coordinator shall initiate a Group Call and quickly determine the extent of the interruption. Communication is vital to an orderly recovery. Operating personnel shall keep conversations concise to keep channels clear. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths.

## 8.2 Information Priority during Emergencies

System status conditions to be surveyed include but are not limited to the following items:

(1) Areas of the electric system which are de-energized,
(2) Areas of the electric system which are functioning,
(3) Amount of generation and generating reserve available in functioning areas,
(4) Power plant availability and time required to restart,
(5) Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,
(6) Status of transmission breakers and sectionalizing equipment at tie points to other areas,
(7) Status of fuel supply from external suppliers,
(8) Under-frequency relay operation,
(9) Relay flags associated with circuits tripped by protective relays.
(10) Status of communication systems.

* Refer to COM-001 and COM-002 for more information on maintaining reliable communications

# Appendix OP-2: Outage Coordination Methodology

**Change History:**

| | |
|---|---|
| **8/16/2011** | **Initial version approved by ORWG** |
| **8/30/2011** | **Corrected typo on Generator Planned Outages Min Lead Time - corrected to "2 Days" from "None".** |
| **9/22/2011** | **Added clarification on Reserve Shutdown submittals and created "Opportunity" outage Priority for Generators.** |
| **2/21/2013** | **Added clarification on business rules of outage priorities detailing which priorities are allowed to be entered in CROW with start times either in the future or in the past. Replaced "members" with Transmission Operators and Generator Operators. Added more language describing SPP's outage request evaluation process. Added further language describing Reserve Shutdown resources.** |
| **6/26/2013** | **Added "Info" Informational Outage Request Type as an available type for Generation Outages.** |
| **12/18/2013** | **Added "Operational" priority and "Upcoming Model Change" as outage reason, misc clarification changes.** |
| **12/1/2015** | **Added language to comply with IRO-017-1. Updated planned lead time requirements.** |
| **4/1/2016** | **Added modifications contained in approved Revision Request 98** |
| **4/27/2017** | **Added modifications contained in approved Revision Request 134** |

**Purpose**

The purpose of this methodology is to provide technical requirements and criteria to Transmission Operators, Generator Operators and SPP Staff related to submission of Transmission and Generation outages to the SPP Reliability Coordinator and SPP Balancing Authority via the SPP CROW tool. Outage submissions will be shared with other Reliability Coordinators, Transmission Operators, and Balancing Authorities via the NERC System Data Exchange (SDX) and will be used for assessing real-time and future reliability of the Bulk Electric System. Transmission and generation operators are responsible for submitting all outages through the CROW tool. All other transmission operators will be able to view and identify all outages that are submitted through CROW. SPP reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure system reliability on a case by case basis regardless of date of submission.

**1. Transmission Outages and Operations**

For the purpose of identifying applicable facilities, the nominal kV level of the facility will be used. For

transformers, use the low side voltage class. Example: A 161/69kV transformer shall be classified as a 69kV facility for the purposes of this methodology.

| **a. Forced Transmission Outage Submission Requirements** | |
|---|---|
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Forced outages of all transmission facilities greater than 60kV that are modeled in the SPP regional models and have been modeled in the CROW tool should be submitted within 30 minutes or as soon as practical after the outage. Each outage submission must be accompanied by a Planned End Time, Forced Outage Priority, an associated Outage Request Type, and an Outage Cause. Forced Outage Priory outages will be considered Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. It is recognized that the duration of a forced outage will typically not be known at the time of the initial submission. The Planned End Time should be the best estimate for the return of the outaged facility. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the CROW tool.

**b. Scheduled Transmission Outage Submission Requirements**

Scheduled outages of all BES elements must be submitted to the CROW tool and approved by the Reliability Coordinator prior to implementing the outage. Scheduled outages of all other transmission elements greater than 60kV that are modeled in the SPP regional models must be submitted to the Reliability Coordinator's CROW tool for coordination and review. Each outage submission must be accompanied by a Planned Outage Start Time and Planned End Time, Outage Priority, Outage Request Type, and Outage Cause. Each outage request must also be designated as Non-Recallable, or provide an expected Recall time if directed. Sufficient notation in the outage scheduler "Requestor Notes" comment field should include a description or explanation for the outage. An incomplete outage request of any missing data could result in the outage being denied. Once the actual outage takes place, the Actual Start Time of the outage must be submitted to the CROW tool. When the outage has ended, the Actual End Time of the outage must be updated.

**c. Transmission Outage Priority and Timing Requirements**

Each Transmission Outage submitted must include one of the following Outage Priorities. Forced outages of equipment must be submitted with a Priority of Forced as defined below. The CROW Outage Scheduler will enforce the lead time requirements of each Outage Priority. Outages that are not planned will have a lower priority and may not be approved by the RC. Outages not submitted as planned will be reviewed and approved by SPP on a case-by-case basis. The risk of imminent equipment failure will have priority over other outages including planned. If sufficient time is not available to analyze the request then the outage will be denied.

| Priority | Definition | Minimum Lead Time | Maximum Lead Time |
|---|---|---|---|
| **Planned** | Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the | **14 Calendar Days** | **None** |

| | | | |
|---|---|---|---|
| | installation of additional facilities, or the replacement of equipment due to obsolescence. | | |
| **Discretionary** | Equipment is known to be operable with little risk of leading to a forced outage; however the timeline for submission of Planned outage priority has passed. Discretionary outages are required to be submitted at least 2 calendar days in advance. Due to the shorter lead time, this outage priority has increased risk of being denied based upon higher priority outage requests. | **2 Days** | **14 Calendar Days** |
| **Opportunity** | Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Generator suddenly offline for forced outage allows transmission work to be done). | **None** | **7 Days** |
| **Operational** | Equipment is removed from service for operational reasons such as voltage control, constraint mitigation as identified in an operating procedure, etc. | **None** | **None** |
| **Urgent** | Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work. | **2 Hours** | **48 Hours** |
| **Emergency** | Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security. | **None** | **2 Hours** |
| **Forced** | Equipment is out of service at the time of the request. | **None** | **1 Hour** |

### d. Transmission Outage Equipment Request Types

Each Transmission outage (scheduled and forced) request submitted must include one of the following Outage Request Types.

| **Outage Request Type** | **Definition** | **Modeling Assumptions** |
|---|---|---|
| **Out of Service (OOS)** | Equipment is out of service. | **SDX = Open**<br>**EMS = Open** |
| **Normally Open (NO)** | Equipment is normally out of service and is identified as normally open in the SPP regional models. Normally Open request type is used to close (place in service) a normally open facility. | **SDX = Closed**<br>**EMS = Closed** |
| **Informational (INF)** | Used for outage events that are not covered by one of the other Outage Equipment Request Types. Not an out of service event. | **None - Informational Only** |
| **Hot Line Work (HLW)** | Work is being performed on live or energized equipment. | **None - Informational Only** |
| **General System Protection (GSP)** | Work is being performed on protection systems. Requestor shall specifically identify protection systems out of service and any modification to operation or behavior of system contingencies. | **None - Informational Only** |

### e. Transmission Outage Request Reasons/Causes

Each Transmission Outage Request must be submitted with one of the following reasons for the outage.

| Reason/Cause | Definition |
|---|---|
| **Maintenance & Construction** | Outages to facilitate repair, maintain, or upgrade of facility related equipment. This includes clearances to perform vegetation management. Does not include outages to support Maintenance & Construction of other facilities. Those should be submitted as Voltage or SOL Mitigation. |
| **Third Party Request** | Non-transmission facility related requests for clearance or work such as highway construction. |

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| **Voltage Mitigation** | Operation of facilities to preserve or correct Bulk Electric System voltage. |
| **SOL Mitigation (Thermal)** | Operation of facilities to preserve or correct Bulk Electric System thermal loading issues. |
| **Weather/Environmental/Fire (excluding Lightning)** | Outages caused by wind, ice, snow, fire, flood, etc. All weather or environmental causes excluding lightning strikes. |
| **Lightning** | Outages caused by direct or indirect Lightning strikes. |
| **Foreign Interference (including contamination)** | Outages caused by blown debris, bird droppings, kites, falling conductors, airplanes, etc. |
| **Vandalism/Terrorism/Malicious Acts** | Outages resulting from known or suspected vandalism, terrorism, or other malicious acts. |
| **Equipment Failure** | Outages resulting from failure of facility related equipment. |
| **Imminent Equipment Failure** | Operation of facilities due to expected imminent facility rated equipment failure. |
| **Protection System Failure including Undesired Operations** | Operation of facilities due to failure or undesired operation of the facility protection systems. |
| **Vegetation** | Outages resulting from contact with vegetation. This does not include outages due to clearances required to perform vegetation management which should be submitted as Maintenance & Construction. This does not include vegetation blown into rights of way or into contact with facilities which should be submitted as Foreign Interference. |
| **BES Condition (Stability, Loading)** | Outages resulting from Bulk Electric System conditions such as islanding, cascading outages, sudden thermal loading due to other contingencies, transient stability conditions, etc. |
| **Unknown** | Operation of facilities due to an unknown reason. Most forced outages will be submitted with an initial reason of Unknown. Once the actual reason for the operation is known, the outage requestor should update the outage request. SPP Staff will follow up after some time to determine the actual outage reason for any outages which still have a reason of Unknown submitted. |
| **Upcoming Model Change** | Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel. |
| **Other** | Operation of facilities due to a reason not listed here. |

## 2. Generation Outages/Derates

### a. Generation Outages/Derate Submission Requirements

All generating resources within the SPP Reliability Coordinator Area or Balancing Authority Area meeting one or more of the criteria listed below (regardless of voltage connection) shall report in CROW all Outages and Derates if the gross reduction in capability is greater than or equal to 25 MW. Changes to the reported capability shall be reported in 25 MW increments from the last reported Derate level regardless of system capability/conditions.

- Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 25 MVA; or
- Blackstart Resources identified in a Transmission Operator's restoration plan; or
- Dispersed power producing resources with aggregate capacity greater than 25 MVA (gross

aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity.

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| If SPP requires generating resources that do not meet the criteria above to report their Outages and/or Derates in CROW, then SPP shall send a written notice to the responsible entity stating their obligations and identifying the specific generating resources. | |
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For the generating resources under the functional control of a Generator Operator (GOP) registered with NERC, the GOP shall be the responsible entity for reporting Outages and Derates in CROW. For all other generating resources not under the functional control of a registered GOP, the resource owner shall be the responsible entity for reporting Outages and Derates in CROW.

**b. Forced Generation Outages/Derate Submission Requirements**

Forced outages or capability limitations in the form of Derates should be submitted within 30 minutes or as soon as practical after the outage or capability limitation occurs. Forced Generation Outages and Derates are required to be accompanied by a reason for the outage or limitation. Each Outage or Derate submission must be accompanied by a Planned End Time, a Forced Outage Priority, Outage Request Type, and an Outage Cause. Forced Outage Priority requests will be assumed to be Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. The Planned Start Time of the outage should reflect the best known time of the actual outage. The CROW tool will ensure that the Actual Start Time and Planned Start Time are equal. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the CROW tool. This outage submission shall be in addition to any other notifications made to SPP such as through a Reserve Sharing event, or Resource Plan submission. SPP shall accept each forced outage within 30 minutes of submission.

**c. Scheduled Generation Outages/Derate Submission Requirements**

Scheduled Outages or capability limitations in the form of Derates should be submitted as soon as possible and to the extent possible on an annual rolling basis. Planned Generation Outages are required to be accompanied by a reason for the outage or limitation. Each Outage or Derate submission must be accompanied by a Planned Outage Start Time and Planned End Time, an associated Outage Priority, an associated Outage Request Type, and an Outage Cause. Each outage request must also be designated as Non-Recallable, or provide an expected Recall time if directed. Once the actual outage takes place, the Actual Start Time of the outage must be submitted to the CROW tool. SPP shall respond to all scheduled outages or capacity limitation changes in the CROW system within 30 minutes from the time of submission for changes that are effective within the next

48 hours. When the outage has ended, the Actual End Time of the outage must be updated. This outage submission shall be in addition to any other notifications made to SPP such as through a Reserve Sharing event or Resource Plan submission.

**1. Reserve Shutdown**

Resources in SPP are considered to be in a Reserve Shutdown outage status when SPP has approved an outage request via the CROW tool, making the Resource unavailable for SPP

commitment and dispatch due to reasons other than to perform maintenance or to repair equipment. These resources will be reflected in Planned Outage for a reason of Excess Capacity/Economic.

Resources that are offline for economic or excess capacity reasons and can be recalled, started, and synchronized to pick up load within 7 days are not required to request an outage via the CROW tool. However, these Resources may request and be shown in Reserve Shutdown outage status if the outage is approved by SPP.

**d. Generation Outage/Derate Priority and Timing Requirements**

Each Generation Outage or Derate submitted must include one of the following Outage Priorities. Forced outages of equipment must be submitted with a Priority of Forced as defined below. The CROW tool will enforce the lead time requirements of each Outage Priority.

| Priority | Definition | Minimum Lead Time | Maximum Lead Time |
|---|---|---|---|
| **Planned** | Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the installation of additional facilities, or the replacement of equipment due to obsolescence. | **14 Calendar Days** | **None** |
| **Opportunity** | Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Loading conditions allow planned work to occur with short lead time). | **None** | **14 Calendar Days** |
| **Operational** | Equipment is removed from service for operational reasons. This could include outages or derates due to reliability directives or other operational concerns not necessarily related to the generating equipment or capability, and outages entered to correct system topology in operating models. | **None** | **None** |
| **Urgent** | Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work. | **24 Hours** | **48 Hours** |
| **Emergency** | Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security. | **None** | **24 Hours** |
| **Forced** | Equipment is out of service at the time of the request. | **None** | **1 Hour** |

**e. Generation Outage/Derate Request Type**

Each Generation outage or Derate request submitted must include one of the following Outage Request Types.

| Request Type | Definition | Modeling Assumption |
|---|---|---|
| **Out of Service** | Generator or Resource is out of service. | SDX = offline |

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| | | EMS = offline |
| **Derate** | Generator or Resource maximum capability is lowered from normal operation. A new maximum capability is required to be submitted with each Outage Request Type of Derate. | SDX = online, with new lower PMAX<br>EMS = online, with new lower PMAX |
| **Informational (INF)** | Used for communicating and documenting information to SPP regarding the resource. This status is not interpreted as a loss of capability or capacity. This status may be used to communicate anticipated fuel delivery issues. | None - Informational Only |

### f. Generation Outage/Derate Request Reasons/Causes

Each Generation Outage or Derate Request must be submitted with one of the following reasons for the outage.

| Reason/Cause | Definition |
|---|---|
| **Equipment Failure** | Failure in station generation, prime mover, or other equipment has occurred. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill). |
| **Imminent Equipment Failure** | Expected failure in station generation, prime mover, or other equipment. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill). |
| **BES Reliability** | Removal from service or limitation to preserve or correct Bulk Electric System reliability issues either through action of a Special Protection System, runback scheme, or as mitigation of another reliability event. |
| **Loss of Interconnection** | Failure in interconnection equipment such as GSU transformers or other interconnection facilities. Does not include loss of synchronization due to stability or islanding type events. |
| **BES Stability** | Removal from service or limitation due to Bulk Electric System stability issues. Includes loss of synchronization due to transient stability and/or islanding issues. |
| **Fuel Supply** | Removal from service or limitation due to fuel supply interruption. Does not include local equipment failures related to fuel supply. Includes loss of gas pressure due to offsite issue, coal supply exhaustion, lack of headwater issues for hydro, etc. |
| **Regulatory/Safety/Environmental** | Removal from service or limitation due to Regulatory/Safety/Environmental restrictions such as emission limits, OSHA, NRC, or other regulatory body limitations. Includes damage caused by weather including but not limited to lightning, flood, earthquake, etc. This may also include limitations to hydro due to low dissolved oxygen in tailwater or to control downstream flooding. |
| **Unknown** | The default Forced Outage/Derate reason will be pre-populated with Unknown at the time of submittal. Either during the initial outage submittal or at a later time, the Unknown reason must be changed to reflect the actual experienced issue. |
| **Routine Generator Maintenance** | Removal from service or limitation in order to perform repair or inspection of generation equipment. |
| **Supporting Transmission Outage** | Removal from service or limitation in order to support a scheduled transmission outage. |
| **Excess Capacity/Economic** | Removal from service or limitation due to seasonal or system capacity need. This includes peaker units not expected to be used during winter months. |

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| **Upcoming Model Change** | Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel. | |
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**3. Outage Review / Approval Process**

All outages submitted will be studied to determine if any potential reliability conflicts are found. The general study method employed by SPP staff involves building representative models of the study time period and implementing all outage requests submitted for that time period. The resulting modeled system is then studied to determine if any reliability issues can be identified. If issues are identified, various mitigation steps are then studied including but not limited to, generation redispatch, system reconfiguration, rescheduling of lower priority outages, and facility rating reviews. If mitigations are unsuccessful in resolving the conflict, an outage request may need to be rescheduled or denied. Priority of outage requests is reviewed based upon initial submission time, outage priority category, reason for the outage, and impact to reliability. To the extent possible, higher priority category requests will be given preference, but ultimately it is up to the SPP RC to resolve any scheduling conflicts.

In the event that a conflict occurs with another Reliability Coordinator's outage, a priority of the outages will be determined based on submitted time, reason for outage, and impact to reliability. The determination will be reviewed and agreed upon by each Reliability Coordinator. The outage that is deemed a higher priority will be approved.

An outage that has been studied will receive a status change to one of the following statuses: Approved, Denied, or Pre-Approved. Pre-Approval will be provided in certain cases where an outage has been submitted, but for various reasons SPP is unable to adequately study the outage or determine that no reliability conflicts exist. The Pre-Approval may also be dependent upon a specific operating condition that may need to be met but cannot be guaranteed at the time the Pre-Approval is issued such as but not limited to a load forecast threshold, simultaneous outage, new facilities in-service, etc. When the outage request can be adequately studied to determine that no reliability conflict exists, the status will be changed to Approved.

All outages submitted within the appropriate advance timeframe will be reviewed as soon as possible by SPP Operations Staff. The review timelines for SPP are as follows:

a. Transmission

1. For all BES outage requests submitted 30 days or more prior to scheduled start time, Preapproval or denial will be provided within 5 business days.

2. For all BES outage requests submitted 14 days or more but less than 30 days prior to the scheduled start time, pre-approval or denial will be provided within 3 business days.

3. For all BES outage requests submitted 14 days or less prior to scheduled start time, preapproval or denial will be provided within 2 business days.

b. Generators

1. For all Generator outage requests submitted 30 days or more prior to scheduled start time, Pre-approval or denial will be provided within 5 business days.

2. For all Generator outage requests submitted 14 days or more but less than 30 days prior to the scheduled start time, Approval, Pre-approval or denial will be provided within 3 business days.

3. For all Generator outage requests submitted 14 days or less prior to scheduled start time, Approval, Pre-approval or denial will be provided within 2 business days.

4. SPP will provide their best effort for outages submitted within 2 business days.

## 4. Outage Status Changes

All outages submitted will reside in one of several status types throughout the life cycle of the outage. These status types and their associated definition are:

| Status | Definition |
|---|---|
| **Proposed** | The outage request has been saved in the CROW tool and remains under the full revision control until the outage is entered into a Submitted state by the requestor. If the requestor does not move a proposed request to the submitted status within 30 days of the planned start date, the outage is automatically Withdrawn. Proposed outage request status dates DO NOT qualify for outage queuing in conflict resolution. Proposed outage requests are not provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Submitted** | The outage request has been submitted into the CROW tool and is ready for review by SPP. The outage requestor does not possess revision control of the outage in this status. A revision request may be submitted to SPP regarding an outage in Submitted status. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Study** | SPP will change the status type to Study once the active study process begins. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Preliminary Approved** | Outage requests with Preliminary Approved status have been approved based on long lead studies and may need additional analysis closer to the planned start date or finalization of an Operating Guide. Once the restudy is complete or final opguide posted, the outage status is changed to Approved. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Approved** | Approved state indicates SPP has completed the study process and the outage request is ready for implementation. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Implemented** | Once the outage request actual start time has been entered, signifying that the outage has begun, the outage status is changed to Implemented. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Completed** | Once the outage request actual end time has been entered, signifying that the outage has ended, the outage status is changed to Completed. Outage requests in this state are NO LONGER provided to external systems such as NERC SDX/IDC or SPP's EMS. |

Certain outage requests may result in a need by the outage requestor to withdraw or cancel the outage request. SPP's study results and coordination may also result in status changes to an outage reflecting the inability of the outage request to be approved or implemented. These status types are:

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| Status | Definition |
|---|---|
| **Withdrawn** | The outage requestor can withdraw an outage request while it is still in Proposed status. Once in Study or Approved status, the request must be Cancelled. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Cancelled** | The outage requestor can cancel a Submitted or Approved outage. Cancelled outages can be reinstated by the requestor, provided the planned start of the outage falls within the business rules for lead time submission. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Denied** | An outage request that is in Submitted or Study status can be Denied. If SPP denies the request, the status changes to Denied. This state indicates the outage request was not approved for implementation. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS. |
| **Revoked** | Once an outage request has been Approved, it can be Revoked at an time (ie, before or during the outage). Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP's EMS. |

## 5. Using CROW to Submit Other Types of Information to SPP

CROW can be used as a mechanism to submit information to SPP other than outage and or status information on lines, transformers, and generators. All other types of information exchange made using CROW not previously described in this Appendix 12 will follow the guidelines below.

For Reactor, Capacitor, Circuit Breaker, Disconnect, and Protection Scheme (Special Protection System) Equipment Types

- All CROW submissions for these equipment types will be made in accordance with Appendix 12 Sections 1d, 1e, and 1f
- Appendix 12 Section 3 Outage Review / Approval Process will not apply to these equipment types
- These equipment types will not progress through the various states described in Appendix 12 Section 4 Outage Status Changes

For Generator Automatic Voltage Regulator (AVR) and Power System Stabilizers Equipment Types

- All CROW submissions for this equipment type will be made in accordance with Appendix 12 Sections 2c, 2d, and 2e
- Appendix 12 Section 3 Outage Review / Approval Process will not apply to these equipment types
- These equipment types will not progress through the various statuses described in Appendix 12 Section 4 Outage Status Changes

# Appendix OP-3: Voltage Stability Assessment and Monitoring Methodology

**Change History:**

**4/27/2017 Initial Version**

**Purpose**

The purpose of this methodology is to provide technical requirements and criteria to Transmission Operators, Generator Operators and SPP Staff related to the voltage stability assessment and monitoring of pre- and postcontingency (single and multiple) operating conditions. Monitored scenarios will be identified using available reliability studies, real-time system information, outage schedules, and other relevant sources. During the different Operating Horizons, the pre- and post-contingency operating conditions being studied may require adjustment. The SPP RC and TOPs must determine and coordinate which Multiple Contingencies within the TOP areas are credible to be utilized for study in the operating horizon.

If the TOP or the SPP RC determine that changes are required for a pre- or post-contingency operating condition, such changes shall be communicated to the affected entities. The SPP RC will coordinate with all applicable impacted TOPs or neighboring RCs.

The use of proxy flowgate limits for voltage stability will be communicated in the same manner as other flowgate limits and information.

1. **Study Models**
    a. SPP utilizes both the EMS model and the approved Planning Base Cases for establishing, calculating and monitoring SOLs/IROLs in the operating horizons. These cases are updated periodically to reflect expected system topology changes based on reported facility outages or upgrades.
2. **Real Time and Post Contingent Voltage Stability Limits**
    a. The SPP RC will perform a voltage stability assessment for identified areas and paths that have a reasonable potential to cause real-time and post-contingency voltage instability.
    b. The SPP RC may identify and establish voltage stability limits based on the voltage stability assessment results and will coordinate the voltage stability limits with the affected TOPs. Voltage stability limits may require development of new temporary flowgates.
    c. Voltage stability real-time and single-contingency limits will include a 5% MW margin.
    d. Voltage stability multiple-contingency limits will include a 2.5 % MW margin.
    e. A voltage stability limit more restrictive than an existing SOL will be identified as the revised SOL and communicated to affected entities prior to implementation in congestion management procedures.
    f. If system conditions in conjunction with real-time voltage stability assessments are determined to be stable, conditions within the 5% MW margin of the voltage stability limit than was previously defined, then the SPP RC may adjust the limit after coordinating an agreement with the affected TOPs.

g. The RC will coordinate with the impacted TOPs to establish necessary mitigations and operating plans.

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# Planning Criteria

## Revision 1.4

MAINTAINED BY:

Transmission Working Group
System Protection and Control Working Group
Supply Adequacy Working Group

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LATEST REVISION: Effective 7/25/2017

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| | | **REVISIONS** |
| | | |
| **Revision** | **Date** | **Description of Modification** |
| 0.0 | 4/10/2015 | Initial Creation |
| 1.0 | 11/20/2015 | Updated to reflect approval of RR117 and RR58 CRR014. |
| 1.1 | 4/26/2016 | Updated to reflect approval of RR141 |
| 1.2 | 4/25/2017 | Updated to reflect approval of RR 186, RR 215, and RR 224 |
| 1.3 | 6/15/2017 | Updated to reflect approval of RR 230 |
| 1.4 | 7/25/2017 | Updated to reflect approval of RR228 |

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# 1. Glossary

# 2. Introduction

## 2.1 Purpose

The Planning Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the SPP Planning Process.

**3.** Placeholder

# 4. Capacity Margin

This Criteria requires and provides for the sharing of reserve generating capacity as a means of reducing capacity requirements of each Member and providing reliable electric service to firm customers due to the equitable purchase, sale and exchange of generating capacity among Members.

## 4.1 Definitions

### 4.1.1 Load Serving Member

A Load Serving Member shall mean any SPP Member assuming legal obligation to provide firm electric service to a customer or group of customers within SPP.

### 4.1.2 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined Capacity Margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Power purchased shall only be considered to be Firm Power if Firm Transmission Service is in place to the Load Serving Member for delivery of such power. Firm Power does not include “financially firm” power.

### 4.1.3 System Capacity

A Load Serving Member’s System Capacity shall be equal to the capability of its generating facilities, including its ownership share of jointly owned units, demonstrated under procedures set forth in SPP Rating of Generating Equipment Criteria, adjusted to reflect the purchase from and/or sale to any other party of generating capacity or SPP defined Operating Reserve, under any appropriate agreement. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load.

Capacity purchases shall only be considered if Firm Transmission Service is in place to the Load Serving Member for delivery of power from such capacity.

Unless reported separately, generating facilities owned by others within the Load Serving Member's system that are obligated to furnish firm power to customers within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements with the

host Control Area, the host Control Area will not be required to be responsible for capacit y and/or reserve requirements. The reporting of generating facilities owned by others does not constitute an obligation on the Load Serving Member's part to furnish reserves or back up power for that generation.

### 4.1.4 Net Load

The term Net Load for any Load Serving Member shall mean, for any clock hour:

a) Net generation by the Load Serving Member's facilities; plus

b) Net receipts into the Load Serving Member's system; minus

c) Net deliveries out of such Load Serving Member's system

Unless reported separately, the Net Load of other non-Load Serving Members located within the Load Serving Member’s system shall also be reported. Absent any bilateral contractual arrangements, the reporting of these loads does not constitute an obligation on the Load Serving Member's part to furnish reserves, back up power, or incur financial obligations from SPP for that load.

### 4.1.5 Capacity Year

Capacity Year shall mean a period of twelve consecutive months beginning on October 1 of each calendar year. Any period less than a Capacity Year shall be designated as Short Term.

### 4.1.6 System Peak Responsibility

System Peak Responsibility of a Load Serving Member for any Capacity Year shall mean the Load Serving Member's greatest Net Load during that Capacity Year plus:

a) The contract amount of Firm Power sold to others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the sale of a specified amount of Firm Power; and minus

b) The contract amount of Firm Power purchased from others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the purchase of a specified amount of Firm Power.

In each case, the contract amount governs regardless of the amount actually delivered at the time of a Load Serving Member's greatest Net Load.

### 4.1.7 Capacity Margin

Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

### 4.1.8 Percent Capacity Margin

Percent Capacity Margin shall be defined by the formula:

Percent Capacity Margin = (Capacity Margin/System Capacity) x 100

### 4.1.9 Minimum Required Capacity Margin

Each Load Serving Member’s Minimum Required Capacity Margin shall be ten point seven (10.7%) percent (equivalent to a 12% reserve margin). If a Load Serving Member’s System Capacity for a Capacity Year is comprised of at least seventy- five percent hydro-based generation, then such Load Serving Member’s Minimum Required Capacity Margin for that Capacity Year shall be nine percent.

### 4.1.10 System Capacity Margin Responsibility

A Load Serving Member’s System Capacity Responsibility for any Capacity Year shall mean the sum of that Load Serving Member's System Peak Responsibility and its Minimum Required Capacity Margin.

### 4.1.11 Capacity Balance

Capacity Balance shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Capacity Responsibility.

### 4.1.12 Firm Transmission Service

Firm Transmission Service is that service defined in any applicable transmission service provider tariff.

## 4.2 Capacity Responsibility

a) Each Capacity Year, each Load Serving Member shall possess System Capacity at least equal to its System Capacity Responsibility.

b) Prior to the establishment of its System Peak Responsibility for each Capacity Year, each Load Serving Member shall provide System Capacity by one or more of the following means:

i) Establishing a unit rating consistent with SPP generating equipment rating Criteria, prior to establishing its System Peak Responsibility;

ii) Reducing its System Peak Responsibility by purchase of Firm Power from any Member or non-Member by separate agreement;

iii) Separate written agreement with another Member or a non-Member for purchase of a specified amount of capacity; and/or

iv) Reducing its Net Load.

c) A Load Serving Member may purchase Short Term capacity to provide a part of its System Capacity or Short Term Firm Power to reduce its System Peak Responsibility subject to each of the following restrictions:

i) Such Short Term period shall not be less than four consecutive months, and shall include the day the Load Serving Member establishes its System Peak Responsibility. Such period shall begin during May 1 to June 1 or November 1 to December 1;

ii) The amount of Short Term capacity or Short Term Firm Power purchased shall not exceed 25% of the Load Serving Member's System Peak Responsibility; and

iii) The Load Serving Member shall purchase such Short Term Capacity or Short Term Firm Power prior to the start of the Short Term period.

d) A Load Serving Member may sell Short Term Capacity or Short Term Firm Power from resources comprising its Capacity Balance, provided that it's System Capacity Responsibility is met.

## 4.3 Records

Each Load Serving Member, upon request, shall provide accurate and detailed records of information related to this Criteria to the SPP Staff. Except for System Peak Responsibility, all other information shall be provided prior to establishing System Peak Responsibility for a Capacity Year and shall include; validation of System Capacity per SPP Rating of Generating Equipment Criteria, Capacity purchase and sale contracts, Firm Power purchase and sale contracts, and firm transmission service agreements. The SPP Staff shall verify information supplied by each Load Serving Member. Calculations shall be based on the highest peak load of each of the Load Serving Members during the Capacity Year. All capacity and demand values will be rounded to the nearest whole MW for purposes of this Criteria. All data submitted to SPP related to this Criteria

shall be considered confidential by the SPP Staff and shall not be released in any form except by force of law

## 4.4 Generation Planning

### 4.4.1 Design Futures

a) In order to maintain a balanced design of the electric system, excessive concentration of generating capacity in one unit, at one location, or in one area shall be avoided.

b) Auxiliary power sources shall be provided in each major generating station to provide for the safe shutdown of all the units in the event of loss of external power.

c) In each major load area of SPP, a unit capable of black start shall be provided having the capability of restarting the other units in the area.

d) Boiler controls and other essential automation of major generating units shall be designed to withstand voltage dips caused by system short circuits.

### 4.4.2 Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for capacity margin requirements.

# 5. Regional Transmission Planning

## 5.1 Concepts

The interconnected transmission system shall be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. The transmission system shall be planned to withstand all single element contingencies and maintenance outages over the load conditions of all seasonal models as developed by the Model Development W orking Group (MDWG). Extreme event contingencies which measure the robustness of the electric systems should be evaluated for risks and consequences. The NERC Reliability Standards define specific requirements that provide a high degree of reliability for the bulk electric system. SPP provides additional coordinated regional transmission planning requirements to promote reliability through this Criterion and related "Coordinated Planning Procedures" in the SPP Open Access Transmission Tariff.

## 5.2 Definitions

All capitalized terms shall have their meaning as contemplated in the SPP OATT, unless defined below.

Bulk Electric System - Bulk Electric System shall have the definition as provided in the NERC Glossary of Terms Used in Reliability Standards, as may be amended from time to time.

NERC - The North American Electric Reliability Corporation, or its successor organization, which is an organization of all segments of the electric industry that recommends, sets, oversees, and implements policies and standards to ensure the continued reliability of North America's bulk electric system.

Nominal Voltage - The root-mean-square, phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. Examples of nominal voltages are 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV and 69 kV. SPP shall evaluate contingencies on the transmission system for all system elements with a Nominal Voltage of 60 kV or greater.

Planned Project - A transmission project, driven by system needs and the recommended solution among considered alternatives, which is a specific commitment to upgrade the transmission system, which has little, if any, outstanding issues, including, but not limited to: budgetary processes, siting, permitting, equipment procurement, installation, regulatory or other approvals, that could delay implementation beyond the expected in-service date.

## 5.3 Coordinated Planning

SPP members operate in a highly interconnected system and shall coordinate transmission planning. This coordination shall include voluntary efforts between interconnected SPP members and non-members. SPP shall be the primary responsible party for coordinated transmission planning.

The planning and development of transmission facilities shall be coordinated with neighboring systems and regions to preserve the reliability benefits of interconnected operations. The transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable NERC Reliability Standards for transmission planning. The MDWG shall annually assemble and verify power flow models, short circuit models, and stability models, which shall be used by SPP staff to check compliance with NERC Reliability Standards for transmission planning. Extreme contingency evaluations shall be conducted to measure the robustness of the transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to understand the risks and consequences of such events and to attempt to limit the significant economic and social impacts that may result.

Sufficient reactive capacity shall be planned within the SPP electric system at appropriate places to maintain transmission system voltages 60 kV and above within plus or minus 5% of nominal voltage on all buses under normal conditions and plus 5% or minus 10% of nominal voltage on load serving buses under single contingency conditions.

### 5.3.1 Planning Criteria

Individual members may develop Planning Criteria that shall, at a minimum, conform to NERC Reliability Standards and SPP Criteria. Individual member Criteria shall consider the following:

(1) Excessive concentration of power being carried on any single transmission circuit, multi-circuit transmission line, or right-of-way, as well as through any single transmission station shall be avoided.

(2) Intra-regional, inter-regional, and trans-regional power flows shall not result in excessive risk to the electric system under normal and contingency conditions as outlined in this criteria.

(3) Switching arrangements shall be planned to permit effective maintenance of equipment without excessive risk to the electric system.

(4) Switching arrangements and associated protective relay systems for all facilities defined in SPP Planning Criteria shall be planned to not limit the capability of a transmission path to the extent of causing excessive risk to the electric system.

(5) Sufficient reactive capacity shall be planned within the SPP electric system at appropriate places to maintain applicable transmission system voltages under base case and contingency conditions.

(6) Facilities shall be rated as assigned in SPP Planning Criteria section 7.

### 5.3.2 Planning Assessment Studies

Individual transmission owners shall perform individual transmission planning studies and shall cooperate in the SPP Transmission Expansion Plan and other SPP coordinated studies. These planning studies are for the purposes of identifying any planning criteria violations that may exist and developing plans to mitigate such violations. Members shall contact the Transmission Working Group whenever new facilities are in the conceptual planning stage so that optimal integration of any new facilities and potentially benefiting parties can be identified. Studies affecting more than one system owner or user will be conducted on a joint system basis. Reliability studies shall examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Updates to the transmission assessments will be performed, as appropriate, to reflect anticipated significant changes in system conditions.

### 5.3.3 Benchmark SPP Models

SPP staff shall benchmark model data against actual SPP system conditions (e.g., generation dispatch, load, and load power factor) which correspond to the time frames for which the models are created. As a minimum the results shall be reported semiannually.

## 5.4 SPP Compliance with NERC Reliability Standards for Transmission Planning

### 5.4.1 Base Case (TPL-001)

All power flow models developed by the MDWG shall be evaluated for compliance with the NERC Reliability Standard for system performance under normal (no contingency) conditions (Category A of Table 1). In addition to the NERC requirements, SPP requires that these models shall conform to the following standards:

(1) Normal Operations - Any established normal (pre-contingency) operating procedures shall be filed by the applicable Transmission Owner with SPP and shall be kept on file by the SPP staff liaison to the SPP MDWG. Normal operations shall reflect a reasonable unit commitment which reflects any contracted or operational limitations. System facilities shall be modeled to reflect normal operation.

(2) Transmission Project Inclusion - All Planned Projects shall be included in the power flow models if the expected in-service date is prior to (i) November 1, for all winter peak cases, and (ii) June 1, for all summer peak cases.

Compliance with NERC Table 1 - Category A System Performance Standards - All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 - Category A, subject to the following clarifications:

(1) Thermal Limits within Applicable Rating - Applicable Rating shall be defined as the Normal Rating per SPP Planning Criteria 7 section 7.2.1.1. The thermal limit shall be 100% of the Applicable Rating

(2) Voltage Limits within Applicable Rating - Applicable Rating shall have the meaning of

Nominal Voltage per Criteria 3. Voltage limits shall be set at plus or minus five percent (+/- 5%) of Applicable Rating.

(3) System Stability - Both dynamic and steady state stability of the Transmission System shall be maintained. Cascading outages shall not occur.

(4) Modeling of Projected Firm Transfers - All contracted firm (non-recallable reserved) transfers shall be maintained. All firm customer demands shall be maintained.

The MDWG shall work with the Transmission Working Group (TWG) to resolve issues not considered data errors.

### 5.4.2 Loss of Single Bulk Electric System Element (TPL-002)

SPP staff shall conduct an assessment of the power flow models by MDWG to assess compliance with the NERC Reliability Standard for system performance following the loss of a single element (Category B). In addition to the NERC requirements, SPP requires that the power flow models conform to the following standards:

(1) Normal Operations - Initiating incident results in a single Bulk Electric System element out of service. Both non-fault and fault initiated events should be evaluated for severity of impact.

(2) Transmission Project Inclusion - All Planned Projects shall be included in the power flow models if the expected in-service date is prior to (i) November 1, for all winter peak cases, and (ii) June 1, for all summer peak cases.

(3) Compliance with NERC Table 1 - Category B System Performance Standards - All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 - Category B, subject to the following clarifications:

(a) Thermal Limits within Applicable Rating - Applicable Rating shall be defined as the Emergency Rating per SPP Planning Criteria 7 section 7.2.1.2. The thermal limit shall be 100% of the Applicable Rating.

(b) Voltage Limits Within Applicable Rating - Applicable Rating shall have the meaning of Nominal Voltage per SPP Planning Criteria 5. Voltage limits shall be set at plus five percent to minus ten percent (+5%/-10%) of Applicable Rating for systems operating at 60 kV or above on load serving buses.

(c) System Stability - Stability of the Transmission System (angular and voltage) shall be maintained. Cascading outages shall not occur.

(d) Modeling of Projected Firm Transfers - All contracted firm (non-recallable reserved) transfers shall be maintained. All firm customer demands shall be maintained.

(4) Loss of Demand - No loss of firm customer demand (except as noted in NERC Reliability Standards Table I, Transmission System Standards - Normal and Emergency Conditions, Footnote b), nor the curtailment of contracted firm (non-recallable reserved) transfers shall be required.

(5) Mitigation Plans - Mitigation plans shall be submitted to SPP to verify effectiveness. Mitigation plans may include Transmission Operating Directives or additional system elements. A mitigation plan is deemed effective if it shall return all system voltages and line and equipment ratings to within the Applicable Rating as defined above. SPP shall document the corrective plans necessary to mitigate effects of those events.

### 5.4.3 Loss of Two or More Elements (TPL-003)

SPP staff shall conduct an assessment of the power flow models by MDWG to assess compliance with the NERC Reliability Standard for system performance following the loss of two or more elements (Category C). In addition to the NERC requirements, SPP requires that the power flow models conform to the following standards:

(1) Normal Operations - Initiating incident may result in two or more (multiple) components out of service. Both non-fault and fault initiated events should be evaluated for severity of impact.

(2) Transmission Project Inclusion - All Planned Projects shall be included in the power flow models if the expected in-service date is prior to (i) November 1, for all winter peak cases, and (ii) June 1, for all summer peak cases.

(3) Compliance with NERC Table 1 - Category C System Performance Standards - All MDWG power flow models shall be tested to verify compliance with the System Performance Standards from NERC Table 1 - Category C, subject to the following clarifications:

(a) Thermal Limits within Applicable Rating - Applicable Rating shall be defined as the Emergency Rating per SPP Planning Criteria 7 section 7.2.1.2. The thermal limit shall be 100% of the Applicable Rating.

(b) Voltage Limits Within Applicable Rating - Applicable Rating shall have the meaning of Nominal Voltage per Criteria 3. Voltage limits shall be set at plus five percent to minus ten percent (+5%/-10%) of Applicable Rating for systems operating at 60 kV or above on load serving buses.

(4) System Stability - Stability of the Transmission System (angular and voltage) shall be maintained. Cascading outages shall not occur.

(a) Modeling of Projected Firm Transfer - All contracted firm (non-recallable reserved) transfers shall be maintained. All firm customer demands shall be maintained.

(i) Loss of Demand - Planned outages of customer demand or generation (as noted in NERC Reliability Standards Table I Transmission System Standards - Normal and Emergency Conditions) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.

(ii) Mitigation Plans - Mitigation plans shall be submitted to SPP to verify effectiveness. Mitigation plans may include Transmission Operating Directives or additional system elements. A mitigation plan is deemed effective if it shall return all system voltages and line and equipment ratings to within the Applicable Rating as defined above. SPP shall document the corrective plans necessary to mitigate effects of those events.

### 5.4.4 Extreme Event (TPL-004)

An extreme event shall have the meaning consistent with Category D of NERC Reliability Standards Table 1, Transmission System Standards - Normal and Emergency Conditions. SPP shall run contingency studies as provided by the transmission owners under the following conditions:

(1) Initiating event(s) shall result in multiple elements out of service.

(2) SPP shall document the measures and procedures to mitigate or eliminate the extent and effects of those events and may at their discretion recommend such measures and procedures where extreme contingency events could lead to uncontrolled cascading outages or system instability.

### 5.4.5 Study Requirements

System contingency studies should be based on system simulation models that should incorporate:

(1) Evaluation of reactive power resources

(2) Existing protection systems

(3) Any existing backup or redundancy protection systems

(4) All projected firm transfers (including rollover rights of long-term firm transactions)

(5) All existing and Planned Projects

These studies shall assist to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in appropriate Category of NERC Reliability Standards Table I, Transmission System Standards - Normal and Emergency Conditions. Studies shall consider all contingencies applicable to the appropriate Category and document the selection rationale. Studies shall be conducted or reviewed annually, shall cover seasonal or expected critical system conditions for near (current or next year) and intermediate (two to five year recommended) planning horizons, and address both intra- and interregional reliability. Detailed analyses of the systems will not be conducted annually if changes to system conditions do not warrant such analyses.

The longer-term (beyond five years) simulations will identify concerns that may surface in the period beyond the more certain intermediate year period. Focus of simulations for the longer term will be on marginal system conditions evident from the intermediate year cases. Cases beyond the five-year horizon will be evaluated as needed to address identified marginal conditions.

### 5.4.6 Mitigation Plans

When simulations indicate an inability of the systems to respond as prescribed by this Criterion, responsible entities must provide a written summary of their mitigation plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon. Mitigation plan summaries should discuss expected required in-service dates of facilities, should consider lead-times necessary to implement plans, and will be reviewed for continuing need in subsequent annual assessments.

### 5.4.7 Transmission Operating Directives

A Transmission Operating Directive qualifies as a valid mitigation measure when the Transmission Operating Directive is effective as written.

### 5.4.8 Reporting Requirements

Entities responsible for the reliability of interconnected transmission systems shall report annually on the performance of their systems in connection with NERC *Reliability Standards* to the SPP Region. The SPP will annually provide a summary of intra- and interregional studies to the NERC. Regional and interregional reliability assessments shall include the results of the system simulation testing as stated in the NERC Reliability Standards.

## 5.5 Interconnection Review Process

Southwest Power Pool Planning Criteria5.3.2 and the Regional Open Access Transmission Tariff both require members to contact the SPP and the Transmission Working Group whenever new transmission facilities that impact the interconnected operation are in the conceptual planning stage so that the optimal integration of any new facilities can be identified. Under this criterion an interconnection involves two or more SPP members or an SPP member and a non-member. A project that creates a non-radial, non-generation interconnection at 69 kV or above or that removes an interconnection at 230 kV or above shall be reviewed for impacts in accordance with Appendix PL-6. A Transmission Service Provider shall be subject to provisions of this criterion.

# 6. Regional Calculation of Available Transfer Capability

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Working Group (TWG) will act as the technical body to determine the ATC to be reported. This Planning Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a “constrained element” approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed “Flowgates”, used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP

Bylaws at the first practical opportunity, with the exception of response factor thresholds for shortterm transmission service which may be approved for immediate implementation by the ORWG subject to subsequent review by the MOPC at the first practical

opportunity. The response factor thresholds for short-term and long-term service are included in Appendix PL-4.

## 6.1 Definitions

### 6.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments.

### 6.1.2 Capacity Benefit Margin

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

### 6.1.3 Contractual Limit

Contractual arrangements between Transmission Providers that define transfer capability between the two.

### 6.1.4 Critical Contingency

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network.

### 6.1.5 Designated Network Resources (DNR)

Any designated generation resource that can be called upon at any time for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load.

### 6.1.6 Emergency Voltage Limits

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency.

### 6.1.7 Firm Available Transfer Capability (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma OATT or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

### 6.1.8 First Contingency Incremental Transfer Capability (FCITC)

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as: "The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

(1) For the existing or planned system configuration, and with normal (precontingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,

(2) The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,

(3) After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any postcontingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

### 6.1.9 Flowgate

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in SPP Planning Criteria Section 6.4.

### 6.1.10 Line Outage Distribution Factor (LODF)

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

### 6.1.11 Local Area Problem

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a

facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

### 6.1.12 Monitored Facilities

Any transmission facility that is checked for predefined transmission limitations.

### 6.1.13 Non-firm Available Transfer Capability (NFATC)

The determined transfer capability available for sale for non-firm Transmission Service as defined by the FERC pro forma OATT for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

### 6.1.14 Normal Voltage Limits

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

### 6.1.15 Open Access Transmission Tariff (OATT)

FERC approved Pro-Forma Open Access Transmission Tariff.

### 6.1.16 Operating Horizon

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to 36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

### 6.1.17 Operating Procedure

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

### 6.1.18 Outage Transfer Distribution Factor (OTDF)

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

### 6.1.19 Participation Factor

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

### 6.1.20 Participation Points

Specified generators that will have their power output adjusted to simulate a transfer.

### 6.1.21 Planning Horizon

Time frame beyond which Hourly transmission service is not offered.

### 6.1.22 Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

### 6.1.23 Power Transfer Voltage Response Factor (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

### 6.1.24 SPP Open Access Transmission Tariff (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

### 6.1.25 Transfer Distribution Factor (TDF)

A general term, which may refer to either PTDF or OTDF -The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

### 6.1.26 Transfer Test Level

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

### 6.1.27 Transmission Owner (TO)

An entity that owns transmission facilities which are operated under a FERC approved OATT.

### 6.1.28 Transmission Provider (TP)

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

### 6.1.29 Transmission User (TU)

Any entities that are parties to transactions under appropriate tariffs.

### 6.1.30 Transmission Reliability Margin (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

### 6.1.31 TRM multipliers (a & b)

(1) "a"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon

(2) "b"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

## 6.2 Concepts

### 6.2.1 Transfer Capability

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

(1) **System Conditions** - Base system conditions are identified and modeled for the period

being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.

(2) **Critical Contingencies** - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

(3) **System Limits** - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TWG.

### 6.2.2 Available Transfer Capability

*NERC Available Transfer Capability Definitions and Determinations*, reference document (June 1996) states: "Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses."

SPP determines ATC as a function of the most limiting Flowgate of the path of interest. Howlimiting a Flowgate is to a path is based on two aspects: (1) The determined firm or nonfirm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

(1) **Firm ATC** = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor (FATC = FAFC/TDF) of the associated path.

Likewise,

(2) **Non-Firm ATC** = the non-firm Available Flowgate Capacity divided by the Transmission Distribution Factor (NFATC = NFAFC/TDF) of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC.

However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non-firm Available Flowgate Capacity or firm Available Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

### 6.2.3 Response Factors

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. The thresholds for several of the following response factors are listed in Appendix PL-4.

(1) Transfer Distribution Factor - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in SPP Planning Criteria section 6.2.4.

(2) Line Outage Distribution Factor - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

(3) Power Transfer Distribution Factor - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. To be considered a valid limit to transfers, a PTDF Flowgate must have a PTDF at or above the applicable shortterm or long-term threshold.

(4) Outage Transfer Distribution Factor - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type

Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability limitations. To be considered a valid limit to

transfers, a Monitored Facility must have an OTDF at or above the applicable short-term or long-term threshold.

(5) Power Transfer Voltage Factor - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. To be considered a valid limit to transfers, a Monitored Facility must have a PTVF at or above the applicable short-term or long-term threshold.

### 6.2.4 Transfer Capability Limitations

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following:

(1) **Thermal Limits** - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.

(2) **Voltage Limits** - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent. The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the SPP Planning Criteria section 5.

(3) **Stability Limits** - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.

(4) **Contractual Requirements**- Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements

are discussed in NERC Operating Policy 3 -Interchange.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time.

### 6.2.5 Invalid Limits

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

(1) An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.

(2) Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.

(3) The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.

(4) The limiting facility is the result of over-generation/under-generation at a participation point.

(5) The contingency is considered improper implementation of an operating procedure.

(6) The facility represents an equivalent circuit.

(7) The limiting facility is declared a Local Area Problem.

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

### 6.2.6 Flowgates

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

(1) OTDF Flowgate; Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.

(2) PTDF Flowgate; Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot exceed a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce. To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

### 6.2.7 Total Flowgate Capacity (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined. A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in SPP Planning Criteria section 6.2.4.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.

Again, limit types could be:

(1) Thermal limits under normal operating conditions or linked contingency events,

(2) Voltage limits under normal operating conditions or linked contingency events,

(3) Stability limits under normal operating conditions or linked contingency events, or

(4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing. Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC) which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path.

## 6.2.8 Flowgate Capacity

### 6.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

### 6.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC -FBL -Impacts of existing commitments -transmission margins

### 6.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the AFC remaining for path ATC. AFC is classified as firm or on firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for AFC:

(AFC = TFC -FBL -Impacts of existing commitments -transmission margins).

### 6.2.9 System Impacts

#### 6.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted - carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

(1) Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.

(2) Adjust for reservations that may have changed status or have been replaced by another reservation, including renewals and redirects.

(3) Check for proper reflection of capacity profiles of reservations.

(4) Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

#### 6.2.9.2 Positive Impacts

The scope of “Impacts of existing commitments” in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the “Impacts of existing commitments” in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

#### 6.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling.

### 6.2.10 Monitored Facilities

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners. In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

### 6.2.11 Critical Contingencies

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multiterminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

## 6.3 Reliability Margins

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system's constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power

between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

### 6.3.1 Transmission Reliability Margin (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM:

(1) Load Forecast

Transmission Providers will forecast hourly load for the next seven days for all applicable control areas. Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.

(2) Variations in Generation Dispatch

Variations to generation patterns constitute a viable concern. Generation dispatch in nearterm models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.

(3) Unaccounted Parallel Flows

Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling

parties are not identified. Provisions in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions. Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted Flowgates from the TWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The TWG shall have the authority to grant or reject requests for the additional TRM requests.

(4) SPP Operating Reserve Sharing

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.

(5) Counter Flow Impacts

Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

### 6.3.2 TRM Coordination

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions. As such it is not necessarily an import or export quantity specifically. The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP

Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner/s, subject to review by the SPP TWG.

### 6.3.3 TRM Availability for Non-firm Service

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The 'a' and 'b' multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

### 6.3.4 TRM Calculation Frequency

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (Spring, Summer, Fall, Winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TWG shall have authority to reject or grant such requests.

### 6.3.5 Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 10.7% capacity margin (equivalent to a 12% reserve margin) for steam-based utilities and 9% for hydro- based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin. SPP does not utilize CBM for calculations of ATC for some or all of the following reasons:

(1) the existing level of internal capacity margin of each member is adequate

(2) historical reliability indicators of transmission strength of the SPP area

(3) Open Access transmission usage environment allows greater purchasing options

Since SPP does not utilize CBM for any flowgate within the SPP footprint, the CBM value used in any calculations will be zero.

## 6.4 Flowgate and TFC Determination

The Flowgates used by SPP to administer the Regional Tariff serve as a proxy of the transmission system. It is therefore essential to the reliable operation of the transmission system for the set of Flowgates to adequately represent the transmission system.

### 6.4.1 Flowgate Updates

Updating the list of Flowgates is a continual process. Flowgate additions and deletions and changes in TFC are the result of studies, analyses, and operating experience of SPP and its member Transmission Owners. At any time during the year, the owner of transmission facilities may require that a set of facilities be used as a Flowgate to protect equipment or maintain system reliability, regardless of the ownership of that set of facilities. SPP will update the Flowgate list as needed. The responsibility for reviewing and monitoring the list will be shared between the individual Transmission Owners, the TWG, the Operating Reliability Working Group (ORWG) and the SPP staff. Updating the Flowgate list may or may not require running a study. If the Transmission Owner is to perform a study, they are responsible for gathering accurate information from neighboring Transmission Owners. The following requirements apply when adding a Flowgate to the list:

(1) Transmission Owners may add OTDF Flowgates, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no operating procedures apply to that Flowgate.

(2) Transmission Owners may add PTDF Flowgates, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no operating procedures apply to that Flowgate.

(3) All other Flowgates proposed by Transmission Owners must have TWG and ORWG

approval. The Reliability Authority can provide interim approval until the TWG and ORWG can convene to assess the request. Examples of such Flowgates are PTDF Flowgates with two or more elements, OTDF Flowgates with three or more elements, or

Flowgates involving operating procedures.

There may be times when significant topological changes occur during operations that create

unexpected loadings on facilities not explicitly modeled as Flowgates. During these conditions, the Reliability Coordinator will work with the Transmission Owner(s) to develop a commercial Flowgate representative of the conditions present. Any such additions will be analyzed at the next Flowgate evaluation to determine if they should remain in the permanent list of Flowgates.

### 6.4.2 Annual Review

In addition to the continual studies and analyses, the Flowgate list will also be reviewed annually by the TWG using seasonal power flow models. This annual assessment will be performed

following the January SPP Model Development Work Group (MDWG) release of each year's load flow cases. This review is intended to serve as a tool by which the TWG, the Transmission Owners, and the SPP may assess the adequacy of the existing list of Flowgates and thereby recommend necessary additions, deletions, and TFC changes. In order to accomplish this assessment, the process herein described will be used to identify the most limiting elements for a variety of transfer directions. Although transfer values will be involved in this process, this process is not intended to produce any viable ATC values for use commercially or otherwise. Rather, ATC values are determined as described in SPP Planning Criteria section 6.5.

#### 6.4.2.1 Power Flow Models

The power flow models to be used in the process will be based on the models developed annually by the SPP MDWG. Application of the models will use the following season definitions. The Summer Model will apply to June through September, the Fall Model will apply to October and November, the Winter Model will apply to December through March and the Spring Model will apply to April and May. Each of these seasonal models developed will represent peak models. In addition, for the summer season only, a Summer Shoulder Case representing a reduced load level, as specified in the MDWG Powerflow Procedure Manual, will be used in the determination process.

#### 6.4.2.2 Parameters supplied by the Transmission Owners

In order to simulate a transfer, certain parameters must be known. These include the participation points of MW increase/decrease and the participation factor of these points. These items will be supplied to SPP by the Transmission Owners.

Participation points for exports will primarily be points of generation within the sending area. Generators that are off-line may be turned on to participate in a transfer. A Transmission Owner

can specify generators to be excluded from use as participation points, such as generators that serve base load. The participation points used for export will be consistent for all transfer directions.

The participation points for imports will primarily be points of generation reduction within the receiving area. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The generation reduction should be based on economics, operating constraints or other criteria as specified by the Transmission Owner. The participation points used for import will be consistent for all transfer directions.

Other parameters that must be supplied by the Transmission Owners include the following:

(1) A contingency list including all critical single contingencies (both transmission and generation) as well as multi-terminal facilities.

(2) All contingencies suspect of causing voltage limitations and the transfers for which they should be studied.

(3) Any additional facilities below 100 kV to be monitored.

(4) High and low voltage limits for system and/or individual buses.

(5) All Contractual Requirements.

#### 6.4.2.3 Default Parameters

The following parameters will be used in the event that a Transmission Owner does not submit the area specific parameters:

(1) For exports, the participation points will include all on-line generating facilities in the model with unused generating capacity available.

(2) The export participation factors will be the amount of unused generating capacity at each point divided by the sum of the unused generating capacity at all export participation points. (i.e., PMAX-PGEN).

(3) For imports, all on-line generators will be decreased prorated by their capable generation (i.e., PGEN-PMIN).

(4) Transfer directions will be a set of all commercial paths.

(5) Exports from merchant power plants will be considered in the determination of Flowgates.

(6) The transfer test levels are specified at the time of the ATC calculations, and are determined by SPP staff.

(7) All facilities 100 kV and above will be included in the contingency list and the monitored facility list. In addition, the largest unit within the area will be included in the contingency list.

(8) Voltage limits will be as specified in SPP Planning Criteria section 5.

#### 6.4.2.4 Voltage Limits

Voltage limits are network and system dependent. Each Transmission Owner will submit an acceptable set of Normal Voltage Limits and Emergency Voltage Limits to be applied for the purpose of Flowgate and TFC determination.

#### 6.4.2.5 Linear Analysis and AC Verification

SPP will perform DC linear analysis studies estimating the import or export ability of the identified commercial paths using a combined linear evaluation of the network models with a follow up AC verification of a minimum of the first three valid operational limitations. Specific AC analysis will also be performed on any specified contingency/transfer combinations noted as voltage limiting contingencies. Monitored Facilities, Contingency Facilities and Participation Points will be implemented as described in SPP Planning Criteria sections 4.4.2.2 and 4.4.2.3 as applicable.

#### 6.4.2.6 Operating Procedures

Operating Procedures are available and may increase the Total Flowgate Capacity of a Flowgate when implemented. Implementation of any available Operating Procedures will be done using a full AC solution to determine the correct limit to be placed on a Flowgate. Any operationally increased Total Flowgate Capacities established will be so noted.

#### 6.4.2.7 Identification of Flowgate Changes

TWG will review the FCITC results of the power flow models and selected paths and identify whether any Flowgates should be added, removed, or changed to better represent the SPP transmission system.

A minimum of the first three valid FCITC limitations to each path will be AC verified. When all paths have been evaluated, the TWG will review the AC verification results and, where needed, the linear results for consideration as potential Flowgates.

Typically, new Flowgates should be either OTDF Flowgates with a TFC representing the total amount of power that can flow during a contingency without violating the emergency rating of the monitored facility or single facility PTDF Flowgates with a TFC equal to the normal rating of

the single facility. In situations involving operating procedures the TFC may be higher than the facility ratings.

The TWG will then determine any needed changes to the existing list of Flowgates. The number of times elements appear as one of the most limiting components for transfers, the rank in the list of most limiting elements, and the TDF level will be the primary factors considered in making the determination. Flowgates can also be developed to represent identified Voltage Limitations and Contractual Requirements.

#### 6.4.2.8 Review and Coordination with Transmission Owners

Each SPP Transmission Owner will have the option of naming a representative to review the results of the Flowgate review or deferring to the TWG finalization of the results. Summary sheets of all interfaces or paths calculated will be communicated to the representatives for review. All data will be made available for review upon request. The results will be approved by the TWG before being reported.

The Transmission Owner should review the TWG proposed Flowgate changes and consider their own operating experience and study results. Any modifications to the TWG proposed changes should be returned to the TWG. Further dialog and justification may be required of a

Transmission Owner if the TWG has concerns about their modifications.

TWG will draft a final Flowgate list, incorporating the comments of the Transmission Owners. The Transmission Owners should approve any additions, deletions, or changes to the Flowgate list.

#### 6.4.2.9 Initiating Interim Review of Flowgate List

Operational condition changes, especially status changes of EHV transmission facilities and large generators, may warrant a partial or full evaluation of the list of Flowgates. A review may also be necessary due to multiple schedules being implemented causing parallel flows.

Transmission Owners will have access to copies of the SPP models and all relevant data used for the annual review. Transmission Owners may at any time request a re-run of the Flowgate evaluations. The Transmission Owner requesting the re-run shall provide their reasons for requesting the re-run to the TWG for consideration. Should the TWG deem a re-run necessary, the SPP staff will perform the additional evaluation.

### 6.4.3 Dispute Resolution

If there is a dispute concerning a Flowgate, the questioning party must contact SPP and the Transmission Owner(s) involved to resolve the dispute.

Examples of reasons for disputing a Flowgate may include:

(1) The contingency used for the Flowgate is not valid.

(2) There is an operating procedure that corrects the violation that is not being properly taken into account.

(3) An operating procedure is being taken into account in an improper manner yielding an incorrect TFC.

If the parties involved do not reach agreement on the selected Flowgates, the SPP TWG will review all of the arguments. Additional analyses will be performed if necessary. SPP TWG will then make a final determination. If a party still wishes to dispute the Flowgate, the SPP Dispute Resolution policy described in Section 2 of the SPP By-laws may be initiated.

### 6.4.4 Coordination with Non-SPP Members

Flowgates involving transfers on interfaces and paths between SPP Transmission Owners and non-SPP Transmission Owners will be coordinated by the parties involved and the TWG.

### 6.4.5 Feedback to SPP Members

The SPP staff shall maintain a table of all Flowgates on the SPP OASIS. The table shall include all Flowgate data, which are applicable, including the Flowgate name, monitored facility, contingency facility, Flowgate rating, TRM, CBM, a and b multipliers, LODF, the TDF basis for the Flowgate (OTDF or PTDF), and the TDF cutoff threshold. This table shall be updated with any new information on or before the first of each month.

## 6.5 ATC Calculation Procedures

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as predetermined limiting constraints to power transfer. The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within this Criteria.

Determination of ATC via Flowgates adheres to the following approach:

(1) establishes a network representation (power flow model)

(2) identifies potential limits to transfer (thermal, voltage, stability, contract)

(3) determines response factors of identified limits relative to transfer directions (TDF)

(4) determines impacts of existing commitments (firm, non-firm)

(5) applies margins (TRM, CBM, a & b multipliers)

(6) determines maximum transfer capabilities allowed by limits and applied margins ( ATC, FATC, NFATC)

### 6.5.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests and provided on a monthly basis to the Transmission Providers in adequate time to post the information on OASIS nodes by the 1st of each month.

Hourly, Daily and Weekly ATC shall be calculated on a daily basis and posted at the time of run. SPP will also provide commercial path conversions to any individual providers needing that information to administer their own tariff. Hourly ATC shall be calculated for 12 to 36 hours ahead depending on time of day. SPP has a firm scheduling deadline at 12:00 noon of the da y prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. At this point SPP will calculate hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again. Again SPP will provide commercial path conversions for any SPP provider that needs them for posting on their own OASIS nodes.

### 6.5.2 Power Flow Models

The monthly calculation of Flowgate based ATC will be made using rolling seasonal models that produce an update for the upcoming sixteen month service window (12 month multi-month service + 4 months advance notice). For example, the required data update for January of any year will yield data for January thru December plus the next January, February, March and April of the following year. The necessary seasonal models will be selected from the approved SPP MDWG set to represent this time frame. Any known system changes/corrections to these models will be included. SPP will routinely calculate ATC for the upcoming 16-month service window. Monthly models will be updated/developed from the latest seasonal models to represent individual months for the purpose of capturing operational conditions that may be unique from other monthly models.

### 6.5.3 Base Loading, Firm and Non-Firm (FBL & NFBL)

Model base flows provide the basis for which to begin determination of Available Flowgate

Capacity. However, there are many transactions within the monthly models that are duplicated

on the OASIS. A record of the network model flows of each Flowgate as found in the solved network models will be used as a beginning point to account for impacts of base case transactions and existing commitments. The impacts on Flowgates due to transactions outside the purpose of representing designated Network Resource exchange will be removed by applying the TDF factors determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and counter impacts of existing OASIS commitments will be applied according to the type of Base Loading (Firm or Non-Firm) under consideration. In non-firm Base Loading, 50% of Counter Impacts resulting from firm Confirmed reservations will act to reduce the overall Base Loading figure. This process will establish the base loading expected with each control area serving its firm Network Load.

### 6.5.4 Transfer Distribution Factor Determinations (TDF)

For export and import participation points all on-line generators, unless otherwise denoted (e.g., nuclear units), will be scaled prorated by their machine base (MBASE). TDF data will be calculated for all commercial paths using the most current participation data, ATC models and Flowgate list on a monthly basis.

### 6.5.5 Existing Commitments and Netting Practices

Existing commitments resulting from Confirmed, Accepted and Study reservations on the SPP OATT OASIS nodes will be considered and accounted for in the determination of Available Flowgate Capacity. Accounting for the impact of existing commitments is a key part of the process for determining which new transfers will be allowed, unlike the TLR implementation process which involves determining which existing transfers must be curtailed. Therefore, unlike TLR implementation which requires a minimum TDF threshold, all positive impacts from existing commitments must be applied without using a minimum TDF threshold. Impacts from these commitments will be applied according to the future time frame of which they are applicable. These time frames are discussed below:

#### 6.5.5.1 Yearly Calculations (whole years, starting 60 days out)

A Yearly transmission service request is defined as a service request with a duration of greater than or equal to 1 year in length. The evaluation of Available Transfer Capability for this service

type is performed utilizing solved network models with existing OASIS commitments figured in as net area interchange values. In addition to monitoring Flowgates, standard N-1 contingency analyses will be performed to study the impact of yearly transmission requests on the

transmission system. The long-term threshold is shown in Appendix PL-4 and is applied to all elements above 60kV.

#### 6.5.5.2 Monthly Calculations (months 2 through 16)

The impacts of OASIS reservations that are Confirmed, Accepted and in Study mode will be applied to each Flowgate according to the TDF values determined. All positive impacts on a Flowgate due to these types of reservations decrease ATC. 100% of counter flow impacts due to reservations supplying Designated Network Resources are allowed to increase ATC. For non-firm service, up to 50% of the counter-flows due to all firm Confirmed reservations will be allowed on a Flowgate. The combined positive impacts and counter flow impacts will be added to the base flows to determine Available Flowgate Capacity for the Monthly calculation.

#### 6.5.5.3 Daily and Weekly Calculations (Day 2 through 31)

For Daily and Weekly calculations, composite area interchange values will be determined by integrating all OASIS Confirmed and Accepted reservations into projection models. Base flows will be determined by the projection models. The impacts of OASIS reservations that are in Study mode will be applied to each Flowgate according to the TDF values determined. Positive impacts on a Flowgate due to Confirmed reservations that are not expected to be scheduled based on actual historical scheduling data will be removed and allowed to increase firm Available Flowgate Capacity. Counter flow impacts of Confirmed reservations that are expected to be scheduled based on actual historical scheduling data will be allowed to increase firm Available Flowgate Capacity. Up to 50% of the counter flow impacts due to all firm Confirmed reservations will be allowed to increase non-firm Available Flowgate Capacity.

#### 6.5.5.4 Hourly Calculations (Day 1)

These calculations are for hourly non-firm service only. All known schedule information from NERC Electronic-tags will be applied to base flow calculations. These schedules determine base interchange values. Since these are expected schedules, all counter flow impacts are allowed in this calculation. OASIS reservation information is not considered for determination of existing impacts in this calculation.

### 6.5.6 Partial Path Reservations

Requests made on individual Transmission Provider's tariffs require two or more reservations to complete a transaction resulting in a partial path reservation. The SPP OATT offers service out of, into and across SPP and between SPP members with a single reservation. For transmission

service under the SPP OATT, only reservations with valid sources and sinks are allowed. However, to avoid double accounting of Flowgate and system impacts due to duplicate reservations documented on Transmission Provider OATT OASIS nodes from partial path

reservations, necessary means will be incorporated to recognize these related reservations and determine the correct singular impacts.

### 6.5.7 ATC Adjustments Between Calculations

ATC will be adjusted following receipt of any valid SPP OASIS node reservation. The requested capacity will be multiplied by the TDF on all affected Flowgates and the resulting amounts will be subtracted from each Flowgates'ATC and posted to the OASIS.

### 6.5.8 Coordination of Transmission Commitments with Neighboring Organizations

Coordination of dispatch information, Confirmed firm and non-firm system commitments from neighboring regions, RTO's, ISO's etc. will be conducted as appropriate to each type of ATC being determined to establish the most accurate system representation of base flows and generation profiles. External reservations may be retrieved from other OASIS sites or locations designated by neighboring Transmission Providers.

### 6.5.9 Margins

Identified TRM and CBM will be applied to each Flowgate as described in SPP Planning Criteria section 6.3.

### 6.5.10 ATC Determination

The following equations are used in ATC determination:

#### 6.5.10.1 Firm Base Loading (FBL)*, **:

Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted and Study) - (100% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments for DNR only)

#### 6.5.10.2 Non-Firm Base Loading (NFBL)*, **:

Non-Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm and Non-Firm OASIS Commitments, Confirmed, Accepted and Study) - (up to 50% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments)

### 6.5.10.3 Firm Available Flowgate Capacity (FAFC):

Firm Available Flowgate Capacity = (Total Flowgate Capacity) - (TRM) - (CBM) - (Firm Base Loading)

**6.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon):**

Non-Firm Available Flowgate Capacity, Operating Horizon = (Total Flowgate Capacity) -(b*TRM) -(CBM) -(Non-Firm Base Loading)

**6.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning Horizon):**

Non-Firm Available Flowgate Capacity, Planning Horizon = (Total Flowgate Capacity) - (a*TRM) -(CBM) -(Non-Firm Base Loading)

**6.5.10.6 Firm Available Transfer Capability (FATC):**

Firm ATC = Most limiting value from associated Flowgates = Min {Firm Available Flowgate Capacity/TDF of appropriate path}

**6.5.10.7 Non-Firm Path Available Transfer Capability (NATC, Operating Horizon):**

Non-Firm ATC, Operating Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Operating Horizon/TDF of appropriate path}

**6.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon):**

Non-Firm ATC, Planning Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Planning Horizon/TDF of appropriate path}

*Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service.

** Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

SPP will calculate the ATC for each of its Transmission Providers on their direct interconnections (either physical interconnections or by rights to a line) and any interface or path requested by a Transmission Provider to fulfill its obligations under FERC Order 889. The ATC for

requested interfaces or paths will be calculated only if requested by the Transmission Provider obligated to post the interfaces or paths.

### 6.5.11 Annual Review of ATC Process

The SPP TWG will conduct an annual review of the Regional ATC determination process including TRM and CBM to assess regional compliance with NERC requirements, regional reliability needs and functionality toward SPP Transmission Owners and Users. This review will be held at the same time as the Flowgate Evaluation process. The applicable long-term TRM is listed in Appendix PL-4.

SPP will conduct a survey of the Transmission Owners and Users and the results will be published on the SPP website. Concerns that are identified from the survey will be forwarded to the appropriate SPP Committee.

### 6.5.12 Dialog with Transmission Users

Transmission Users may contact the TWG with any concerns regarding this criterion, its implementation, or the resulting ATC values. The concerns should be in writing and sent to the chair of the TWG. The chair will then draft a written response to the Transmission User containing either an answer or a schedule for when such an answer can be provided. If the Transmission User is not satisfied, the concerns can be sent to the chair of the Markets and Operations Policy Committee.

# 7. Electrical Facility Ratings

## 7.1 Accredited Net Generating Capacity

This Section shall be used to determine the annual and seasonal accredited net generating capacity of generators in calculating the capacity/reserve margin. Procedures are herein for establishing a system of records so that changes in capacity during the life of the equipment can be recognized. These procedures define the framework under which the net generating capacity are to be established while recognizing the necessity of exercising judgment in their determination. The terms defined and the net generating capacity established pursuant to these procedures shall be used for SPP purposes, including determining capacity margins for capacity planning and preparation of reports of other information for industry organizations, news media, and governmental agencies. These net generating capacity are not intended to restrict daily operating practices associated with SPP operating reserve sharing, for which more dynamic ratings may be necessary. Each member shall test its generating equipment in accordance with the procedures contained herein. On the basis of these tests summer and winter net capability ratings for each generating unit and station on the member's electric system shall be established. This net capability is the maximum capacity a unit can sustain over a specified period modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries. The summer net capability of each unit may be used as the winter net capability without further testing, at the option of the member. As a minimum, each member shall conduct tests on all its generators that are designated as a part of the resource for supplying a member's peak load and minimum capacity/reserve margin requirement of this Criteria. The seasonal net capabilities shall be furnished to SPP for all existing generating units and upon installation of new generating units and shall be revised at other times when necessary. Members shall annually report the seasonal net generating unit capability in conjunction with the Department of Energy 411 Report data gathering effort.

### 7.1.1 Accredited Capability Test

Capability Tests are required to demonstrate the claimed capability of all synchronous generating units, excluding run-of-the-river hydroelectric plants and wind/solar plants. During a Capability Test, a unit shall generate its rated net capability for a minimum of one hour period. Only minor changes in unit controls shall be made during this time as required to bring the unit into normal, steady-state operation.

### 7.1.2 Operational Test

An Operational Test is used to demonstrate the ability of a generating unit to be loaded to its nominal rating. Operational tests shall be conducted at a minimum of 90% of claimed member's peak season capability for a minimum of 1 hour. Any normal operating hour with the unit at or above 90% of claimed capability may be deemed an Operational Test.

### 7.1.3 Frequency of Testing

Summer Capability Tests shall be conducted once every 5 years. If the winter capability rating is greater than summer, winter tests shall also be conducted once every 5 years. Operational Tests shall be conducted once every year during the member's peak season. New units or units undergoing a physical or operational modification which could impact capability shall be given a capability test.

### 7.1.4 Net generating capacity and Testing Conditions

Ambient conditions at the time of running capability tests shall be recorded so that appropriate adjustments can be made when establishing seasonal capabilities. Conditions to be recorded are: dry-bulb temperature, wet-bulb temperature, barometric pressure, and condenser cooling water inlet temperature. Summer Capability Tests are to be conducted at an ambient temperature within 10 degrees Fahrenheit of Rating dry-bulb temperature.

Winter Capability Tests are to be conducted at an ambient temperature equal to or greater than the minimum dry-bulb temperature for winter testing and rating defined in paragraph SPP Planning Criteria 7.1.5.2.(7).

### 7.1.5 Procedures For Establishing Capability Ratings

#### 7.1.5.1 External Factors

(1) Units dependent upon common systems which can restrict total output shall be tested simultaneously.

(2) When the total output of a member's system is reduced due to restrictions placed upon the

output of individual generating units through the operation of the Clean Air Act, or similar legislation, then the total of the individual unit ratings of a member's generating resources shall not exceed the modified system capacity.

(3) The fuel used during testing shall be the general type expected to be used during peak load conditions or adjustments made to test data if an alternate fuel is used.

(4) Net Capability is the net power output which can be obtained for the period specified on a seasonally adjusted basis with all equipment in service under average conditions of operation and with the equipment in an average state of maintenance. Deductions from net capability shall not be made for equipment temporarily out of service for normal maintenance or repairs.

(5) The seasonal net capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others, except that in the event multiple unit plant capability is limited by fuel limitations, transmission limitations or other auxiliary devices or equipment, each unit shall be assigned a net generating capacity by apportioning the combined capability among the units. The seasonal net capability shall be determined as a group for common header sections of steam plants or multiple unit hydro plants, and each unit shall be assigned a net generating capacity by apportioning the combined capability among the units.

### 7.1.5.2 Seasonality

(1) The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February, and March. The adjustments required to develop seasonal net capabilities are intended to include seasonal variations in ambient temperature, condenser cooling water temperature and availability, fuel changes, quality and availability, steam heating loads, reservoir levels, scheduled reservoir discharge, and wind speed.

(2) The total seasonal net capability rating shall be that available regularly to satisfy the daily load patterns of the member and shall be available for a minimum of four continuous hours taking into account possible fuel curtailments and thermal limits.

(3) The seasonal net capability of each generating unit shall be based upon a set of conditions, referred to as the "Net generating capacity Conditions" for that unit. This set of conditions is determined by the geographical location of the unit, and is composed of three or four factors, depending upon the type of unit. The three factors which can affect most generating units are: Ambient dry-bulb temperature, Ambient wet-bulb temperature and Barometric pressure. Condensing steam turbines which obtain condenser cooling water from a lake, river, or comparable source have a fourth factor: Condenser cooling water source temperature.

(4) The Rating dry-bulb and wet-bulb temperatures shall be obtained from weather data provided in the most recently published American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook, Chapter 27 Climatic

Design Information. The handbook is published every four years; 1997, 2001, etc., and is based on 15 years of historical weather data where available. If the generating station is within 30 miles of the nearest weather station reported in the Handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. The steps to be used for interpolating weather data and correcting for elevation are presented in SPP Criteria Appendix PL-1.

(5) If experience for a given unit suggests otherwise, members may optionally use their own site specific temperature data if accurate hourly data is available to allow calculation of the temperature levels as defined in the Criteria. Site specific data shall contain both drybulb and wet-bulb temperatures.

(6) Temperatures for summer rating of equipment should be taken from Handbook Table 1B: Cooling and Dehumidification Design Conditions - Cooling DB/MWB for 0.4% DB (dry-bulb) and MWB (mean wet-bulb) (Column 2a and 2b, respectively). According to the 2001 Handbook Page 27.2, "The 0.4% annual value is about the same as the 1.0% summer design temperature in the 1993 ASHRAE Handbook." In older Handbooks, the dry-bulb temperature for summer rating of equipment shall be taken as that which is equaled or exceeded 1% of the total hours during the months of June through September for the plant's geographical location. The wet-bulb temperature for the summer rating shall be the "mean coincident wet-bulb" temperature corresponding to the above dry-bulb temperature.

(7) The temperature for winter rating of equipment should be taken from Handbook Table 1A: Heating and Wind Design Conditions-United States - Heating Dry Bulb 99% (Column 2b). According to the 2001 Handbook Page 27.3, "Annual 99.6% and 99.0% design conditions represent a slightly colder condition than the previous cold season design temperatures, although there is considerable variability in this relationship from location to location." In older Handbooks, the minimum dry-bulb temperature for winter testing and net generating capacity shall be taken as that which is equaled or exceeded 99% of the total hours during the months of December through February (per Handbook definition) for the plant's geographical location. The wet-bulb temperature is not significant for the winter rating and can be disregarded.

(8) Standard barometric pressure for a plant site shall be determined for each plant elevation from the equation provided in Appendix PL-1.

(9) For those units using a lake or river as a source of condenser cooling water, the summer standard inlet temperature is the highest water inlet temperature during the month

concurrent with the Load Serving Member's peak load of the year, averaged over the past ten years.

(10) Ambient wet-bulb temperature and condenser cooling water temperature are generally not significant factors in adjusting cold weather capability of generating units. Shall special situations arise in which these temperatures are required, reasonable estimates for temperatures occurring coincidentally with the winter rating dry-bulb temperature as defined in the Criteria shall be used.

### 7.1.5.3 Net Generating Capacity Adjustments

(1) The rated net capability of a unit may be above or below the actual tested net generation as a result of adjustments for Net generating capacity Conditions, with the exception of units with winter season net generating capacity greater than their summer net generating capacity. For these units, the winter season rated net capability shall be no greater than the actual tested net generation. No net generating capacity adjustment for ambient conditions shall be made.

(2) Seasonal net capability shall not be reduced to provide regulating margin or spinning reserve. It shall reflect operation at the power factor level at which the generating equipment is normally expected to be operated over the daily peak load period.

(3) Extended capability of a unit or plant obtained through bypassing of feed-water heaters, by utilizing other than normal steam conditions, by abnormal operation of auxiliaries in steam plants, or by abnormal operation of combustion turbines or diesel units may be included in the seasonal net capability if the following conditions are met; a) the extended capability based on such conditions shall be available for a period of not less than four continuous hours when needed and meets the other restrictions, and b) appropriate procedures have been established so that this capability shall be available promptly when requested by the system operator.

(4) The seasonal net capability established for nuclear units shall be determined taking into consideration the fuel management program and any restrictions imposed by governmental agencies.

(5) The seasonal net capability established for hydroelectric plants, including pumped storage projects, shall be determined taking into consideration the reservoir storage program and any restrictions imposed by governmental agencies and shall be based on median hydro conditions.

(6) The seasonal net capability established for run-of-the-river hydroelectric plants shall be determined using historical hydrological data on a monthly basis.

(7) The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

(a) Assemble all available hourly net power output (MWH) data measured at the system interconnection point.

(b) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.

(c) Select the hourly net power output value that can be expected from the facility 60% of the time or greater. For example, for a 5 year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.

(d) A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the Load Serving Entity's peak load month of the season of interest (e.g., 22 hours for a typical 30 day month and 110 hours for a 5 year period).

(e) Facilities in commercial operation 3 years or less:

(i) The data must include the most recent 3 years.

(ii) Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific data.

(iii) If the Load Serving Entity chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the Load Serving Entity may submit 5% for wind facilities and 10% for solar facilities of the site facility's nameplate rating.

(f) Facilities in commercial operation 4 years and greater:

(i) The data must include all available data up to the most recent 10 years of commercial operation.

(ii) Only metered hourly net power output (MWH) data may be used.

(iii) After three years of commercial operations, if the Load Serving Entity does not perform or provide the net capability calculations to SPP as described above, then the net capability for the resource will be 0 MW.

(g) The net capability calculation shall be updated at least once every three years.

## 7.2 Rating of Transmission Circuits

Each SPP member shall rate transmission circuits operated at 69 kV and above in accordance with this criteria. A transmission circuit shall consist of all elements load carrying between circuit breakers or the comparable switching devices. Transformers with both primary and secondary windings energized at 69 kV or above are subject to this criteria. All circuit ratings shall be computed with the system operated in its normal state (all lines and buses in-service, all breakers with normal status, all loads served from their normal source). The circuit ratings will be specified in "MVA" and are taken as the minimum ratings of all of the elements in series. The minimum circuit rating shall be determined as described in this criteria and members shall maintain transmission right-of-way to operate at this rating. However, SPP members may use circuit ratings higher than these minimums. Each element of a circuit shall have a normal and an emergency rating. For certain equipment, (switches, wave traps, current transformers and circuit breakers), these two ratings are identical and are defined as follows:

(1) NORMAL RATING: Normal circuit ratings specify the level of power flow that facilities can carry continuously without loss of life to the facility involved.

(2) EMERGENCY RATING: Emergency circuit ratings specify the level of power flow that a facility can carry for the time sufficient for adjustment of transfer schedules, generation dispatch, or line switching in an orderly manner with acceptable loss of life to the facility involved.

At a minimum, each member shall compute summer and winter seasonal ratings for each circuit element. The summer season is defined by the months June, July, August and September. The winter season is defined by the months December, January, February and March. The seasonal rating shall be based upon an ambient temperature (either maximum or average) developed using the methodology described in Appendix PL-2.A. A member may elect to compute a third set of

seasonal ratings for the remaining months of the year (April, May, October and November). If that election is not made, summer ratings shall be used for these remaining months.

### 7.2.1 Power Transformer

Power transformer ratings are discussed in ANSI/IEEE C5791, IEEE Guide for Loading MineralOil-Immersed Power Transformers. Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55°C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

#### 7.2.1.1 Normal Rating

The normal circuit rating for power transformers shall be its highest nameplate rating. The nameplate rating shall include the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

#### 7.2.1.2 Emergency Rating

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The emergency circuit rating for power transformers shall be a minimum of 100% of its highest nameplate rating. Member systems may use a higher emergency rating if they are willing to experience more transformer loss-of-life.

#### 7.2.1.3 Loss of Life

In ANSI/IEEE C57.91, a 65°C rise transformer can operate at 120% for an 8 hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences 4 incidents where it operates at or below 120% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year. In ANSI/IEEE C57.91, a 55°C rise transformer can operate at 123% for an 8 hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences 4 incidents where it operates at or below 123% for an 8 hour peak load cycle, it will still be within the target of 1% loss of life per year.

#### 7.2.1.4 Ambient Temperature

Average ambient temperature is an important factor in determining the load capability of a transformer since the temperature rise for any load must be added to the ambient to determine operating temperature. Transformers designed according to ANSI standards use a 30°C average

ambient temperature (average temperature for 24 consecutive hours) when setting nameplate rating. Transformer overloads can be increased at lower average ambient temperatures and still experience the same loss of life. This allows seasonal ratings with higher normal and emergency

ratings. However, this circuit rating criteria does not call for seasonal transformer ratings. In ANSI/IEEE C57.91, transformers can be loaded above 110% and experience no loss of life when the average ambient temperature is below 78°F. By not having seasonal ratings, the four occurrences that contribute to loss of life are limited to days when the average ambient temperature exceeds 78°F. The Power Transformer Rating Factors include:

(1) Nameplate rating, normal loss of life for 55°C and 65°C rise transformers with cooling equipment operating.

(2) Average ambient temperature, 30°C.

(3) Equivalent load before peak load, 90% of nameplate rating.

(4) Hours of peak load, 8 hour load cycle.

(5) Acceptable annual loss of life, 1%.

### 7.2.2 Overhead Conductor

Overhead conductor ratings are discussed in IEEE Standard 738, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors. Ampacity values are to be determined using the fundamental heat balance equation outlined in the House and Tuttle method. Because of the amount and complexity of the equations, this method lends itself to computer application. The recommended computer programs to be used for this calculation either include the BASIC program listed in Annex B of IEEE Standard 738 or an equivalent program, such as the DYNMAP program which is part of the EPRI TLWorkstation ™ software package. While tables and graphs may be convenient to use, they fail to take into account the geographic location of the line and often lack either the desired ambient temperature and/or the desired conductor temperature. The use of tables and graphs is not acceptable.

#### 7.2.2.1 Conductor Properties

Some computer programs used to compute ampacity values have a conductor property library whereby a user simply specifies the conductor code name and the program will search the conductor property file and select the proper input properties. Those using the BASIC program from Annex B of IEEE Standard 738 or another computer program that does not have a conductor property library will obtain conductor properties from an appropriate data source (Aluminum Electrical Conductor Handbook, EPRI Transmission Line Reference Book 345 kV and Above, Westinghouse Transmission and Distribution Book, etc.).

#### 7.2.2.2 Line Geographic Location

These factors specify the location of the line, its predominant direction and its predominant

inclination. These numbers can either be line specific or they can represent a general line within the control area. One ambient temperature shall be agreed upon for tie lines traversing several geographic areas and interconnections among different control areas.

### 7.2.2.3 Radiation Properties

The two radiative properties of conductor material are solar absorptivity and infrared emissivity.

**Solar Absorptivity** The fraction of incident solar radiant energy that is absorbed by the conductor surface. This value shall be between 0 and 1. Recommendedvalues are given in the followi[redacted]bles:

| COPPER CONDUCTORS | |
|---|---|
| **Oxidation Level** | **Absorptivity** |
| None | 0.23 |
| Light | 0.5 |
| Normal | 0.7 |
| Heavy | 1.0 |

| ALUMINUM CONDUCTORS | |
|---|---|
| **Service Years** | **Absorptivity** |
| 0<5 | 0.43 |
| | 1.00 |

Source: Glenn A. Davidson, Thomas E. Donoho, George Hakun III, P. W. Hofmann, T. E

Bethke, Pierre R. H. Landrieu and Robert T. McElhaney, "Thermal Ratings for Bare Overhead Conductors", IEEE Trans., PAS Vol. 88, No.3, pp. 200-05, March 1969.

**Infrared Emissivity** The ratio of infrared radiant energy emitted by the conductor surface to the infrared radiant energy emitted by a blackbody at the same temperature. This value shall be between 0 and 1. Recommended values are given in tables below:

| COPPER CONDUCTORS | |
|---|---|
| **Oxidation Level** | **Emissivity** |
| None | 0.03 |
| Light | 0.3 |
| Normal | 0.5 |
| Heavy | 0.8 |

| ALUMINUM CONDUCTORS | |
|---|---|
| **Service Years** | **Emissivity** |
| 0 | 0.23 |
| [redacted] | 0.82 |
| 10-20 | 0.88 |
| | 0.90 |

Source: W. S. Rigdon, H. E. House, R. J. Grosh and W. B. Cottingham, "Emissivity of Weathered Conductors After Service in Rural and Industrial Environments," AIEE Trans., Vol. 82, pp. 891-896, Feb. 1963.

#### 7.2.2.4 Weather Conditions

Ambient temperature represents the maximum seasonal temperature the line may experience for summer and winter conditions. Appendix PL-2.A contains a methodology to compute maximum ambient temperature. Wind speed is assumed at 2 ft/sec (1.4 mph) or higher. Wind direction is assumed perpendicular to the conductor.

#### 7.2.2.5 Maximum Conductor Temperature

The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet some operating standard that was in effect at the time the line was built. That standard specified the maximum conductor temperature which maintained acceptable ground clearance while allowing for acceptable loss of strength. Over time, the required amount of ground clearance and the maximum conductor temperature needed to maintain acceptable ground clearance have changed. The changes are reflected in the revisions that have been made to the National Electric Safety Code (NESC) over the years. Although this Criteria specifies a maximum conductor temperature that could be met by current line design practices, consideration must be given to existing lines that were built according to an earlier standard. This Circuit Rating Criteria specifies a maximum conductor temperature (for both normal and emergency operating conditions) that shall be used for seasonal circuit ratings. For those existing lines that were designed to meet an earlier standard, it is the responsibility of the line owner to establish a rating that is consistent with the NESC design standards being practiced at the time the line was built. This Criteria specifies the use of maximum conductor temperatures that either maintain acceptable ground clearance requirements from earlier NESC's or meet the temperature requirements in SPP Planning Criteria section 7.2.2.6, whichever is lower.

#### 7.2.2.6 Determination of Maximum Conductor Temperature

The maximum conductor temperature for normal ratings may be limited by conductor clearance concerns. Normal ratings are at a level where loss of strength is not a concern. The maximum

conductor temperature for emergency ratings have both conductor clearance and loss of strength concerns. By setting a maximum conductor temperature and the length of time a conductor may operate at this temperature, the maximum allowable loss of strength over the life of the conductor

is prescribed. Unless conductor clearance concerns dictate otherwise, at least the following maximum conductor temperatures shall be used. This allows for the efficient utilization of the transmission system while accepting minimal risk of loss of conductor strength during emergency operating conditions. These conductor temperatures are a result of the examination of SPP members practices.

| | Maximum Conductor Temperature | |
|---|---|---|
| | **Normal Rating** | **Emergency Rating** |
| ACSR | 85°C | 100°C |
| ACAR | 85°C | 100°C |
| Copper | 85°C | 100°C |
| Copperweld | 85°C | 100°C |
| AAC | 85°C | 100°C |
| AAAC | 85°C | 100°C |
| SSAC | 200°C | 200°C |

Note: Annealing of copper and aluminum begins near 100°C.

#### 7.2.2.7 Hours of Operation at Emergency Rating

The effect of conductor heating due to operating at the maximum temperature during emergency conditions is cumulative. If a conductor is heated under emergency loading for 4 hours 8 times during the year, the total effect is nearly the same as heating the conductor continuously at the temperature for 32 hours. Using a useful conductor life of 30 years, the conductor will have been heated to the maximum temperature for 1000 hours. For an all aluminum conductor (AAC), this results in a 7% reduction from initial strength. Since the steel core of an ACSR conductor is essentially unaffected by the temperature range considered for emergency loadings, for an ACSR conductor, this results in a 3% reduction from initial strength. Both of these amounts are acceptable loss of strength. The daily load cycle for operating at the emergency rating shall not exceed 4 hours. This load cycle duration for conductors operating at the emergency rating is more restrictive than power transformers because power transformers have a delay in the time required to reach a stable temperature following any change in load (caused by a thermal lag in oil rise) and because seasonal ratings shall allow transmission lines to achieve a maximum conductor temperature throughout the year, not just days when the ambient exceeds 78°F.

### 7.2.3 Underground Cables

Ampacities are calculated by solving the thermal equivalent of Ohm's Law. Conceptually, the solution is simple, however the careful selection of the values of the components of the circuit is necessary to ensure an accurate ampacity calculation. The recognized standard for almost all steady-state ampacity calculations, in the United States, is taken from a publication, "The Calculation of the Temperature Rise and Load Capability of Cable Systems," by J.H. Neher and M.H. McGrath, 1957, hereafter referred to as the Neher-McGrath method. The procedure is relatively simple to follow and has been verified through testing. In recent years, some of the parameters have been updated, but the method is still the basis of all ampacity calculations.

#### 7.2.3.1 Cable Ampacity

Cable ampacity is dependent upon the allowable conductor temperature for the particular insulation being used. Conductor temperature is influenced by the following factors:

(1) Peak current and load-cycle shape;

(2) Conductor size, material and construction;

(3) Dielectric loss in the insulation;

(4) Current-dependent losses in conductor, shields, sheath and pipe;

(5) Thermal resistances of insulation, sheaths and coverings, filling medium, pipe or duct and covering, and earth;

(6) Thermal capacitances of these components of the thermal circuit;

(7) Mutual-heating effects of other cables and other heat sources; and

(8) Ambient earth temperatures.

Both steady-state and emergency ampacities depend upon these factors, although emergency ratings have a greater dependency upon the thermal capacitances of each of the thermal circuit components.

### 7.2.3.2 Conductor Temperature

The maximum allowable conductor temperature is 85°C for high-pressure fluid-filled (HPFF), pipe-type cables and 90°C for crosslinked, extruded-dielectric cables.

The table below summarizes allowable conductor temperatures for different insulation materials. Two values are given for each cable insulation. The higher temperature may be used if the thermal environment of the cable is well-known along the entire route, or if controlled backfill is used, or if fluid circulation is present in an HPFF circuit. The maximum conductor temperatures allowed under steady-state conditions are limited by the thermal aging characteristics of the insulation structure of the cable. For emergency-overload operating conditions, maximum conductor temperatures are also limited by the thermal aging characteristics. The temperature is also limited by the melting temperature range of the insulation structure of the cable, its deformation characteristic with temperatures, restraints imposed by the metallic shield, deformation characteristic of the jacket, and the decrease in ac and impulse strengths with increases in temperature.

| Insulation Material | Maximum Temperature | |
|---|---|---|
| | Normal | Emergency |
| Impregnated paper (AEIC CS2-90 for HPFF and HPGF<br>(AEIC CS4-79 for SCLF) | 85°C<br>(75°C) | 105°C for 100 hr<br>100°C for 300 hr |

| | | |
|---|---|---|
| Laminated paper-polypropylene (AEIC CS2-90) | 85°C (75°C) | 105°C for 100 hr 100°C for 300 hr |
| Crosslinked polyethylene (AEIC CS7-87) | 90°C (80°C) | 105°C cumulative for 1500 hr |
| Ethylene-propylene rubber (AEIC CS6-87) | 90°C (80°C) | 105°C* cumulative for 1500 hr |
| Electronegative gas/spacer | Consult manufacturer for specific designs | |

* Emergency operation at conductor temperatures up to 130°C may be used if mutually agreed between purchaser and manufacturer and verified by qualification and prequalification tests.

### 7.2.3.3 Ambient Temperature

The ambient temperature is measured at the specified burial depth for buried cables and the ambient air temperature is used for cables installed above ground. IEC Standard 287-1982 (2-5) recommends that in the absence of national or local temperature data the following should be used:

| Climate | Ambient Air Temperature °C | Ambient Ground Temperature °C |
|---|---|---|
| Tropical | 55 | 40 |
| Sub-tropical | 40 | 30 |
| Temperature | 25 | 20 |

The electrical resistance is composed of conductor dc resistance, ac increments due to skin and proximity effects, losses due to induced currents in the cable shield and sheath and induced

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magnetic losses in the steel pipe. Heat generated in the cable system will flow to ambient earth and then to the earth surface. This heat passes through the thermal resistances of the cable insulation, cable jacket, duct or pipe space, pipe covering and soil. Adjacent heat sources, such as other cables or steam mains, will provide impedance to the heat flow and thus reduce cable ampacity. Further information concerning the components of the ampacity calculations are summarized in Appendix PL-2.B and fully detailed in the EPRI Underground Transmission Systems Reference Book. An example calculation, from the EPRI book, is also provided in Appendix PL-2.B.

### 7.2.4 Switches

Appendix PL-2.C contains a discussion on developing ratings for switches. In general, switches have seasonal ratings that are a function of the maximum ambient temperature. A switch part class designation is used to differentiate loadability curves that give factors which can be multiplied by the rated continuous current of the switch to determine temperature adjusted normal and 4 hour emergency ratings. The summer normal and emergency switch ratings can be computed by selecting the appropriate loadability factor curve for the switch part class, reading the loadability factors that are appropriate for the summer maximum ambient temperature (40°C or the summer maximum ambient temperature determined in Appendix PL-2.A), and multiplying the continuous current ratings by the loadability factor. The switch winter normal and emergency ratings can be computed by multiplying the continuous current rating by the normal and emergency loadability factors that are appropriate for the winter maximum ambient temperature (0°C or the winter maximum ambient temperature determined in Appendix PL-2.A). Appendix PL-2.C contains loadability factor curves (both normal and emergency) for various switch part classes. The ANSI/IEEE standard referenced in Appendix PL-2.C allows for emergency ratings to be greater than normal ratings. This Criteria does not require the emergency rating to be greater than the normal rating.

### 7.2.5 Wave Traps

Appendix PL-2.D contains a discussion on developing ratings for wave traps. The two types of wave traps are the older air-core type and the newer epoxy-encapsulated type. In general, both types have a continuous current rating based on a 40°C maximum ambient temperature. Both types have a loadability factor that can be used to determine seasonal ratings that are a function of the maximum ambient temperature. However, the older air-core type has another loadability factor that can be used to determine a four-hour emergency rating that is also a function of the

maximum ambient temperature. The newer epoxy encapsulated type does not have an emergency rating.

### 7.2.6 Current Transformers

Appendix PL-2.E contains a discussion on developing ratings for current transformers. The two types of current transformers are the separately-mounted type and the bushing type. In general, both types have a continuous current rating based on a 30°C average ambient temperature.

#### 7.2.6.1 Separately Mounted Current Tranformers

The separately-mounted type has an ambient-adjusted continuous thermal current rating factor that can be multiplied by the rated primary current of the current transformer to determine seasonal ratings. Separately-mounted current transformers do not have emergency ratings.

#### 7.2.6.2 Bushing Current Transformers

Bushing current transformers are subject to and influenced by the environment of the power apparatus in which they are mounted. Bushing current transformers can be located within circuit breakers and power transformers. Since bushing current transformers are subject to the environment within the power apparatus, they do not have ambient adjusted continuous thermal current rating factors. Rather, if the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer, this restricts the breaker or power transformer to operate below its rated current which reduces the current transformer temperature. This allows the current transformer to be operated at a continuous thermal rating factor greater than 1.0. Having a bushing current transformer whose primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer is an unusual case. However, the formula to develop the rating factor for this case is located in Appendix PL-2.E. Although bushing current transformers have some short-term emergency overload capability, it must be coordinated with the overall application limitation of the other equipment affected by the current transformer loading. Consequently, this criteria does not recognize an emergency rating for bushing current transformers.

### 7.2.7 Circuit Breakers

Appendix PL-2.F contains a discussion on developing ratings for circuit breakers. This discussion centers on the use of specific circuit breaker design information to set seasonal and emergency ratings. This design information is not readily available to the owners of such equipment. To use the rating methodology discussed in Appendix PL-2.F would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Rather than

doing that, this circuit rating criteria specifies that the nameplate rating shall be used for seasonal normal and emergency ratings. The nameplate rating is based on a maximum ambient temperature of 40°C. If a circuit breaker is found to be a limiting element in a circuit

and is experiencing loadings that limit operations, a member system may pursue the methodology outlined in Appendix PL-2.F to determine the circuit breakers seasonal normal and emergency rating.

### 7.2.8 Ratings of Series and Reactive Elements

The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g., breakers) that are in series with the interconnected transmission circuit. Shunt reactive elements (e.g., capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

The documentation of the methodology(ies) used to determine the rating of series and reactive elements shall be provided to SPP and/or NERC on request within five business days.

### 7.2.9 Ratings of Energy Storage Devices

The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request. The documentation of the methodology(ies) used to rate electrical energy storage devices shall be provided to SPP and/or NERC on request within five business days.

### 7.2.10 Circuit Rating Issues

#### 7.2.10.1 Dynamic (Real Time) Ratings

The calculation of static thermal ratings specified in SPP Planning Criteria section 7.2.2.6 uses worst case thermal and operational factors and therefore apply under all conditions. Often times, these worst case thermal and operational factors do not all occur at the same time. Consequently, a static rating may understate the thermal capacity of the circuit. For operation purposes, some members have elected to monitor the factors that affect circuit ratings and use this information to set dynamic ratings. A member can develop and use a rating that exceeds the static thermal rating for operating purposes. The ratings developed by using this criteria are not intended to restrict daily operations but set a minimum rating that can be increased when factors for determining the equipment rating have changed. However, if transmission line ratings are changed dynamically, the required clearances shall still be met.

#### 7.2.10.2 Non-Thermal Limitations

There may be instances when the flow on a transmission circuit is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as dynamics, phase angle difference, relay settings or voltage limited.

#### 7.2.10.3 Tie Lines

When a tie line exists between two member systems, use of this criteria shall result in a uniform circuit rating that is determined on a consistent basis between the two systems. For tie lines between a SPP member and a non-member, the member shall follow this criteria to rate the circuit elements owned by them and shall coordinate the rating of the tie line with the non- member system such that it utilizes the lowest rating between the two systems.

#### 7.2.10.4 Rating Inconsistencies

A member may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon the thermal capacity of the line or other considerations. Members shall use good faith effort to amend their transmission line agreements to reflect the effects of new circuit ratings. There may exist other transmission agreements or regulatory mandates that use the thermal capacity of transmission circuits in allocation of cost and determination of network usage formulas (for example, the MW-mile in ERCOT). These agreements and mandates may specify a methodology and/or factors for computing thermal capacity used in the formulas. Since these amounts are only used in assignment of cost or usage responsibility and not in actual operations of the transmission system, there is no conflict with using a different set of ratings for this specific purpose.

#### 7.2.10.5 Damaged Equipment

There may be instances when a derating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.

### 7.2.11 Reporting Requirements

Each member will administer this Criteria and will make available upon request the application of this Criteria for those facilities that impact another member (i.e. force them to curtail schedules due to line loadings, denies them access to transmission service or requires them to build new transmission facilities or pay opportunity costs to receive transmission service).

## 7.3 System Operating Limits (SOLs)

The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria.

These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)
- transient stability ratings (applicable pre- and post-Contingency stability limits)
- voltage stability ratings (applicable pre- and post-Contingency voltage stability)
- system voltage limits (applicable pre- and post-Contingency voltage limits)

### 7.3.1 Methodology for Determination of Operating Horizon SOLs

SPP's Methodology designates System Operating Limits in the Operating Horizon to consist of defined flowgate limits, limits defined in operating guides, and limits designated by agreement between the RC and TOP. SPP respects all BES Facility Ratings in both Real-Time Assessments and through Operational Planning Analysis. SPP primarily controls the BES using both permanent and temporary flowgates per defined congestion management processes. SPP also controls the BES using coordinated operating plans or operator actions in specific situations in the absence of a flowgate. During the time a flowgate or an operating guide is being created, SPP shall issue Operating Instructions to implement manual actions as deemed necessary by the Reliability Coordinator to control the BES and operate within SOLs.

(1) TOPs shall develop, at minimum, thermal SOLs that respect all BES Facility Ratings in coordination with the SPP RC. In addition, SOLs may be developed based on transient stability ratings, voltage stability ratings, system voltage limits, and/or other operating criteria.

(2) SOLs shall not exceed Facility Ratings. SOLs equal applicable Facility Ratings unless additional studies have established a lower limit based on other operational issues such as transient, dynamic and voltage stability, etc. The Facility Ratings used in the Operating Horizon or Real-Time Horizon may be higher or lower than the Facility Ratings used in the Planning Horizon. All Facility Ratings shall be calculated in accordance with the appropriate Transmission Owner's Facility Rating methodology. Ratings that have been adjusted must be coordinated so that the impacted operating entities are aware of the duration that the adjusted rating may be used.

(3) Including anticipated system topology, generation dispatch, and load levels, SOLs shall be determined per this SOL methodology and based on results of system studies as described below.

(4) Pre-contingency and first contingency studies will be conducted to identify Facility Rating exceedances for current and next day.

(5) Voltage stability and angular stability issues are studied as deemed necessary by operator and engineer experience and engineering judgment to identify stability SOLs.

(6) As deemed necessary by study results, an operating guide to aid operators in mitigating potential SOL exceedances may be produced. These guides may be temporary or permanent, depending whether the violation is due to a short-term outage, seasonal loading issues, etc. At a minimum, this operating guide will include:

(a) Statement of type(s) of limit exceedances revealed by study (voltage/thermal/stability)
(b) Applicable dates
(c) Available/recommended mitigation methods, including generation redispatch (maximum MW and/or minimum Mvar generation), transmission reconfiguration, reclosing reconfiguration, load shedding, and Transmission Loading Relief (TLR).

(7) Identified SOLs are screened to compile a list of potential IROLs per the following criteria**:**

(a) Potential IROLs will be investigated when a contingency analysis highlights a thermal overload in excess of 120% of the SOL of the monitored facility.
(b) Potential IROLs will also be investigated when a contingency analysis highlights an under-voltage condition characterized by bus voltages of less than 90% across three or more BES facilities.

The potential IROL condition will be reviewed further by evaluating the system response to the loss of the facility with the SOL expected to be exceeded. The original potential IROL condition will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing loss of the facility with the SOL exceedance results in another BES facility being overloaded to greater than 120% of its SOL or three or more additional BES facilities with bus voltages in the area experiencing projected post-contingency voltages less than 90% of nominal voltage, unless there are studies or system knowledge that the SOL is not an IROL.

(8) The IROL TV is 30 minutes unless studies dictate a shorter time.
(9) Remedial Action Schemes (RAS's) are allowed to prevent prolonged undervoltage and to preserve system voltage and machine stability.

### 7.3.1.1 SOL Provisions

(1) In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. In determining SOLs, the BES condition used shall reflect future system conditions with all facilities operated in their normal operating condition.

(2) Following single contingencies as defined in (a), (b), and (c) below, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

(a) Single-line-to-ground or three-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.

(b) Loss of any generator, line, transformer, or shunt device without a Fault.

(c) Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage

direct current system.

(3) In determining the system's response to a single Contingency starting with all facilities operated in their normal operating condition, the following shall be acceptable:

(a) Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

(b) System reconfiguration through manual or automatic control or protection actions.

(4) To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

(5) Starting with all facilities operated in their normal operating condition and following any of the multiple contingencies identified in Reliability standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability; all facilities shall be operating within their facility ratings and within their thermal, voltage and stability limits; and cascading or uncontrolled separation shall not occur.

(6) In determining the system's response to any of the multiple contingencies identified in Reliability standard TPL-003, in addition to the actions identified in (a) and (b) above, the following shall be acceptable:

(a) Planned or controlled interruption of electric supply to customers (load shedding) the planned removal from service of certain generators, and/or curtailment of contracted firm electric power transfers. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

### 7.3.1.2 System Modeling and Contingency Definition

(1) All offline models shall be based on a coordinated model of the Eastern Interconnect and any necessary facilities in other Interconnections. The model shall include all Transmission Operator (TOP) Areas within the SPP RC footprint as well as facilities in adjacent TOP Areas that have been determined to have impact on the SPP RC footprint.

(2) The model shall include all non-radial facilities within the BES. Loads served over radial lines may be modeled as aggregate at the delivery bus. Distribution capacitors can be modeled as aggregate at a load bus.

(3) The online model used by the SPP EMS application is constructed from data in the offline model (PSS/E).

(4) At a minimum the contingency list used in the operating horizon shall include all non-radial BES transmission lines and transformers and all generators rated 300MW and above. Additional contingencies will be included as provided by other applicable

registered entities.

### 7.3.2 Methodology for Determination of Planning Horizon SOLs

(1) This methodology is applicable for developing SOLs used in the planning horizon. SPP monitors all BES facilities within its footprint in its planning assessments.

(2) SOLs shall not exceed applicable Facility Ratings. SOLs equal applicable Facility Ratings unless additional studies have established a lower limit based on other operational issues such as transient, dynamic and voltage stability, etc.

(3) Voltage SOLs exceedances are identified as any pre-contingent or post-contingent bus voltages outside the Transmission Owner's applicable Facility Ratings and applicable voltage limits.

(4) Anticipated system topology, generation dispatch, and load levels are based on the modeling data provided in the annual Loadflow Model Development process coordinated by the MDWG. Individual Transmission Owners may request development of additional models for SOL analysis as needed to evaluate regional transfer conditions which are not captured in existing MDWG models.

(5) Pre-contingency, first contingency and multiple contingency studies will be conducted to investigate thermal and voltage violations for all those future year loadflow models developed by the MDWG.

(6) Voltage and angular stability issues are studied in the annual Dynamic Stability models developed by the MDWG.

(7) As deemed necessary by study results, an operating guide to aid operators in mitigating potential SOL violations may be produced. These guides may be temporary or permanent, depending whether the violation is due to a short-term outage, seasonal loading issues, etc. At a minimum, this operating guide will include:

(a) Statement of type(s) of violations revealed by study (voltage/thermal/stability)

(b) Applicable dates

(c) Available/recommended mitigation methods, including generation redispatch (maximum MW and/or minimum Mvar generation), transmission reconfiguration, reclosing reconfiguration, load shedding, and Transmission Loading Relief (TLR).

(8) Identified SOLs are screened to compile a list of potential IROLs per the following criteria:

(a) Potential IROLs will be investigated when a contingency analysis highlights a thermal overload in excess of 120% of the SOL of the monitored facility.

(b) Potential IROLs will also be investigated when a contingency analysis highlights an under-voltage condition characterized by bus voltages of less than 90% across three or more BES facilities.

(9) The potential IROL condition will be reviewed further by evaluating the system response to the loss of the SOL violated facility. The original potential IROL contingency will be assumed to be a confirmed IROL condition if the evaluation reveals that the ensuing SOL violated facility contingency results in another BES facility being overloaded to greater

than 120% of its SOL or three or more additional BES facilities with bus voltages in the area experiencing projected post contingency voltages less than 90%, unless there are studies or system knowledge that the SOL is not an IROL.

(10) The IROL TV is 30 minutes.

(11) Remedial Action Schemes (RAS's) are allowed to prevent prolonged undervoltage and to preserve system voltage and machine stability. The Transmission Owner shall provide the RC with the location and description of each SPS, and shall notify the RC when the schemes are enabled/disabled.

### 7.3.2.1 SOL Provisions

(1) In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. In determining SOLs, the BES condition used shall reflect future system conditions with all facilities operated in their normal operating condition.

(2) Following single contingencies as defined in (a) and (b) below, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur.

- (a) Single-line-to-ground or three-phase fault (whichever is more severe), with normal clearing, on any faulted generator, line, transformer, or shunt device.
- (b) Loss of any generator, line, transformer, or shunt device without a Fault.

(3) In determining the system's response to a single Contingency starting with all facilities operated in their normal operating condition, the following shall be acceptable:

- (a) Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.
- (b) System reconfiguration through manual or automatic control or protection actions.
- (c) Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

(4) To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.

(5) Starting with all facilities operated in their normal operating condition and following any of the multiple contingency planning event, excluding extreme events, identified in Reliability standard TPL-001-4 the system shall demonstrate transient, dynamic and voltage stability; all facilities shall be operating within their facility ratings and within their thermal, voltage and stability limits; and cascading or uncontrolled separation shall not occur.

(6) In determining the system's response to any of the multiple contingency planning events, excluding extreme events, identified in Reliability standard TPL-001-4,

in addition to the actions identified in (a) and (b) above, the following shall be acceptable:

(a) Planned or controlled interruption of electric supply to customers (load shedding) the planned removal from service of certain generators, and/or curtailment of contracted firm electric power transfers. System reconfiguration should be implemented to minimize the interruption of electric supply to the extent possible.

**7.3.2.2 System Modeling and Contingency Definition**

(1) All planning models are based on the ERAG MMWG model of the Eastern Interconnect power system. The model includes all TOs within the SPP RC footprint. Updates shall be made to reflect the most accurate system configuration, generation, and load representation for each pertinent individual balancing authority area for the study period. The following guidelines for system representation in modeling shall be applied:

(a) Full loop representation is to be used with the entire Eastern Interconnect power system modeled. The model includes all non-radial facilities within the BES. Loads served over radial lines are typically modeled as aggregate at the delivery bus. Many systems are modeled in greater detail down to subtransmission level voltages (<69kV). This is typically true only when the subtransmission system is networked (nonradial). In a few cases distribution level voltages are also modeled. Distribution capacitors can be modeled as aggregate at a load bus.

(b) The study model will assume all facilities in their normal operating condition, with no planned outages, except those facilities normally operated in a de-energized condition.

(c) System transfer levels for major Eastern Interconnect paths should be agreed upon and listed. Additional transfer paths should be included as appropriate.

(d) Voltage profile and equipment loading will be within the ratings of the facilities and will be determined using existing criteria.

(e) The phase shifter methodology to be followed for all applicable phase shifters should be identified.

(f) Generation and load shedding may exceed the minimum requirement to ensure margin for system security.

(g) A MMWG model base case will be selected based on the generation dispatch, load level (peak/off-peak) for seasonal (i.e. winter, spring, summer, and/or fall) system conditions. The generation dispatch may vary due to wind, hydro or other conditions.

(h) Residential, commercial, and industrial load models, with constant power, current and impedance should be included as appropriate. Transient stability models shall represent voltage and frequency characteristics, either actual load models when available, or accepted industry models. Loads shall be modeled as accurately as possible, including the appropriate load power factor. Margins provided to allow for load model uncertainty shall be explicitly stated.

(2) At a minimum the contingency list used in the planning horizon should include all non-radial BES transmission lines and transformers > 100kV and all generators rated 300MW and above. Additional contingencies will be included as provided by BA's and/or TOs within the RC footprint.

(3) Special Protection Schemes (SPS) or Remedial Action Schemes (RAS). All SPS required to obtain the Accepted Rating should be described in details and modeled as they will be applied in operation.

### 7.3.2.3 Methodology Distribution

SPP shall issue this methodology and any changes to the methodology, prior to the changes taking effect, to all the following:

(1) Adjacent Planning Coordinator and each Planning Coordinator that has indicated it has a reliability-related need for the methodology

(2) Each RC and Transmission Operator that operates any portion of the Planning Coordinator's Planning Coordinator Area.

(3) Each Transmission Planner (TP) that works in the Planning Coordinator's Planning Coordination Area.

# 8. System Protection Requirement

Section Owner: Special Protection and Controls Working Group (SPCWG)

## 8.2 Transmission Protection Systems

### 8.2.1 Introduction

The goal of Transmission Protection Systems (TPS) is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network to preserve electric system integrity.

They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred. The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure, misoperation of the protection system, and the need to maintain overall system reliability. All reviews of facilities as included in Criteria 8.2 shall be for those operated at 100kV or above.

### 8.2.2 Protection System Review

#### 8.2.2.1 Assessment of System Performance

The transmission or protection system owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of Standard I.A. (NERC Planning Standard). These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in NERC Standard I.A. and associated Table I. Therefore, the relative effects on the interconnected transmission systems due to a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters. All noncompliance findings shall be documented including a plan for achieving compliance. These

assessments should be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems within 30 days of the request.

### 8.2.3 System Redundancy

Transmission Protection Systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I (NERC). Each Transmission or Protection System Provider shall develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Where redundancy in the protection systems (due to single protection system component failures) is necessary to meet the system performance requirements (of the I.A. Standards on Transmission Systems and associated Table I), the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated. Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault while maintaining performance requirements. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition. When two independent protection systems are required, dual circuit breaker trip coils should be considered. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

### 8.2.4 Monitoring, Analysis and Notification of Misoperations

Each Transmission or protection system owner shall have a process in place for the monitoring, notification, and analysis of all transmission protection trip operations. Any of the following

events constitute a reportable TPS misoperation:

1) Failure to trip - Any failure of a Protection System element to operate when a fault or abnormal condition occurs within a zone of protection. (Note: Lack of targeting, such as when a high-speed pilot system is beat out by a high-speed zone, is not a reportable misoperation. If a fault or abnormal condition is cleared in the time normally expected with proper functioning of at least one Protection System, failure of a Protection System element is not a reportable misoperation.)

2) Slow Trip - Any failure of a Protection System element that is slower than planned to operate when a fault or abnormal condition occurs within the zone of protection. (Note:

Delayed Fault Clearing, where a high-speed system is employed but is not essential for transmission system performance, is not a reportable misoperation.)

3) Unnecessary Trip During a Fault - Any unnecessary Protection System operation for a fault not within the zone of protection. An example of this type of Misoperation is an over-trip due to lack of coordination between Protection Systems. (Note: Operation as properly coordinated backup protection for a fault in an adjacent zone that is not cleared within the specified time for the protection for that adjacent zone is not a reportable Misoperation.)

4) Unnecessary Trip Other Than Fault - Any unnecessary Protection System operation when no fault or other abnormal condition has occurred. (Note that an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable Misoperation.)

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. An operation of a TPS that only has an effect on a nontransmission component operated at less than 100kV need not be reported. Documentation of all protection trip misoperations shall be provided to SPP and NERC within five (5) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all TPS trip operations. It shall also provide consistent documentation of all TPS trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested, supporting documentation shall be provided to SPP and include all fault and sequence of events data relevant to the cause of the misoperation. The facility owner shall maintain the documentation of all operations for a minimum of one (1) year. The facility owner's processes should include items such as:

1) Uniform format to the extent possible.

2) Content guidelines.

3) Requirements for periodic review.

4) Requirements for updating data.

5) Procedures for analysis of all trip misoperations.

### 8.2.6 Requests for Transmission Protection System Data

SPP shall function as a requesting agent and clearinghouse for the collection of TPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

### 8.2.7 Transmission Protection Systems Criteria Updates

The SPCWG will update, if necessary, this transmission Protection Systems Criteria every three (3) years.

## 8.3 Under-Frequency Load Shedding and Restoration

### 8.3.1 Automatic Load Shedding

A major disturbance among the interconnected bulk electric system may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. The areas of separation are unpredictable. To provide load relief and minimize the probability of network collapse the following practices are established. For more details refer to SPP UFLS Plan and NERC PRC-006-1.

#### 8.3.1.1 Operating Reserve

All SPP operating reserve shall be utilized before resorting to shedding firm load. During a period of declining frequency, there may be violent swings of both real and reactive power. For this reason, all generator governors and voltage regulators shall be kept in automatic service as much as practical.

#### 8.3.1.2 Operating Principles

To realize the maximum benefit from a load shedding program the points at which the load is shed in a company area shall be widely dispersed. This can be accomplished at the subtransmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining frequency. The only practical way to remove load from a member in an attempt to stabilize the frequency is to do so automatically by the use of under-frequency relays. Since a geographical area or the timing of a period of low frequency cannot be predicted, all of the designated underfrequency relays on a member system shall be in service at all times. Underfrequency relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

#### 8.3.1.4 Restoration

After the frequency has stabilized the following procedure shall be followed:

1) In the event the frequency stabilized below 60 Hz, system operators shall coordinate operations to utilize all available generating capacity to the maximum extent possible in order to restore the frequency to 60 Hz. Deficient systems shall continue to shed load until the frequency can be restored to normal.

2) At 60 Hz the isolated areas shall be synchronized with the remainder of the interconnected systems. Synchronization between individual members shall be performed only upon direct orders of the system operators of both companies involved.

3) System operators shall coordinate load restoration as generating capability, voltage levels and tie-line loadings allow.

4) Any shed load shall be restored only upon direct orders of the system operator. Extreme care shall be exercised as to the rate at which load is restored to the system in order that limits of generation and transmission line loading are not exceeded. Insofar as possible, supervisory control shall be used to restore load; otherwise, manual restoration is preferable to insure positive control by the system operators.

5) It is recommended that a restoration plan be furnished by each company for use by its system operators for implementation of a coordinated and successful recovery.

### 8.3.2 Manual Load Shedding

A situation can arise when a control area must reduce load even though the frequency is normal. Since an automatic load shedding program will be of no avail in this case, manual load shedding

procedures shall be utilized. One of the basic principles of interconnected operation is that a control area will match the area generation to area load at 60 Hz at all times. Should a generation deficiency develop for any reason, arrangements shall be made with adjacent control areas to

cover the deficiency; but failing this, the affected control area shall reduce the area load until the available generation is sufficient to match it. In some cases a generation deficiency can be foreseen and will develop gradually; whereas, in other cases the deficiency will develop immediately with no forewarning. A gradually developing deficiency can probably be offset by using conservation procedures; whereas, an immediate deficiency will probably require customer service interruption. The importance of a load reduction plan cannot be overemphasized. A plan is offered here which can be modified to fit individual cases.

#### 8.3.2.1 Conservation

1) Interruption of service to interruptible customers. Utilize to the extent that the situation requires.

2) Reduction of load in company facilities.

3) Reduction of distribution voltage level. Utilize to the extent possible and as the situation requires.

4) Load reduction by request to company employees and general public. The company employees and the general public shall be notified through news media to curtail the use of electricity.

5) Load reduction by request to bulk power users. Concurrent with voltage reduction and asking employees and the general public to reduce load, bulk power users (municipals and cooperatives) will be asked to reduce load in their areas using the same methods.

6) Load reduction by large use customers. Large use commercial and industrial customers will be requested to curtail electric power usage where such curtailment will not seriously disrupt customers' operations.

#### 8.3.2.2 Service Interruption

Manual load interruption shall be implemented by a pre-determined plan, an example of which follows.

1) Each company operating subdivision shall select distribution circuits in approximately 5% increments in the order of their priority that will be taken out of service. The 5% increments will be labeled "A", "B", "C", "D", "E", and "F". The interruption and the restoration of these circuits will be under the control of the system operator. When the system operator determines that load must be reduced, he shall direct the subdivision operators to

open all "A" circuits. This will reduce the system load 5%. If further load reduction is necessary, the system operator shall direct all "B" circuits to be opened which will result in an additional 5% reduction. This shall continue through "C", "D",

"E", and "F" until the generation deficiency is eliminated.

2) The objective of this plan is to have no circuits open more than two hours. If the duration of the system emergency exists in excess of two hours and only the "A" circuits have been opened, then at the end of two hours the "B" circuits shall be opened and the "A" circuits reclosed. If a 10% reduction is necessary, "C" and "D" circuits shall be opened and "A" and "B" reclosed, after "A" and "B" have been open for two hours. Obviously, no circuits shall be open longer than is absolutely necessary. The "E" and "F" circuits shall be opened to avoid opening "A" and "B" circuits twice in one day.

3) When a generation deficiency develops, or begins to develop, the system operator shall alert all involved operating personnel to the effect that certain circuits may have to be interrupted. This action will reduce the time required to execute circuit interruption orders of the system operator. Some control areas in SPP have extensive supervisory control systems while others have little, if any, supervisory control. Obviously, any implementation plan shall make best use of available equipment.

## 8.4 Special Protection Systems Equipment

A Special Protection Systems (SPS) or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take automatic pre-planned, coordinated, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings. All reviews of facilities as included in Criteria 8.4 shall be for those used to monitor and control transmission facilities operated at 100kV or above. The SPS design shall not create cascading transmission outages or system instability. One possible SPS may be the automatic and sequential dropping of load, generation, or adjacent high voltage (HV) lines, if a HV line trips. A SPS does not include (a) underfrequency load shedding or undervoltage load shedding as they are addressed under NERC Planning Standards III.D, SPP Planning Criteria section 8.3, and III.E or (b) fault conditions that must be isolated or (c) out-of-step relaying. The SPS shall not require operator action, and all actions of the SPS are automatic. SPS shall be automatically armed

without human intervention when appropriate. The status indication of any automatic or manual arming of SPS shall be provided as SCADA alarm inputs.

### 8.4.1 Operating Requirements and System Redundancy

Special Protection Systems shall include redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of NERC I.A. Standards on Transmission Systems in

Categories A, B or C of the associated Table I. Each facility owner shall develop a plan for reviewing the need for redundancy in its existing special protection systems and for implementing any required redundancy. Documentation of these reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request. Also, the misoperation, incorrect operation, or unintended operation of an SPS when considered by itself and not in combination with any other system contingency shall meet the system performance requirements as defined under Category C of Table I of the NERC I.A Standards on transmission systems.

### 8.4.2 Location and Data Reporting for Special Protection Systems Equipment

The number, type and location of SPS equipment will normally be the responsibility of the facility owners based on recommendations by the owners' and SPP's studies. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in databases by the SPP staff for a period of at least five (5) years. These databases shall be monitored as necessary by the SPP System Protection and Control Working Group (SPCWG). The Transmission Assessment Working Group and Operating Reliability Working Group will review the databases and recommend that equipment with adequate capabilities be installed at critical locations throughout the system as determined in power flow and dynamic stability studies. The specific data that is required in SPP's circuit analysis models shall be maintained and submitted to SPP by the facility owners or their designated representatives on an annual basis or as otherwise required. This data shall represent the designed functionality of the system. Documentation by facility owners for each SPS utilized shall include details on its design, its operation, its control, its functional testing, and coordination with other schemes that are part of or impact the SPS.

### 8.4.4 Periodic Review of Special Protection Systems Equipment

SPP members shall maintain a list of substations where SPS equipment is located for all areas including those designated as being critical by the Transmission Assessment and Operating Reliability Working Groups. The facility owner will be responsible for providing required data on forms developed by the SPCWG and supplied by SPP. Each facility owner will provide updates to the SPP as requested. The SPP staff will maintain and update the SPS equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 8.4.2. The SPCWG will update, if necessary, this SPS Criteria every three (3) years. Based upon (a) a five year interval or other interval as required by electric system changes, or (b) if a new SPS, or (c) if a modified SPS, each facility owner will review and document

their SPS for compliance with Regional planning criteria and guides, and the NERC Planning Standard I.A including the associated Table I. This review shall include system studies to evaluate the consequences of:

1) the proper operation of the SPS,

2) the failure of an SPS to operate due to a single component failure of the SPS, and

3) the misoperation, incorrect operation, or the unintended operation of an SPS when considered by itself without any other system contingency.

These consequences shall not include cascading transmission outages or system instability. These studies shall include the date that they were performed, who performed them, the methodology of the study, the results of the study, and when the next study is anticipated.

### 8.4.5 Requests for Special Protection Systems Data

SPP shall function as a requesting agent and clearing house for the collection of SPS data on an as-needed basis. Facility owners should provide the requested data within thirty (30) days with a copy of the requested information forwarded to the SPP. If a facility owner cannot provide the requested data within this specified time frame, SPP shall be notified of the delay and the anticipated date of forwarding the requested data. SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

### 8.4.6 Submittals of Special Protection Systems Misoperations

All misoperations of a SPS shall be reported to the SPP within five (5) business days after receipt of the request, or as soon as possible thereafter. Any of the following events constitute a reportable SPS misoperation:

1) Failure to Operate - Any failure of a SPS to perform its intended function within the designated time when system conditions intended to trigger the SPS occur.

2) Failure to Arm - Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed.

3) Unnecessary Operation - Any failure of a SPS that occurs without the occurrence of the intended system trigger condition(s) including human error.

4) Unnecessary Arming - Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s).

5) Failure to Reset - Any failure of a SPS to automatically reset following a return of normal system conditions if that is the design intent.

Misoperations at lower voltages that cause an operation of a SPS, in systems 100kV or higher, shall be reported. A detailed analysis of the misoperation, its consequences, and the corrective actions taken to prevent a reoccurrence will be reported to the SPP within thirty (30) days. SPP shall be notified of any delay and the anticipated date of forwarding the required data. This analysis to be provided by the facility owner shall include, at a minimum, the description of

facility as identified on a form, developed by the SPCWG and supplied by SPP, including a complete summary report of the misoperation, its consequences, corrective actions taken, and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. The analysis and corrective actions shall be reviewed by the SPCWG. If these reported corrective actions are deemed inadequate, then the corrective actions that SPP recommends shall be completed as soon as possible subject to equipment availability.

### 8.4.7 Submittals for New, Modified, (including Removal) or Renewed Special Protection Systems

The owner of the SPS shall notify SPP of its intent to construct a new, modified, or renewed SPS with sufficient lead time to allow for an orderly review by SPP's working groups and committees. This notification will include statements on whether misoperation or failure of the SPS would have local, inter-company, inter-area or interregional consequences, when the SPS is planned for service, how long it is expected to remain in service, what specific contingency(s) it is designed to operate for and whether the SPS will be designed according to all SPP operating requirements of the bulk transmission system and NERC Standards. For a new or modified SPS prior to construction of facilities, one (1) electronic version in legible format and three (3) hard copies of all applicable studies supporting the design requirements of the SPS including a complete set of electrical design specifications, drawings and operating plans shall be submitted to the SPP with this notification. The drawings shall include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The documentation of the proposed system will include any special conditions or design restrictions that exist in the proposed system. For renewed SPS prior to the expiration date, the facility owner shall supply all the above information plus any changes in the original coordination studies, operation history, maintenance history, and any change in the original coordination with other schemes that are part of or impact the SPS. The System Protection and Control, Transmission and Operating Reliability Working Groups will assess the SPS's conformance with all SPP operating requirements of the bulk transmission system and NERC Standards. If necessary, the working groups will request that the facility owner conduct additional studies and provide additional details of design specifications, drawings and operating plans. The results of such compliance review shall be documented with all recommendations that are deemed appropriate by the SPP and forwarded to the requesting party normally within 120 days from the date of request. The recommendations of SPP shall be completely incorporated into the design of the SPS.

A presentation will be made to appropriate working groups when a facility owner deviates from any of the SPP operating requirements of the bulk transmission system and NERC Standards as well as when a member system is in doubt as to whether the design meets these requirements. The facility owner shall arrange for the technical presentation by advising SPP approximately

four months prior to the presentation and by providing copies of the materials to be presented 30 days prior for new or modified SPS. The facility owner will advise appropriate working groups of the basic design of the proposed system and include a geographical map, a one-line diagram of all affected areas, and the associated protection and control function diagrams. The proposed system should be explained with due emphasis on any special conditions or design restrictions that exist in the proposed system. A presentation will also be made to appropriate working groups relating to new facilities or a modification to an existing facility when requested by either a member system or a working group.

## 8.5 Undervoltage Load Shedding

One characteristic of electric systems that experience heavy loadings on transmission facilities with relatively limited reactive power control is the susceptibility to voltage instability. Such instability can cause tripping of generation and transmission facilities resulting in loss of customer demand as well as collapse of the bulk transmission system. A major disturbance among the interconnected bulk electric systems may result in certain areas becoming isolated and experiencing abnormally low frequency and voltage levels. Since voltage collapse can occur rapidly, operators may not have sufficient time to stabilize the systems. Therefore, a load- shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse

### 8.5.1 Program Participants

Facility Owners who determine it beneficial to install undervoltage load shedding (UVLS) equipment may do so. However, UVLS schemes must coordinate with all protection and underfrequency load shedding schemes for the reliable operation of facilities operated at 100kV and above. Also, members are not required to install such equipment unless deemed necessary by either SPP or NERC to ensure the reliability of bulk transmission systems.

### 8.5.2 Operating Reserve and Principles

All SPP operating reserve shall be utilized before resorting to shedding firm load. All generator governors and voltage regulators shall be kept in automatic service as much as practical so that generating units may be used to their maximum capability for supplying voltage support during disturbances.

1) To realize the maximum benefit from a load shedding program, the points at which the load is shed in a company area should be widely dispersed. This can be accomplished at the sub-transmission and distribution voltage level where the types of load and the increments of load to be shed can be selected.

2) The time interval involved in shedding load is of extreme importance. System operators cannot and shall not be required to manually shed load during a period of rapidly declining voltage. One practical way to remove load from a member in an attempt to stabilize the voltage is to do so automatically by the use of undervoltage relays. All of the designated undervoltage relays on a member system shall be in service at all times. Undervoltage relays shall not be installed on transmission interconnections unless considered necessary and has been mutually agreed upon between the members involved.

3) Loads may be shed in multiple steps. Whatever actions are planned or implemented by one member, including actions other than load shedding, shall be coordinated with neighboring members and SPP. All UVLS programs shall coordinate with underfrequency load shedding requirements of other members and SPP to maintain the reliability of the bulk transmission system operated at 100kV and above.

4) Should the utilization of various assets, such as responsive voltage-supporting resources, generation, capacitors and static var systems, fail to stop a voltage decline, load shedding shall be initiated as determined by the member of which is conditional upon the regional requirements of SPP. The relays used to accomplish load shedding shall be high speed with the necessary external intentional time delay devices employed to eliminate nuisance

trips during faults, reclosing delays, etc.

### 8.5.8 Coordination of Undervoltage Load Shedding Programs

The facility owners and operators of an UVLS program shall ensure that their programs are consistent with Regional UVLS program requirements including automatically shedding load in the amounts and at the locations, voltages, rates and times consistent with those Regional requirements. When an undervoltage event occurs which is below the initializing set points of their UVLS programs, the owners or operators shall analyze and document the event. Documentation of the analysis shall be provided to SPP and NERC on request in the time frames established in 8.5.7.

## 8.6.5 Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality and availability of the ARL equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request.

ARL systems shall be functionally tested when initially placed in service, when modifications are made, and at a frequency of no less than three (3) years to verify the dependability and security aspects of the design. The maintenance and testing program of the ARL system should include provisions for relay calibration, functional trip testing, communications system testing, and breaker closure testing. All maintenance and testing shall be documented as described below:

1) Automatic Restoration of Load system identification.

2) Summary of testing procedures.

3) Frequency of testing.

4) Date last tested.

5) Results of last testing.

## 8.7 Generation Control and Protection

The objectives of protective relaying and control schemes within generation facilities are to promptly detect abnormal conditions and isolate or control equipment to minimize damage to equipment. Some of these abnormal conditions which will result in an alarm or tripping of generation include faults, overload, overheating, off-frequency, loss of field, motoring, single phase or unbalance current operation, and out-of-step. The selection and settings of equipment should not result in erroneous tripping for acceptable operating conditions or for faults outside the intended zones of protection.

Generation Control and Protection Systems (GCP) must be coordinated with excitation and

governor controls to minimize generator tripping during disturbance-caused abnormal voltage, current and frequency conditions. Therefore, protection and control schemes should be designed and installed with appropriate settings to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need

to adequately protect the generator equipment from damage. All reviews, monitoring and analysis of each generator, rated at 20MW or above, shall be completed as described in Criteria 8.7.

### 8.7.1 Reviews of Components and Systems

The owner shall conduct periodic reviews of the components and systems that make up the generation protection system to assure that components and systems function as desired to minimize outages. The design and implementation of all new protection schemes shall be in accordance with IEEE and ANSI Standards, Guides and Recommended Practices as well as NERC Standards and Guides. Should it be determined that the design and application of protection equipment do not adhere to such requirements, then these findings, as a result of this review, shall be documented including a plan for achieving the necessary results. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 8.7.2. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.

2) Current carrying capability of all components (Bus, cables, lines, CTs, breakers, switches, etc.).

3) Interrupting capability of all components (breakers, fuses, etc.).

4) Breaker failure and trip schemes.

The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generator protection systems should not operate for stable power swings except when that particular generator is out of step with the remainder of the system. Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

All underfrequency, overfrequency, undervoltage and overvoltage protection systems shall be coordinated with system underfrequency and undervoltage load shedding schemes. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B and C of NERC I.A Standards unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

Redundant generator protection schemes are required for all new generator installations and all re-powering projects where the generator is rated at 20MW or above. Redundant generator protection schemes for the step-up transformer and the main auxiliary transformer (if any) are not required but encouraged. Where redundant protection systems are being used, efforts should

be made to use separate current transformers, potential transformers, and DC control power circuits to minimize the risk of both systems being disabled by a single event or condition.

The use of dual trip coils, if available, on both generator and unit circuit breakers are required for all new generator installations at 20MW or above. The installation of breaker failure relaying for generator and unit circuit breakers are also required for all new generator installations at 20MW or above. The addition of breaker failure relaying for all generator and unit circuit breakers at existing sites is not required but encouraged.

### 8.7.6 Generation Protection Systems Criteria Updates

The SPCWG will update, if necessary, this Generation Control and Protection Systems Criteria every three (3) years.

## 8.8 Generator Controls - Status and Operations

### 8.8.1 Generator Excitation System Control Operation

All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation systems in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless approved by the control area operator.

#### 8.8.1.1 Reporting Procedures

Control Area Operators shall implement procedures that require Synchronous Generator Operator/Owners to provide information to the Control Area Operator, SPP, and NERC upon request (30 business days) concerning the generators' automatic voltage control regulator. The procedures shall include the following.

1) Summary report showing the number of hours each synchronous generator did not operate in automatic voltage control mode during each calendar month. Information shall be provided on the "Generator Owner/Operator Excitation System Summary Report" supplied by SPP, if control area operator does not have its own form.

2) Detailed reports of the date, duration, and reason for each instance in which a synchronous generator was not operated in the automatic voltage control mode for a specific calendar

month. Information shall be provided on the "Generator Unit Excitation System Status Report" supplied by SPP, if control area operator does not have its own form.

3) The Generator Owner/Operator shall retain the reports mentioned in (a.) and (b.) for a period of 12 rolling months.

#### 8.8.1.2 Exempt Generators

Control Area operators shall have criteria stating which generators may be exempt from these procedures. Exemptions shall include the following.

1) Generator output less than 20MW

1) Other criteria as control area operator deems appropriate.

### 8.8.2 Generator Operation for Maintaining Network Voltage

Synchronous generators shall maintain a network voltage or reactive power output as required by the control area operator within the reactive capability of the units.

#### 8.8.2.1 Control Area Responsibilities

1) Each control area operator shall specify a voltage or reactive schedule to be maintained by each synchronous generator at a specified bus and shall provide this information to the generator owner/operator. Documentation of the information shall be provided on the "Generator Owner/Operator Voltage Schedule Requirements" report supplied by SPP, if the control area operator does not have its own form. This information shall be made available to SPP and NERC on request (30 business days).

2) Each control area operator shall maintain a list of synchronous generators that are exempt from the requirement of maintaining a network voltage or reactive schedule. The list of exempt generators shall be made available to SPP and NERC on request (30 business days) and shall be supplied on "Control Area Operator's List of Exempt Generators" report supplied by SPP, if control area does not have its own form.

#### 8.8.2.2 Generator Owner/Operator Responsibility

1) Synchronous generator owner/operators shall maintain the voltage or reactive output as specified by the control area operator.

2) When requested by SPP and NERC, the synchronous generator owner/operator shall provide (30 business days) a log that specifies the date duration, and reason for not maintaining the established voltage or reactive schedule, along with approvals for such operation received from the transmission operator. This information shall be provided on

the "Generator Unit Voltage Schedule Status Report" supplied by SPP, if control area operator does not have its own form.

### 8.8.3 Generator Step-Up and Auxiliary Transformer Tap Settings

Generator step-up and auxiliary transformers shall have their tap settings coordinated electric system voltage requirements.

#### 8.8.3.1 Reporting Procedures

Control Area operators shall implement procedures concerning the reporting and changing of transformer tap settings. The procedures shall at a minimum include the following.

1) Owner/Operators shall provide current tap settings, tap setting ranges, and impedance data for all Generator Step-Up (GSU) and Auxiliary Transformers to the control area operator, SPP, and NERC upon request (30 business days). This information shall be supplied on 'Generator Unit Transformer Tap Setting Report" supplied by SPP is control area operator does not have its own form.

2) When tap setting changes are necessary, the control area operator shall notify generator owner/operator with "Generator Unit Transformer Tap Setting Change Request" supplied by SPP, if control area operator does not have its own report. In this report, tap setting changes are specified along with a technical justification for the changes.

3) Generator Owner/Operators shall have a period of nine (9) months in which tap setting changes must be made. After setting changes have been made, Generator Owner/Operator shall supply new "Generator Unit Transformer Tap Setting Report" for the affected generating station.

4) Criteria for Generating units whose GSU and AUX transformers would be exempted.

5) List of generating units that meet exemption criteria shall be documented on "Generation Units Exempt from Tap Setting Reporting Procedures" report supplied by SPP, if Control Area Operator does not have its own form.

### 8.8.4 Generator Performance during Temporary Excursions

#### 8.8.4.1 Excursions Voltage

During Emergency and/or transient system conditions, all reasonable measures should be taken to avoid tripping of the generator due to high or low voltage.

#### 8.8.4.2 Excursions in Real and Reactive Power Output

Generators shall be able to sustain temporary excursions in real and reactive power output that may occur during a period of declining frequency or voltage. For this reason, all generator governors and automatic voltage regulators shall be kept in automatic mode as much as practical. A generator shall not trip during stable power swings except when that particular generator is out of step with the remainder of the system.

Generators shall be able to run at maximum rated reactive and real output according to each unit's Capability Curves during emergency conditions for as long as acceptable frequency and voltages allow the generator to continue to operate.

#### 8.8.4.3 Exempt Generators

Generators shall be exempt from this section if they meet the following criteria:

1) Generator output less than 20MW

### 8.8.5 Generator Voltage Regulator Controls and Limit Functions

Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short term duration capabilities and protective relays.

#### 8.8.5.1 Reporting Procedures

Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with information that ensures generator controls coordinate with the generator short term duration capabilities and protective relays. The information shall be supplied on the "Voltage Regulator Control Setting Status Report" as supplied by SPP is control area operator does not have its own form.

### 8.8.6 Governor Control Operation

Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency. Governors' speed regulation response shall be set such that a decrease in system frequency causes the governor to respond by increasing the generator real power output.

#### 8.8.6.1 Reporting Procedures

1) Generator Owner/Operators shall provide control area, SPP, and NERC as requested (30 business days) with the characteristics of the generator's speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance. Information shall be supplied on "Generator Governor Characteristic Reporting" report supplied by SPP if control area operator does not have its own form.

2) Non-functioning or blocked speed/load governor controls shall be reported to control area, SPP, and NERC on request (30 business days). Information shall be supplied on "Non-Functioning Governor Control" report supplied by SPP if control area operator

does not have its own form.

## 8.9 Inter-connection Revenue Metering

### 8.9.1 Meter Technical and Data Reporting Protocols

The protection design may also include various types and accuracies of metering and associated equipment. The metering may include, but not be limited to, the following: local station or plant

annunciated / displayed metering, SCADA type operational metering exchanged among parties within a station or plant, SCADA type station to control center metering used for operational purposes, control center to control center ICCP type metering, and inter-connection revenue metering. These metering types may or may not have specific SPP criteria requirements. Other metering design requirements may need to be referenced when creating metering and protection design, especially those that include the control center to control center metering and revenue metering. SPP has specific functional and design type requirements for Inter-Connection Revenue Metering.

### 8.9.2 Revenue "Meter Technical and Data Reporting Protocols" Cross Reference

The Southwest Power Pool (SPP) Market Working Group's (MWG) Settlement Data and Meter Standards Task Force (SDMSTF) subcommittee has jurisdictional control over the power plant and transmission system "inter-connection settlement revenue metering". The SPP System Protection and Control Working Group (SPCWG) and other parties providing inter-connection settlement revenue metering designs in the SPP area must refer to the MWG - - SDMSTF Market Protocol Document "Appendix D: Meter Technical and Data Reporting Protocols" for inter-connection settlement revenue metering equipment design requirements. Per the SPP Market Protocol Document, the inter-connection revenue metering design requirements must be met for all new installations

## 4.0 EXAMPLE

Given: Plant site is 39°, 15‘ latitude; 94°, 58’ longitude.
Elevation is 750 feet.
Find: Generator rating conditions.

1. Determine the three nearest weather stations and temperatures from the ASHRAE Handbook.

| Station | Latitude | Longitude | Elevation | Td | Tw |
|---|---|---|---|---|---|
| Kansas City, MO | 39°, 07’ | 94°, 35’ | 791 | 99 | 75 |
| Atchison, KS | 39°, 34’ | 95°, 07’ | 945 | 96 | 77 |
| Topeka, KS | 39°, 04’ | 95°, 38’ | 877 | 99 | 75 |

2. Correct the temperatures to the plant elevation

| Station | Elevation above Plant | Effect on Td | Effect on Tw | Corrected Td | Corrected Tw |
|---|---|---|---|---|---|
| Kansas City, MO | 41 | 0.2 | 0.1 | 99.2 | 75.1 |
| Atchison, KS | 195 | 1 | 0.4 | 97 | 77.4 |
| Topeka, KS | 127 | 0.6 | 0.3 | 99.6 | 75.3 |

3. Using 39°, 00’; 94°, 00’ as the origin determine the relative location of each point A, B, and C from the plant P. To obtain the east-west dimensions, multiply the longitude minutes from 94°, 00’ by the cosine of plant latitude; cos (39.25) = 0.7744. Doing so, the following coordinates are obtained:

| | North | West | Point |
|---|---|---|---|
| Plant | 15 | 44.9 | P |
| Kansas City, MO | 7 | 27.1 | A |
| Atchison, KS | 34 | 51.9 | B |
| Topeka, KS | 4 | 75.9 | C |

4. Calculate the distance between P and points A, B, and C, and then temperatures at P.

$$D_{PA} = ((y_P - y_A)^2 + (x_P - x_A)^2)^{2\,½} = 19.5$$
$$D_{PB} = ((y_P - y_B)^2 + (x_P - x_B)^2)^{2\,½} = 20.2$$
$$D_{PC} = ((y_P - y_C)^2 + (x_P - x_C)^2)^{2\,½} = 32.9$$

so,

$$T_i = \Sigma(T_i/D_i) / \Sigma(1/D_i)$$
$$T_d = (T_{dA}/D_{PA} + T_{dB}/D_{PB} + T_{dC}/D_{PC})/(1/D_{PA} + 1/D_{PB} + 1/D_{PC}) = 98.46°F$$
$$T_w = (T_{wA}/D_{PA} + T_{wB}/D_{PB} + T_{wC}/D_{PC})/(1/D_{PA} + 1/D_{PB} + 1/D_{PC}) = 76.01°F$$

5. The standard barometric pressure for the site is:

$P_{SB} = 29.921 \times (1 - 6.8753 \times 0.000001 \times \text{Elevation})^{5.2559} = 29.12$ inches Hg

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App. PL-1

## Appendix P L - 2 . A- Ambient T emperature

### 1.0 Purpose

The purpose of this Appendix is to describe the methodology to be used when determining ambient temperature for circuit rating purposes. This methodology allows for the flexibility of computing ambient temperatures that are location specific and allows for the ease of using default values.

### 2.0 Types of Ambient Temperature

Maximum ambient temperatures are used when calculating seasonal ratings for overhead conductors, disconnect switches, circuit breakers and wave traps. Average ambient temperatures are used when calculating seasonal ratings for power transformers and current transformers.

#### 2.1 Maximum Ambient Temperature

Circuit rating criteria specify the maximum temperature an overhead conductor, switch, circuit breaker, and wave trap may experience. As the ambient temperature increases, the temperature rise that produces the same maximum equipment temperature is reduced. The reduced temperature rise results in a reduced load carrying capability. Consequently, increases in the maximum ambient temperature does not alter the maximum temperature the equipment was designed to withstand, but it does reduce the current carrying capability for the same maximum equipment temperature.

Selection of the maximum ambient temperature used in rating transmission circuits involves trade- offs. If you select an ambient temperature that is the highest temperature ever recorded for your control area, you may be limiting the use of the transmission system on an ongoing basis for a temperature that has a very small likelihood of occurring. On the other hand, if you select an ambient temperature that is frequently exceeded, you put the transmission system at risk of operating equipment at temperatures in excess of design when it is carrying rated load.

This circuit rating criteria attempts to achieve a balance by specifying a method for determining the maximum ambient temperature that allows for full utilization of the transmission system without experiencing frequent violations of equipment design temperatures. When selecting a maximum ambient temperature for seasonal ratings, a system may choose to either compute a temperature based on local weather station data or may use a default value.

Switches, circuit breakers and wave traps have nameplate ratings based on a 40°C (104°F) maximum ambient temperature (if designed according to ANSI/IEEE standards). The 40°C shall be used as the summer default value for this equipment along with overhead conductors. A system that elects to use the summer default

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value shall utilize the nameplate rating. Those systems wanting to compute their own maximum ambient temperature shall use the procedure described in section 3.1 and must adjust the nameplate rating using the procedure described in the appropriate appendix for that piece of equipment. The winter default temperature is 1oac (50°F). Whether a system elects to use the winter default value or compute its own, it shall still need to determine winter ratings for overhead conductors, switches, circuit breakers and wave traps using the procedures described in the appropriate appendix (nameplate ratings apply for summer months only).

The maximum ambient temperature, whether based on a default value or a computed value, represents a ceiling or highest number that can be used for rating circuits. A system may rate their equipment at some lower temperature but cannot exceed the default value or the computed value. This allows systems that have historically computed their circuit ratings using an ambient temperature below the default value or the computed value to continue using this value for rating purposes.

However, for a system that has historically utilized an ambient temperature that exceeds both the default value and the computed value, it must lower the maximum ambient temperature it is using for rating purposes such that it equals either the default value or the computed value, whichever of the two the system elects to use.

**2.2 Average Ambient Temperature**

According to ANSI standards, both power transformers and current transformers are rated using average ambient temperature. The average temperature is calculated by averaging 24 consecutive hourly readings. The maximum daily temperature should not be more than $10^{o}$C greater than the average temperature. Power transformers and current transformers both have nameplate ratings based on a 30°C (86°F) average ambient temperature. The 30°C shall be used as the summer default value for this equipment. Using the 30°C average ambient temperature allows for a maximum daily temperature of 40°C that is consistent with the summer default value used for other equipment. The winter default value is $0^{o}$C (32°F). It allows a maximum daily temperature of $10^{o}$c (50°F) for the winter months and is consistent with the winter default value used for other equipment. A system can elect to compute its own average temperature using the procedure described in Section 3.2. Using a computed average ambient temperature (either summer or winter) for power transformers shall require adjusting its nameplate rating. The default average ambient temperature value of the transformer has been used to determine its emergency rating and an acceptable loss of life. This circuit rating criteria uses the power transformer nameplate rating as a year-round rating (both summer and winter). Consequently, even though an average ambient temperature can be computed, using it to adjust transformer nameplate ratings will affect emergency ratings and is not recommended.

Similar to the maximum ambient temperature the default or computed average ambient temperature represents a ceiling or highest number that can be used for rating power transformers and current transformers. A system can use an average

ambient temperature that is less than the default or computed amount but cannot use one that exceeds the default or computed amount.

## 3.0 Procedure for Computing Ambient Temperature

Systems have the option of either using default values or computing maximum ambient temperature and average ambient temperature. This section describes the procedure for computing ambient temperatures. In general, it is intended that a system would use this procedure a single time and once they have determined their maximum and average ambient temperature, these amounts would remain constant for all future circuit ratings.

When computing ambient temperature, systems shall use temperature readings from nearest weather stations. Some control areas span a large area that may encompass several weather stations. If a large enough geographic area is involved, it is also possible that the computed ambient temperature could be significantly higher at one or more of the weather stations. For these control areas, they may choose to either divide the control area into sections using the highest ambient temperature readings from weather stations within the section or, to maintain consistent ratings throughout the control area, they may choose to use the highest ambient temperature of all weather stations within the control area.

A system is not required to use the same weather station when computing summer and winter ambient temperature. However, the weather station selected must be within the control area or, if there are no weather stations within the control area, it must be the nearest weather station to the control area. Once a weather station is selected for either summer readings or winter readings, all or the readings for each season must come from the same weather station.

### 3.1 Maximum Ambient Temperature

The summer maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the summer months (June through September). The summer average shall be computed each year for the past five years and the highest average shall be selected as the summer maximum ambient temperature.

The winter maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the winter months (December through February). The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter maximum ambient temperature.

### 3.2 Average Ambient Temperature

The summer average ambient temperature is determined by averaging the 24 consecutive hourly temperature readings from the nearest weather station for the summer months (June through September). This summer average shall be computed using an average of the five hottest days during the four months. It shall be

computed for each year for the past five years and the highest average shall be selected as the summer average ambient temperature.

The winter average ambient temperature shall be computed in a similar manner but shall use the average of the hottest 24 consecutive hourly temperature readings from the nearest weather station for the winter months (December through February). The winter months are defined as the three consecutive months that overlap the end of the year. The winter average shall be computed similar to the summer average using an average of the five hottest days during the three months. The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter average ambient temperature.

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## Appendix P L-2 . B - Underground Cables

The determination of the ampacity of an underground cable is dependent upon the maximum temperature the conductor can withstand without causing significant thermal deterioration. This temperature can refer to steady-state, emergency or short-circuit conditions. It is the specification of this temperature limit that limits the cable's ampacity. The Neher-McGrath procedure is the basis of steady-state ampacity calculations. This current rating can be calculated by solving the thermal equivalent of Ohm's Law and in its basic form is shown by the equation below:

$$I = \sqrt{\frac{T_c - T_a - \Delta T_d}{R_{et} \times R_{,h}}} \times 10^{3} \; A$$

where

Tc =allowable conductor temperature, $^{o}$C Ta
=ambient earth temperature, $^{o}$C
ΔTd =temperature rise due to dielectric loss, $^{o}$C
Rel, = electrical resistance, μ Ω / ft
$R_{th}$ = thermal resistance, TOF (thermal ohm-feet)

The basic thermal circuit consists of cable heat (in watts) that corresponds to electrical current (in amperes), thermal resistance (in thermal ohm-feet) that corresponds to electrical resistance (in ohms) and temperature drop (in $^{o}$C) that corresponds to voltage drop (in volts). The electrical analogy and thermal circuit are shown below.

Simply stated, the ampacity calculation consists of the calculation of losses and the temperature rise due to those losses flowing through the various resistances. The procedure can be summarized as follows:

1. Determine the cable construction and conductor size of the existing cable.

2. Refer to AEIC specifications for the maximum allowable conductor temperature f o r this cable. Determine the temperature rise over ambient earth temperature that will give this value.

3. Calculate dielectric loss.

4. Calculate the electrical resistances of each current-carrying component of the system for the expected operating temperature of that component.

5. Calculate the thermal resistance of each component of the system, including the earth.

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6. Calculate the temperature rise due to dielectric loss flowing through the thermal resistances, and subtract that number from the total available temperature rise.

7. Solve the Ohm's law equivalent circuit to determine the ampacity that achieves the allowable temperature rise.

The total thermal circuit for a self-cooled buried transmission cable is shown as an electrical analog in figure below.

The following equations summarize the calculation of the allowable current.

*Calculating Allowable Current*

I =

*Temperature Rise Due to Dielectric Losses*

For pipe-type cables,

$$\Delta T_d = W_d \left( \frac{1}{2} \overline{R_i} + \overline{R_{sd}} + \overline{R_{pc}} + \overline{R_{de}} + \overline{R_{dcor}} \right), \ (C^\circ)$$

for single-conductor cables,

$$\Delta T_d = W_d \left( \frac{1}{2} \overline{R_i} + \overline{R_j} + \overline{R_{sd}} + \overline{R_d} + \overline{R_{pc}} + \overline{R_{de}} + \overline{R_{dcor}} \right), \ (C^\circ)$$

where

| | |
|---|---|
| R; = | insulation thermal resistance (TOF) |
| Ri = Rsd = | jacket thermal resistance (TOF) |
| | thermal resistance between cable surface and surrounding enclosure (TOF) |
| Rd = Rpc | duct thermal resistance (TOF) |
| = Rde' = | pipe-covering thermal resistance (TOF) |
| Rdcorr = | earth thermal resistance for dielectric losses (TOF)<br>correction factor for controlled backfill or concrete-encased duct (TOF) |

*Available Temperature Rise for Current-Dependent Losses*

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$$\Delta T_c = T_c - T_a - \Delta T_d - \Delta T_{int}, (C^\circ)$$

where

| | | |
|---|---|---|
| $T_c$ | = | allowable conductor tem perature ($C^o$) |
| $T_a$ | = | ambient earth temperature ($C^o$ |
| $\Delta T_d$ | = | conductor temperature rise due to dielectric and charging-current losses ($C^o$} |
| $\Delta T_{int}$ | = | tem perature rise due to extraneous heat source ($C^o$) |

*Summation of Electrical and Thermal Resistances*

for pipe-type cables:

$$\sum R_{ac} R_{th} °C / kA^2 R_{acc} R_i + R_{acs} R_{sil} + R_{acp} R_{pc} + R_{acp} R_{dx} + R_{acp} R_{earth} + R_{acp} R_{mut} + R_{acp} R_{cccrr}$$

$$\sum R_{ac} \overline{R_{th}} °C / kA^2 = R_{acc} \overline{R_i} + R_{acs} \overline{R_j} + R_{acs} \overline{R_{sil}} + R_{acs} \overline{R_{il}} + R_{acs} \overline{R_{dx}} + R_{acs} \overline{R_{earth}} + R_{acs} \overline{R_{mut}} + R_{acs} \overline{R_{cccrr}}$$

for single-conductor cables:

where

| | |
|---|---|
| De = $D_x$ = Race = Racp = Racs = Rcccrr = Rdx = Rearth = R mut = | diameter at start of the earth or external portion of the thermal circuit (in.)<br>fictitious diameter at which the effect of loss factor begins (in.)<br>conductor ac resistance ( μ Q/ft)<br>ac resistance at pipe ( μQ/ft)<br>ac resistance at shield ( μQ/ft)<br>correction factor, current-dependent losses (TOF)<br>thermal resistance from De to diameter $D_x$ (TOF)<br>thermal resistance from Dx to ambient earth (TOF)<br>mutual-heating earth thermal resistance term (TOF) |

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For further and more detailed information see the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity. The above equations apply to buried cable installations. For above ground installation (e.g. bridge crossings, tunnel installations or riser sections), there are three main differences. First, solar radiation provides heat input. The Neher-McGrath method does not consider this factor. Second, heat transfer by conduction is negligible. And third, heat transfer for cables in air is by free or forced convection and by radiation. Generally, the ampacity of an identical cable circuit installed in the air will be greater than that for a buried cable circuit. The equations will not be presented here and may be found in the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity.

Under emergency conditions it may become necessary to exceed the normal temperature limit of the cable. A new cable rating may be calculated by substituting the new temperature limit into the equations seen above. The key to calculating the emergency rating will be establishing the allowable temperature increase. One must be careful not to overestimate the ability of the cable to withstand higher temperatures as well as not to underestimate the loss of life that will occur with operation above normal temperatures.

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# APPENDIX PL-2.C

APPENDIX PL-2.C Switches

Switch ratings are discussed in ANSI/IEEE C37.37 **Loading Guide for AC High-Voltage Air Switches (in excess of 1000 volts)** and in ANSI/IEEE C37.37a- IEEE Loading Guide for AC High-Voltage Air Switches Under Emergency Conditions. In general, the allowable continuous current of a switch is based on the allowable maximum temperature of the switch parts and is affected by the ambient temperature. Provisions are made for loading the switches under emergency conditions in the above referenced ANSI/IEEE Standard C37.37a- Therefore, both Normal and Four-Hou r Emergency circuit ratings will be developed based upon the allowable continuous current capability rating of the switch. These ratings will be treated as the loading limits for normal and emergency conditions.

A switch is made up of a number of different switch parts, which are classified and grouped in accordance with their material and function into switch part classes, each of which is given a switch part class designation of the form xO#. Examples of the switch part class designations are A01, 006, J010, N01, and W09. The loadability factors of each switch part class, as a function of ambient temperature, are represented by a curve. Tabular representations of these curves for normalcontinu ous load conditions are contained in Table C - 3 for non-enclosed i ndoor and outdoor switches and in Table C- 4 for enclosed indoor and outdoor switches. Tabular representations of these curves for emergency load conditions with a maximum emergency loading duration of four hours are contained in Table C - 5 for non-enclosed indoor and outdoor switches and in Table C- 6 for enclosed indoor and outdoor switches.

The Allowable Continuous Current Class (ACCC) designation of a switch is a code which identifies a composite loadability curve made up from the limiting switch part classes. In most instances, the ACCC designation will be contained on the switch's nameplate. However, air switches designed in accordance with ANSI C37.30- and earlier may not have an ACCC designation on the nameplate. Such non-- enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 40°C, indicative of an allowable maximum temperature of 70°C, are assigned an ACCC designation of AO1. r n like manner, such enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 55°C, indicative of an allowable maximum temperature of 85°C, are assigned an ACCC designation of N01.

ACCC designations were developed such that the first character, x, designates that the specific normal loadability factors for that class are represented by Curve x when the ambient is between 60°C and 25°C.; the second character in the ACCC designation, 0, represents the specific normal loadability factor for that class at 25°C. (All curves intersect at 0 and have a l oadability factor of 1.2 2 at 25°C ambient); and the third character, #, designates that the specific normal loadability factors for that class are represented by Curve# when the ambient is between 25°C and -30°C.

In some instances, a composite curve must be developed due to the fact that the switch is constructed such that some parts of the switch have different switch part class designations than other parts of the switch. In this situation, the switch's ACCC designation will differ from the standard ACCC designations listed in the tables and instead will be a composite of two of the standard ACCC designations. An example of this would be a switch having a designation of 006, signifyi ng that the switch is constructed using some parts having the switch part class desi gnations of 004 and some parts having the switch part class designations of F06.

Based upon the ACCC designation of a switch, a normal l oadability factor curve can be developed for the switch in the following manner.

1. Using Table C - 2 for non-enclosed indoor and outdoor switches or Table C- 3 for enclosed

Indoor and outdoor switches, the appropriate values for Curve x, Curve 0, and Curve# are determined based upon the switch's ACCC designation. These curves will be joined together to form a composite normal loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

is not represented in the composite table

2. The normal loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the normal loadability factor for a specific temperature, which is desired, the normal loadability factor may be calculated by interpolating between the nearest known values. In no case shall the normal loadability factor exceed 2.00.

3. The Allowable Continuous Current Capability of a switch at a given ambient temperature is equal to the normal loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Allowable Continuous Current Capability of a switch at a given ambient temperature will be treated as the normal ratings of the switch for that ambient temperature.

**Example:** The following example should serve to clarify this process:

**Problem:**

(a) Develop a loadability factor table for a 1200-amp non-enclosed switch with ACCC designation D06.

(b) Using this table, determine the Allowable Continuous Current Capability of this switch at an ambient temperature of 0°C.

**Solution:**

(a) The normal loadability factor table, Table C - 1, was created using Table C - 3 for a non-enclosed switch with ACCC designation 006. For the temperatures from 25°C to 60°C, the loadability factors from Curve D were used. The standard loadability factor of 1.22 was used for an ambient of 25°C. The loadability factors from Curve 6 were used for the temperatures from
20°C to -30°C.

(b) Based upon Table C - 1, the Allowable Continuous Current Capability of a 1200-A nonenclosed switch designated DO6 at 0°C would be:

Loadability Factor @ 0°C * Rated Current

or

1.41 * 1200 amps= 1692 amps

For operation at 0 $^{o}$c, the Normal rating of switch would be 1692 amps.

| Maximum Ambient Temperature | Loadability Factor | Curve Used |
|---|---|---|
| 60°C | 0.84 | |
| 50°C | 0.96 | |
| 40°C | 1.07 | |
| 30°C | 1.18 | |
| 25°C | 1.22 | Standard |
| 20°C | 1.27 | |
| 10°C | 1.34 | |
| 0°C | 1.41 | |
| -10°C | 1.47 | |
| -20°C | 1.54 | |
| -30°C | 1.60 | |

Table C -1: N ormal Loadability Factors for a Type 006 Sw itch

The Four-Hour Emergency Load Current carrying capability of a switch can be determined based upon the switch's ACCC designation. A four-hour emergency loadability factor curve can be developed for the switch in the following manner.

1. Using Table C - 5 for non-enclosed indoor and outdoor switches or Table C - 6 for enclosed indoor and outdoor switches, the appropriate emergency loadability factors are determined based upon the switch's ACCC designation. In developing the composite curve, the emergency loadability factor curves of the two standard ACCC designations must be examined and the most limiting loadability factor at each ambient temperature will be used to form a composite emergency loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

2. The emergency loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the emergency loadability factor for a specific temperature, which is not represented in the composite table, is desired, the emergency loadability factor may be calculated by interpolating between the nearest known values. In no case shall the emergency loadability factor exceed 2.00.

3. The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature is equal to the emergency loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature will be treated as the Emergency ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process:

Problem:

(a) Develop an emergency loadability factor table for a 1200-amp non-enclosed switch with ACCC designation 006.

(b) Using this table, determine the Four-Hour Emergency Load Current Capability of this switch at an ambient temperature of 0°C. .

Solution:

(a) The emergency loadability factor table, Table C - 2, was created using Table C- 5 for a non-enclosed switch with ACCC designation D06. The composite curve was developed by examining the emergency loadability curves for switches having ACCC designations of 004 and F06. At each of the ambient temperatures, the most limiting loadability factor was chosen from the D04 and F06 curves to form the composite curve.

(b) Based upon Table C- 3, the Four-Hour Emergency Load Current Capability of a 1200-A non-enclosed switch designated D06 at 0°C would be:

Emergency Loadability Factor@ $0^{o}$C * Rated Current

or

1.54 * 1200 amps = 1848 amps

For operation at 0°C, the Four-Hour Emergency ratings of the switch would be 1848 amps.

| Maximum Ambient Temperature | Loadability Factor Curve 004 | Loadability Factor Curve F06 | Composite Curve for a 006 Switch |
|---|---|---|---|
| 60°C | 1 08 | 1 11 | 1 08 |
| 50°C | 1.18 | 1.19 | 1.18 |
| 40°C | 1 28 | 1.27 | 1.27 |
| 35°C | 1.32 | 1.30 | 1.30 |
| 30°C | 1.36 | 1.34 | 1 34 |
| 25°C | 1.41 | 1.37 | 1.37 |
| 20°C | 1 45 | 1.41 | 1.41 |
| 10°C | 1.53 | 1.47 | 1.47 |
| 0°C | 1.60 | 1.54 | 1.54 |
| -10°C | 1.67 | 1.60 | 1.60 |
| -$20^{0}$C | 1.74 | 1.65 | 1.65 |
| -30°C | 1.81 | 1.71 | 1.71 |

. Table C- 2: Four-Hour Emergency Loadabillty Factors for a Type D06 Switch

| Maximum Ambient Temperature | | ACCC Designation | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| °C | °F | A01 | B02 | C03 | D04 | E05 | F06 | G07 | H08 | 109 | J010 | K011 |
| 60 | 140 | 0.58 | 0.67 | 0.74 | 0.84 | 0.86 | 0.92 | 0.94 | 0.98 | 1.03 | 1.06 | 1.10 |
| 50 | 122 | 0.82 | 0.87 | 0.90 | 0.96 | 0.96 | 1.02 | 1.03 | 1.05 | 1.09 | 1.12 | 1.14 |
| 40 | 104 | 1.00 | 1.03 | 1.04 | 1.07 | 1.06 | 1.11 | 1.11 | 1.13 | 1.15 | 1.16 | 1.16 |
| 30 | 66 | 1.15 | 1.17 | 1.17 | 1.16 | 1.16 | 1.19 | 1.19 | 1.20 | 1.20 | 1 20 | 1.21 |
| 25 | 77 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 | 1.22 |
| 20 | 66 | 1.29 | 1.29 | 1.26 | 1.28 | 1.27 | 1.27 | 1.27 | 1.26 | 1.25 | 1.24 | 1.24 |
| 10 | 50 | 1.41 | 1.40 | 1.36 | 1.36 | 1.34 | 1.34 | 1.32 | 1.32 | 1.30 | 1.26 | 1. 28 |
| 0 | 32 | 1.53 | 1.51 | 1.47 | 1.45 | 1.42 | 1.41 | 1.39 | 1.38 | 1.34 | 1.32 | 1.31 |
| -10 | 14 | 1.63 | 1.60 | 1.56 | 1.52 | 1.49 | 1.47 | 1.45 | 1.44 | 1.39 | 1.36 | 1.34 |
| -20 | -4 | 1.73 | 1.70 | 1.64 | 1.60 | 1.56 | 1.54 | 1.51 | 1.49 | 1.44 | 1.40 | 1.37 |
| -30 | -22 | 1.63 | 1.78 | 1.72 | 1.67 | 1.63 | 1.60 | 1.57 | 1.54 | 1.46 | 1.44 | 1.40 |

**Table C 3: Non-enclosed Indoor and Outdoor Switches**
**Sw itch Part Normal Loadability Factors (LF) for Various Ambient Temperatures**

| Maximum Ambient Temperature | | ACCC Designation | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Q03 | | P02 | | N01 | | R04 | | S05 | | T06 | | U07 | | V08 | | W09 | | X010 | | Y011 | |
| | °f | | | | | | | | | | | | | | | | | | | | | | |
| 60 | 140 | 0.00 | Curve Q | 0.45 | Curve P | 0.58 | Curve N | 0.67 | Curve R | 0.74 | Curve S | 0.84 | Curve T | 0.86 | Curve U | 0.92 | Curve V | 1.00 | Curve W | 1.05 | Curve X | 1.09 | Curve Y |
| 50 | 122 | 0.71 | | 0.77 | | 0.82 | | 0.87 | | 0.90 | | 0.96 | | 0.98 | | 1.02 | | 1.07 | | 1.10 | | 113 | |
| 40 | 104 | 1.00 | | 1.00 | | 1.00 | | 1.03 | | 1.04 | | 1.08 | | 1.08 | | 1.11 | | 1.13 | | 1.15 | | 1.17 | |
| 30 | 86 | 1.22 | Curve 3 | 1.18 | Curve 2 | 1.15 | | 1.16 | | 1.16 | | 1.18 | | 1.18 | | 1.19 | | 1.20 | | 1.20 | | 1.20 | |
| 25 | 77 | 1.32 | | 1.26 | | 1.22 | | 1.22 | | 1.22 | | 1.22 | | 1.22 | | 1.22 | | 1.22 | | 1.22 | | 1.22 | |
| 20 | 68 | 1.41 | | 1.34 | | 1.29 | Curve 1 | 1.29 | Curve 4 | 1.28 | Curve 5 | 1.28 | Curve 6 | 1.26 | Curve 7 | 1.26 | Curve 8 | 1.25 | Curve 9 | 1.25 | Curve 10 | 1.24 | Curve 11 |
| 10 | 50 | 1.58 | | 148 | | 1.41 | | 1.40 | | 1.38 | | 1.36 | | 1.35 | | 1.34 | | 1.31 | | 1.29 | | 1.28 | |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 32 | 1.73 | 1.61 | 1.53 | 1.51 | 1.47 | 1.45 | 1.42 | 1.41 | 1.36 | 1.34 | 1.31 |
| -10 | 14 | 1.87 | 1.73 | 1.63 | 1.61 | 1.56 | 1.53 | 1.50 | 1.47 | 1.41 | 1.40 | 1.35 |
| -20 | -4 | 2.00 | 1.84 | 1.73 | 1.70 | 1.64 | 1.60 | 1.56 | 1.54 | 1.46 | 1.42 | 1.38 |
| -30 | -22 | 2.00 | 1.95 | 1.83 | 1.78 | 1.72 | 1.67 | 1.63 | 1.60 | 1.51 | 1.46 | 1.41 |

**Table C - 4: Enclosed Indoor and Outdoor Switches**
**Sw itch Part Normal Loadability Factors {LF) for Various Ambient Temperatures**
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| Maximum Ambient Temperature | | ACCC Designation | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | A01 | 802 | C03 | D04 | E05 | F06 | GO7 | HOB | I09 | J010 | K0 11 |
| °C | °F | | | | | | | | | | | |
| 60 | 140 | 1 00 | 1 03 | 1 04 | 1 08 | 1 08 | 1 11 | 1 11 | 1 13 | 1 15 | 1 16 | 1 18 |
| 50 | 122 | 1.15 | 1.17 | 1.16 | 1.18 | 1.18 | 1.19 | 1.18 | 1.20 | 1.20 | 1.20 | 1.21 |
| 40 | 104 | 1.29 | 1.29 | 1.27 | 1.28 | 1.26 | 1.27 | 1.26 | 1.26 | 1.25 | 1.24 | 1.24 |
| 35 | 95 | 1.35 | 1.35 | 1.33 | 1.32 | 1.30 | 1.30 | 1.29 | 1.29 | 1.27 | 1.26 | 1.26 |
| 30 | 86 | 1.41 | 1.40 | 1.38 | 1.36 | 1.34 | 1.34 | 1.32 | 1.32 | 1.30 | 1.28 | 1.28 |
| 25 | 77 | 1.47 | 1.46 | 1.42 | 1.41 | 1.38 | 1.37 | 1.36 | 1.35 | 1.32 | 1. 30 | 1.29 |
| 20 | 68 | 1.53 | 1.51 | 1.47 | 1.45 | 1.42 | 1.41 | 1.39 | 1.38 | 1.35 | 1.32 | 1.31 |
| 10 | 50 | 1.63 | 1.61 | 1.56 | 1.53 | 1.49 | 1.47 | 1.45 | 1.44 | 1.39 | 1.36 | 1.34 |
| 0 | 32 | 1.73 | 1.70 | 1.64 | 1.60 | 1.56 | 1.54 | 1.51 | 1.49 | 1.44 | 1.40 | 1. 37 |
| -10 | 14 | 1.83 | 1.78 | 1.72 | 1.67 | 1.63 | 1.60 | 1.57 | 1.54 | 1.48 | 1.44 | 1.40 |
| -20 | -4 | 1.92 | 1.87 | 1.80 | 1.74 | 1.69 | 1.65 | 1.62 | 1.59 | 1.52 | 1.47 | 1.43 |
| -30 | -22 | 2.00 | 1.95 | 1.87 | 1.80 | 1.76 | 1.71 | 1.68 | 1.64 | 1.56 | 1. 51 | 1.45 |

**Table C - 5: Non-enclosed Indoor and Outdoor Switches**
**Sw itch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures**

| Maximum Ambient Temperature | | ACCC Designation | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Q0 3 3 | P0 2 2 | N01 | R04 | S05 | T06 | U07 | V08 | W09 | X010 | Y011 |
| | °F | | | | | | | | | | | |
| 60 | 140 | 1.00 | 1.00 | 1.00 | 1.03 | 1.04 | 1.08 | 1.08 | 1.11 | 1.13 | 1.15 | 1.17 |
| 50 | 122 | 1.22 | 1.18 | 1.15 | 1.17 | 1.16 | 1.18 | 1.18 | 1.19 | 1.20 | 1.20 | 1.21 |
| 40 | 104 | 1.41 | 1.34 | 1.29 | 1.29 | 1.27 | 1.28 | 1.26 | 1.27 | 1.25 | 1.25 | 1.24 |
| 35 | 95 | 1.50 | 1.41 | 1.35 | 1.35 | 1.33 | 1.32 | 1.30 | 1.30 | 1.28 | 1.27 | 1.26 |
| 30 | 86 | 1.58 | 1.48 | 1.41 | 1.40 | 1.38 | 1.36 | 1.34 | 1.34 | 1.31 | 1.29 | 1.28 |
| 25 | 77 | 1.66 | 1.55 | 1.47 | 1.46 | 1.42 | 1.41 | 1.38 | 1.37 | 1.34 | 1.31 | 1.30 |
| 20 | 68 | 1.73 | 1.61 | 1.53 | 1.51 | 1.47 | 1.45 | 1.42 | 1.41 | 1.36 | 1.33 | 1.31 |
| 10 | 50 | 1.87 | 1.73 | 1.63 | 1.61 | 1.56 | 1.53 | 1.49 | 1.47 | 1.41 | 1.38 | 1.35 |
| 0 | 32 | 2.00 | 1.84 | 1.73 | 1.70 | 1.64 | 1.60 | 1.56 | 1.54 | 1.46 | 1.42 | 1.38 |
| -10 | 14 | 2.00 | 1.95 | 1.83 | 1.78 | 1.72 | 1.67 | 1.63 | 1.60 | 1.51 | 1.46 | 1.41 |
| -20 | -4 | 2.00 | 2.00 | 1.92 | 1.87 | 1.80 | 1.74 | 1.69 | 1.65 | 1.56 | 1.50 | 1.44 |
| -30 | -22 | 2.00 | 2.00 | 2.00 | 1.95 | 1.87 | 1.80 | 1.76 | 1.71 | 1.60 | 1.54 | 1.47 |

**Table C- 6: Enclosed Indoor and Outdoor Switches**
**Sw itch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures**

**APPENDIX P L - 2 . D - Wave Traps**

W ave trap ratings are discussed in several sources. The ratings for the older wave traps in which the main coil is designed as a single-phase, air-cored inductor of the dry type are discussed in ANSI C93.3-1981, **Requirements for Pow er-Line Carrier Line Traps** and in W estinghouse Electric's Curve No. 511545 (Copy included in this Appendix). The ratings of the newer type of wave traps consisting of a coil of wire encapsulated in an epoxy resin are not covered in an ANSI/IEEE standard. The ratings for this type of wave trap were developed based upon guidelines supplied by the manufacturer, Trench Electric, (Copy included in this Appendix). In general, the rated continuous current for wave traps is based on the maximum permissible temperature rise limitations of the wave trap when it is carrying rated current at an ambient temperature of 40°C. The total temperature of the wave trap under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature rise limitation is not exceeded.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of both types of wave traps. These seasonal ratings will be based on the nameplate rating of the wave trap with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The ambient-compensated normal loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D- 1 and were obtained from W estinghouse Electric's Curve No. 511545. The ambient- compensated loadability factors for Epoxy-Encapsulated Inductor wave traps were developed from Trench Electric's loadability curves and are given in Table D- 2. To determine the normal seasonal circuit rating, simply multiply the wave trap's nameplate rating by the appropriate normal loadability factor. Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Normal life expectancy will occur with a wave trap operated at or below its ambient-compensated normal current rating. Any value of currents in excess of the ambient-compensated normal current ratings may cause the designed temperature rise to be exceeded and may shorten the life expectancy of the wave trap. For wave traps utilizing an air-cored inductor, an acceptable level of emergency overload current has been determined and is specified in ANSI Standard C93.3-1981, **Requirements for Pow er-Line Carrier Line Traps.** Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of wave traps utilizing an air-cored inductor. These seasonal ratings will be based on the Four-Hour Emergency Overload Current-Carrying capability of the wave trap with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The wave traps may be loaded to this emergency level for a maximum of four hours per cycle. Before an emergency load cycle, the wave trap loading must be at or below the normal seasonal loading level for at least two hours.

The emergency seasonal circuit rating can be developed by simply multiplying the wave trap's nameplate rating by the appropriate emergency loadability factor. The ambient-compensated emergency loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D- 1 and were obtained from ANSI Standard C93.3-1981, **Requirements for Pow er-Line Carrier Line Traps.** Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

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| Average Ambient Air Temperature | Loadability Factors | |
|---|---|---|
| | **Normal** | **4-Hour Emergency** |
| 40°C | 1 00 | 1 10 |
| 20°C | 1.05 | 1.15 |
| | 1.10 | 1.20 |
| -20°C | 1.10 | 1.25 |

Table D- 1: Loadab1hty Factors for Dry-Type A1r-Cored Inductor Wave Traps

| Average Ambient Air TemperaOure | Loadability Factors | |
|---|---|---|
| | **Normal** | **4-Hour Emergency** |
| 40°C | 1 00 | N/A |
| 20°C | 1.13 | N/A |
| | 1.25 | N/A |
| -20°C | 1.36 | N/A |

**Table D - 2:** Loadability Factors for Epoxy-Encapsulated Inductor Wave Traps

Trench Electric, the manufacturer of the newer type of wave traps which consist of a coil of wire encapsulated in an epoxy resin, has stated that no overload capability is available on this type of wave trap. For this reason, no separate emergency rating will be assigned to this type of wave trap and the ambient-compensated current rating will be used for both the circuit's normal and emergency ratings.

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| | | |

July 16, 1985

Westinghouse Electric Corporation

Subject: Line Trap Loadings

Attached is one cop y of the Appendix to ANSI Standard C93.3-1981 titled "Guide for Emergency Overload Current Capability of Line Traps".

This guide is current and, all W estinghouse traps built since 1970 conform s to the overload capability designated therein.

The Curve No. 511545 supplied applies to W estinghouse Line Traps built prior to 1970. Note that the overload capability of traps 2000 amperes and below on this curve are the same as that specified in the Standard. The larger traps were modified in design in order to conform to the Standard requirement.

PL-2.D-3 January 1996

July 25, 1985

Trench Electric

Attached are three copies of the overload current U.S. temperature curves. General Electric did not send any such information when we purchased their Line Trap division but the curves should be approximately the same.

PL-2.D-4

January 1996

# Appendix PL-2.E

**APPENDIX PL-2.E** - Current Transformers

Current transformer ratings are discussed in ANSI/IEEE C57.13 **IEEE Standard Requirements for Instrument Transformers** and in Westinghouse Electric's technical paper titled **"Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers**" (Copy included in this Appendix). In general, the rated continuous current for current transformers is based on the maximum permissible temperature limitations of the various parts of the current transformer when it is carrying rated current at a 24-hour average ambient temperature of 30°C (with a maximum hourly temperature of 40°C). The total temperature of these parts under service conditions depends both on the actual load current, the actual average ambient temperature, and the service environment of the current transformer. Depending on the environment, it is, therefore, possible to operate at a current higher than rated continuous current when the average ambient temperature is less than 30 °C, provided that the allowable total temperature limit is not exceeded. Similarly, when the average ambient temperature is greater than 30°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

The environment in which a current transformer operates has a large effect on the current-carrying capability of the current transformer. Separately mounted current transformers have been assigned rated primary and secondary currents and continuous-thermal-current rating factors by the manufacturer. Separately mounted current transformers are designed to meet these characteristics by the independent control of such parameters as: current density in the primary and secondary windings, geometry, area of radiating surfaces, and heat transfer characteristics. Permissible loading as a function of ambient temperatures and continuous-thermal-current rating factors, and permissible overloading under emergency conditions, is covered in **ANSI/IEEE C57.13 IEEE Standard Requirements for Instrument Transformers.**

Bushing current transformers mounted in power circuit breakers and power transformers differ from separately mounted current transformers in that the design parameters cannot be independently controlled since they are restricted by the characteristics of the power apparatus in which they are mounted. Bushing current transformers, when attached to various power apparatus, are subjected to wide variations in their environmental ambient temperature. This variation is dependent upon the thermal characteristics of the power apparatus and the relative current loading with respect to the rated current of the power apparatus and its bushing current transformer. For this reason, continuous-thermal-current rating factors are not typically calculated by the manufacturer for bushing current transformers. Instead, the continuous-thermal-current rating factors must be determined for each application. Permissible loading and permissible overloading of bushing current transformers is covered in Westinghouse Electric's technical paper titled "**Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers".**

**Rating Separately Mounted Current Transformers**: The maximum continuous-thermal-current ratings for separately-mounted current transformers designed for 55°C temperature rise above 30°C average ambient air temperature will vary according to actual ambient cooling air temperature. The adjusted continuous current ratings will be based on three items:

1. The nameplate primary and secondary current ratings at the ratio setting being used.
2. The average cooling air temperature at which the rating is being calculated. Note: The maximum cooling air temperature must not exceed the average cooling air temperature by more than 10°C.
3. The ambient-adjusted Continuous-Thermal-Current rating factor from Table E - 1. The value used from this table is based upon the nameplate Continuous-Thermal-Current rating factor of the current transformer and the average ambient air temperature.

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| Average Cooling Temperature (°C) | Nameplate Continuous-Thermal-Current Rating Factor | | | | | |
|---|---|---|---|---|---|---|
| | 1.00 | 1.33 | 1.50 | 2.00 | 3.0_0 | 4.00 |
| 60°C | 0.65 | 0.85 | 1.00 | 1.35 | 2.00 | 2.70 |
| 50°C | 0.80 | 1.05 | 1.20 | 1.60 | 2.40 | 3.20 |
| 40°C | 0.90 | 1.20 | 1.35 | 1.80 | 2.70 | 3.65 |
| 30°C | 1.00 | 1.33 | 1.50 | 2.00 | 3.00 | 4.00 |
| 20°C | 1.05 | 1.45 | 1.65 | 2.20 | 3.30 | 4.35 |
| 10°C | 1.20 | 1.55 | 1.75 | 2.35 | 3.50 | 4.70 |
| 0°C | 1.30 | 1.65 | 1.85 | 2.45 | 3.70 | 5.00 |

Table E -1 : Ambient-Adjusted Continuous-Thermal-Current Rating Factors

The ambient-adjusted continuous-thermal-current rating of a separately-mounted current transformer is equal to the ambient adjusted continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified. According to ANSI/IEEE C57.13-1978, **IEEE Standard Requirements for Instrument Transformers**, no overload capability is available on separately-mounted current transformers. For this reason, normal rating of the separately-mounted current transformer will be used for both the normal seasonal circuit rating and the emergency seasonal circuit rating.

**Example**: The following example should serve to clarify this process:

**Problem**:

(a) Determine the summer seasonal normal and emergency ratings for a separately-mounted current Transformer operating on a 2000:5 amp ratio with a nameplate Continuous-Thermal-Current rating of 1.50. Assume the average ambient air temperature is 30°C with a maximum temperature of 40°C for the summer period.

(b) Determine the winter seasonal normal and emergency ratings for this same separately-mounted current transformer assuming an average ambient air temperature of 0°C wth a maximum temperature of 10 C for the winter period.

**Solution**

(a) From Table E - 1, the 30°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Therma-Current rating factor of 1.50 is 1.50 (They are the same due to the fact that the nameplate C-T-C rating factor is developed at an average ambient of 30°C). The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 30°C • Rated Primary Current of CT Ratio

or

$$1.50 \cdot 2000 \text{ amps} = 3000 \text{ amps}$$



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For operation at 30°C, both the Summer Normal and Emergency ratings of current transformer would be 3000 amps. **Note:** When the primary current is 3000 amps, the secondary current would be 7.5 amps due to the 2000:5 ratio used in the current transformer.

(b) From Table E - 1, the 0°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.85. The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 0°C *Rated Primary Current of CT Ratio

or

1.85 * 2000 amps = 3700 amps

For operation at 0°C, both the Winter Normal and Emergency ratings of current transformer would be 3700 amps. **Note:** When the primary current is 3700 amps, the secondary current would be 9.25 amps due to the 2000:5 ratio used in the current transformer.

**Rating Bushing Current Transformers Mounted in Power Apparatus:** The continuous current rating of current transformers mounted in power circuit breakers or power transformers is determined as follows:

1. When the bushing current transformer ratio being used has the same primary current rating as the breaker continuous current rating or the power transformer rated current, the continuous current rating factor of the current transformer is 1.0 (unity).

2. When the primary current rating of the ratio being used on the current transformer is greater than the continuous current rating of the breaker or greater than the power transformer rated current, then the maximum load current is limited by the breaker or power transformer rating, which ever is applicable.

3. When the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, then the maximum load current is limited by the continuous thermal current rating of the current transformer when operating on that ratio. Under these conditions, the temperature rises of the current transformer and the power apparatus would be lower, and therefore, the current transformer can be operated at a continuous thermal rating factor greater than 1.0. In this situation, the permissible continuous-thermal-current rating factor is calculated based upon constant maximum power dissipation, using the following equation:

$$R.F. = \left[ \frac{I_{pa}}{I_{ct}} \right]^{1/2}$$

where

R.F. =Continuous-thermal-current rating factor

$I_{pa}$ = Power apparatus continuous current rating (amps)

$I_{ct}$ = Primary current rating of bushing current transformer ratio used (amps)

The results calculated from this equation should be so limited that the maximum rating factor does not exceed 2.0 and that the continuous current rating of the breaker or the rated current of the power transformer is not exceeded.

**Note:** The situation, in which the primary current rating of the current transformer ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, is an unusual case and should be viewed as the exception rather than the rule.

The normal rating of a bushing current transformer is equal to the continuous-thermal -current rating factor multiplied by rated primary current of the current transformer at the ratio specified.

Some short-term emergency overload capability is typically available on bushing current transformers mounted on power circuit breakers and power transformers. However, when utilizing this emergency overload capability, care must be taken to coordinate the loading limit of the current transformer with the overall application limitations of the other equipment affected by the current transformer loading. Particular care should be taken to avoid exceeding the maximum metering capablity of metering equipment attached to the current transformer secondary.

APPENDIX PL-2.F

## APPENDIX PL-2.F - Circuit Breakers

Circuit breaker ratings are discussed in ANSI/IEEE C37.010· 1EEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis and in ANSI/IEEE C37.010b- IEEE Standard for Emergency Load Current-Carrying Capability. These standards discuss the development of ratings for circuit breakers from the standpoint of the manufacturers. From a practical standpoint. the application of the methods discussed in these standards to circuit breakers in operation will be very difficult. due to the fact that this application would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Therefore, it is recommended that for any circuI t breakers which do not limit flows on the transmI ssion system, the nameplate rated continuous current be used as the circuit breaker's normal and emergency circuit ratings. For circuit breakers which limit flows on the transmission system, the manufacturer could be consulted and ambient-compensated normal and emergency ratings could be developed for the circuit breaker using the methods described in the ANSI/IEEE Standards. These methods are described in the remainder of this Appendix.

In general, the rated continuous current for circuit breakers is based on the maximum permissible temperature limitations of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The total temperature of these parts under service conditions depends both on the actual load current and the actual ambient temperature. It I s, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature limit is not exceeded. Similarly, when the ambient temperature is greater than 40°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings w ill be based on the nameplate rating of the circuit breaker with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The seasonal loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers. (See other appropriate appendices to determne limitations on the other equipment.) For circuit breakers used in metal-clad switchgear, no seasonal ratings will be calculated. Instead, the loading limit shall be coordinated with the overall application limitations of the switchgear.

The seasonal normal circuit breaker ratings can be determined in the following manner:

1. A circuit breaker's rated continuous current is based on the maximum permissible total temperature limitations, $\emptyset_{max}$"" and $\emptyset_{r}$, of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The constructional features of a circuit breaker dictate the appropriate values of $\emptyset_{max}$ and $\emptyset$, to be used in the calculation of ambient-compensated ratings. The major components of a circuit breaker have several different temperature limitations which are shown in Table F - 1.
In order that none of these temperature limitations be exceeded when the load current is Adjusted to the value permitted by the actual ambient temperature, the values of $\emptyset_{max}$ and 0, should be determined as follows:

(a) If the actual temperature is Jess than 40°C, the applicable component with the highest specified values of allowable temperature limitations should be used for determining $Ø_{max}$ and Ø,.

(b) If the actual temperature is greater than 40°C, the applicable component with the lowest specified values of allowable temperature limitations should be used for determining $Ø_{max}$ and Ø ,.

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| Component Description | Limit of Temperature Rise, •C Ø, | limit of Total Temperature, •C Ø max |
|---|---|---|
| Circuit breaker parts handled by the operator in the normal course of his duties | 10 | 50 |
| Copper contacts, copper-to-copper conducting joints, external surfaces accessible to the operator in the normal course of his duties, external terminalconnected to bushing | 30 | 70 |
| Top oil | 40 | 80 |
| Breaker terminals to be connected to 85"C insulated cable | 45 | 85 |
| Hottest spot temperature of parts where they contact oil; silver (or equal) contacts in oil;Silver (or equal) conducting joints in oil | 50 | 90 |
| Silver (or equal) contacts in air; silver (or equal) conducting joints in air, hottest spot of bushing conductor or of bushing metal parts in contact with Class A insul ation or with oil; hottest spot winding temperature 55"C rise of current transformers | 65 | 105 |
| External surfaces not accessible to an operator in the normal course of his duties | 70 | 110 |
| Hottest spot wi nding temperature of BO"C dry-type current transformers | 110 | 150 |

**Table F - 1**: Summary of Temperature L1m1tat1ons for C1-rcu1t Breaker Components

2. The continuous current which a circuit breaker can carry at a given ambient temperature without exceeding its total temperature limitations is given by the formula:

r Ømax - Øa 1/1.8

Ia = Ir

I, =

0max =

where

18 =

I
L Ø r,

allowable continuous load current, in amperes, at the actual ambient temperature $0_3$ ($1_2$ is not to exceed two times I,
rated continuous current, in amperes
allowable hottest spot total temperature ($0_{max}$ = 0, + 40°C), in degrees Celsius
0a = actual ambient temperature expected (between -30°C and 60°C), in degrees Celsius
0, = allowable hottest spot temperature rise at rated current, in degrees Celsius

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3. The ambient-compensated allowable continuous load current, Ia. calculated in Step 2 will

be treated as the seasonal normal rating of the circuit breaker.

Normal life expectancy will occur with a circuit breaker operated at continuous nameplate rating. When operated for one or more load cycles above nameplate rating, the material used in manufacturing the circuit breaker deteriorates at a faster rate than normal. The rate of deterioration is commonly expressed as a percentage loss *of* life. According to ANSI/IEEE C37.010b- IEEE **Standard for Emergenc y Load Current-Carr ying Capabilit y,** a circuit breaker can experience operation at 10°C above the limits of total temperature for which the circuit breaker was designed for up to two periods of an emergency cycle of eight hours before an unreasonable loss of life occurs and maintenance is required. Inspection and maintenance must be performed in accordance with manufacturer's recommendations before the circuit breaker can be subjected to additional emergency cycles. In addition, following each emergency cycle, the load current shall be limited to 95% of the rated continuous current as modified by ambient compensation for a minimum of two hours.

Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the Eight-Hour Emergency Load Current-Carrying capability of the circuit breaker with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The seasonal emergency loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers.

The seasonal emergency circuit breaker ratings can be determined in the following manner:

1. Emergency load current-carrying capability factors with ambient temperatures at 40°C are listed in Table F - 2 for each limiting temperature of various circuit breaker components. The factors have been selected to allow operation at 1oac above the limits of total temperature for an emergency period of eight hours. The factors are expressed as the ratio of emergency load current allowed at an ambient temperature of 40°C, $_{1}$•• to the rated continuous current, $_{1}$,, and can be applied with the following restrictions:

   (a) The.circuit breaker component with the highest values of limiting temperature, $0_{max}$ and $0_{r}$. shall be used to select the proper emergency load current-carrying capability factor from Table F- 2.

   (b) The Eight-Hour factor shall be used for a cycle of operation consisting of separate periods of no longer than eight hours each, with not more than two such occurrences before maintenance.

   (c) Each cycle of operation is separate, and no time-current integration is permissible to increase the number of periods within a given maintenance cycle.

**Limiting Temperatures** (°C) **of Different Breaker Components**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Ømax | 70 | 80 | 85 | 90 | 105 | 110 | 150 |
| Ø r· | 30 | 40 | 45 | 50 | 65 | 70 | 110 |

Table F- 2: Emergency Load Current. Carrying Capab1hty Factor (IJ,

| | | | | | | |
|---|---|---|---|---|---|---|
| 1.17 | 1.13 | 1.11 | 1.10 | 1.08 | 1.07 | 1.05 |

I)

2. The emergency load current, $I_{emg}$, of a circuit breaker operating at an ambient temperature other than 40°C can be calculated by the equation:

$$I_{emg} = I_r \left[ \frac{\theta_{max} - \theta_a}{\theta_r} + 1.18 \right]^{1/1.8}$$

not to exceed two times $I_r$

where

$I_{emg}$ = emergency load current, in amperes, at the actual ambient temperature $\theta_a$ (lea is ,)

$I_r$ = Rated continuous current, in amperes

$\theta_{max}$ = emergency load current, in amperes, at 40°C ambi ent temperature

allowable hottest spot total temperature ($\theta_{max}$ = $\theta_a$ + 40°C), in degrees Celsius

$\theta_a$ = actual ambient temperature expected (between -30°C and 60°C}, in degrees Celsius

$\theta_r$ = allowable hottest spot temperature rise at rated current, in degrees Celsius

$I_r$ = emergency load current-carrying capability factor from Table F - 2

3. The ambient-compensated emergency load current, $I_{emg}$, calculated in Step 2 will be treated as the seasonal emergency rating of the circuit breaker.

# Southwest Power Pool Generator Owner/Operator Excitation System Summary Report

Instructions: Generator Owner/Operator shall fill out summary information for all units under your control concerning the number of hours the Excitation System was not operated in Automatic Voltage Control Mode.

**Generator Owner/Operator Month Reporting Data**

**Contact Name**

**Contact Phone**

| Station | Unit # | # Hours Excitation System not operated in Automatic Voltage Control Mode |
|---|---|---|

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# Southwest Power Pool
# Generator Unit Excitation System Status Report

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|---|---|
| Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of events of a particular generating unit's excitaton system not being operated in automatic voltage control mode. | |
| **Generator Owner/Operator** | |
| **Generating Unit** | |
| **Month Reporting Data** | |
| **Contact Name** | |
| **Contact Phone** | |

| **Date (unit not operated in automatic mode)** | **Unit #** | **Reason unit's excitation system was operated out of automated voltage control mode** |
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# Southwest Power Pool Generator Owner/Operator
# Voltage Schedule Requirements

| | |
|---|---|
| Instructions: Control Area Operator shall specify voltage schedule to be maintained by each Generator Owner/Operator's units at a specified bus. | |
| **Generator Owner/Operator** | |
| **Control Area** | |
| **Voltage Schedule Date** | |

| | | | |
|---|---|---|---|
| **Contact Name (Control Area)** | | | |
| **Contact Phone (Control Area)** | | | |
| | | | |
| **Station** | **Unit #** | **Specified Voltage** | **Specified Bus** |
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# Southwest Power Pool Generator Unit
# Voltage Schedule Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of periods in which particular generating units did not adhere to control area's prescribed voltage schedule. If event was approved by control area operator, please attach written approvals.

**Generator**
**Owner/Operator**
**Generating Unit**

**Month Reporting Data**

**Contact Name**

**Contact Phone**

| Date | Duration (hr:min) | Reason unit did not adhere to voltage schedule | Approved (yes/no) |
|---|---|---|---|

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# Southwest Power Pool
# Control Area's List of Exempt Generators

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|---|---|
| Instructions: Control Area Operator shall list units in their area of responsibility that are exempt from following prescribed Control Area Voltage Schedules. | |
| **Control Area Operator** | |
| **Last Updated** | |

**Contact Name**

| | | |
|---|---|---|
| | | |
| **Contact Phone** | | |
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| | | |
| **Generator Owner/Operator** | **Generating Station** | **Unit** |
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# Southwest Power Pool
# Generator Unit Transformer Tap Setting Report

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|---|---|
| Instructions: Generator Owner/Operators shall fill out information concerning the tap settings and impedances of all GSU and AUX transformers under their control. | |
| **Generator Owner/Operator** | |
| **Generating Station** | |
| **Last Updated** | |

**Contact Name**

| | | | |
|---|---|---|---|
| **Contact Phone** | | | |
| | | | |
| **GSU/AUX Transformer I.D.** | **Current Tap Setting** | **Tap Setting Range** | **Transformer Impedence (OA Base)** |
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# Generator Unit Transformer Tap Setting Change Request

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|---|---|
| Instructions: Control Area Operator shall complete information necessary to let affected Generator Owner/Operator know of needed Generator Unit Transformer settings changes. | |
| **Generator Owner/Operator** | |
| **Generating Station** | |
| **Control Area** | |
| **Date** | |

| | | | |
|---|---|---|---|
| **Contact Name (Control Area)** | | | |
| **Contact Phone (Control Area)** | | | |
| | | | |
| **GSU/AUX Transformer I.D.** | **Current Tap Setting** | **New Tap Setting** | **Technical Justification for Tap Setting Change** |
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# Generator Units Exempt from Tap Setting Reporting Procedures

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|---|---|
| Instructions: Generator Owner/Operators shall fill out information for all units under their control that are exempt from Transformer Tap Setting Procedures. The criteria that is met must also be documented | |
| **Generator Owner/Operator** | |
| **Control Area** | |
| **Date** | |

| | | |
|---|---|---|
| **Contact Name (Control Area)** | | |
| **Contact Phone (Control Area)** | | |
| | | |
| **Generating Station** | **Unit #** | **Exemption Criteria Met** |
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# Voltage Regulator Control Setting Status Report

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|---|---|
| Instructions: Generator Owner/Operators shall fill out information for all units under their control. | |
| **Generator Owner/Operator** | |
| **Generating Unit** | |
| **Date** | |

**Contact Name**

| | | | |
|---|---|---|---|
| **Contact Phone** | | | |
| | | | |
| **Generating Control** | **Control Setting** | **Generator Short Term Capability** | **Protective Relay Setting** |
| Overexcitation Limiter | | | |
| Underexcitation Limiter | | | |
| Volts/Hertz Limiter | | | |
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# Southwest Power Pool
# Generator Governor Characteristic Reporting

| | |
|---|---|
| Instructions: Generator Owner/Operators shall fill out information for all units under their control. | |
| **Generator Owner/Operator** | |
| **Generating Unit** | |
| **Last Updated** | |

**Contact Name**

| | |
|---|---|
| **Contact Phone** | |
| **Governor Control** | **Control Setting** |
| Speed Regulation | |
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# Southwest Power Pool
# Non-Functioning Governor Controls

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|---|---|
| Instructions: Generator Owner/Operators shall fill out information for all units under their control that has a non-functioning or a blocked speed/load governor control. | |
| **Generator Owner/Operator** | |
| **Last Updated** | |

**Contact Name**

| | | |
|---|---|---|
| **Contact Phone** | | |
| | | |
| **Generating Station** | **Unit** | **Governor Status (Blocked/Non-functioning)** |
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## Appendix PL-3 - SPP Misoperation Report

**Reporting Utility:** **Date:**

**Contact Person:**

**Name**

**Phone**

**Fax**

**E-Mail**

**Address**

### Equipment Category and Operating Voltage:

| | | |
|---|---|---|
| **DME (Yes/No):** | **TPS (Yes/No):** | **GCP (Yes/No):** |
| **SPS (Yes/No):** | **UFLS (Yes/No):** | **UVLS (Yes/No):** |
| **ARL (Yes/No):** | | **Voltage (kV):** |

### Time, Equipment Location & Description:

| | | |
|---|---|---|
| **Incident Date:** | **Incident Time:** | **Time Zone:** |
| **Relay MFGR:** | **Relay Type:** | **Relay Flags:** |
| **Substation Name/Number:** | **Line/Bus/Auto/Unit Name/No.:** | **Circuit Breaker Numbers:** |

**Description of Misoperation/Failure:**

**Investigation Results:**

**Corrective Action:**

**Target Date To Complete Recommendations:**

**Recommendations:**

### Person Verifying That All Corrective Actions And Recommendations Have Been Completed:

**Name:** **Title:** **Date:**

Note: Equipment categories include DME - Disturbance Monitoring Equip, TPS - Transmission Protection Systems, GCP - Generator Control & Protection, SPS - Special Protection Systems, UFLS -

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| **Appendix** | **PL-4 - Response Factor** | | **Thresholds** | **June** |
| | | | | |
| **Factor** | **Short-term** | **Long-term *** | **Date Approved** | **Comments** |
| | | | | |
| PTDF | 3% | 3% | 4/27/2004 | |
| OTDF | 3% | 3% | 4/27/2004 | |
| PTVF | 0.02 p.u. | 0.02 p.u. | 12/12/2001 | |
| TRM | | 0% | 12/12/2001 | See SPP website for short-term TRM |

* Long-term factors apply to all elem ents above 60kV.

## Appendix PL-6 - Interconnection Review Process Details

This appendix shall be subject to review and approval of the Transmission W orking Group. Given the limited amount of time during a regular Transmission W orking Group meeting, and given the need for timely responses, the majority of the interconnection review process will take place outside of a regular meeting. A Transmission Assessment Report will be prepared by the parties to the proposed interconnection and presented to the TWG for review. Once received, the Transmission W orking Group will review the information provided in the assessment of impacts on the interconnected system. This appendix details the technical requirements which shall be the minimum necessary.

Coordination

1. The party proposing the interconnection shall appoint a person who will serve as the primary contact with SPP staff and with the Transmission W orking Group.
2. If the proposal for interconnection comes from the SPP, then SPP shall appoint its primary contact.
3. The primary contact shall ensure that all affected parties are identified, shall provide a proposed timeline for the studies shall ensure that all affected parties are notified of and kept informed of progress, and provided the opportunity to review all study results prior to submission to the Transmission W orking Group. The rationale for determining affected parties shall be included.
4. The primary contact shall coordinate any joint studies that may be necessary and shall report the results to all affected parties.
5. All affected parties shall cooperate in joint planning efforts.
6. All affected parties will work together to develop an estimated timeline for the completion of the study.
7. SPP shall coordinate activities that affect other regions pursuant to an applicable seams agreement.

Prior To The Review

Affected parties shall jointly develop and evaluate both the proposed interconnection and any mitigation plans. The primary contact shall submit a request for review of the interconnection request to the Transmission W orking Group through the group's Secretary. The request for review shall include the following:

1. A list of all affected parties and the contact person at each affected party. The rationale for determining affected parties shall be included.
2. A brief summary of the results of planning studies. Each affected party shall provide a copy of its own planning criteria as documentation of the need of mitigations that exceed regional requirements.
3. A detailed description of the project including: in-service date; design information; ratings of the interconnection; a geographic map of the interconnection area; electrical one-line diagrams of the facilities being connected.
4. A summary of the results of power flow, short circuit, and dynamic analyses specifically addressing compliance to NERC Reliability Standards, SPP Criteria, other regional requirements, and affected party planning criteria.
5. Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
6. Details of any required mitigation plans including identification of the parties

responsible for mitigation. The detailed description of mitigation plans shall include such information as detailed in Item 3 above.7. Any comments of the affected parties.

Technical Study Requirements

The following are minimum requirements for power flow analysis:

1. Impact analysis shall be performed using an N-1 contingency assessment of all single

elements in the entire first-tier area of the combined areas which the proposed interconnection connects. This area maybe expanded or reduced as mutually agreed upon. The rationale for expansion or reduction of the study area shall be documented and agreed upon by all affected areas.

2. N-1 contingency assessment shall not be limited to a breaker-to-breaker outage assessment, but such assessment may also be included.
3. A review of impacts shall utilize all applicable Scenario Cases developed by the SPP extending to the planning horizon year.
4. If, at any time, impacts are identified affecting a nuclear power plant, it shall be included separately as an affected party.
5. Affected parties shall report adverse impacts and required mitigations.

The TWG may request additional studies at its discretion. The rationale for requesting additional studies shall be provided to all affected parties. If the proposed interconnection was previously evaluated by SPP and included in the most recent STEP,
the power flow analysis described here does not need to be repeated.

The following are minimum requirements for short circuit analysis:

1. The model(s) assessed shall be determined by the affected parties. The rationale for the model(s) assessed shall be included
2. Assessment shall consist of 3-phase and phase-to-ground faults applied at the buses of the proposed interconnection plus all first-tier buses to the interconnection.
3. Additional buses may be studied as mutually agreed upon and documentation for including such additional buses shall be included.
4. Assessments shall document the before and after fault currents on all monitored busses.
5. Affected parties shall report adverse impacts and the required mitigation.

The following are minimum requirements for dynamics analysis:

1. The model(s) assessed shall be determined by the affected parties. The rationale for the model(s) assessed shall be included. If no dynamics analysis is performed the rationale for not performing such studies shall be provided.
2. The assessments performed shall be determined by the affected parties. The rationale for the assessments shall be included.
3. Assessments shall document the before and after dynamic performance on all monitored busses.
4. Affected parties shall report adverse impacts and the required mitigation.
5. If the interconnection is to be made at 345 kV or higher voltage, an assessment of reactive power impacts and management shall be made and provided for review. This assessment may include but is not limited to power flow, transient network analysis, or electromagnetics transients studies, insulation coordination studies and dynamics studies clearly indicating any required levels of shunt compensation.

Dispute Resolution

All disputes between SPP members shall be resolved using the procedures of Section 3.13 of the SPP Bylaws.

Review and Ballot by the Transmission W orking Group

1. The Transmission Working Group Secretary shall review the request for interconnection for completeness.
2. Any deficiencies shall be reported to the primary contact.
3. Once a complete request is received, it shall be forwarded to the Transmission W orking Group for a 14 day review and comment period.
4. The primary contact shall be responsible for coordinating any response necessary to comments and questions raised by the Transmission W orking Group.
5. The Transmission Working Group shall schedule a ballot to accept or to reject

the
interconnection
request.

6. Any action taken by the TransmissionW orking Group will be included in the minutes.

Transmission Interconnection Review Data Checklist

1. Primary contact and all affected parties' contact information.
2. Overview of the proposed interconnection and its need.
3. Estimated or proposed in-service date.
4. List of all studies run by season.
   a. Power flow studies minimum requirements met. b. Short circuit studies minimum requirements met. c. Dynamics studies minimum requirements met.
5. Affected parties planning criteria, if applicable.
6. A detailed description of the proposed interconnection. a. In- service date
   b. Design information
   c. Ratings of the interconnection
   d. A geographic map of the interconnection area
   e. Electrical one-line diagrams of the facilities being connected.
7. Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
8. Details of any required mitigation plans including identification of the affected parties responsible for mitigation. a. In-service date
   b. Design information
   c. Ratings of the facilities
   d. A geographic map of the facility area
   e. Electrical one-line diagrams of the facilities being connected.
9. Comments of affected parties covering agreement or points of disagreement of the proposed interconnection, if any.

The Transmission Working Group shall review and modify this appendix as needed but not less frequently than once every 3 years.A

# ATTACHMENT AE
# INTEGRATED MARKETPLACE

# Attachment AE
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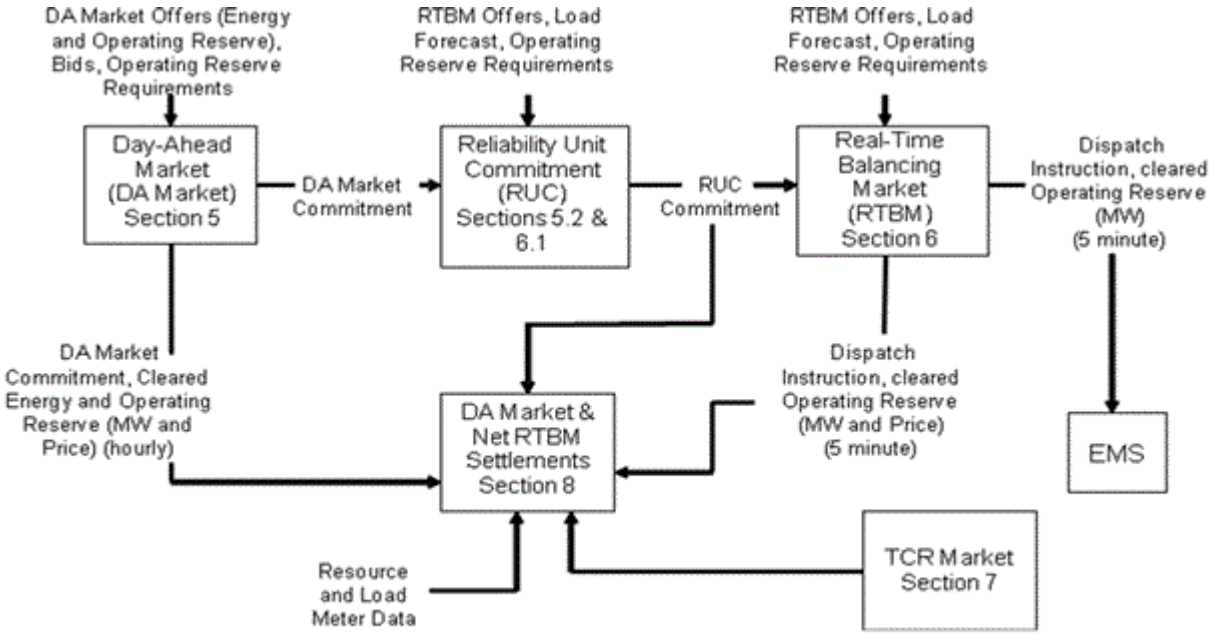
## 1. Introduction

This Attachment sets forth the Bidding, Offering and dispatching responsibilities of the Transmission Provider and Market Participants relating to the Integrated Marketplace and sets forth the operation, pricing and settlement of the Day-Ahead Market, the Real-Time Balancing Market ("RTBM") and the Transmission Congestion Rights ("TCRs") Market. All time references in this Attachment AE shall be the prevailing time as specified in the Market Protocols. Figure 1 shows the relationships and general timing sequence between the various market processes.

**Figure 1**



## 1.1 Definitions and Acronyms

## 1.1 Definitions A

**Actual Regulation-Down Mileage**

The sum of the absolute values of actual movements by a Resource with cleared Regulation-Down Service MW in response to Regulation Deployment instructions for Regulation-Down Service.

**Actual Regulation-Up Mileage**

The sum of the absolute values of actual movements by a Resource with cleared Regulation-Up Service MW in response to Regulation Deployment instructions for Regulation-Up Service.

**Asset Owner**

An owner of any combination of: (1) registered physical assets (Resource, load, Import Interchange Transaction, Export Interchange Transaction, Through Interchange Transaction), (2) Transmission Congestion Rights, (3) Virtual Energy Offers, (4) Virtual Energy Bids, or (5) Bilateral Settlement Schedules.

**Asset Owner Reserve Zone Load Ratio Share**

The sum of an Asset Owner's Reported Load, Self-Charging MSRs and Export Interchange Transactions in a Reserve Zone divided by the sum of all Asset Owners' Reported Load, Self-Charging MSRs and Export Interchange Transactions in all Reserve Zones for a given hour.

**Assistance Period**

Assistance Period is that time frame when any SPP Reserve Sharing Group member receives Contingency Reserve assistance from other SPP Reserve Sharing Group members.

**Auction Clearing Price ("ACP")**

The price generated at each source and sink Settlement Location in each round of the Annual Transmission Congestion Right Auction and Monthly Transmission Congestion Right Auction based upon the Transmission Congestion Right Offers and Bids submitted.

**Auction Revenue Right ("ARR")**

A right, awarded during the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process, which entitles the holder to a share of the auction revenues generated in the applicable Transmission Congestion Rights auction(s) and entitles the holder to self-convert the Auction Revenue Right to a Transmission Congestion Right.

**Auction Revenue Right Nomination Cap ("ARR Nomination Cap")**

A cap on the maximum total amount of Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

## 1.1 Definitions B

**Balancing Authority**

As defined in Section 1 of the Tariff

**Balancing Authority Area**

As defined in Section 1 of the Tariff.

**Behind-The-Meter Generation**

A generation unit that is connected on the load side of a load Meter Settlement Location and is used by the load Market Participant that is the registered owner for the Meter Settlement Location to serve all or part of its capacity, Energy or Ancillary Service needs.

**Bid**

A commitment to pay (i) a specific maximum price for a quantity of Energy that includes a Demand Bid, a Virtual Energy Bid, or an Export Interchange Transaction Bid, or (ii) a specific maximum price for a quantity of Transmission Congestion Rights, where such quantities may be submitted in 0.1 Megawatt increments.

**Bilateral Settlement Schedule**

An arrangement between two Market Participants for transfer of Energy or Operating Reserve obligations.

**Block Demand Response Load Settlement Location**

A registered load Settlement Location that contains the Demand Response Load associated with a Block Demand Response Resource.

**Block Demand Response Resource**

A Resource created to model Demand Response Load reduction associated with controllable load that can only be committed and dispatched in hourly blocks.

## 1.1 Definitions C

**CFTC**

The Commodity Futures Trading Commission

**Combined Interest Resource**

A Resource registered to reflect shared interest among multiple Asset Owners who elect to model as one commercial Resource. Credits and charges for these Resources are allocated post market using the submitted interest share percentages.

**Commercial Model**

A representation of the attributes of and the relationships between Market Participants, Asset Owners, Resource and load assets and Price Nodes for use in the Integrated Marketplace.

**Commercial Operation**

As defined in Attachment V of this Tariff.

**Commitment Instruction**

An instruction issued by the Transmission Provider or a local transmission operator to a Market Participant in the Day-Ahead Market or any Reliability Unit Commitment process to (i) either start up or shut down a specified Resource and/or (ii) transition an MCR from one configuration to another.

**Commit Time**

The time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which a Resource is to be synchronized and operating at or above its Minimum Economic Capacity Operating Limit. For an MSR, this is the time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which the Resource should be connected and at or above its Minimum Discharge Limit or its Minimum Charge Limit.

**Common Bus**

A single bus to which two or more Resources owned by the same Asset Owner are connected in an electrically equivalent manner where such Resources may be treated as interchangeable for certain compliance monitoring purposes.

**Confidential Information**

As referenced within Attachments AE, AF and AG to this Tariff, information containing or revealing:

(1) (a) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant that is conspicuously designated as Confidential Information in writing, on each page of the document, by disclosing party at the time the information is provided to receiving party, whether conveyed electronically, in writing, through inspection, or otherwise;

(b) Any confidential, proprietary, or commercially sensitive information, or information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Market Participant that is provided orally and designated as Confidential Information by disclosing party at the time the information is provided to receiving party;

(c) Any customer information designated by the customer as proprietary, unless the customer has authorized the release for public disclosure of such information;

(d) Any software, products of software or other vendor information that the Transmission Provider is required to keep confidential under its agreements.

(2) Confidential Information does not include Critical Energy Infrastructure Information ("CEII") materials as designated by FERC, which must be obtained in accordance with FERC regulations.

**Contingency Reserve**

Qualified Resource capacity held in reserve for Resource contingencies that is the sum of Spinning Reserve and Supplemental Reserve.

**Contingency Reserve Deployment Instruction**

An instruction issued by the Transmission Provider to Resources cleared for Contingency Reserve in the Real-Time Balancing Market to deploy a specific Megawatt quantity of Contingency Reserve as communicated as a component of the Setpoint Instructions.

**Contingency Reserve Deployment Period**

The time allowed to deploy Contingency Reserve following the issuance of a Contingency Reserve Deployment Instruction, as specified in the Market Protocols.

**Contingency Reserve Scarcity Factor**

A multiplier used to define shortage regions of Contingency Reserve and the appropriate scarcity price value associated with the shortage.

**Control Status**

A parameter communicated electronically to the Transmission Provider by a Market Participant at any time during an Operating Hour indicating a Resource's ability to follow Setpoint Instructions.

**Coordinated Flowgate**

A flowgate defined within a joint operating agreement between the Transmission Provider and another transmission provider as being affected by the transmission of Energy on either party's transmission system.

**Current Operating Plan**

The Transmission Provider's internal hourly Resource commitment schedule for the Operating Day resulting from the Day-Ahead Market and Day-Ahead Reliability Unit Commitment

processes and updated, as required, during the Intra-Day Reliability Unit Commitment process that is used as input into the Real-Time Balancing Market.

## 1.1 Definitions D

**Data Error**

A data error shall be the following:

(i) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is inaccurately modified by the Transmission Provider during the execution of a market function; or

(ii) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is patently incorrect and is used by the Transmission Provider during the execution of a market function; or

(iii) Incorrect data produced and used by the Transmission Provider during the execution of a market function.

**Day-Ahead**

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

**Day-Ahead Market**

As defined in Section 1 of the Tariff.

**Day-Ahead Market Commitment Period**

The contiguous period of time between a Resource's Day-Ahead Market Commit Time and Day-Ahead Market De-Commit Time.

**Day-Ahead Reliability Unit Commitment ("Day-Ahead RUC")**

The process performed by the Transmission Provider following the close of the Day-Ahead Market and prior to the Operating Day to assess Resource and Operating Reserve adequacy for the Day-Ahead period and the remainder of the current Operating Day, commit or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

**De-Commit Time**

The time specified by the Transmission Provider or a local transmission operator in a Commitment Instruction at which a Resource is to begin de-synchronization procedures.

**Demand Bid**

A proposal by a Market Participant associated with a physical load to purchase a fixed or price sensitive amount of Energy at a specified location and period of time in the Day-Ahead Market.

**Demand Bid Curve**

A Demand Bid specified as Megawatt and dollars per Megawatt hour with up to ten (10) price/quantity pairs.

**Demand Curve**

A series of quantity/price points used to set Locational Marginal Prices and Market Clearing Prices when there is a shortage of Energy or Operating Reserve.

**Demand Response Load**

A registered measurable load that is capable of being reduced at the instruction of the Transmission Provider and subsequently may be increased at the instruction of the Transmission Provider.

**Demand Response Resource**

A Dispatchable Demand Response Resource or a Block Demand Response Resource.

**Designated Resource**

As defined in Section 1 of the Tariff.

**Discrete Delivery Point**

An injection point or withdrawal point connected to the Transmission System at which Locational Marginal Prices are calculated.

**Dispatch Interval**

The five (5) minute interval for which the Transmission Provider issues Dispatch Instructions for Energy and clears Operating Reserve in the Real-Time Balancing Market.

**Dispatch Instruction**

The communicated Resource target Energy Megawatt output level at the end of the Dispatch Interval.

**Dispatch Locational Marginal Price ("DLMP")**

The price for Energy at a given Price Node, which is equivalent to the marginal cost of serving demand at the Price Node while meeting the Transmission Provider Operating Reserve requirements, that results from the dispatch function in SCED as described under Section 3.3.1 of this Attachment AE.

**Dispatchable Demand Response Load Settlement Location**

A registered load Settlement Location that contains the Demand Response Load associated with a Dispatchable Demand Response Resource.

**Dispatchable Demand Response Resource**

A Resource created to model Demand Response Load reduction associated with controllable load or a Behind-The-Meter generator that is dispatchable on a five (5) minute basis.

**Dispatchable Resource**

A Resource for which an Energy Offer Curve has been submitted and that is available for dispatch by the Transmission Provider on a Dispatch Interval basis.

**Dispatchable Variable Energy Resource**

A Variable Energy Resource registered in the Integrated Marketplace that is capable of being incrementally dispatched by the Transmission Provider.

## 1.1 Definitions E

**Electrical Node ("ENode")**

A physical node represented in the Network Model where electrical equipment and components are connected.

**Electric Storage Resource ("ESR")**

As defined in Section 1 of the Tariff.

**Electric Storage Resource Loss Factor**

The factor that represents round-trip efficiency related to the amount of Energy an ESR loses from charge to discharge. This loss factor is the ratio of (1) the Energy the ESR is able to inject via discharge to (2) the Energy withdrawn in order to store that charge.

**Eligible Entity**

A Transmission Customer or Market Participant having firm SPP Transmission Service or firm non-SPP transmission service (referred to as a "grandfathered agreement" or "GFA") into, out of, within or through the SPP Region.

**Emergency Condition**

As defined in Section 1 of the Tariff.

**Energy**

An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold or transmitted over a period of time, which is measured or calculated in Megawatt hours.

**Energy and Operating Reserve Markets**

As defined in Section 1 of the Tariff.

**Energy Offer Curve**

A set of price/quantity pairs that consists of Megawatts and dollars per Megawatt hour with up to ten (10) price/quantity pairs.

**Excess Regulation-Down Mileage**

The amount calculated under Section 8.6.2 of this Attachment AE.

**Excess Regulation-Up Mileage**

The amount calculated under Section 8.6.2 of this Attachment AE.

**Expected Regulation-Down Mileage**

The amount of Regulation-Down Service MW cleared multiplied by the Regulation-Down Mileage Factor.

**Expected Regulation-Up Mileage**

The amount of Regulation-Up Service MW cleared multiplied by the Regulation-Up Mileage Factor.

**Export Interchange Transaction**

A Market Participant schedule for exporting Energy out of the SPP Balancing Authority Area.

**Export Interchange Transaction Bid**

A proposal by a Market Participant to purchase a fixed or price sensitive amount of Energy for delivery outside of the SPP Balancing Authority Area at a specified External Interface and for a period of time.

**External Dynamic Resource**

A registered Resource that represents one or more resources, located external to the SPP Balancing Authority Area, which is dynamically scheduled into or out of the SPP Balancing Authority Area.

**External Interface**

A Settlement Location representing a physical interconnection point(s) between the SPP Balancing Authority Area and an external Balancing Authority Area.

## 1.1 Definitions F

**Fast-Start Resource ("FSR")**

A Resource with the following submitted offer parameters for a Day-Ahead Market or Real-Time Balancing Market interval: a Start-Up Time offer of ten (10) minutes or less and a Minimum Run Time offer of sixty (60) minutes or less. MSRs must also have a Minimum Discharge Time offer of sixty (60) minutes or less to qualify as a Fast-Start Resource. MCRs must also have a Group Minimum Run Time offer of sixty (60) minutes or less to qualify as a Fast-Start Resource.

**Federal Service Exemption ("FSE")**

As defined in Section 1 of the Tariff.

**Firm Point-To-Point Auction Revenue Right Nomination Cap**

The maximum total amount of Firm Point-To-Point Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Firm Point-To-Point Candidate Auction Revenue Right**

All or portion of the Megawatt quantity of a confirmed Firm Point-To-Point Transmission Service reservation which the holder of the Transmission Service reservation can nominate for conversion into an Auction Revenue Right in the Auction Revenue Right allocation process.

**Firm Point-To-Point Candidate Long-Term Congestion Right**

The Megawatt quantity of a confirmed Firm Point-To-Point Transmission Service reservation with rollover rights that is used by the Transmission Provider to determine available rights which the holder of the Transmission Service reservation can select for conversion into a Long-Term Congestion Right in the Long-Term Congestion Right allocation process.

**Firm Point-To-Point Transmission Service**

As defined in Section 1 of the Tariff.

**FSE Schedule**

A schedule entered by Western-UGP for administering the FSE.

**FSE Transfer Point**

A Settlement Location established by the Transmission Provider that represents the FSE energy ownership transfer from Western-UGP to a Market Participant external to the UMZ and internal to the SPP market. This interface is between the UMZ and the other Zones.

## 1.1 Definitions G

**Good Utility Practice**

As defined in Section 1 of the Tariff.

**Grandfathered Agreement ("GFA")**

As defined in Section 1 of the Tariff.

**GFA Carve Out**

Removal of the congestion and marginal loss charges for the amount of energy (MWh) actually transacted associated with GFAs.

**GFA Carve Out Schedule**

A schedule entered by the GFA Responsible Entity for administering the GFA Carve Out.

**GFA Responsible Entity**

An entity designated by agreement of the parties to a GFA or, absent such agreement, the Transmission Owner under such GFA that is registered or shall register as a Market Participant and is financially responsible for all Day-Ahead and transactional costs applicable to a GFA Carve Out under this Tariff.

**Grandfathered Agreement Firm Point-To-Point Auction Revenue Right Nomination Cap**

The maximum amount of Grandfathered Agreement Firm Point-To-Point Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process or the monthly Auction Revenue Right allocation process.

**Grandfathered Agreement Firm Point-To-Point Candidate Auction Revenue Right**

All or a portion of the Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Firm Point-To-Point Transmission Service, as defined in the Tariff which the applicable Eligible Entity can nominate for conversion into an Auction Revenue Right in the annual Auction Revenue Right allocation process.

**Grandfathered Agreement Firm Point-To-Point Candidate Long-Term Congestion Right**

The Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Firm Point-To-Point Transmission Service with rollover rights, which is used by the Transmission Provider to determine available rights that the applicable Eligible Entity can select for conversion into a Long-Term Congestion Right in the annual Long-Term Congestion Right allocation process.

**Grandfathered Agreement Network Integration Transmission Service Auction Revenue Right Nomination Cap**

The maximum amount of Grandfathered Agreement Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Grandfathered Agreement Network Integration Transmission Service Candidate Auction Revenue Right**

All or a portion of the Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Network Integration Transmission Service, as defined in the Tariff, verified prior to the start of the annual ARR allocation process, that the applicable Eligible Entity can nominate for conversion into an ARR in the ARR allocation process.

**Grandfathered Agreement Network Integration Transmission Service Candidate Long-Term Congestion Right**

The Megawatt quantity of the transmission service component of a Grandfathered Agreement providing service equivalent to Network Integration Transmission Service verified prior to the start of the annual Long-Term Congestion Right allocation process, that is used by the Transmission Provider to determine available rights that the applicable Eligible Entity can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

**Group Minimum Down Time**

For an MCR, the minimum length of time a defined group of configurations must remain offline following transition to a different defined group of configurations.

**Group Minimum Run Time**

For an MCR, the minimum length of time a defined group of configurations must run from the time the group is put online to the time the group is shut down.

## 1.1 Definitions H

### Hybrid Storage Market Resource ("HSMR")

Generating resource(s) and ESR(s) located behind the same point of interconnection that are registered together in the Energy and Operating Reserve Markets as a single Resource.

## 1.1 Definitions I

**Import Interchange Transaction**

A schedule for importing Energy into the SPP Balancing Authority Area.

**Import Interchange Transaction Offer**

A proposal by a Market Participant to provide Energy from a source external to the SPP Balancing Authority Area at a specified External Interface and period of time.

**Instantaneous Load Capacity**

The achievable change in real power output required to account for differences between the average load and the projected instantaneous load.

**Instructed Regulation-Down Mileage**

The sum of the absolute values of instructed movements to a Resource with cleared Regulation-Down Service through Regulation Deployment instructions for Regulation-Down Service.

**Instructed Regulation-Up Mileage**

The sum of the absolute values of instructed movements to a Resource with cleared Regulation-Up Service MW through Regulation Deployment instructions for Regulation-Up Service.

**Integrated Marketplace**

The Day-Ahead Market, the Real-Time Balancing Market, the Transmission Congestion Rights Market and the Reliability Unit Commitment processes.

**Integrated Marketplace Counterparty**

The Transmission Provider, as counterparty to all Integrated Marketplace transactions (and not in any other capacity of the Transmission Provider under the Tariff) in accordance with the provisions of Section 3.8 of this Attachment AE.

**Interchange Transaction**

Any Energy transaction that is crossing the boundary of the SPP Balancing Authority Area and requires checkout with one or more external Balancing Authority Areas. This includes any Import Interchange Transaction, Export Interchange Transaction or Through Interchange Transaction.

**Intra-Day Reliability Unit Commitment ("Intra-Day RUC")**

The process performed by the Transmission Provider throughout the Operating Day to assess Resource and Operating Reserve adequacy for the Operating Day, commit or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

## 1.1 Definitions J

### Jointly Owned Unit

A Resource that is owned by more than one Asset Owner or a Resource for which multiple Asset Owners have contractual rights or financial obligations.

## 1.1 Definitions L

**Load Serving Entity ("LSE")**

A distribution utility or an electric utility that has a service obligation, where a service obligation, as defined in Section 217(a) of the Federal Power Act, means a requirement applicable to, or the exercise of authority granted to, an electric utility under Federal, State, or local law or under long-term contracts to provide electric service to end-users or to a distribution utility.

**Local Emergency Condition**

A condition or situation determined by the local transmission operator that is imminently likely to cause a material adverse effect on the security of or damage to the local transmission operator's facilities not modeled by the Transmission Provider.

**Local Reliability Issue**

A local voltage or reliability condition necessitating a Local Reliability Issue Commitment.

**Local Reliability Issue Commitment**

A Resource commitment in addition to, or in lieu of, commitments resulting from the Security Constrained Unit Commitment in the Day-Ahead Market or any Reliability Unit Commitment, in order to mitigate issues with Transmission System voltage or other local reliability concerns, including providing assistance to an adjacent balancing authority, as defined in the NERC glossary of terms, to address local reliability concerns. These Resource commitment requirements are established prior to or during an Operating Day and are based on projected local reliability requirements, operational considerations, and generation and transmission outages. These commitments will be based on Operating Guides for recurring local voltage and reliability requirements, but an Operating Guide is not required prior to a Resource commitment being designated as a Local Reliability Issue Commitment. Resource commitments to relieve a potential or actual Interconnection Reliability Operating Limit violation will not be designated in this category.

**Local Settlement Area**

A geographic area equivalent to an SPP BA Participant Area, as defined under Attachment AN of this Tariff, for purposes of the local allocation of costs pursuant to Section 8.6.7(B) of this Attachment AE.

**Locational Marginal Price ("LMP")**

The price for Energy at a given Price Node which is equivalent to the marginal cost of serving demand at the Price Node while meeting the Transmission Provider Operating Reserve requirements.

**Long-Term Congestion Right ("LTCR")**

An instrument that entitles the holder to a Transmission Congestion Right over a period of more than one year, which is awarded during the Transmission Provider's annual Long-Term Congestion Rights allocation process.

**Loss Pool**

A collection of either (i) Settlement Locations within a Settlement Area (a "Settlement Area Loss Pool"), or (ii) all External Interfaces, Trading Hubs, and Resource Hubs located throughout the Transmission System, that is used for the purpose of determining an Asset Owner's allocation of over-collected loss revenues in Sections 8.5.16 or 8.6.16 of Attachment AE.

## 1.1 Definitions M

**Market Clearing Price ("MCP")**

The price used for settlements of an Operating Reserve product in each Reserve Zone. A separate price is calculated for Regulation-Up Service, Expected Regulation-Up Mileage, Regulation-Down Service, Expected Regulation-Down Mileage, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, and Ramp Capability Down.

**Market Flow**

The aggregate Megawatt flow on a Coordinated Flowgate or a Reciprocal Coordinated Flowgate caused by the Real-Time Balancing Market.

**Market Participant**

As defined in Section 1 of the Tariff.

**Market Storage Resource ("MSR")**

An ESR that registers consistent with the requirements under Section 2.17 of this Attachment AE.

**Marginal Congestion Component ("MCC")**

The calculated portion of the Locational Marginal Price at a Settlement Location representing transmission congestion costs between that Settlement Location and a reference location as calculated under Section 8.3 of this Attachment AE.

**Marginal Loss Component ("MLC")**

The calculated portion of the Locational Marginal Price at a Settlement Location representing marginal loss costs between that Settlement Location and a reference location as calculated under Section 8.3 of this Attachment AE.

**Maximum Charge Limit**

The maximum MW level that an MSR is able to withdraw from the grid during normal operating conditions.

**Maximum Charge Time**

The maximum duration of time that an MSR is able to withdraw from the grid.

**Maximum Discharge Limit**

The maximum MW level that an MSR is able to inject into the grid used during normal operating conditions.

**Maximum Discharge Time**

The maximum duration of time that an MSR is able to inject into the grid.

**Maximum Economic Capacity Operating Limit**

An economic MW level at or below a Resource's Maximum Normal Capacity Operating Limit used for constraining Energy dispatch and Contingency Reserve clearing during normal system conditions.

**Maximum Emergency Capacity Operating Limit**

The maximum Megawatt level at which a Resource other than a Block Demand Response Resource may operate under Emergency Conditions.

**Maximum Emergency Charge Limit**

The maximum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.

**Maximum Emergency Discharge Limit**

The maximum MW level that an MSR is able to inject into the grid during an Emergency Condition.

**Maximum Normal Capacity Operating Limit**

The maximum Megawatt level at which a Resource may operate continuously.

**Maximum Off-line Supplemental Reserve Response Limit**

The maximum amount of off-line Supplemental Reserve that can be provided by a Resource.

**Maximum Regulation Capacity Operating Limit**

The maximum Megawatt level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

**Maximum State of Charge**

The maximum State of Charge that should not be exceeded.

**Megawatt ("MW")**

A measurement unit of the instantaneous demand for Energy.

**Meter Agent**

An entity responsible for collecting load and Resource data associated with identified Meter Settlement Locations within a Settlement Area for the purpose of energy accounting that impacts market settlements.

**Meter Data Submittal Location**

One or more Meter Settlement Locations contained within a single Settlement Area for which meter data is submitted to the Transmission Provider by the Meter Agent for settlement purposes.

**Meter Settlement Location**

The point at which a Market Participant's registered load and Resources interchange Energy with the Real-Time Balancing Market.

**Minimum Charge Limit**

The minimum MWs level an MSR is able to withdraw from the grid during normal operating conditions.

**Minimum Charge Time**

The minimum duration of time an MSR is able to withdraw from the grid.

**Minimum Discharge Limit**

The minimum MW level that an MSR is able to inject into the grid during normal operating conditions.

**Minimum Discharge Time**

The minimum duration of time that an MSR is able to inject into the grid.

**Minimum Economic Capacity Operating Limit**

A Megawatt level at or above a Resource's Minimum Normal Capacity Operating Limit used for energy dispatch at a minimum level during normal operating conditions.

**Minimum Emergency Capacity Operating Limit**

The minimum Megawatt level at which a Resource other than a Block Demand Response Resource may operate under Emergency Conditions.

**Minimum Emergency Charge Limit**

The minimum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.

**Minimum Emergency Discharge Limit**

The minimum MW level that an MSR is able to inject into the grid during an Emergency Condition.

**Minimum Normal Capacity Operating Limit**

The minimum Megawatt level at which a Resource may operate continuously.

**Minimum Regulation Capacity Operating Limit**

The minimum Megawatt level at which a Regulation Qualified Resource, a Regulation-Up Qualified Resource or a Regulation-Down Qualified Resource may operate while providing Regulation Deployment.

**Minimum Run Time**

The minimum length of time a Resource must run from the time the Resource is put online to the time the Resource is shut-down.

**Minimum State of Charge**

The minimum State of Charge that should be maintained.

**Min-To-Off Time**

The time for a Resource to de-synchronize from the grid starting from the Resource's Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable.

**Most Severe Single Contingency**

The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority's area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of an RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

**Multi-Configuration Resource ("MCR")**

A combined cycle Resource registered consistent with the offer submission option as defined under Section 4.1.2.2(4) of this Attachment AE.

**Multi-Day Reliability Assessment**

The process to assess Resource adequacy for the Operating Day, commit Resources with long Start-Up Times that cannot be considered as part of the Day-Ahead Market or Day-Ahead Reliability Unit Commitment, and communicate commitment of such Resources as necessary.

## 1.1 Definitions N

**Net Benefits Test**

A calculation that measures the threshold price at which the benefits of dispatching Demand Response Load outweigh the costs.

**Network Integration Transmission Service**

As defined in Section 1 of the Tariff.

**Network Integration Transmission Service Auction Revenue Right Nomination Cap**

The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

**Network Integration Transmission Service Candidate Auction Revenue Right**

The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

**Network Integration Transmission Service Candidate Long-Term Congestion Right**

The Megawatt quantity associated with Network Integration Transmission Service with rollover rights from Network Resources that is used by the Transmission Provider to determine available rights that the holder of the Network Integration Transmission Service can select for conversion into a Long-Term Congestion Right during the Long-Term Congestion Right allocation process.

**Network Model**

A representation of the transmission, generation, and load elements of the interconnected Transmission System and the transmission systems of other regions in the Eastern Interconnection.

**No-Load Offer**

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) Megawatt output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output. For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption. For an MSR, No-Load Offers are the cost to maintain a State of Charge when the MSR has a zero (0) MW output (i.e., the Resource is operating under a "No-Load" condition).

**Non-Conforming Load**

Load that is process driven that does not follow a predictable pattern.

**Non-Dispatchable Variable Energy Resource**

A Variable Energy Resource registered in the Integrated Marketplace that is not capable of being incrementally dispatched by the Transmission Provider.

## 1.1 Definitions O

**Offer**

A commitment to sell (i) a quantity of Energy at a specific minimum price that includes a Resource Offer, a Virtual Energy Offer or an Import Interchange Transaction Offer, or (ii) a quantity of Transmission Congestion Rights at a specific minimum price, where such quantities may be submitted in 0.1 MW increments.

**Off-Peak**

As defined in Schedule 1 of the Tariff.

**On-Peak**

As defined in Schedule 1 of the Tariff.

**Operating Day**

A daily period beginning at midnight.

**Operating Hour**

A sixty (60) minute period of time during the Operating Day corresponding to a clock hour typically expressed as hour-ending.

**Operating Reserve**

Resource capacity required to provide for Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and Ramp Capability Down for reasons including, but not limited to; load forecasting error, instantaneous load changes, Variable Energy Resource forecast error, and equipment forced outages.

**Operating Tolerance**

The Megawatt range of actual Resource output above and below the Resource's average Setpoint Instruction over the Dispatch Interval where the Resource will not be subject to charges associated with Uninstructed Resource Deviation.

**Out-of-Merit Energy (OOME)**

(a) A Dispatch Instruction from the Transmission Provider to address an Emergency Condition or reliability issue that the market systems cannot resolve, (b) a Dispatch Instruction from a local transmission operator to address a Local Emergency Condition, or (c) a non-Energy manual exclusion, by the Transmission Provider, of a Resource from providing Operating Reserves after the Day-Ahead Market clears.

## 1.1 Definitions P

**Parallel Flow**

Flow on the Transmission System not scheduled with SPP caused by entities external to the SPP Balancing Authority Area (also known as loop flow).

**Plant Minimum Down Time**

For an MCR, the minimum length of time required following complete desynchronization that the entire combined cycle plant must remain offline prior to a subsequent synchronization.

**Plant Minimum Run Time**

For an MCR, the minimum length of time the combined cycle plant must run from the time the plant is committed to the time the plant is shut down.

**Portal**

Internet interface between SPP and its Members.

**Pre-Day-Ahead**

The time period starting six (6) days prior to Day-Ahead and ending midnight on the day prior to Day-Ahead.

**Price Node ("Pnode")**

A single node in the Commercial Model that has a one-to-one relationship to an Electrical Node where Locational Marginal Prices are calculated.

## 1.1 Definitions R

**Ramp Capability Down**

An Operating Reserve product, procured by the Transmission Provider from a Resource capable of following Setpoint Instructions, that is reserved to provide downward flexibility during periods in which net obligations decrease in future Dispatch Intervals. There is no explicit offer for this product. The value is derived using loss of opportunity.

**Ramp Capability Up**

An Operating Reserve product, procured by the Transmission Provider from a Resource capable of following Setpoint Instructions, that is reserved to provide upward flexibility during periods in which net obligations increase in future Dispatch Intervals. There is no explicit offer for this product. The value is derived using loss of opportunity.

**Ramp-Rate-Down**

A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the down direction. For MSRs, Ramp-Rate-Down is the rate at which a MSR can move from zero output to Maximum Charge Limit, which is represented as a negative (-) value for the MW breakpoint. This rate also represents the rate at which the MSR can move from Maximum Discharge Limit to zero output.

**Ramp-Rate-Up**

A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the up direction. For MSRs, Ramp-Rate-Up is the rate at which a MSR can move from zero output to Maximum Discharge Limit. This rate also represents the rate at which the MSR can move from Maximum Charge Limit, which is represented as a negative (-) value for the MW breakpoint, to zero output.

**Real-Time**

The continuous time period during which the Real-Time Balancing Market is operated.

**Real-Time Balancing Market ("RTBM")**

As defined in Section 1 of the Tariff.

**Real-Time Capability**

The amount (MW) of real power output the Resource is capable of instantaneously producing, excluding any dispatch, deployment, or curtailment instructions.

**Real-Time Load Ratio Share**

The sum of a Market Participant's Reported Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations divided by the sum of all Market Participants' Reported Load, Self-Charging MSRs, and Export Interchange Transactions at all Settlement Locations for a given hour.

**Reciprocal Coordinated Flowgate**

A Coordinated Flowgate defined within a joint operating agreement between SPP and another transmission provider as being affected by the transmission of Energy on both of their respective transmission systems.

**Reference Bus**

The location on the Transmission System relative to which all mathematical quantities, including shift factors and penalty factors relating to physical operation, will be calculated.

**Regulation Deployment**

The utilization of Regulation-Up Service and/or Regulation-Down Service through automatic generation control equipment to automatically and continuously adjust Resource output to balance the real power requirements of the SPP Balancing Authority Area.

**Regulation-Down**

An Operating Reserve product procured by the Transmission Provider from qualified Resources that reduce their energy output (or increase consumption of the Demand Response Load associated with a qualified Dispatchable Demand Response Resource) in response to a Regulation Deployment instruction from the Transmission Provider.

**Regulation-Down Mileage Factor**

A factor determined through historical Regulation Deployment analysis that represents the ratio of the Transmission Provider's total Instructed Regulation-Down Mileage to the Transmission Provider's total cleared Regulation-Down Service. The Regulation-Down Mileage Factor shall initially be set equal to 1.0 and shall be updated periodically pursuant to the Market Protocols.

**Regulation-Down Mileage Offer**

The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has agreed to sell Expected Regulation-Down Mileage.

**Regulation-Down Offer**

The price at which a Regulation Qualified Resource or a Regulation-Down Qualified Resource has committed to sell Regulation-Down.

**Regulation-Down Qualified Resource**

A Resource that has met the requirements to be eligible to submit Regulation-Down Offers and Regulation-Down Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation-Down Scarcity Factor**

A multiplier used to define shortage regions of Regulation-Down and the appropriate scarcity price value associated with the shortage.

**Regulation-Down Service**

The provision of Actual Regulation-Down Mileage associated with cleared Regulation-Down Service MW in response to Regulation Deployment instructions.

**Regulation-Down Service Offer**

The sum of (i) a Resource's Regulation-Down Mileage Offer multiplied by the Regulation-Down Mileage Factor and (ii) that Resource's Regulation-Down Offer.

**Regulation Mileage Operating Tolerance**

The allowable percentage deviation below a Resource's Instructed Regulation-Up Mileage and/or Instructed Regulation-Down Mileage over the Dispatch Interval where the Resource will settle based upon Instructed Regulation-Up Mileage and/or Instructed Regulation-Down Mileage versus Actual Regulation-Up and/or Actual Regulation-Down Mileage. Such percentage is set at 5%.

**Regulation Qualified Resource**

A Resource that has met the requirements to be eligible to submit Regulation-Up Offers, Regulation-Up Mileage Offers, Regulation-Down Offers and Regulation-Down Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation Response Time**

The maximum amount of time allowed for a Resource to move its output from zero (0) Regulation Deployment to the full amount of Regulation-Up cleared or to move from zero (0) Regulation Deployment to the full amount of Regulation-Down cleared.

**Regulation-Up**

An Operating Reserve product procured by the Transmission Provider from qualified Resources that increase their energy output (or reduce consumption of the Demand Response Load associated with a qualified Dispatchable Demand Response Resource) in response to a Regulation Deployment instruction from the Transmission Provider.

**Regulation-Up Mileage Factor**

A factor determined through historical Regulation Deployment analysis that represents the ratio of the Transmission Provider's total Instructed Regulation-Up Mileage to the Transmission

Provider's total cleared Regulation-Up Service. The Regulation-Up Mileage Factor shall initially be set equal to 1.0 and shall be updated periodically pursuant to the Market Protocols.

**Regulation-Up Mileage Offer**

The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has agreed to sell Expected Regulation-Up Mileage.

**Regulation-Up Offer**

The price at which a Regulation Qualified Resource or a Regulation-Up Qualified Resource has committed to sell Regulation-Up.

**Regulation-Up Qualified Resource**

A Resource that has met the requirements to be eligible to submit Regulation-Up Offers and Regulation-Up Mileage Offers into the Energy and Operating Reserve Markets.

**Regulation-Up Scarcity Factor**

A multiplier used to define shortage regions of Regulation-Up and the appropriate scarcity price value associated with the shortage.

**Regulation-Up Service**

The provision of Actual Regulation-Up Mileage associated with cleared Regulation-Up Service MW in response to Regulation Deployment instructions.

**Regulation-Up Service Offer**

The sum of (i) a Resource's Regulation-Up Mileage Offer multiplied by the Regulation-Up Mileage Factor and (ii) that Resource's Regulation-Up Offer.

**Reliability Unit Commitment ("RUC")**

The process performed by the Transmission Provider to assess resource and Operating Reserve adequacy for the Operating Day, commit or de-commit resource as necessary, and communicate

commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

**Reliability Unit Commitment Period ("RUC Commitment Period")**

The contiguous period of time between a Resource's Reliability Unit Commitment Commit Time and Reliability Unit Commitment De-Commit Time.

**Reported Load**

A Market Participant's actual value of energy withdrawn from the Transmission System at a Settlement Location adjusted as described under Section 8.6.1.1 of Attachment AE and further adjusted, if necessary, to account for distribution system losses between the actual metering point and the Transmission System Settlement Location as described under Appendix D of the Market Protocols.

**Reservation Capacity**

The reservation Megawatt between a specified source and sink associated with SPP Transmission Service.

**Reserve Sharing Event**

A request for assistance to deploy Contingency Reserve by any member of the Reserve Sharing Group following the sudden loss of a Resource.

**Reserve Sharing Group**

A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group.

**Reserve Zone**

A zone containing a specific group of Price Nodes for which a minimum and maximum Operating Reserve requirement is calculated.

**Resettlement**

The settlement of an Operating Day subsequent to the posting of the S120 Scheduled Settlement Statement for that Operating Day.

**Residual Load**

Settlement Area Net Load less all other directly metered Reported Load within the Settlement Area.

**Resource**

As defined in Part I, Section 1 of this Tariff.

**Resource Hub**

A Settlement Location consisting of an aggregation of Resource Price Nodes developed for financial and trading purposes.

**Resource Offer**

For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Transition State Offer, Regulation-Up Service Offer, Regulation-Down Service Offer, Spinning Reserve Offer, Supplemental Reserve Offer and Resource physical operating parameters.

## 1.1 Definitions S

**S7 Scheduled Settlement Statement**

As defined in Section 10.1(1) of this Attachment AE.

**S53 Scheduled Settlement Statement**

As defined in Section 10.1(2) of this Attachment AE.

**S120 Scheduled Settlement Statement**

As defined in Section 10.1(3) of this Attachment AE.

**Scarcity Price**

The Locational Marginal Price and Market Clearing Price levels determined through the use of Demand Curves when there is insufficient Energy or Operating Reserve available to meet the requirements.

**Scarcity Pricing**

The calculation of Scarcity Prices in accordance with Sections 8.3.1 and 8.3.4.2 of this Attachment AE.

**Scheduled Settlement**

The mandatory Settlement of an Operating Day that is posted on a prescribed schedule.

**Scheduled Settlement Statement**

The statement produced from a Scheduled Settlement.

**Security Constrained Economic Dispatch ("SCED")**

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve on a co-optimized basis that minimizes overall cost while enforcing security constraints.

**Security Constrained Unit Commitment ("SCUC")**

An algorithm capable of committing Resources to supply Energy and Operating Reserve on a co-optimized basis that minimizes capacity costs while enforcing security constraints.

**Self-Charging**

Withdrawing Energy from the Transmission System without a Transmission Provider Dispatch Instruction to provide a service under the Tariff.

**Setpoint Instruction**

The Real-Time desired Megawatt output signal calculated for a specific Resource by SPP's control system for a specified period.

**Settlement Area**

A geographic area within an SPP BA Participant Area, as defined under Attachment AN of this Tariff, for which transmission interval metering can account for the net area load.

**Settlement Area Metered Net Interchange**

The algebraic sum of all Energy flowing into or out of a Settlement Area during an hour.

**Settlement Area Net Load**

The sum of (a) net injections at each Settlement Location within the Settlement Area and (b) Settlement Area Metered Net Interchange.

**Settlement Invoice**

A weekly summary of the Integrated Marketplace net daily charges and payments by Asset Owner and Operating Day that is generated for each Market Participant and contains data for all of the Operating Days settled, either on a Scheduled Settlement or Resettlement basis, during the invoice period. For each Operating Day, only the net amounts (current total less previously invoiced – excluding the S7 Scheduled Settlement Statement) contribute to the invoice amounts.

**Settlement Location**

A location of finest granularity for calculation of settlements in the Day-Ahead Market, Real-Time Balancing Market, and TCR Market. The five (5) types of Settlement Locations are: Resource (including pseudo-tied resources), Load (including pseudo-tied loads), Trading Hub, Resource Hub, and External Interface.

**Settlement Statement**

A daily summary of the Integrated Marketplace total daily charges and payments by charge type, Asset Owner and Operating Day which is generated for each Market Participant and contains data for all of the Operating Days settled, either on a Scheduled Settlement or Resettlement basis, on that day. For each Operating Day, the current, previous and net amounts are included on the statement.

**Shadow Price**

A price for a commodity that measures the marginal value of the commodity.

**Simultaneous Feasibility Test**

A test for a state in which each set of injections and withdrawals associated with Long-Term Congestion Rights, Auction Revenue Rights and Transmission Congestion Rights would not exceed any thermal, voltage, or stability limits within the Transmission System under normal operating conditions or for monitored contingencies.

**Software Error**

A software error is a software execution that is inconsistent with the requirements of this Attachment AE.

**Spin Qualified Resource**

A Resource that has met the requirements to be eligible to submit Spinning Reserve Offers into the Energy and Operating Reserve Markets.

**Spinning Reserve**

The portion of Contingency Reserve from qualified Resources synchronized to the system that is fully available to serve load within the Contingency Reserve Deployment Period following a contingency event.

**Spinning Reserve Offer**

The price at which a Spin Qualified Resource has agreed to sell Spinning Reserve.

**SPP Holidays**

New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Day After Thanksgiving, Christmas Eve, Christmas Day.

**SPP Region**

As defined in Section 1 of the Tariff.

**Staggered Start Resource**

A Resource for which an attestation was submitted prior to October 1, 2017, identifying system configuration, mechanical, or environmental constraints which limits the start-up of that Resource with another Resource and that was registered in the Integrated Marketplace prior to October 1, 2017.

**Start-Up Offer**

The compensation required by a Market Participant for bringing an off line Resource on line or for reducing consumption of a Dispatchable Demand Response Resource or Block Demand Response Resource.

**Start-Up Time**

The time required to start a Resource and reach the Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable, following receipt of a Commitment Instruction to start-up from the Transmission Provider.

**State of Charge**

The amount of Energy stored expressed in MWhs.

**State of Charge Forecast**

The projected State of Charge for the beginning of each market interval used in the Day-Ahead Market and the RUC.

**State Estimator**

A standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at busses for which Real-Time information is unavailable.

**Statutory Load Obligations**

As defined in Section 1 of the Tariff.

**Supplemental Qualified Resource**

A Resource that has met the requirements to be eligible to submit Supplemental Reserve Offers into the Energy and Operating Reserve Markets.

**Supplemental Reserve**

The portion of Operating Reserve from qualified on-line Resources or qualified off-line Resources that is capable of being synchronized to the system that is fully available to serve load within the Contingency Reserve Deployment Period following a contingency event.

**Supplemental Reserve Offer**

The price at which a Supplemental Qualified Resource has agreed to sell Supplemental Reserve.

**Synchronized Resource**

A Resource that is electrically connected to the grid as evidenced by the closing of the Resource circuit breaker.

**Sync-To-Min Time**

The time required for a Resource's output to reach Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit, as applicable, following synchronization to the grid.

## 1.1 Definitions T

**Through Interchange Transaction**

A Market Participant schedule submitted between two External Interfaces for use in the Day-Ahead Market or Real-Time Balancing Market for moving Energy through the SPP Balancing Authority Area.

**Trading Hub**

A Settlement Location consisting of an aggregation of Price Nodes developed for financial and trading purposes.

**Transition State Offer**

An offer representing the cost to move an MCR to another configuration.

**Transition State Time**

An operating parameter representing the time required to move an MCR to another configuration.

**Transitional ARR Allocation**

An interim, multi-period, single-round process, outside of the annual ARR process schedule, used by an Eligible Entity when a Transmission Owner brings existing transmission facilities and transmission service under the SPP Tariff.

**Transmission Congestion Right ("TCR")**

A right that entitles the holder to be compensated or charged for congestion in the Day-Ahead Market between two Settlement Locations.

**Transmission Congestion Rights Markets ("TCR Markets")**

The annual Long-Term Congestion Rights allocation process, the annual and monthly Transmission Congestion Rights auctions and the Auction Revenue Rights annual and monthly allocation processes.

**Transmission Customer**

As defined in Section 1 of the Tariff.

**Transmission Provider**

As defined in Section 1 of the Tariff.

**Transmission Service**

As defined in Section 1 of the Tariff.

**Transmission System**

As defined in Section 1 of the Tariff.

**Transmission System Injection**

Injecting energy to the Transmission System, or providing other services under the Tariff that support the delivery of energy to the Transmission System, at a Discrete Delivery Point including a generator that is collocated with the load and exceeds the load that it is contractually permitted to supply at such Discrete Delivery Point. This does not include generators that are acting as transmission facilities.

**Tariff**

The Transmission Provider's Open Access Transmission Tariff.

## 1.1 Definitions U

**Uninstructed Resource Deviation ("URD")**

The Megawatt amount by which a Resource's actual output in a Dispatch Interval is above or below that Resource's average Setpoint Instruction in the Dispatch Interval.

**Unused Regulation-Down Mileage**

The amount calculated under Section 8.6.2 of this Attachment AE.

**Unused Regulation-Up Mileage**

The amount calculated under Section 8.6.2 of this Attachment AE.

## 1.1 Definitions V

**Variable Energy Resource**

A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

**Violation Relaxation Limit ("VRL")**

The values described under Section 8.3.2 of this Attachment AE.

**Virtual Energy Bid**

A proposal by a Market Participant to purchase Energy at a specified price, Settlement Location and period of time in the Day-Ahead Market that is not associated with a physical load.

**Virtual Energy Bid Curve**

A set of price/quantity pairs that consists of Megawatt and dollars per Megawatt hour with up to ten (10) price/quantity pairs.

**Virtual Energy Offer**

A proposal by a Market Participant to sell Energy at a specified price, Settlement Location and period of time in the Day-Ahead Market that is not associated with a physical Resource.

# 2.0 Market Participant Obligations

## 2.1 Service Agreement

Each Market Participant must execute the Service Agreement specified in Attachment AH. If the Market Participant fails or refuses to execute this service agreement, the Transmission Provider will file an unexecuted agreement with the Commission in accordance with Section 2.2(6) of this Attachment AE. Except as may otherwise be provided in this Tariff with respect to Reserve Sharing Group members, entities that are external to the Integrated Marketplace footprint and that do not take services under the Tariff are not subject to the rules and practices of the Integrated Marketplace.

## 2.2 Application and Asset Registration

(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements ("GFAs"), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant's share of a Jointly Owned Unit as a separate Resource must choose the option described below and provide the specified additional information.

(a) Individual Resource Option

Under the individual Resource option, each participant's share is modeled as a separate Resource for the purposes of commitment, dispatch and Operating Reserve Clearing, and each Resource may be committed independent of the other Resource shares.

A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit under the individual Resource option.

The operating owner's Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

- Jointly Owned Unit maximum physical capacity operating limit; and
- Maximum physical ten (10) minute response from an off-line state.

(5) Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

(6) All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts ("MWs"), must register. Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the (i) Network Customer, (ii) Transmission Customer, or (iii) Transmission Owner serving load under a Grandfathered Agreement for which the Transmission Owner is neither taking Network Integration Transmission Service nor Firm Point-To-Point Transmission Service. Failure or refusal to register a Resource will result in the Transmission Provider

filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

(7) A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2)

affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment, as required.

(10) All Variable Energy Resources in the Integrated Marketplace, including Variable Energy Resources for which the Transmission Provider does not have an executed Generator Interconnection Agreement, must be registered as a Dispatchable Variable Energy Resource except for (1) a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (2) a Resource having a primary fuel source of run of the river hydro-electric that is incapable of following Dispatch Instructions. A Generation Interconnection Customer with Variable Energy Resources, as well as Variable Energy Resources for which the Transmission Provider does not have an executed Generator Interconnection Agreement, that are not Qualifying Facilities exercising their rights under PURPA previously registered as a Non-Dispatchable Variable Energy Resource or are not run of the river hydro-electric Resources incapable of following dispatch instructions must convert to a Dispatchable Variable Energy Resource by the later of January 1, 2021 or the 10 year anniversary of a Resource's original Commercial Operation Date.

A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer's load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer's load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer's load by the seller shall be accounted for by including such load in the seller's Reported Load and not including such load in the buyer's Reported Load, as described under Section 2.11.1(A)(1) of this Attachment AE, and such associated bilateral contracts shall not be included in either the buyer's or seller's net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;

(b) Load Settlement Location;

(c) The maximum MW capacity contracted under the GFA Carve Out;

(d) The identification of the GFA in Attachment W; and

(e) Any other information reasonably required by the Transmission Provider.

(14) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.23 and 8.6.24 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market Participant shall not generate any energy in excess of the available pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

(15) Western-UGP shall provide to the Transmission Provider the information necessary to administer the FSE. The required information shall include the following:

(a) Resource Settlement Locations;

(b) Load Settlement Locations;

(c) The maximum MW capacity contracted under the FSE;

(d) The identification of the FSE Statutory Load Obligations as described in the SPP-Western-UGP NITSA; and

(e) Any other information reasonably required by the Transmission Provider.

(16) The Transmission Provider shall establish FSE Transfer Points consistent with the FSE transmission service power flow impacts.

(17) A Market Participant registering a Staggered Start Resource shall attest that the Resource meets the Staggered Start Resource definition in this Attachment AE.

The attestation shall contain sufficient detail regarding the specific circumstances of the Resource to demonstrate that it meets the definition of a Staggered Start Resource. A Market Participant that has registered a Staggered Start Resource shall change the registration status no later than thirty (30) business days from the date the Resource ceases to meet the Staggered Start Resource definition.

(18) In addition to the responsibilities described in section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants registering a Resource may indicate if the Resource is a Jointly Owned Unit that is not electing to model each share as an individual Resource. This Combined Interest Resource modeling is used to distribute all Day-Ahead Market and Real-Time Balancing Market charges and payments associated with the Resource between the Asset Owners that have contractual rights or financial obligations for that Resource. Market Participants registering a Resource with combined interest shall provide the individual Interest Percent Share by Asset Owner.

(19) A Market Participant registering an ESR must register as described in Section 2.17 of this Attachment AE.

a) An ESR of at least 0.1 MW that is capable of Transmission System Injection or directly connected to the Transmission System must register; however, if the ESR is exclusively a transmission facility with recovery through transmission rates, registration is not required.

b) A Market Participant registering an ESR that is not required to register under this Tariff, or a Market Participant registering an ESR that intends to participate in both wholesale and retail markets, must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. ESRs not directly connected to the Transmission System must specify, through meter data submittal, all withdrawals and injections subject to wholesale settlements. Withdrawals are subject to wholesale settlements when the Energy withdrawn is later injected back to the Transmission System. If an ESR is behind-the-meter of another registered Resource or load, the Meter Agent for the ESR is responsible for coordinating any wholesale withdrawal or injection to the

Transmission System with the Meter Agent for the Resource or load so that the ESR activity is removed from the Resource or load meter data. Further details are contained in the Meter Technical Protocols found in Appendix C of the Market Protocols, the Meter Agent Services Agreement in Attachment AM of this Tariff, and the Billing Determinant Anomalies in Section 4.5.17 of the Market Protocols.

1. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

## 2.3 Market Manipulation

Market Participants shall not engage in any market manipulation activities. Such actions or transactions that are without a legitimate business purpose and that are intended to, or foreseeably could, manipulate market prices, market conditions, or market rules for electric energy or electric products are prohibited. Such activities include, but shall not be limited to, the activities specified in Attachment AG.

## 2.4 Commitment and Dispatch

Market Participants shall, where applicable:

(1) Follow the Transmission Provider's Commitment Instructions and Dispatch Instructions as described under this Attachment AE;

(2) Abide by the procedures set forth in the Market Protocols.

## 2.5 Provision of Load and Generation Data

Market Participants, or their designated Meter Agent, shall submit to the Transmission Provider data for the Operating Day representing the actual Resource output, where such output is either on a gross or net basis as specified during market registration as described under Section 2.2(2) of this Attachment AE, and actual load consumption, or where actual data is not available, estimates thereof, associated with their registered load and Resources in accordance with the timelines specified in the Market Protocols. A Market Participant may designate any qualified entity to perform the Meter Agent function or perform this function on its own behalf.

Any entity performing the Meter Agent function for a Market Participant must execute the Meter Agent Agreement specified in Attachment AM prior to performing such function.

## 2.6 Dispatchable Demand Response Resource

In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants registering a Dispatchable Demand Response Resource must:

(1) Identify an associated Demand Response Load Meter Data Submittal Location;

(2) Identify an associated Dispatchable Demand Response Load Settlement Location;

(3) Specify one of the following two options for calculation of the Dispatchable Demand Response Resource output as described in Section 4.1.2 of this Attachment AE:

  (a) Submitted Resource production option; or

  (b) Calculated Resource production option.

The Transmission Provider will notify the applicable retail provider and the relevant electric retail regulatory authority of the registration and the expected MW level of participation.

## 2.7 Block Demand Response Resource

In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants registering a Block Demand Response Resource must:

(1) Identify an associated Demand Response Load Meter Data Submittal Location; and

(2) Identify an associated Block Demand Response Load Settlement Location

The Transmission Provider will notify the applicable retail provider and the relevant electric retail regulatory authority of the registration and the expected MW level of participation.

## 2.8 Aggregators of Retail and Wholesale Customers

### 2.8.1 Aggregators of Retail Customers

(1) An aggregator of retail customers offering a Block Demand Response Resource or a Dispatchable Demand Response Resource associated with one or more end-use retail customers in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants.

(2) For purposes of participation in the Energy and Operating Reserve Markets, an aggregator of retail customers may aggregate Demand Response Load associated with a Block Demand Response Load Settlement Location or Demand Response Load associated with a Dispatchable Demand Response Load Settlement Location of: (1) End-use retail customers of utilities that distributed more than 4 million MW hours ("MWh") in the previous fiscal year, unless precluded by the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s); and (2) End-use retail customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority, including any state-approved retail tariff(s), affirmatively permits such customer's demand response to be offered into the Energy and Operating Reserve Markets by an aggregator of retail customers. Aggregators of retail customers shall be treated comparably to other Market Participants offering Resources in the Energy and Operating Reserve Markets.

Aggregations pursuant to this section shall be subject to the following requirements:

(a) End-use customers may be aggregated into a single Dispatchable Demand Response Resource or a single Block Demand Response Resource. The Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes, provided that such aggregated Price Node is served by the same retail provider;

(b) All end-use customers in an aggregation shall be specifically identified.

(c) For a Block Demand Response Resource or a Dispatchable Demand Response Resource of an aggregator of retail customers that chooses to

measure demand reductions using the calculated Real-Time response methodology, a single hourly baseline for each registered Resource shall be used to determine settlements pursuant to Section 8 of this Attachment AE.

### 2.8.2 Aggregators of Wholesale Customers

(1) An aggregator of wholesale customers offering a Block Demand Response Resource or a Dispatchable Demand Response Resource associated with one or more wholesale customers in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants.

Aggregations pursuant to this section shall be subject to the following requirements:

(a) Wholesale customers may be aggregated into a single Dispatchable Demand Response Resource or a single Block Demand Response Resource. The associated Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes, provided that such aggregated Price Node is served by the same wholesale provider;

(b) All wholesale customers in an aggregation shall be specifically identified.

(c) For a Block Demand Response Resource or a Dispatchable Demand Response Resource of an aggregator of wholesale customers that chooses to measure demand reductions using the calculated Real-Time response methodology, a single hourly baseline for each registered Resource shall be used to determine settlements pursuant to Section 8 of this Attachment AE.

## 2.9 Combined Cycle Resource

Market Participants registering Resources with combined cycle capability as described in Section 4.1.2.2 of this Attachment AE shall select only one modeling option during market registration. Market Participants that jointly participate in a combined cycle Resource that desire to use the Jointly Owned Unit modeling options described under Section 2.2(4) of this Attachment AE must register as a Jointly Owned Unit and cannot register the Resource as a combined cycle Resource. Modifications to combined cycle Resource modeling options may be made in accordance with timing requirements defined in the Market Protocols.

## 2.10 Operating Reserve Certification

In order to be eligible to submit Operating Reserve Offers, a Market Participant's Resource must meet the certification requirements in the Subsections below. Dispatchable Variable Energy Resources may only qualify to provide Regulation-Down. Dispatchable Variable Energy Resources are not eligible to provide Regulation-Up or Contingency Reserve.

### 2.10.1 Spin Qualified Resources

There are no specific testing requirements for a Resource to become a Spin Qualified Resource. A Market Participant will self-certify that its Resource is capable of deploying Spinning Reserve or on-line Supplemental Reserve during the registration process. In such case, that Resource will become a Spin Qualified Resource. The Transmission Provider may perform, at its discretion, Contingency Reserve deployment tests, as described in the Market Protocols, in order to verify that any cleared Spinning Reserve or on-line Supplemental Reserve is capable of being deployed.

If the Resource deploys less than seventy-five percent (75%) of the MW deployment instruction, the Resource has failed the test and the Resource will not be eligible for compensation for out-of-merit Energy ("OOME") and the maximum online Contingency Reserve available for sale in the Integrated Marketplace shall be limited to the actual MW deployed during the test. Such restriction shall continue to apply until the Resource passes a retest. The Market Participant representing the Resource must obtain Transmission Provider approval regarding the timing of a retest and the Resource will not be eligible for compensation for OOME as a result of the retest.

### 2.10.2 Supplemental Qualified Resources

There are no specific testing requirements for an off-line Resource to become a Supplemental Qualified Resource. A Market Participant will self-certify that its off-line Resource is capable of deploying Supplemental Reserve during the registration process. In such case, that Resource will become a Supplemental Qualified Resource. The Transmission Provider may perform, at its discretion, Contingency Reserve deployment tests, as described in the Market Protocols, in order to verify that any cleared Supplemental Reserve is capable of being deployed.

If the Resource deploys less than seventy-five percent (75%) of the MW deployment instruction, the Resource has failed the test and the Resource will not be eligible for Reliability Unit Commitment ("RUC") make whole payment compensation and the maximum off-line Supplemental Reserve available for sale in the Integrated Marketplace shall be limited to the actual MW deployed during the test. Such restriction shall continue to apply until the Resource passes a retest. The Market Participant representing the Resource must obtain Transmission Provider approval regarding the timing of a retest and the Resource will not be eligible for RUC make whole payment compensation as a result of the retest.

### 2.10.3 Regulation Qualified Resources

A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined below and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols. The specific testing procedures for a Resource to become a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource are described in the Market Protocols and are coordinated by the Transmission Provider.

The following requirements apply when a Resource is currently registered in the Integrated Marketplace or when a Market Participant requests that the Transmission Provider administer the test for a non-registered Resource:

(1) A resource may become a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource only after it achieves three regulation test scores of seventy-five percent (75%) or greater where the calculation of the regulation test score is defined in the Market Protocols;

(2) The Market Participant must notify the Transmission Provider at least one hundred twenty (120) minutes before the test is scheduled to begin;

(3) The Transmission Provider has final authority to determine whether a regulation test can be performed and reserves the right to alter the start time or terminate the test at any time;

(4) The Transmission Provider will verify the test results and send confirmation to the Market Participant within fourteen (14) Operating Days;

(5) The Transmission Provider may administer a regulation test on any Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource to verify continued qualification;

(6) The Transmission Provider may disqualify a previously qualified resource for persistent failure to follow regulation deployment instructions as described in the Market Protocols. A Market Participant may request a re-test if the Resource was disqualified as a Regulation Qualified Resource, Regulation-Up Qualified

Resource or Regulation-Down Qualified Resource. The Resource must attain a test score of seventy-five percent (75%) or greater in order to be re-qualified.

(7) After initial qualification, a compliance rating of seventy-five percent (75%) or greater must be maintained where the compliance rating calculation is defined in the Market Protocols.

The following requirements apply when a resource is not registered in the Integrated Marketplace and is in the process of being registered:

(1) A Market Participant or prospective Market Participant shall either self-test as described in the Market Protocols or request that the Transmission Provider administer testing as an alternative to self-testing;

(2) If the Market Participant or prospective Market Participant performs a self-test on the resource, it shall submit all testing data to the Transmission Provider;

(3) The resource will be qualified to become a Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource after the resource achieves three regulation test scores of seventy-five percent (75%) or greater. The regulation test score calculation is defined in the Market Protocols. If a Market Participant achieves these passing scores before completion of registration, the resource will become a Regulation-Up Qualified Resource, Regulation-Down Qualified Resource or Regulation Qualified Resource upon entry into the Integrated Marketplace.

### 2.10.4 Ramp Capability Qualified Resources

Ramp Capability Up and Ramp Capability Down are procured from Resources to respond to future net obligation changes in the SPP Energy and Operating Reserve Markets. There are no specific testing requirements for a Resource to become a ramp capability qualified Resource. A Resource that is capable of following Setpoint Instructions will be considered qualified to clear Ramp Capability Up and Ramp Capability Down products. The Transmission Provider will provide the Ramp Capability Up service and Ramp Capability Down service and the Transmission Customer will pay for these services through Sections 8.5.26, 8.5.27, and 8.6.26 of this Attachment AE.

## 2.11 Must-Offer Requirement

### 2.11.1 Day-Ahead Market

A. Each Market Participant must satisfy the must offer obligation for an Asset Owner as set forth in Section 2.11.1(B) of this Attachment AE based on the following criteria:

(1) A Market Participant's load for an Asset Owner for purposes of this section shall be equal to that Market Participant's maximum hourly Reported Load for an Asset Owner for the Operating Day. Such Asset Owner's Reported Load shall include load registered as described under Section 2.2(11) of this Attachment AE, where the buyer's Reported Load shall be reduced by the amount of the buyer's load registered by the seller and the seller's Reported Load shall be increased by the amount of the buyer's load registered by the seller. If an MSR is Self-Charging during the maximum Reported Load hour, the Market Participant's available generation that is used to satisfy the must offer obligation is reduced by the Self-Charging MW.

(2) A Market Participant's daily Operating Reserve obligation for an Asset Owner shall be equal to the sum of that Market Participant's maximum daily Regulation-Up Service, Regulation-Down Service, Contingency Reserve, Ramp Capability Up, and Ramp Capability Down obligations for an Asset Owner as estimated by the Transmission Provider in accordance with Section 3.1.4(3) of this Attachment AE.

(3) A Market Participant may satisfy this requirement by offering Resources for an Asset Owner with a commitment status indicating either that the Market Participant is self-committing the Resource, the Resource may be committed by the Transmission Provider, or the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or Local Reliability Issue, as specified in Sections 4.1(10)(a), 4.1(10)(b), and 4.1(10)(c) of the Attachment AE.

(4) A Market Participant's net resource capacity for an Asset Owner, for purposes of this section shall include:

i. Offered capacity by Resources identified in Section 2.11.1(A)(3) of Attachment AE less the Operating Reserve obligation identified in Section 2.11.1(A)(2) of Attachment AE; and

ii. Firm power purchases less firm power sales, except that, if the seller has registered the buyer's load associated with a firm power sale as described in Section 2.2(11) of this Attachment AE, such firm power sale shall not act to increase the buyer's net resource capacity or act to reduce the seller's net resource capacity. For purposes of this Section 2.11.1 of this Attachment AE firm power purchases and firm power sales shall mean sales and purchases that are deliverable with transmission service comparable to Firm Point-To-Point Transmission Service or Firm Network Integration Transmission Service with the supplier assuming the obligation to provide both capacity and energy. Additionally, firm power purchases shall include an Asset Owner's share of a Jointly Owned Unit to the extent that such shares have not been registered as separate Resources either under Jointly Owned Unit individual Resource option as described under Section 2.2(4) of this Attachment AE, or under Combined Interest Resource modeling as described under Section 2.2(18) of this Attachment AE.

In order to verify firm power purchases and firm power sales, supporting documentation must be provided to the Market Monitor upon request. Market Participants have the option to input information regarding firm power purchases and firm power sales into the Market Monitor website. If no information is input into this website, the Market Monitor will contact the Market Participant for that information. The Market Monitor may communicate with the counterparty to confirm the firm purchase or sale and will include the transacted MWs to calculate net resource capacity for both purchaser and seller. If one of the parties disputes the firm purchase or sale to the Market Monitor, then the firm purchase or sale will not be used in the calculation of either the purchaser's or seller's net resource capacity subject to any dispute resolution.

B. A Market Participant's compliance with the must offer obligation for an Asset Owner is as follows:

(1) A Market Participant that has offered all of its available Resources for an Asset Owner, with a commitment status described in Sections 4.1(10)(a), 4.1(10)(b), and/or 4.1(10)(c) of this Attachment AE, for an hour of the Operating Day is deemed to be in compliance with the must offer requirement for that Asset Owner for that hour regardless of its maximum hourly Reported Load and/or, Operating Reserve obligation.

(2) A Market Participant that does not meet the condition described in Section 2.11.1(B)(1) of this Attachment AE for an Asset Owner for an hour of the Operating Day, but has net resource capacity for that Asset Owner for that hour greater than or equal to 90% of its load for that Asset Owner as described in Section 2.11.1(A)(1) of this Attachment AE is deemed to be in compliance for that Asset Owner with the must offer requirement for that hour.

(3) To the extent that a Market Participant does not meet the conditions described in either Section 2.11.1(B)(1) or (2) of this Attachment AE for an Asset Owner, the Market Participant shall be deemed noncompliant with the must offer requirement for that Asset Owner for that hour and will be assessed a penalty for that hour as determined in Section 3.9 of Attachment AF of this Tariff.

C. Market Monitor shall monitor a Market Participant's Load, Operating Reserve obligation, offered Resources and net resource capacity, for an Asset Owner for each hour of the Operating Day to determine whether the Market Participant has complied with the must offer obligation set forth in Section 2.11.1(B) of this Attachment AE.

### 2.11.2 Reliability Unit Commitment and the Real-Time Balancing Market

For the RUC processes and RTBM, Market Participants must submit Resource Offers for all Resources to the extent these Resources are available. Market Participants must include in their Resource Offers the full amount of physical capacity available as reflected in the Resource's submitted Maximum Normal Capacity Operating Limit and Maximum Emergency Capacity Operating Limit, or for MSRs, their Maximum Discharge Limit and Maximum Emergency Discharge Limit and/or their Minimum Charge Limit and Minimum Emergency Charge Limit.

## 2.12 Non-Conforming Load

Market Participants must:

(1) Provide hourly estimates of their registered Non-Conforming Load to the Transmission Provider no later than 1445 hours Day-Ahead for the remainder of the Operating Day and for the next six (6) Operating Days;

(2) Update their submitted Non-Conforming Load estimates as described in the Market Protocols;

(3) Provide the Transmission Provider with actual Non-Conforming Load data in Real-Time to the extent that telemetering is available;

(4) Provide the Transmission Provider with the charging activity of an ESR not registered as an MSR.

## 2.13 Market Protocols and SPP Criteria

Market Participants must comply with the requirements and procedures described in the Transmission Provider's Tariff, the Market Protocols and the SPP Criteria.

## 2.14 External Dynamic Resource

Market Participants with resources external to the SPP Balancing Authority Area that are not External Resources may register such resources for participation in the Energy and Operating Reserve Markets as an External Dynamic Resource ("EDR"). The following specific registration rules pertain to EDRs:

(1) An EDR may represent an external entity's resource or fleet of resources;

(2) EDRs that are located within the Eastern Interconnection are eligible to submit Offers for qualified Operating Reserve only.

(3) EDRs that are located within Interconnections other than the Eastern Interconnection are eligible to submit Offers for Energy and/or qualified Operating Reserve using a qualified DC Tie where such technical qualifications are specified in the Market Protocols;

(4) In order to facilitate the provision of Regulation-Down, Market Participants registering the EDRs that are not qualified to provide Energy may link a dynamic schedule for Energy at a fixed MWh amount that is greater than or equal to the amount of Regulation-Down to be provided by the EDR as specified in the Market Protocols;

(5) The Transmission Provider will assign all registered EDRs to the Reserve Zone containing the PNode or aggregated PNode associated with the EDR as described under Section 3.1.3;

(6) A firm transmission service reservation and associated dynamic schedule is required from the source Balancing Authority to the SPP Balancing Authority border for all registered EDRs offering Energy, Regulation-Up and/or Contingency Reserve into the Integrated Marketplace.

(7) A firm transmission service reservation and associated dynamic schedule is required from the SPP Balancing Authority border to the source Balancing Authority for all registered EDRs offering Regulation-Down that are not qualified to offer Energy unless the EDR has an associated dynamic

schedule for a fixed MWh in amount greater than or equal to the amount of Regulation-Down service as described under Section 2.14(4) of this Attachment AE.

## 2.15 Provision of Wind Forecast Data

(1) Geographic data and wind turbine availability data for each wind-powered Variable Energy Resource must be submitted to the Transmission Provider as specified in the interconnection customer's interconnection agreement.

(2) An interconnection customer with a wind-powered Variable Energy Resource that executed an interconnection agreement on or after June 16, 2013 must submit, as specified in the interconnection customer's interconnection agreement in accordance with Attachment V: (i) site-specific meteorological data including temperature, wind speed, wind direction, relative humidity and atmospheric pressure and (ii) site specific geographic data including location (latitude and longitude) of the wind-powered Variable Energy Resource and location (latitude and longitude) and height of the facility that will contain the equipment necessary to provide the meteorological data for such resource. The Transmission Provider will accept such data from interconnection customers with other wind-powered Variable Energy Resources that executed an interconnection agreement prior to June 16, 2013 if provided by the interconnection customer.

## 2.16 Grandfathered Agreement Carve Out

(a) Transmission Owners that are a party to GFA(s) eligible for GFA Carve Out 30 days prior to the start of the initial transmission service verification as described in 7.1.1 of Attachment AE shall:

1. Elect GFA Carve Out;
2. Elect such GFA(s) be treated comparably to other firm transmission reservations eligible for ARR and TCR in accordance with Attachment AE of this Tariff; or
3. Convert such GFA to Transmission Service or Network Integration Transmission Service under this Tariff.

(b) A GFA added to Attachment W of the Tariff after October 18, 2012 shall be subject to the following treatment:

(1) ARR and TCR eligibility under Attachment AE of this Tariff; or

(2) Full conversion to Transmission Service or Network Integration Transmission Service under this Tariff.

## 2.17 Electric Storage Resource

ESRs may register as any valid Resource type and are subject to the same service provision rules as any other Resource within that type.

(1) If not registered as an MSR the energy withdrawal from the Transmission System must be included in a Load Settlement Location and are subject to the same rules as other Load.

(2) If an ESR is registered as an MSR, the following applies:

a) MSRs may provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve services upon meeting the technical and applicable requirements for these services in this Attachment AE and the Market Protocols.

b) MSRs must provide Offer parameters as prescribed in Section 4.1 of this Attachment AE.

c) MSR Offer Curves may include negative MW values to account for the entire dispatchable range of the MSR.

d) As with other Resources, the metering requirements for MSRs include real-time and settlement quality metering. For MSRs that are not directly connected to the Transmission System, metering may include facilities used by the distribution company.

e) Self-Charging MSRs or MSRs charging beyond the instructed amount are subject to all applicable transmission charges under the Tariff.

f) Market Participants registering an MSR must also request transmission service under Part II or Part III of this Tariff.

i. In the absence of explicit transmission service reservation arrangements by the Market Participant for the uninstructed energy withdrawals, the Market Participant will be billed the unreserved use rate as defined in Section 13.7 (c) or 14.5 of this Tariff.

ii. Dispatch Instruction by the Transmission Provider for the MSR to provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, or Supplemental Reserve that incidentally results in charging activity shall not be subject to a bill for transmission service during those actions.

g) The Real-Time Energy consumption is settled at the LMP as per Section 8.3 of this Attachment AE.

   i. In the event that the MSR is not directly connected to the Transmission System and the distribution company is unable or unwilling to separate the charging activity from other retail service, the MSR will not be subject to settlement by the Transmission Provider for either the transmission charge or the energy consumption.

h) MSRs are not considered continuously dispatchable in a given interval if a directional commitment limitation exists for that interval. A directional commitment limitation occurs when the Minimum Charge Time is not equal to zero, Minimum Discharge Time is not equal to zero, Minimum Charge Limit is not equal to zero, or Minimum Discharge Limit is not equal to zero. If such a limitation exists, the MSR may offer either charge or discharge capacity in a given interval but not both. MSRs that do not have a directional commitment limitation are considered continuously dispatchable and will be evaluated for commitment and dispatch from the Maximum Charge Limit to the Maximum Discharge Limit.

## 2.18 Hybrid Storage Market Resource ("HSMR")

HSMRs may register as any valid Resource type and are subject to the same service provision rules as any other Resource within that type. HSMRs are also eligible to register as MSRs described in Section 2.17 (2) of this Attachment AE.

(1) HSMRs directly connected to the transmission grid will have the generating resource(s) be modeled separately behind a single point of interconnection in the Network Model. Physical and operational characteristics, real-time telemetry and other information for the generating resource(s) and the ESR(s) must be provided for individual components to the Transmission Provider for situational awareness, grid security, and also for informational purposes through telemetry in the Network Model. The submitted revenue meter data for settlement of the Resource response will represent the total combined HSMR response at the point of interconnection.

(2) If an HSMR is not registered as an MSR the Energy withdrawal from the Transmission System must be included in a load Settlement Location and is subject to the same rules as other load.

(3) If an HSMR is registered as an MSR then rules in Section 2.17(2) of this Attachment AE apply.

## 3.0 Transmission Provider Rights and Obligations

## 3.1 Transmission Provider Scope of Services

The Transmission Provider shall perform the services pertaining to the Integrated Marketplace specified in this Tariff, including, but not limited to, the following.

(1) Develop and maintain rules, practices and procedures for the Integrated Marketplace.

(2) Operate and administer the Integrated Marketplace,

(3) Function as the Integrated Marketplace Counterparty for all Integrated Marketplace transactions in accordance with the provisions of Section 3.8 of this Attachment AE.

In addition, the Transmission Provider, in its functional entity roles as the Reliability Coordinator, Balancing Authority, Transmission Service Provider, Planning Coordinator, Reserve Sharing Group Administrator, Interchange Authority and Market Operator shall act in compliance with and perform such functional entity roles as defined by NERC in the Reliability Functional Model.

### 3.1.1 Trading Hub Establishment and Modification

The Transmission Provider must establish and maintain at least one Trading Hub in accordance with the provisions of this section. In addition, the Transmission Provider may establish additional Trading Hubs. The Transmission Provider shall review the proposed establishment, modification or termination of a Trading Hub with stakeholders. The Markets and Operations Policy Committee will consider the proposed establishment, modification or termination of a Trading Hub and will provide its own recommendation regarding such action to the SPP Board of Directors for review and approval. Updating an existing Trading Hub to reflect a terminated Pnode due to the termination of the load or generation at that Pnode is not considered a modification and does not require consideration by the Markets and Operations Policy Committee or review and approval by the SPP Board of Directors. An existing Trading Hub may be modified or terminated only in the event that the LMP at that Trading Hub can no longer be calculated. The Transmission Provider shall post any approved establishment of a Trading Hub at least forty-five (45) days prior to the proposed effective date. The Transmission Provider shall post any modification or termination of a Trading Hub within thirty (30) days after SPP has determined that there is a need for modification or termination.

The Transmission Provider shall maintain and facilitate the use of a Trading Hub(s), comprised of a set of active nodes within the SPP Balancing Authority Area, which nodes and their current Settlement Location name shall be identified by the Transmission Provider on the Portal. The Transmission Provider shall use the following criteria to establish Trading Hubs:

(1) Each Trading Hub shall contain a sufficient number of nodes to ensure that a Trading Hub Locational Marginal Price ("LMP") can be calculated for that Trading Hub at all times;

(2) Each Trading Hub shall contain a sufficient number of nodes to ensure that the unavailability of, or an adjacent line outage to, any one node or set of nodes would have only a minor impact on the Trading Hub LMP;

(3) Each Trading Hub shall consist of nodes with a relatively high rate of service availability; and

(4) Each Trading Hub shall consist of nodes among which Transmission Service is relatively unconstrained.

(5) A Trading Hub shall not encompass the combined loads and Resources of a single vertically-integrated utility into a single Settlement Location.

### 3.1.2 Forecasting

(1) The Transmission Provider shall develop load forecasts for the SPP Balancing Authority Area for use in the RUC processes and RTBM. The Transmission Provider shall adjust such forecasts in order to remove average system losses prior to execution of the market applications in order for the dispatch to properly reflect the treatment of marginal losses.

(2) The Transmission Provider shall develop hourly forecasts for wind powered Variable Energy Resources for use in the RUC processes and Dispatch Interval forecasts for wind powered Variable Energy Resources for use in the RTBM as follows:

(a) The Transmission Provider shall use an industry standard wind generation output forecast software tool.

(b) To develop the forecasts, the software tool uses estimates of wind flow pertaining to the wind powered Variable Energy Resource location using regional atmospheric weather condition predictions obtained from weather forecasting services and the geographic data provided pursuant to Section 2.15(1) of this Attachment AE. In order to obtain increased accuracy, the estimates of wind flow are adjusted using the site-specific meteorological and geographical data provided pursuant to Section 2.15(2) of this Attachment AE.

(c) To develop the site-specific wind powered Variable Energy Resource output forecast, the site-specific estimates of wind flow described under Section 3.1.2(2)(b) of this Attachment AE are applied to either (i) wind flow versus power output curves developed from historical output data or (ii) the manufacturer's wind flow versus power output curve if there is no historical data available, adjusted as required to account for turbine availability data specified under Section 2.15(1) of this Attachment AE.

### 3.1.3 Reserve Zone Establishment

(1) The Transmission Provider shall identify the need for Reserve Zones within the SPP Balancing Authority Area through Reserve Zone studies that identify constrained areas that may require a minimum amount of Operating Reserve procurement and/or that may be limited to a maximum amount of Operating Reserve procurement to ensure system-wide procurement of Operating Reserve is deliverable when deployed.

(a) Reserve Zone studies will be conducted semi-annually and the Reserve Zone configuration will be made effective December 1 and June 1 of each year, with the study results posted on the Transmission Provider's website no later than thirty (30) days prior to each effective date. Normal Transmission System topology will be used for the study along with selected, approved outages. All Resources and loads in the SPP Balancing Authority Area will be evaluated.

(b) In order to ensure deliverability of reserves, the most likely constrained transmission facilities must be identified. Monitored constraints will be identified through analysis of historical congestion activity, planned transmission and Resource outages, and forecasted system demands and Resources.

(c) Once a final set of transmission constraints is identified, the Reserve Zones are established by grouping the PNodes, including PNodes contained in an aggregated PNode associated with an EDR, based on similar impact on all of the remaining transmission constraints. The groups of PNodes represent the Reserve Zones. Each PNode, and aggregated PNode associated with an EDR, will be placed into only one Reserve Zone.

(2) The Transmission Provider may add or reconfigure a Reserve Zone between semiannual updates to address significant changes in system conditions that would cause adverse reliability impacts absent the Reserve Zone addition or reconfiguration. The Transmission Provider will notify the Market Participants of any resulting changes made to the Reserve Zones and will post the results on the

Transmission Provider's website no less than two (2) Business Days prior to becoming effective.

### 3.1.4 Operating Reserve, Instantaneous Load Capacity Requirements and Ramp Capability Requirements

The Transmission Provider shall calculate the amount of Operating Reserves required for the Operating Day, on both a system-wide and Reserve Zone basis, in order to comply with the reliability requirements specified in the SPP Criteria. In addition, the Transmission Provider shall calculate the amount of Instantaneous Load Capacity required for the Operating Day on a system-wide basis in order to ensure that load can be reliably serviced in real-time. The Transmission Provider shall, on a daily basis:

(1) Calculate the hourly Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and Ramp Capability Down requirements on an SPP Balancing Authority Area basis and post such results by 0600 hours Day-Ahead for use in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and RTBM;

(2) Calculate the total minimum and total maximum Operating Reserve requirement for Operating Reserve deployment in the up direction and for deployment of Operating Reserve in the down direction for each Reserve Zone. These minimum and maximum Operating Reserve requirements will be determined by conducting a simulated energy transfer study for each hour of the Operating Day on the transmission system, reflecting expected outages and economic energy flows, in order to determine the energy transfer limitations into or out of a Reserve Zone in any hour. If a Reserve Zone is unable to import enough Energy after a contingency and still maintain all necessary operating limits, a minimum amount of Operating Reserve may be required to be carried in that Zone. The minimum Operating Reserve requirement is the largest difference between the Resource MW lost in the simulated contingency and the resulting import capability of that Reserve Zone. Similarly, if a Reserve Zone is unable to export additional Energy after a contingency outside of that Reserve Zone, then a maximum amount of Operating Reserve that is deliverable from that Zone will be specified in order to ensure that deliverable reserves are carried in other Zones. The maximum Operating Reserve limitation is equal to the export capability of that Reserve Zone when replacing Energy lost due to a Resource contingency outside of that Reserve Zone. The Transmission Provider may, at its option, set specific

Regulation-Up and/or Spinning Reserve minimum requirements for each Reserve Zone, as needed, to address reliability issues that can only be alleviated through carrying synchronized reserves. In such cases, the Transmission Provider will include these minimum Regulation-Up and/or Spinning Reserve requirements when posting the Operating Reserve requirements by 0600 Day-Ahead;

(3) Estimate each Market Participant's Operating Reserve obligation by Asset Owner in each Reserve Zone and provide such information to Market Participants by 0600 hours Day-Ahead. The Transmission Provider shall calculate such estimates by multiplying the system-wide Operating Reserve requirements calculated in (1) above by the Transmission Provider's estimate of each Asset Owner's load in each Reserve Zone divided by the Transmission Provider's estimate of system-wide load;

(4) The Transmission Provider may increase Operating Reserve requirements for the Day-Ahead RUC, Intra-Day RUC and RTBM above the requirements used in the Day-Ahead Market, including changes to Reserve Zone minimums and maximums, as required to meet increases in reliability requirements caused by changes in system conditions; and

(5) Calculate the hourly Instantaneous Load Capacity requirements for an interval on an SPP Balancing Authority Area basis for use in the Day-Ahead Market, Day-Ahead RUC and Intra-Day RUC in accordance with the calculation procedures specified in the Market Protocols.

### 3.1.5 Outage Scheduling and Reporting

The Transmission Provider is responsible for coordinating and approving the scheduling of outages on all transmission and generation facilities in the Transmission System. Procedures regarding submittal of requested transmission and generation outages and reporting of unplanned outages through the Transmission Provider's outage scheduler are described in the SPP Criteria. The Transmission Provider shall approve all requested outages to the extent that such outage requests can be accommodated reliably. To the extent that granting a requested outage would cause a reliability issue on the Transmission System, the Transmission Provider may deny the request. When the Transmission Provider denies an outage request, the Transmission Provider shall recommend an alternative timeframe within which the outage can be accommodated reliably.

### 3.1.6 Resource Hub Establishment

A Resource Hub is a Settlement Location representing an aggregation of Resource Price Nodes. The Transmission Provider will not limit the number of Resource Hubs established at any one time. The Resource Hub proposal may be composed of any combination of Resources that have not been retired or otherwise decommissioned with which the requesting Market Participant has affiliation. Proposals for the establishment or termination of Resource Hubs shall be submitted to The Transmission Provider by the Market Participants within the Settlement Location update duration set forth in the Market Protocols. The Transmission Provider will review and approve Resource Hubs based on the criteria defined in this Resource Hubs process. The Transmission Provider shall post any approved establishment of a Resource Hub at least forty-five (45) days prior to the proposed effective date. The Transmission Provider shall post any approved termination of a Resource Hub at least six (6) months prior to the proposed effective date of the termination which will coincide with the annual TCR auction period end. The Transmission Provider: (a) shall honor any LTCR or ILTCR that is based on a Resource Hub for the full term of the LTCR or ILTCR; and (b) shall not terminate a Resource Hub that is tied to a bilateral contract and related Bilateral Settlement Schedule unless both parties to the Bilateral Settlement Schedule agree to the termination of the Resource Hub.

### 3.1.7 Product Substitution

To ensure rational pricing of cleared Operating Reserve products, the SCED algorithm will include product substitution logic as follows:

A. Any Regulation-Up Offers may be used to meet Contingency Reserve requirements if Regulation-Up Offer is more economic or is required to meet the overall Contingency Reserve requirement;

B. Any Spinning Reserve Offers may be used to meet Supplemental Reserve requirements if the Spinning Reserve Offer is more economic or is required to meet the overall Operating Reserve requirement;

C. The product substitution logic ensures that the MCP for Regulation-Up Service is always greater than or equal to the Spinning Reserve MCP and that the Spinning Reserve MCP is always greater than or equal to the Supplemental Reserve MCP.

D. Ramp Capability Up and Ramp Capability Down products are not eligible for product substitution with other Operating Reserves.

## 3.2 Market Protocols

The Transmission Provider shall prepare, maintain and update the Market Protocols consistent with this Tariff. The Market Protocols shall be posted on the Transmission Provider's website.

## 3.3 Integrated Marketplace Operations

The Transmission Provider shall evaluate Offers and Bids submitted by Market Participants for use in the Day-Ahead Market and Offers submitted for use in the Day-Ahead RUC to ensure sufficient Resources are committed to meet the SPP Balancing Authority Area projected load and Operating Reserve requirements for the upcoming Operating Day. For the Intra-Day RUC, the Transmission Provider shall evaluate Offers to ensure sufficient Resources are committed to meet the SPP Balancing Authority Area projected load and Operating Reserve requirements throughout the Operating Day. In performing these processes, the Transmission Provider shall commit Resources on a least cost security constrained basis and shall clear Energy and Operating Reserve in the Day-Ahead Market on the basis of security constrained economic dispatch ("SCED") in accordance with Sections 5 and 6 of this Attachment AE.

Throughout the execution of the RTBM, the Transmission Provider shall dispatch Energy and clear Operating Reserve on Resources on the basis of SCED as described under Section 6 of this Attachment AE.

The Transmission Provider shall conduct the annual Auction Revenue Right ("ARR") allocation, annual TCR auction, monthly ARR allocation and monthly TCR auction in accordance with Section 7 of this Attachment AE.

### 3.3.1 Day-Ahead Market and RTBM SCED

The SCED used in the Day-Ahead Market and RTBM produces both a dispatch solution and a pricing solution. The dispatch solution and pricing solution are executed independent of each other. The MW quantities used in settlements for the dispatch and clearing of Energy and Operating Reserves result from the dispatch solution. Except where specified as DLMP, prices used in settlements result from the pricing solution and will be specified as LMP, MCC, MCP, MEC, and MLC. The DLMP results from the dispatch solution. The differences between the dispatch solution and the pricing solution are:

(1) SCED dispatch solution

(a) Co-optimization of Energy and Operating Reserves is based on the Energy Offers and Bids and Operating Reserve Offers submitted by the Market Participants.

(2) SCED pricing solution

(a) For non-FSRs, co-optimization of Energy and Operating Reserves is based on the Energy Offers and Bids and Operating Reserve Offers submitted by the Market Participants.

(b) For FSRs committed by the Transmission Provider, including FSRs committed at the request of a local transmission operator, but not including self-committed FSRs, the Transmission Provider calculates a composite Energy Offer for use in the co-optimization of Energy and Operating Reserves. The composite Energy Offer will be calculated and applied as follows:

(i) The Transmission Provider calculates a composite Energy Offer for an FSR by modifying each price point on the Energy Offer Curve for each market interval of the Minimum Run Time by adding amortized start-up and no-load costs. For FSRs that are MSRs, the composite Energy Offer applies only to the discharge portion of the Energy Offer curve.

1. The commitment costs (i.e. start-up cost and no-load cost) in effect at the time of the commitment are amortized over the Maximum Economic Capacity Operating Limit and the Minimum Run Time.

a. The start-up cost added to each breakpoint of the Energy Offer Curve is calculated by dividing the Start-Up Offer by the Maximum Economic Capacity Operating Limit and by the Minimum Run Time rounded up to the nearest interval.

b. The no-load cost added to each breakpoint of the Energy Offer Curve is calculated by dividing the No-Load Offer by the Maximum Economic Capacity Operating Limit and by the ratio of the number of intervals needed to meet the Minimum Run Time to the number of intervals in an hour.

2. The application of the composite begins with the commitment interval and extends through the Minimum Run Time.

(c) In addition to dispatchable Bids and Offers, FSRs committed by the Transmission Provider, including FSRs committed at the request of a local transmission operator, but not including self-committed FSRs, will have their minimum operating limit relaxed to 0 MW.

For Day-Ahead Market and RTBM SCED, mitigation measures for Energy Offers and Operating Reserve Offers, described under Sections 3.2 and 3.4 of Attachment AF of this Tariff will be performed in the SCED pricing solution.

An FSRs composite Energy Offer Curve will be subject to the Energy offer cap described under Section 4.1.1 of this Attachment AE.

## 3.4 Violation Relaxation Limit Reporting

Each year, prior to November 1, the Transmission Provider will provide analysis as well as a set of proposed Violation Relaxation Limits ("VRLs") for review by the applicable working groups and committees as described in the Market Protocols. Each year by November 1, VRLs and their associated values shall be reviewed and approved by the SPP Board of Directors. Any changes to the VRLs or associated values must be approved by the Commission prior to their implementation. The most recent Commission approved VRLs and their associated values are listed in Addendum 1 to this Attachment AE.

## 3.5 Integrated Marketplace Pricing

The Transmission Provider shall calculate Day-Ahead Market and RTBM LMPs for Energy at each Settlement Location.

The Transmission Provider shall calculate the Reserve Zone Market Clearing Prices ("MCPs") for Regulation-Up Service, Regulation-Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, and Ramp Capability Down for the Day-Ahead Market and RTBM and Market Clearing Prices for Expected Regulation-Up Mileage and Expected Regulation-Down Mileage for the RTBM.

The Transmission Provider shall calculate annual and monthly Auction Clearing Prices ("ACPs") at each Settlement Location.

## 3.6 Integrated Marketplace Settlements

For both the Day-Ahead Market and the RTBM, the Transmission Provider shall calculate Energy and Operating Reserve settlement quantities at each Settlement Location, calculate charges and payments associated with the provision of Energy and Operating Reserve based upon the settlement quantities and the associated LMPs and MCPs for each Asset Owner and render invoices to Market Participants detailing net charges or payments associated with provision of Energy and Operating Reserve.

The Transmission Provider shall calculate charges and payments to ARR and TCR holders based upon the ARRs determined in the annual allocation and TCRs cleared in the annual and monthly TCR auctions. Such charges and payments shall be included on the Settlement Statements consistent with the timing of the Day-Ahead Market settlement and RTBM settlement.

## 3.7 Integrated Marketplace Participation Readiness

The Transmission Provider shall validate each Market Participant's ability to provide services for which the Market Participant has registered in the Integrated Marketplace. Such validation shall include verification that the Market Participant has met the technical and communications requirements specified in the Market Protocols and has met the credit requirements specified under Attachment X of this Tariff.

## 3.8 Integrated Marketplace Counterparty

3.8.1 The Integrated Marketplace Counterparty settles, collects and distributes all charges in the Integrated Marketplace; and is the contracting party, as a principal and not as an agent, with each Market Participant for that Market Participant's Integrated Marketplace agreements and transactions in the TCR Market, Day-Ahead Market, and Real-Time Balancing Market. Notwithstanding the above, the Integrated Marketplace Counterparty shall not be a contracting party as described under Section 3.8.3 of this Attachment AE.

3.8.2 The Integrated Marketplace Counterparty will serve as the counterparty to Transmission Congestion Rights ("TCRs") and Auction Revenue Rights ("ARRs") instruments held by a Market Participant. The Integrated Marketplace Counterparty shall be the contracting party with respect to the contractual rights and obligations of the holders of ARRs and TCRs.

3.8.3 Exclusions

3.8.3.1 The Transmission Provider's capacity as the Integrated Marketplace Counterparty shall not include agreements and transactions for Transmission Service, Network Integrated Transmission Service, or Ancillary Services under Schedules 1 and 2 provided pursuant to Parts II, III and IV, and related rate Schedules contained in the Tariff.

3.8.3.2 To the extent Market Participants conduct bilateral transactions with other Market Participants, self-commit or self-supply power and energy to the loads they serve, such bilateral transactions, self-commitment, self-scheduled, and self-supply arrangements are not transactions with the Integrated Marketplace Counterparty.

3.8.3.3 The Integrated Marketplace Counterparty shall not be a counterparty to bilateral agreements for the transfer of ARRs and TCRs between Market Participants.

## 3.9 Calculation of Net Benefits Test for Compensation of Demand Response Load

The Transmission Provider shall identify each month the price on a supply curve, representative of economic conditions expected for that month, at which the benefits of dispatching Demand Response Load exceed the costs of the load reductions to other loads ("Net Benefits Threshold"). In formulaic terms, the Net Benefits Threshold is deemed to be realized at the price point on the supply curve where the market price ("P") change attributable to dispatching Demand Response Load times the MWh consumed is greater than the new market price (after dispatching Demand Response Load) times the Demand Response Load, as set forth in the following formula:

(Delta P x MWh consumed) > ($P_{NEW}$ x Demand Response Load),

where Delta P = P before Demand Response Load is dispatched minus $P_{NEW.}$

The Transmission Provider shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. The Net Benefits Threshold shall be calculated using the following steps:

Step 1: Retrieve historical Integrated Marketplace offers for all hours of each day from the same calendar month (of the prior calendar year) for which the calculation is being performed.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the SPP Region for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 oil shall be priced at the Gulf Coast price, and coal shall be priced at the Powder River Basin price.

Step 3: Combine the offers to create an hourly supply curve for each hour in the period.

Step 4: Determine the average of each supply curve and then smooth each average supply curve by fitting the following function to the raw data using a non-linear, least-squares regression:

$$P(MW) = A + B * MW + C * MW^2 + D * MW^3 + e^{(E*MW+F)},$$

where *P(MW)* is the historical Integrated Marketplace offer price in $/MWh, and *MW* is cumulative capacity. *A* through *F* are the parameters to be estimated.

Step 5: Compute the price elasticity of the smoothed supply curves at each *MW* point, finding the threshold price for each supply curve at which elasticity falls below one for the duration of the curve.

Step 6: Compute the average of the threshold prices identified in Step 5. This is the Net Benefits Threshold for the month.

## 3.10 Electronic Delivery of Data to the Commission

The Transmission Provider will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the market that it administers, in accordance with the Commission's regulations.

## 3.11 Transparency Reporting Requirements

The following reports shall be compiled by the Transmission Provider monthly and posted on a publicly-accessible portion of its website, within the time frame specified for each report.

### 3.11.1 Zonal Uplift Report

Within 20 days of the end of each month, a report of uplift categories, paid in dollars, and categorized by Settlement Area and uplift category shall be compiled and posted. Uplift categories reported, broken out by day, will include: Day-Ahead Make Whole Payment Amount, Reliability Unit Commitment Make Whole Payment Amount, Real-Time Out-Of-Merit Amount, Real-Time Regulation Service Deployment Adjustment Amount, Unused Regulation-Up Mileage Make Whole Payment Amount, Unused Regulation-Down Mileage Make Whole Payment Amount, and Real-Time Reserve Sharing Group Amount. If any Settlement Area has fewer than four Resources, it may be aggregated with one or more neighboring Settlement Areas until each aggregated zone contains at least four Resources, and reported collectively.

### 3.11.2 Resource-Specific Uplift Report

Within 90 days of the end of each month, a report of the total amount of uplift paid in dollars aggregated across the month by Resource shall be compiled and posted. The report shall include the following uplift categories: Day-Ahead Make Whole Payment Amount, Reliability Unit Commitment Make Whole Payment Amount, Real-Time Out-of-Merit Amount, Real-Time Regulation Service Deployment Adjustment Amount, Unused Regulation-Up Mileage Make Whole Payment Amount, Unused Regulation-Down Mileage Make Whole Payment Amount, and Real-Time Reserve Sharing Group Amount.

### 3.11.3 Operator-Initiated Commitment Report

Within 30 days of the end of each month, a report of each operator-initiated commitment, listing the size of the commitment, Settlement Area, commitment reason, and commitment start time shall be compiled and posted. All commitments that are made for a reason other than to minimize the total production cost of serving load will be posted, including those made under the Day-Ahead Reliability Unit Commitment, Short-Term Reliability Unit Commitment, and Intra-Day Reliability Unit Commitment processes.

# 4.0 Pre-Day-Ahead Period Activities

## 4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to the close of the Day-Ahead Market and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

(1) Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM except that, if Regulation-Up Service and/or Regulation-Down Service is cleared in the Day-Ahead Market, Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources for use in the RTBM are set equal to the Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources submitted for use in the Day-Ahead Market;

(2) Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;

(a) Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of "not participating" as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.

(3) Submitted Resource Offers will automatically roll forward hour to hour within each respective market only when no Resource Offer has been submitted for that interval;

(4) Offers may be submitted that vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour of the subsequent Operating Day only when no unit commitment Offer parameters have been submitted for that Operating Day;

(5) Offers submitted for use in the RTBM are also used in the RUC;

(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location;

(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Regulation-Up Offers, Regulation-Up Mileage Offers, Spinning Reserve Offers and Supplemental Reserve Offers provided that if the Regulation-Up Offer is negative, the Regulation-Up Mileage Offer must equal zero. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Regulation-Down Offers and Regulation-Down Mileage Offers provided that if the Regulation-Down Offer is negative, the Regulation-Down Mileage Offer must equal zero. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. If a Spinning Reserve Offer is submitted for a Resource, and a Resource Offer for Supplemental Reserve is not submitted, then the Supplemental Reserve Offer is set equal to zero. Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve and/or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and

provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(c) Supplemental Qualified Resource:

(i) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(ii) Alternatively, an MCR may also become a Supplemental Qualified Resource by self-certifying that the MCR is capable of deploying 100% of cleared Supplemental Reserve through a transition to a higher capacity configuration within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;

(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

- Resource Name
- Resource Type
- Start-up Offer
- No-Load Offer
- Energy Offer Curve
- Transition State Offer (for an MCR)
- Transition State Time (for an MCR)
- Regulation–Up and Regulation-Down Offers
- Regulation-Up Mileage and Regulation-Down Mileage Offers

- Spinning and Supplemental Reserve Offers
- Sync-To-Min and Min-To-Off Times
- Start-Up Time
- Hot to Intermediate and Hot to Cold Times (not applicable to an MSR)
- Maximum Daily and Weekly Starts
- Maximum Daily Energy
- Maximum and Minimum Run Times
- Plant Minimum Down Time (for an MCR)
- Plant Minimum Run Time (for an MCR)
- Group Minimum Down Time (for an MCR)
- Group Minimum Run Time (for an MCR)
- Minimum Down Time
- Minimum Emergency Capacity Operating Limit and Run Time (not applicable to an MSR)
- Minimum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
- Maximum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
- Maximum Emergency Capacity Operating Limits and Run Time (not applicable to an MSR)
- Maximum Off-line Supplemental Reserve Response Limit
- Maximum Transition State Supplemental Reserve Resource Response Limit (for an MCR)
- Ramp-Rate-Up and Ramp-Rate-Down
- Turn-Around Ramp Rate Factor
- Regulation Ramp Rate
- Contingency Reserve Ramp Rate
- Resource Status
- Interest Percent Share
- State of Charge Forecast (MSR only)

- Maximum and Minimum State of Charge (MSR only)
- Maximum and Minimum Charge Limit (MSR only)
- Maximum and Minimum Discharge Limit (MSR only)
- Maximum and Minimum Charge Time (MSR only)
- Maximum and Minimum Discharge Time (MSR only)
- ESR Loss Factor (MSR only)
- Maximum and Minimum Emergency Charge Limit (MSR only)
- Maximum and Minimum Emergency Discharge Limit (MSR only)

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate;

(a) Whether they are self-committing a Resource;

(b) Whether the Resource may be committed by the Transmission Provider;

(c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue;

(d) Whether the Resource is on an outage; or

(e) Whether the Resource is not participating in the Day-Ahead Market.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:

(a) Eligible for Energy Dispatch;

(b) Eligible for Operating Reserve clearing; or

(c) Self-scheduled for Operating Reserve.

If the dispatch status for a Resource does not indicate it is eligible for Energy Dispatch, then such Resource shall not be subject to charges and credits calculated under Section 8.6.15 of this Attachment AE and shall not be subject to the deviation calculations under Sections 8.6.7(A)(2)(e) and 8.6.7(A)(2)(g) of this Attachment AE.

(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and

(13) The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.

### **4.1.1** Offer Caps and Floors

Submission of Energy Offer Curves, Start-Up Offers, No-Load Offers, and Operating Reserve Offers by Market Participants for use in the Day-Ahead Market and the RTBM shall be limited by the following Offer caps and floors:

(1) Safety-net Energy Offer cap = $1,000/MWh; Energy Offers greater than $1,000/MWh are subject to Section 3.2(F) of Attachment AF of this Tariff.

(2) Virtual Energy Offer Cap = $2,000/MWh;

(3) Import/Export Transaction Offer Cap = $2,000/MWh;

(4) Regulation-Up Service Offer cap = $500/MW;

(5) Regulation-Down Service Offer cap = $500/MW;

(6) Contingency Reserve Offer cap = $100/MW;

(7) Energy Offer floor = Negative $500/MWh;

(8) Regulation Service Offer floor = Negative $500/MW;

(9) Regulation-Up Mileage Offer floor = $0/MW;

(10) Regulation-Down Mileage Offer floor = $0/MW;

(11) Contingency Reserve Offer floor = Negative $100/MW;

(12) Start-Up Offer floor = $0;

(13) No-Load Offer floor = $0.

In addition to these Offer caps and floors, submission of Offers may be limited by the requirements of Attachment AF of this Tariff.

### 4.1.2 Additional Provisions for Non-Traditional Resources

#### 4.1.2.1 Demand Response Resources

(1) Dispatchable Demand Response Resource - A Dispatchable Demand Response Resource is modeled in the Commercial Model the same as any other Resource, except that the Settlement Location associated with the Dispatchable Demand Response Resource must contain the Price Node, or aggregated Price Node as described in Section 2.2(2) of this Attachment AE, associated with the Demand Response Load. The Market Participant must submit the Real-Time value of the Demand Response Load to the Transmission Provider via telemetering that meets the technical requirements specified in the Market Protocols. A Dispatchable Demand Response Resource shall submit Energy Offer Curves based on the criteria in Section 3.2(F) of Attachment AF of this Tariff. For purposes of these Resources, the short-run marginal cost may equal opportunity cost. A Dispatchable Demand Response Resource may select one of two options for reporting of the actual Dispatchable Demand Response Resource output:

(a) Submitted Resource production option:

The Dispatchable Demand Response Resource output is sent directly to the Transmission Provider by the Market Participant via telemetering for Real-Time operational purposes and the Meter Agent submits either five (5) minute or hourly actual output values to the Transmission Provider for use in settlements. The submitted Resource production option is only allowed for Demand Response Resources that are: (1) utilizing strictly Behind-The-Meter Generation to provide the response and are utilizing Real-Time metering capable of reporting both the Behind-The-Meter Generation output and the load; (2) Demand Response Resources where the Market Participant is offering the Resource under a retail tariff provision that includes near Real-Time measurement and verification terms that are compliant with the Business Practices for Measurement and Verification of Wholesale Electricity Demand Response of the North American Energy Standards Board, incorporated by reference in the

Commission's Regulations, 18 C.F.R. § 38.2(a)(12); or (3) Demand Response Load utilizing near Real-Time measurement and verification capability that is compliant with the Business Practices for Measurement and Verification of Wholesale Electricity Demand Response of the North American Energy Standards Board, incorporated by reference in the Commission's Regulations, 18 C.F.R. § 38.2(a)(12).

(b) Calculated Resource production option:

(i) For each Dispatch Interval in each hour in which the Demand Response Resource has been committed, the Demand Response Resource output for Real-Time operational purposes is calculated by the Transmission Provider as the greater of zero (0) or the difference between:

- The lesser of the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource or the hourly baseline as described in (3) below for the hour, and
- The actual value of the associated Demand Response Load received via telemetering.

(ii) For each Dispatch Interval in each hour in which the Demand Response Resource has been committed, the Demand Response Resource output for settlement purposes is calculated by the Transmission Provider as the maximum of zero (0) or the difference between:

- The lesser of the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource or the hourly baseline as described in (3) below for the hour, and

- The actual value of the associated Demand Response Load received from the Meter Agent either on a five (5) minute basis or an hourly basis.

(2) Block Demand Response Resource – A Block Demand Response Resource is modeled in the Commercial Model the same as any other Resource except that the Settlement Location associated with the Block Demand Response Resource must contain the Price Node, or aggregated Price Node as described in Section 2.2(2) of this Attachment AE, associated with the Demand Response Load. The Market Participant must submit the Real-Time value of the Demand Response Load to the Transmission Provider via telemetering that meets the technical requirements specified in the Market Protocols. All Block Demand Response Resources will use the calculated Resource production option, described in Section 4.1.2.1(1)(b) above, to determine the amount of Real-Time Resource production and actual Resource production.

(a) If the Block Demand Response Resource is committed and dispatched in the Day-Ahead Market, Day-Ahead RUC or Intra-Day RUC, the Block Demand Response Resource's Minimum Economic Capacity Operating Limit will be increased in the RTBM to match the dispatched amount. Spinning Reserve or Supplemental Reserve will be allowed to clear above minimum output if the Block Demand Response Resource is a Spin Qualified Resource and Supplemental Reserve will be allowed to clear above minimum output if the Block Demand Response Resource is a Supplemental Qualified Resource.

(b) Spinning Reserve and/or Supplemental Reserve clearing will be based upon submitted ramp rates for the Block Demand Response Resource, the submitted Spinning Reserve Offer, the Supplemental Reserve Offer and the Block Demand Response Resource's Maximum Economic Capacity Operating Limit.

(3) Hourly Baseline

(a) The Market Participant must submit an hourly baseline for the Demand Response Load indicating the level of energy consumption expected at

that location in MWh if the Demand Response Resource is not dispatched. The baseline must cover, at a minimum, all hours the Resource is submitting Offers for in the Energy and Operating Reserve Markets. This baseline must be submitted by 1100 hours on the day prior to the Operating Day and may be updated up to thirty (30) minutes in advance of the operating hour. The baseline should be based on the average of the hourly integrated Demand Response Load for the same hours in the last 30 calendar days when the Resource was not dispatched, adjusted by the Market Participant as necessary to account for changes in the expected level of energy consumption by the Demand Response Load.

(b) If there have been deviations in hourly integrated metered load from the hourly baseline during periods when the Resource was not dispatched the hourly baseline will be adjusted as follows by the Transmission Provider prior to the calculation of the Demand Response Load. If the average of the hourly deviation between integrated metered load and submitted hourly baseline for the hours in the last thirty (30) calendar days when the Resource was not dispatched is more than five percent (5%) below the hourly baseline, the hourly baseline will be adjusted by the average deviation. The Transmission Provider will perform this assessment each day and notify the Market Participant of any adjustment.

(c) If the hourly baseline has not been submitted, the Transmission Provider shall set the hourly baseline equal to the Real-Time consumption of the Demand Response Load associated with the Demand Response Resource in the Dispatch Interval immediately preceding initial commitment of the Demand Response Resource.

#### 4.1.2.2 Combined Cycle Resource

Market Participants shall select from one of the four following options regarding submitting Resource Offers for their registered combined cycle Resources, which will be declared during asset registration as described under Sections 2.2 and 2.9 of this Attachment AE:

(1) A Resource Offer may be submitted for a single aggregate combined cycle Resource, where the aggregate will represent a Market Participant selected operating configuration of combustion turbines and steam turbines. Under this option, the combined cycle Resource will be committed, dispatched and settled the same as any other Resource; or

(2) A Resource Offer may be submitted for each combined cycle Resource combustion turbine and/or steam turbine and each component will be committed and dispatched independently and settled the same as any other single Resource; or

(3) A Resource Offer may be submitted for each pseudo combined cycle Resource, where each pseudo combined cycle Resource will represent the combination of one combustion turbine and a portion of the steam turbine. Under this option, each pseudo combined cycle Resource must be capable of being committed and dispatched independently the same as any other Resource and each pseudo combined cycle Resource will be settled the same as any other Resource; or

(4) A Resource Offer may be submitted for each registered combined cycle configuration, where each configuration represents an operating state of the combined cycle Resource with a distinct set of physical operating characteristics, as dictated by the physical attributes of the combined cycle Resource. The Transmission Provider will determine the most economic commitment configuration, if requested to do so by the Market Participant as part of the submitted Resource Offer, and once committed, the most economic configuration to transition to for use in both the Day-Ahead Market and Real-Time Balancing Market. Settlement for a combined cycle Resource submitting offers in this manner will occur in the same manner as any other Resource except for Contingency Reserve during transitions as described under Section 8.5.9 of this Attachment AE and adjustments for Operating Reserves during transitions as described under Section 8.6.5 of this Attachment AE. Under this option, Market Participants must define during asset registration the:

(a) Valid configurations, one of which must represent the maximum capacity of the combined cycle Resource;

(b) Valid transitions between configurations as defined in the Market Protocols; and

(c) One or more sets of physical units that can participate in a configuration.

#### 4.1.2.3 Jointly Owned Unit

Under the individual Jointly Owned Unit Resource option, each Market Participant may submit Resource Offers for its share of the Jointly Owned Unit as specified in the Market Protocols. Offer parameters must meet the following criteria in order to be accepted as valid Offers, otherwise the last submitted valid offer shall apply:

(1) The sum of the Maximum Emergency Capacity Operating Limits of all shares of the Jointly Owned Unit must be less than or equal to the Jointly Owned Unit maximum physical capacity operating limit.

Commitment of individual Jointly Owned Unit shares that have registered under the individual Resource option will be evaluated by security constrained unit commitment ("SCUC") based on the individually submitted Offers for each Jointly Owned Unit share.

#### 4.1.2.4 Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that:

(1) The minimum operating limits specified in the Resource Offer must be equal to zero;

(2) The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource

Offer or the Transmission Provider's output forecast for that Resource to the extent that such output forecast is available;

a) Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.

(3) For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of less than two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed forty (40) MWs;

(4) For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of greater than or equal to two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed twenty percent (20%) of the maximum capability;

(5) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to reduce output, the Resource's Setpoint Instruction shall be equal to the sum of the Resource's Dispatch Instruction and any Regulation-Down deployment;

(6) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to increase output in Dispatch Intervals immediately following a Dispatch Interval in which a Dispatch Instruction was issued to reduce output as described in Section 4.1.2.4(5) of this Attachment AE, the Transmission Provider shall calculate the Resource maximum operating limit to be equal to:

(a) The lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource to the

extent the such forecast is available, except that, the Transmission Provider's output forecast for the Resource shall be used for the maximum operating limits when: (i) maximum operating limits have not been submitted; (ii) the maximum operating limits submitted in the Resource Offer were not updated during the Operating Hour prior to the Operating Hour in which the Resource limit would apply but before the lead time described in Section 4.1 of this Attachment AE; or (iii) the maximum operating limits submitted in the Resource Offer exceed the maximum physical rating of the Resource as stated during market registration; or

(b) The maximum operating limits submitted in the Resource Offer if the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource is not available.

The Transmission Provider shall continue to calculate such maximum operating limits for each subsequent Dispatch Interval until the maximum operating limit is equal to the lesser of the Transmission Provider's Dispatchable Variable Energy Resource output forecast for that Resource or the maximum operating limit submitted in the Resource Offer, after which, the Dispatchable Variable Energy Resource's maximum operating limit shall be calculated as described in Section 4.1.2.4(7) of this Attachment AE.

(7) For the RTBM, during times other than those times described under Section 4.1.2.4(6) of this Attachment AE, the Resource's maximum operating limit for use in the current Dispatch Interval shall be equal to the Resource's actual output at the start of the Dispatch Interval and the ramping restrictions described under Sections 4.1.2.4(3) and (4) of this Attachment AE shall not apply.

(8) Dispatchable Variable Energy Resources may also receive an OOME according to the rules in Section 6.2.4 of this Attachment AE.

### 4.1.2.5 Non-Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Non-Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that

(1) The minimum operating limits specified in the Resource Offer must be equal to zero;

(2) For the RTBM, the Resource's Energy Offer Curve shall not apply;

(3) For the RTBM, the Resource's Dispatch Instruction shall be equal to the Resource's actual output at the start of the Dispatch Interval and the Resources must operate as non-dispatchable;

(4) Resource Energy Offer Curve prices shall be assumed equal to zero (0) for the purposes of calculating production costs relating to RUC make whole payments and cost allocation thereof under Sections 8.6.5 and 8.6.7 of this Attachment AE;

(5) An OOME may be issued to a Non-Dispatchable Variable Energy Resource. In addition, the Transmission Provider will issue the dispatch instruction to the Resource in accordance with Section 6.2.4 of this Attachment AE; and

(6) The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider's output forecast for that Resource to the extent that such output forecast is available, otherwise the maximum operating limits shall be equal to those submitted in the Resource Offer;

(a) Non-Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.

#### 4.1.2.6 External Dynamic Resource

Each Market Participant may submit Resource Offers for External Dynamic Resources ("EDR") using the same Offer parameters available to any other Resource, except that:

(1) A Market Participant may only submit a commitment status as defined in Section 4.1(10)(a) or (d) of this Attachment AE;

(2) For an EDR in the Eastern Interconnection, a Market Participant must submit a dispatch status indicating that the EDR is not available for energy dispatch as described under Section 4.1(11)(a) of this Attachment AE;

(3) For an EDR in the Eastern Interconnection, Resource Offer parameters are limited to: Regulation-Up and Regulation-Down Offers, Spinning and Supplemental Reserve Offers, Regulation Ramp Rate, Contingency Reserve Ramp Rate and Resource Status. All other Resource Offer parameters as listed in Section 4.1(9) of this Attachment AE shall not apply to EDRs in the Eastern Interconnection.

(4) For an EDR that is not in the Eastern Interconnection, Resource Offer parameters are limited to: Energy Offer Curve, Ramp-Rate-Up, Ramp-Rate-Down, Regulation-Up and Regulation-Down Offers, Spinning and Supplemental Reserve Offers, Regulation Ramp Rate, Contingency Reserve Ramp Rate and Resource Status. All other Resource Offer parameters as listed in Section 4.1(9) of this Attachment AE shall not apply to EDRs that are not in the Eastern Interconnection.

## 4.2 Provisions for Non-Resource Related Offers

### 4.2.1 Virtual Energy Offers

(1) Virtual Energy Offers are submitted in the Day-Ahead Market only.

(2) A Virtual Energy Offer consists of an Energy Offer Curve only.

(3) A Market Participant may submit no more than one Virtual Energy Offer for itself at each Settlement Location for each Operating Hour. Where a Market Participant represents multiple Asset Owners, the Market Participant may submit no more than one Virtual Energy Offer for each Asset Owner it represents at each Settlement Location for each Operating Hour.

(4) Virtual Energy Offers may be submitted up to $2,000/MWh and are not subject to cost verification.

### 4.2.2 Import Interchange Transaction Offers

(1) The MW amount of Import Interchange Transactions will be limited on a Dispatch Interval basis by the amount of the Transmission Provider system ramping capability available. A Market Participant must use the Transmission Provider ramp reservation system as described in the Market Protocols to ensure there is sufficient ramp to accommodate its transaction. An Import Interchange Transaction Offer must have an associated Transmission Service reservation. There are three types of Import Interchange Transaction Offers:

(a) A fixed Offer – Specifies a MW amount that will be cleared regardless of the price at the External Interface Settlement Location. If the fixed Import Interchange Transaction is submitted for use in the Day-Ahead Market, it will be cleared in the Day-Ahead Market and automatically roll forward as a fixed schedule for use in RUC and the RTBM. If specified for use in the RTBM only, the fixed Import Interchange Transaction will be considered a fixed schedule for the Day-Ahead RUC, Intra-Day RUC and RTBM.

(b) A Dispatchable Offer - Specifies both a MW amount and a minimum dollars per MW hour price that the Market Participant must be paid if the transaction clears the Day-Ahead Market. Dispatchable Offers are only available for use in the Day-Ahead Market and cannot be submitted for use in the RTBM. Import Interchange Transactions may be submitted up to $2,000/MWh and are not subject to cost verification. If the transaction clears the Day-Ahead Market, it automatically rolls forward as a fixed schedule for use in Day-Ahead RUC, Intra-Day RUC and the RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule.

(c) An up-to-transmission usage charge Offer - Specifies both a MW amount and the combined maximum amount of congestion cost and marginal loss cost between the specified Source and Sink Settlement Location that the Market Participant is willing to pay if the transaction clears the Day-Ahead Market. Up-to-transmission usage charge Offers are only available for use in the Day-Ahead Market and cannot be submitted for use in the

RTBM. If the transaction clears the Day-Ahead Market, it automatically rolls forward as a fixed schedule for use in the Day-Ahead RUC, Intra-Day RUC and RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule.

(2) All Import Interchange Transactions from a source located in Canada shall be deemed to have a point-of-receipt at the U.S./Canada border. For purposes of this Section 4.2.2(2), the point-of-receipt must be located at an interconnection between a transmission facility under the functional control of the Transmission Provider and a transmission facility operated by a Canadian transmission service provider.

## 4.3 Bid Submittal

(1) Beginning seven (7) days prior to the Operating Day, Market Participants may submit Demand Bids and Virtual Energy Bids for the purchase of Energy in the Day-Ahead Market.

(2) Beginning seven (7) days prior to the Operating Day, Market Participants may submit Export Interchange Transaction Bids for the purchase of Energy in the Day-Ahead Market or RTBM.

(3) Submitted Bids do not roll forward hour to hour.

(4) Demand Bids may only be submitted at load Settlement Locations.

(5) Export Interchange Transaction Bids may only be submitted at External Interface Settlement Locations.

(6) Virtual Energy Bids may be submitted at any Settlement Location.

(7) Bid submittal associated with a load pseudo-tied out of the SPP Balancing Authority is not permitted.

### 4.3.1 Demand Bids

(1) Only Market Participants with registered physical load assets may submit Demand Bids for use in the Day-Ahead Market.

(2) A Market Participant can submit Demand Bids only at Settlement Locations where its physical load assets are registered.

(3) A Market Participant is not permitted to submit a Demand Bid for a load asset pseudo-tied out of the SPP Balancing Authority.

(4) A fixed Demand Bid is a specified MW that will be cleared in the Day-Ahead Market regardless of the price at the load Settlement Location based on the start and stop time submitted for the applicable Operating Day.

(5) A price sensitive Demand Bid is specified as a Demand Bid Curve. A price sensitive Demand Bid will clear when the price at the applicable load Settlement Location is less than or equal to the specified Demand Bid Curve price for that Operating Hour.The maximum MW amount that can be cleared is equal to the highest Megawatt quantity submitted in the Demand Bid Curve . The minimum MW amount that can be cleared is equal to zero.

### 4.3.2 Virtual Energy Bids

(1) Virtual Energy Bids may be submitted in the Day-Ahead Market only.

(2) Virtual Energy Bids only apply to Energy, are not associated with a physical load asset and can be submitted at any Settlement Location in the form of a Virtual Energy Bid Curve.

(3) A Market Participant may submit no more than one Virtual Energy Bid at each Settlement Location for each Operating Hour. Where a Market Participant represents multiple Asset Owners, the Market Participant may submit no more than one Virtual Energy Bid for each Asset Owner it represents at each Settlement Location for each Operating Hour.

(4) Virtual Energy Bids may be submitted up to $2,000/MWh and are not subject to cost verification.

### 4.3.3 Export Interchange Transaction Bids

(1) Market Participants may submit bids to purchase Energy from the Day-Ahead Market for sale outside of the SPP Balancing Authority Area. A Market Participant must reserve Transmission Service prior to submittal of the Bid. There are three types of Export Interchange Transaction Bids:

(a) A fixed Bid:

Specifies a MW amount that will be cleared regardless of the price at the External Interface Settlement Location. If the fixed Export Interchange Transaction is submitted for use in the Day-Ahead Market, it will be cleared in the Day-Ahead Market and automatically roll forward as a fixed schedule for use in RUC and the RTBM. If specified for use in the RTBM only, the fixed Export Interchange Transaction will be considered a fixed schedule for the Day-Ahead RUC, Intra-Day RUC and RTBM;

(b) A dispatchable Bid:

Specifies both a MW amount and a maximum price that the Market Participant is willing to pay if the transaction clears the Day-Ahead Market. Dispatchable Bids are only available for use in the Day-Ahead Market and cannot be submitted for use in the RTBM only. Export Interchange Transactions may be submitted up to $2,000/MWh and are not subject to cost verification. If the transaction clears the Day-Ahead Market, it automatically rolls forward as a fixed schedule for use in the Day-Ahead RUC, Intra-Day RUC and the RTBM. Any adjustment to the schedule will be settled in the RTBM as a deviation from the Day-Ahead Market schedule; and

(c) An up-to transmission usage charge Bid:

Specifies both a MW amount and the combined maximum amount of congestion cost and marginal loss cost the Market Participant is willing to pay if the transaction clears the Day-Ahead Market. Up-to transmission usage charge Bids are only available for use in the Day-Ahead Market. If the transaction clears the Day-Ahead Market, it automatically rolls forward as a fixed schedule for use in the Day-Ahead RUC, Intra-Day

RUC and RTBM. Any adjustment to the schedule will be settled as a deviation in the RTBM from the Day-Ahead Market schedule.

(2) The total MW amount of Export Interchange Transactions is limited on a Dispatch Interval basis by the amount of the Transmission Provider system ramping capability available. A Market Participant must use the Transmission Provider ramp reservation system as described in the Market Protocols to ensure there is sufficient ramp to accommodate its transaction.

(3) An Export Interchange Transaction Bid is eligible to reduce a Market Participant's Supplemental Reserve obligation subject to meeting the eligibility requirements under subsections (a) through (c) below. The reduction to a Market Participant's Supplemental Reserve obligation will be the lesser of (i) the reduction in the system requirement based on the delivery of reserve energy provided by the curtailment of the export schedule as determined by the Transmission Provider; or (ii) the Market Participant's Supplemental Reserve obligation. The reduction, if applied, will be proportional to the Market Participant's zonal Supplemental Reserve obligations,

(a) The Export Interchange Transaction Bid must be fixed and submitted for use in the Day-Ahead Market and cannot be submitted for use in the RTBM only;

(b) The Export Interchange Transaction must be fully recallable within a ten (10) minute period for the amount of Supplemental Reserve specified;

(c) Supplemental Reserve supplied by an Export Interchange Transaction in excess of the Market Participant's Supplemental Reserve obligation within the applicable Reserve Zone will not be eligible for payment; and

(d) Provision of Supplemental Reserve from an Export Interchange Transaction Bid is limited to Export Interchange Transactions associated with DC tie-lines.

(4) All Export Interchange Transactions to serve load located in Canada shall be deemed to have a point-of-delivery at the U.S./Canada border. For purposes of this Section 4.3.3(4), the point-of-delivery must be located at an interconnection between a transmission facility under the functional control of the Transmission

Provider and a transmission facility operated by a Canadian transmission service provider.

## 4.4 Through Interchange Transactions

Market Participants may submit Through Interchange Transactions in the Day-Ahead Market, RTBM or both. A Market Participant must reserve Transmission Service prior to submittal of the schedule in accordance with the procedures specified in the OATT Business Practices in an amount sufficient to cover the request. There are two types of Through Interchange Transactions:

(1) Fixed transaction:

Defines a specific MW amount that will be cleared regardless of the price at either of the External Interface Settlement Locations. If submitted for use in the Day-Ahead Market, a fixed Through Interchange Transaction will automatically roll forward as a fixed schedule for use in RUC and the RTBM. If submitted for use in the RTBM, the fixed Through Interchange Transaction will clear in the RTBM and will be considered a fixed schedule for use in the Day-Ahead RUC and the Intra-Day RUC; and

(2) Up-to transmission usage charge transaction:

Specifies both a specific MW amount and the combined maximum amount of congestion cost and marginal loss cost the Market Participant is willing to pay if the transaction clears the Day-Ahead Market. Up-to transmission usage charge Through Interchange Transactions are only available for use in the Day-Ahead Market. If the transaction clears the Day-Ahead Market, it will automatically roll forward as a fixed schedule for use in the Day-Ahead RUC, the Intra-Day RUC and the RTBM.

(3) All Through Interchange Transactions with a source or load located in Canada shall be deemed to have an External Interface, respectively, at the U.S./Canada border. For purposes of this Section 4.4(3), the External Interface must be located at an interconnection between a transmission facility under the functional control of the Transmission Provider and a transmission facility operated by a Canadian transmission service provider.

## 4.5 Multi-Day Reliability Assessment

The Multi-Day Reliability Assessment identifies Resources that must be given Commitment Instructions prior to completion of the Day-Ahead RUC in order for such Resources to be available in the applicable Operating Day. Each day, the Transmission Provider will perform a Multi-Day Reliability Assessment for at least three (3) days prior to the Operating Day, to assess capacity adequacy for each Operating Day. The purpose of the Multi-Day Reliability Assessment is to evaluate the need to issue Commitment Instructions to start-up for Resources that cannot be committed in the Day-Ahead RUC because of their long lead times.

### 4.5.1 Multi-Day Reliability Assessment Inputs

Inputs to the Multi-Day Reliability Assessment will include the following:

(1) RTBM Resource Offers;

(2) Estimated fixed Export Interchange Transaction Bids;

(3) Estimated fixed Import Interchange Transaction Offers;

(4) Estimated Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum) based on historical requirements;

(5) Transmission Provider load forecast;

(6) Transmission Provider wind Resource MWh output forecast;

(7) Transmission Provider's estimate of Parallel Flows;

(8) Transmission System topology with approved Transmission System outages; and

(9) Actual and approved scheduled Resource outages as documented in the Transmission Provider's outage scheduler.

### 4.5.2 Multi-Day Reliability Assessment Analysis

Using the inputs described above, the Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day as follows:

(1) The Transmission Provider will calculate a Transmission Provider system requirement for each hour of the Operating Day as the sum of (a) Transmission Provider load forecast, (b) fixed Interchange Transaction Bids, (c) Regulation-Up requirement and (d) the Contingency Reserve requirement in each hour reduced by the wind Resource output forecast;

(2) The Transmission Provider will then calculate available Resource capacity in each hour as the sum of (a) Maximum Emergency Capacity Operating Limit, Maximum Emergency Discharge Limit, or Minimum Emergency Charge Limit, as applicable, for Resources other than long lead time Resources that are not on an approved Transmission Provider outage as submitted as part of the Resource Offer and (b) fixed Import Interchange Transaction Offers;

(3) For each hour of the Operating Day, the Transmission Provider will then compare the values calculated under (1) above and (2) above. If in any hour of the Operating Day, the values calculated under (1) above exceed the values calculated under (2) above, the Transmission Provider will commit available long lead time Resources on an economic basis to eliminate the deficiency as follows:

(a) For each available long lead time Resource, the Transmission Provider will calculate a commitment cost in dollars that is equal to:

(i) The sum of 1) the Resources Start-Up Offer, 2) the Resource's No-Load Offer multiplied by the greater of the Resource's Minimum Run Time (in hours) or the number of hours the Resource would be committed ignoring the Minimum Run Time, and 3) the Resources average cost to operate at Minimum Economic Capacity Operating Limit, Minimum Discharge Limit or Minimum Charge Limit, as applicable and as calculated from the Resource's Energy Offer Curve, multiplied by the greater of the Resource's Minimum Run

Time (in hours), Minimum Discharge Time or Minimum Charge Time, as applicable, or the number of hours the Resource would be committed ignoring the Minimum Run Time, Minimum Discharge Time or Minimum Charge Time, as applicable.

(ii) The Transmission Provider will then create a merit order list starting with the least cost Resource based upon the commitment cost calculated in (i) above. The Transmission Provider will then select Resources for commitment in merit order until sufficient capacity is committed to relieve the anticipated capacity shortage with the objective of minimizing the total capacity committed to meet the anticipated shortage at the lowest overall commitment cost.

Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

(4) The Transmission Provider may also commit Resources to address Transmission System related reliability problems. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

(5) The Transmission Provider may also commit Resources as part of Conservative Operations as defined in the Emergency Operating Plan posted on the Transmission Provider's website. Such commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE.

### 4.5.3 Multi-Day Reliability Assessment Results

The Transmission Provider will communicate the Commitment Instructions resulting from the Multi-Day Reliability Assessment to the affected Market Participants. At the time of this notification, the submitted Offers become binding and the selected Resource(s) Offers are committed in the Day-Ahead Market. Multi-Day Reliability Assessment Resources committed by the Transmission Provider will be eligible for Day-Ahead Market make whole payment guarantees. Resources committed as part of the Multi-Day Reliability Assessment during Conservative Operations as described under Section 4.5.2(5) of this Attachment AE may only be de-committed by the Transmission Provider to address an Emergency Condition pursuant to Sections 5.2.3 and 6.1.3 of this Attachment AE.

# 5.0 Day-Ahead Period Activities

## 5.1 Day-Ahead Market

The Transmission Provider shall conduct the Day-Ahead Market as described in the Subsections below. Offers and Bids must be submitted by the close of the Day-Ahead Market which is 0930 hours Day-Ahead. The Transmission Provider shall post the Day-Ahead Market results from the SCED dispatch solution, described in Section 3.3.1 of this Attachment AE, by 1300 hours Day-Ahead. The Transmission Provider will post the Day-Ahead Market LMP and MCP results from the SCED pricing solution, described in Section 3.3.1 of this Attachment AE after the posting of the dispatch solution results. The Transmission Provider may extend these times to account for unforeseen circumstances and, under such circumstances, the Transmission Provider shall notify Market Participants of any such timing delays.

### 5.1.1 Day-Ahead Market Inputs

Inputs to the Day-Ahead Market will include the following:

(1) Day-Ahead Market Resource Offers, Virtual Energy Offers, Demand Bids and Virtual Energy Bids;

(2) Resource Offers for long lead time Resources selected by the Transmission Provider for commitment during the Multi-Day Reliability Assessment process;

(3) Through Interchange Transactions with confirmed Transmission Service reservations;

(4) Export Interchange Transaction Bids with confirmed Transmission Service reservations;

(5) Import Interchange Transaction Offers with confirmed Transmission Service reservations;

(6) Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);

(7) Transmission System topology consistent with the Network Model in place for the upcoming Operating Day;

(8) Actual and approved scheduled Transmission System outages as documented in the Transmission Provider's outage scheduler;

(9) Actual and approved scheduled Resource outages as documented in the Transmission Provider's outage scheduler;

(10) The Transmission Provider's estimate of Parallel Flows; and

(11) Instantaneous Load Capacity requirements.

### 5.1.2 Day-Ahead Market Execution

The Transmission Provider will employ a simultaneous co-optimization methodology to perform the following tasks in order to clear the Day-Ahead Market for each hour of the upcoming Operating Day:

(1) Commit Offered Resources, Import Interchange Transaction Offers and Virtual Energy Offers using the SCUC algorithm to meet the Demand Bids, Virtual Energy Bids, Export Interchange Transactions Bids, Instantaneous Load Capacity requirements, and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day.

(a) The Day-Ahead Market SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, including Resources committed in the Multi-Day Reliability Assessment, up to the Resources' Maximum Economic Capacity Operating Limit (Maximum Discharge Limit or Minimum Charge Limit, when applicable, for MSRs) or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up Service and/or Regulation-Down Service, and down to the Resources' Minimum Economic Capacity Operating Limit (Maximum Charge Limit or Minimum Discharge Limit, when applicable, for MSRs) or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down Service and/or Regulation-Up Service. In addition, an MCR is not eligible to be selected for Regulation-Down Service and/or Regulation-Up Service in any hour in which it is transitioning between configurations.

(i) If this capacity is not sufficient to meet the fixed Demand Bids and fixed Export Interchange Transaction Bids, the upper bound of Instantaneous Load Capacity requirement, and Operating Reserve requirements on a system-wide basis, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) incorporate capacity up to Resources'

Maximum Emergency Capacity Operating Limits, Maximum Emergency Discharge Limit, and down to Minimum Emergency Charge Limit, as applicable, and/or commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible, and/or de-commit Self-Charging MSR.

(ii) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transaction Offers, the lower bound of Instantaneous Load Capacity requirement, Regulation-Down requirement, and the Ramp Capability Down requirement that is in excess of the sum of fixed Demand Bids and fixed Export Interchange Transaction Bids, the Day-Ahead Market SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; and (2) incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limit, and Maximum Emergency Charge Limit until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement, and/or commit any MSR available for charging designated as "reliability" use only, as described in Section 4.1(10)(c) of this Attachment AE.

(b) To the extent that a particular security constraint impacting only the Transmission System cannot be directly addressed within the Day-Ahead Market SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such a Transmission System security constraint in accordance with its authority as Reliability Coordinator. Such manual commitments shall be selected

by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Additionally, such manual commitments shall be selected by the Transmission Provider to ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the Day-Ahead Market Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.5.9 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.5.10 of this Attachment AE.

(c) A Local Reliability Issue or Local Emergency Condition may need to be addressed during the Day-Ahead Market process. Local Reliability Issues, either initially recognized directly as part of the Day-Ahead Market process or previously recognized and committed as part of any Reliability Unit Commitment process, may require manual commitment or decommitment to one or more Resources in the Day-Ahead Market to recognize or continue to recognize the Local Reliability Issue. A Local Emergency Condition previously recognized and committed as part of any Reliability Unit Commitment process may require manual commitment or decommitment to one or more Resources in the Day-Ahead Market to continue to recognize the Local Emergency Condition. In the case where a Local Reliability Issue Commitment is initiated directly as part of the Day-Ahead Market process, the Transmission Provider shall issue or the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider, at the request of a local transmission operator, initially issues or continues to issue instructions to a Resource to address a

Local Reliability Issue or continues to issue instructions to a Resource to address a Local Emergency Condition, such Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.5.9 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(d) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider, including such commitments made at the request of the local transmission operator to relieve known and recurring Local Reliability Issues in the Day-Ahead Market. Such Resources will be compensated in the same manner as any other Resource. The recovery of such compensation paid by the Transmission Provider for such committed Resources under Section 8.5.9 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(e) The Transmission Provider will re-run the Day-Ahead SCUC algorithm after any manual commitments, time permitting, if such manual commitments were not included in the initial run and will notify the Market Participants that units were manually committed.

(2) Using the Resource commitment results from the SCUC, clear Resource Offers, Virtual Energy Offers and Import Interchange Transaction Offers to meet Demand Bids, Virtual Energy Bids, Export Interchange Transaction Bids and Operating Reserve requirements on a least cost basis for each hour of the upcoming Operating Day using the SCED algorithm as described in Section 3.3.1 of this Attachment AE.

(a) The SCED algorithm includes marginal loss sensitivity factors that approximate the change in marginal system losses for a change in Energy dispatch.

(b) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED as described in Section 8.3.2 of this Attachment AE.

(c) Use of co-optimization logic will provide, through the Shadow Price calculation, MCPs for Operating Reserve that include any lost opportunity costs incurred as a result of Operating Reserve clearing.

(d) An MCR with a Transition State Time greater than 30 minutes in any hour in which it is transitioning between configurations is not eligible to clear Operating Reserve.

### 5.1.2.1 Clearing During Capacity Shortage

(1) In the event of an Operating Reserve shortage in any hour, Scarcity Pricing shall be implemented.

(2) In the event of a capacity shortage to meet the fixed Demand Bids, fixed firm Export Interchange Transactions, and Resources' charge MWs in any hour, the fixed Demand Bids, fixed firm Export Interchange Transactions, and Resources' charge MWs will be reduced on a pro-rata reduction basis based on the MW amounts to match the available capacity and Scarcity Pricing shall be implemented.

(3) If a transmission constraint cannot be relieved due to a shortage of capacity in any hour, the SCED algorithm will clear the bid-in demands on a pro-rata basis based upon the impact on relieving the constraint.

### 5.1.2.2 Clearing During Excess Generation Conditions

In the event the sum of the Minimum Emergency Capacity Operating Limits on self-committed Resources plus Minimum Emergency Discharge Limits on self-discharging MSRs plus Maximum Emergency Charge Limits for Self-Charging MSRs plus the Regulation-Down requirement plus the Ramp Capability Down requirement is in excess of the cleared bid-in demands in any hour, the SCED algorithm will reduce Resources on a pro-rata reduction basis such that the resulting sum of minimum limits

matches the bid-in demand. LMPs will be set by the Offer prices associated with Energy down to the Minimum Emergency Capacity Operating Limit, Minimum Emergency Discharge Limit, and Maximum Emergency Charge Limit to the extent that the Regulation-Down requirement can be maintained. If the actions under Section 5.1.2(1)(a)(ii) of this Attachment AE above create an Operating Reserve shortage (Regulation-Down Service and/or Ramp Capability Down) during any hour either on a system-wide basis or Reserve Zone basis, the MCPs for the Operating Reserve(s) with the shortage will reflect Scarcity Prices and LMPs will reflect negative Scarcity Prices as set by the Operating Reserve(s)' Demand Curve price described under Section 8.3.4.2 of this Attachment AE.

### 5.1.3 Day-Ahead Market Results

The Transmission Provider will notify each Market Participant of the Day-Ahead Market results for each hour of the Operating Day.

A. The following results are communicated to each Market Participant for only its specific Resources, no later than the posting of the Day-Ahead Market:

(1) Cleared Resource quantities for Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, or Ramp Capability Down;

(a) Cleared Offers for Energy associated with Resource Offers represent a physical Resource commitment.

(b) Resources committed by the Transmission Provider in the Day-Ahead Market that incur one or more start-up costs within the Operating Day as a result of the Transmission Provider Day-Ahead Market commitment are guaranteed to receive revenues that are at least equal to the Resource Offer costs for the cleared amount of Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve or Supplemental Reserve for that Resource.

(c) Cleared Regulation-Up Service MWs represent only those MWs cleared to meet the Regulation-Up Service requirement.

(d) Cleared Regulation-Down Service MWs represent only those MWs cleared to meet the Regulation-Down Service requirement.

(e) Cleared Spinning Reserve MWs represent the Spinning Reserve MWs cleared to meet the Spinning Reserve requirement and Regulation-Up Service MWs cleared to meet the Spinning Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(f) Cleared Supplemental Reserve MWs represent the sum of Supplemental Reserve MWs cleared to meet the Supplemental Reserve requirement and Regulation-Up Service MWs and Spinning Reserve MWs cleared to meet the Supplemental Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(g) Cleared Ramp Capability Up MWs represent only those MWs cleared to meet the Ramp Capability Up requirement.

(h) Cleared Ramp Capability Down MWs represent only those MWs cleared to meet the Ramp Capability Down requirement.

(2) Cleared Virtual Energy Offers;

(3) Cleared Import Interchange Transaction Offers;

(4) Cleared Demand Bids;

(5) Cleared Virtual Energy Bids;

(6) Cleared Export Interchange Transaction Bids; and

(7) Cleared Through Interchange Transactions.

B. The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution results:

(1) LMPs for each Settlement Location, the marginal Energy component ("MEC") of the LMP, the Marginal Congestion Component ("MCC") of the LMP and the Marginal Loss Component ("MLC") of the LMP for each Settlement Location; and

(2) MCPs for Regulation-Up Service, Regulation-Down Service, Spinning Reserve and Supplemental Reserve for each Reserve Zone.

## 5.2 Day-Ahead Reliability Unit Commitment

The Transmission Provider will begin the Day-Ahead RUC by 1345 or 45 minutes following the posting of the Day-Ahead Market results, whichever is later, to assess capacity adequacy during the Day-Ahead period and the remainder of the current Operating Day.

### 5.2.1 Day-Ahead Reliability Unit Commitment Inputs

Inputs to the Day-Ahead RUC will include the following:

(1) RTBM Resource Offers;

(2) Confirmed cleared Export Interchange Transaction Bids from the Day-Ahead Market;

(3) Confirmed cleared Import Interchange Transaction Offers from the Day-Ahead Market;

(4) Confirmed cleared Through Interchange Transactions from the Day-Ahead Market;

(5) Confirmed Export Interchange Transactions specified for use in the RTBM only;

(6) Confirmed Import Interchange Transactions specified for use in the RTBM only;

(7) Confirmed Through Interchange Transactions specified for use in the RTBM only;

(8) Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);

(9) Transmission Provider load forecast;

(10) Transmission System topology consistent with Network Model in place for the upcoming Operating Day;

(11) Resource commitment schedules from the Day-Ahead Market unless the Transmission Provider is informed by the Market Participant that the Resource is unable to meet its Day-Ahead Market cleared Resource Offers.;

(12) Commitment schedules for long lead time Resources selected in the Multi-Day Reliability Assessment unless the Transmission Provider is informed by the Market Participant that the Resource is unable to meet its commitment schedule;

(13) The Transmission Provider’s wind Resource MWh output forecast;

(14) Actual and approved scheduled Transmission System outages as documented in the Transmission Provider’s outage scheduler;

(15) Actual and approved scheduled Resource outages as documented in the Transmission Provider’s outage scheduler;

(16) The Transmission Provider’s estimate of Parallel Flows;

(17) Instantaneous Load Capacity requirements; and

(18) Operator input.

### 5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider load forecast, Export Interchange Transactions, Instantaneous Load Capacity requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources' Maximum Economic Capacity Operating Limit, Maximum Discharge Limit, or Minimum Charge Limit, or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up and/or Regulation-Down Service, and down to the Resources' Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Maximum Charge Limit, or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down and/or Regulation-Up Service. In addition, an MCR is not eligible to be selected for Regulation-Down Service and/or Regulation-Up Service in any hour in which it is transitioning between configurations.

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider load forecast, Export Interchange Transactions, the upper bound of Instantaneous Load Capacity requirement, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources' Maximum Emergency Capacity Operating Limits, Maximum Emergency Discharge Limit, or Minimum

Emergency Charge Limit, commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement, (3) de-commit charging Resources that were committed in the Day-Ahead Market with a commitment status of "market" as described in Section 4.1(10)(b) of this Attachment AE until the capacity shortage is eliminated, and (4) de-commit self-committed charging Resources.

(b) If there is a capacity surplus on a system-wide basis calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, the lower bound of Instantaneous Load Capacity requirement, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transactions, the SCUC algorithm will, in priority order: (1) curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limit, or Maximum Emergency Charge Limit until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) commit any available Resource with a commitment status of "reliability" as described in Section 4.1(10)(c) of this Attachment AE that is capable of charging, (4) de-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (5) de-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular security constraint impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such a Transmission System security constraint in accordance with its

authority as Reliability Coordinator. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Additionally, such manual commitments shall be selected by the Transmission Provider to ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Day-Ahead Reliability Unit Commitment process. Such Local Reliability Issues may require manual commitment or decommitment to be issued to one or more Resources to resolve the reliability issue. In such cases, the Transmission Provider shall issue or the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider, at the request of a local transmission operator, issues instructions to a Resource to address a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(5) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider, including such commitments made at the request of the local transmission operator to relieve known and recurring Local Reliability Issues in the Day-Ahead RUC. Such Resources will be compensated in the same

manner as any other Resource. The recovery of such compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

### 5.2.3 Day-Ahead Reliability Unit Commitment Results

No later than two-and-one-half (2.5) hours following the start of the Day-Ahead RUC, the Transmission Provider shall communicate the following results to Market Participants. The Transmission Provider will update the Current Operating Plan, if needed, and issue start-up and/or shut-down orders simultaneously, which may occur anytime after the Transmission Provider posts the results of the Day-Ahead RUC. The Day-Ahead RUC results include:

(1) For any future hours in which the Transmission Provider anticipates an emergency situation, the Transmission Provider shall notify all Market Participants identifying: the hours in which the emergency capacity of any Resources are expected to be required; the hours in which Resources are identified for reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, are expected to be committed; the hours in which non-firm fixed Export Interchange Transactions are expected to be curtailed; and the hours in which non-firm fixed Import Interchange Transactions are expected to be curtailed.

(a) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Maximum Emergency Capacity Operating Limit, Maximum Emergency Discharge Limit, or Minimum Emergency Charge Limit, as applicable, will be used; and

(b) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Minimum Emergency Capacity Operating Limit, Minimum Emergency Discharge Limit, or Maximum Emergency Charge Limit, as applicable, will be used.

(2) Using the results from the Day-Ahead RUC analysis, the Transmission Provider will update the Current Operating Plan and will issue start-up and shut-down orders as appropriate. The Transmission Provider can only de-commit Day-Ahead Market committed Resources or move a Day-Ahead Market MCR from a

higher capacity configuration to a lower capacity configuration to address an anticipated excess supply condition as described under Section 5.2.2(2)(b) of this Attachment AE and/or to address any other Emergency conditions. If the Transmission Provider de-commits a Transmission Provider committed Resource or moves an MCR from a higher capacity configuration to a lower capacity configuration for any hour of the Day Market commitment schedule, and causes that the Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the Day Ahead Market prices for the comparable products, that Resource is eligible for compensation under Section 8.6.6(2) of this Attachment AE.

# 6.0 Operating Day Activities

## 6.1 Intra-Day Reliability Unit Commitment

The Transmission Provider will continually evaluate the need to execute an Intra-Day RUC. The Transmission Provider will perform an Intra-Day RUC consistent with the timing requirements specified in the Market Protocols. Consistent with the Day-Ahead RUC, these Intra-Day RUCs assess capacity adequacy during the Operating Day.

### 6.1.1 Intra-Day Reliability Unit Commitment Inputs

Inputs to the RUC will include the following:

(1) RTBM Resource Offers;

(2) Confirmed Export Interchange Transactions;

(3) Confirmed Import Interchange Transactions;

(4) Confirmed Through Interchange Transactions;

(5) Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);

(6) Transmission Provider load forecast;

(7) Transmission System topology consistent with Network Model;

(8) Resource commitment and de-commitment schedules from the Day-Ahead RUC or previous Intra-Day RUCs;

(9) The Transmission Provider's wind Resource MWh output forecast;

(10) Actual and approved scheduled Transmission System outages as documented in the Transmission Provider's outage scheduler;

(11) Actual and approved scheduled Resource outages as documented in the Transmission Provider's outage scheduler;

(12) The Transmission Provider's estimate of Parallel Flows;

(13) Instantaneous Load Capacity requirements; and

(14) Operator input.

### 6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider's load forecast, Export Interchange Transactions, Instantaneous Load Capacity requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, only including capacity up to the Resources' Maximum Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up Service and/or Regulation-Down), Maximum Discharge Limit or Minimum Charge Limit and down to the Resources' Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down Service and/or Regulation-Up), Minimum Discharge Limit or Maximum Charge Limit. In addition, MCRs are not eligible to be selected for Regulation-Up Service and/or Regulation-Down Service in any hour in which they are transitioning between configurations.

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider's load forecast, Export Interchange Transactions, the upper bound of Instantaneous Load Capacity requirement, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export

Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources' Maximum Emergency Capacity Operating Limits, Maximum Emergency Discharge Limit or Minimum Emergency Charge Limit and/or, commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement; (3) de-commit charging Resources that were committed in the Day-Ahead Market with commitment status of "market" as described in Section 4.1(10)(b) of this Attachment AE until capacity shortage is eliminated, and (4) de-commit self-committed charging Resources.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, the lower bound of Instantaneous Load Capacity requirement, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources' Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limit or Maximum Emergency Charge Limit, and/or commit any MSR available for charging designated with a commitment status of "reliability" as described in Section 4.1(10)(c) of this Attachment AE, until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular reliability issue impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a

Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such Transmission System reliability issues. Such manual commitments shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. The Transmission Provider shall ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Intra-Day Reliability Unit Commitment Process. Such Local Reliability Issue may require manual commitment or decommitment to be issued by the Transmission Provider to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. To the extent that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE. To the extent time does not permit, the local transmission operator may issue such instructions to the Resource if the Local Reliability Issue is a Local Emergency Condition. In such cases, the following shall take place:

(a) If initial instructions are issued by a local transmission operator, the

transmission operator shall notify the Transmission Provider of the instructions given to the Resource.

(b) The transmission operator and Transmission Provider will coordinate to ensure subsequent instructions are provided by the Transmission Provider.

(c) The transmission operator shall log such instructions, and shall notify the Transmission Provider of such action. The Transmission Provider shall log such instructions as manual commitment or decommitment, as appropriate, as if it gave such instruction to the Resource.

(d) The Resource shall be eligible to receive the compensation for such instructions in the same manner as if it had been committed by the Transmission Provider; except that if the Market Monitor determines that the Resource selected in response to such instructions was selected in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible to receive compensation under Section 8.6.5 of this Attachment AE. Such determination shall be made by the Market Monitor using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. Recovery of any compensation shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(e) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider including such commitments made at the request of the local transmission operator or manual commitments made by the local transmission operator during a Local Emergency Condition to relieve known and recurring Local Reliability Issues in the Intra-Day RUC. Such Resources will be compensated in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

### 6.1.2.1 Determination of Non-Discriminatory Manual Resource Selection

The Market Monitor shall verify that the process used by the Transmission Provider and local transmission operator to manually select Resources in response to a reliability issue was performed in a non-discriminatory manner. Such verification shall be performed as follows:

(i) The Market Monitor's evaluation of whether the Transmission Provider's selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the Transmission Provider manually committed Resources to resolve the same reliability issue. The Transmission Provider's manual commitment of a Resource to resolve a reliability issue shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively and economically mitigated the reliability issue, as verified by the Market Monitor.

(ii) The Market Monitor's evaluation of whether the local transmission operator's selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the local transmission operator committed Resources to resolve the same Local Emergency Condition. The manual commitment of a Resource by a local transmission operator to resolve a Local Emergency Condition shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively mitigated the Local Emergency Condition, as verified by the Market Monitor.

(iii) The Market Monitor shall obtain the necessary information to perform the verification from submitted Resource Offer parameters (cost, operating parameters, availability of non-selected Resources), Market Participant

registration (Resource ownership, affiliation), and the Transmission Provider and/or local transmission operator (prior commitments, other Resources considered to resolve the reliability issue or Local Emergency Condition). The Market Monitor shall perform such verification as soon as the necessary information is available, but by no later than the day on which S120 Scheduled Settlement Statements are issued for the Operating Day in which the manual commitment occurred, as set forth in Section 8.0 and 10.1 of Attachment AE of this Tariff.

(iv) When the Market Monitor determines that a Resource may have been selected in a discriminatory manner pursuant to this Section 6.1.2.1, the Market Monitor shall report such suspected discrimination to the Commission's Office of Enforcement or successor organization promptly upon completing the verification set forth in this Section 6.1.2.1, and the Transmission Provider shall notify the local transmission operator of the best practice should the situation arise again.

### 6.1.3 Intra-Day Reliability Unit Commitment Results

The Transmission Provider will electronically communicate the Intra-Day RUC results for each hour of the Operating Day to Market Participants following completion of each Intra-Day RUC execution. The results consist of the following:

(1) For any future hours in which the Transmission Provider anticipates an Emergency situation, the Transmission Provider shall notify all Market Participants identifying: the hours in which the emergency ranges of any Resources are expected to be required; the hours in which identified or reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, are expected to be committed; the hours in which non-firm fixed Export Interchange Transactions are expected to be curtailed; and the hours in which non-firm fixed Import Interchange Transactions are expected to be curtailed.

(a) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Maximum Emergency Capacity Operating Limit, Maximum Emergency Discharge Limit, or Minimum Emergency Charge Limit, as applicable, will be used; and

(b) Affected Market Participants will be notified at least ten (10) minutes prior to the beginning of the Operating Hour but not more than thirty (30) minutes prior to the beginning of the Operating Hour that the Minimum Emergency Capacity Operating Limit, Minimum Emergency Discharge Limit, or Maximum Emergency Charge Limit, as applicable, will be used.

(2) Using the results from the Intra-Day RUC, the Transmission Provider will update the Current Operating Plan and will issue start-up and shut-down orders as appropriate. The Transmission Provider can only de-commit a Transmission Provider committed Day-Ahead Market Resource or move a Day-Ahead Market committed MCR submitting from a higher capacity configuration to a lower capacity configuration to address an anticipated excess supply condition as described under Section 6.1.2(2)(b) of this Attachment AE and/or to address any other Emergency conditions. If the Transmission Provider de-commits a

Transmission Provider committed Resource or moves an MCR from a higher capacity configuration to a lower capacity configuration for any hour of the Day-Ahead Market commitment schedule and causes that the Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the Day-Ahead Market prices for the comparable products, that Resource is eligible for compensation under Section 8.6.6(2) of this Attachment AE.

## 6.2 Real-Time Balancing Market

The Transmission Provider will clear the RTBM by determining the security-constrained dispatch that is the least costly means of balancing generation and load while meeting Operating Reserve requirements within the SPP Balancing Authority Area.

### 6.2.1 Real-Time Balancing Market Inputs

Inputs into the RTBM will include the data provided prior to each Operating Hour and data provided within each Operating Hour.

#### 6.2.1.1 Pre-Operating Hour Inputs

Pre-Operating hour inputs to the RTBM will include the following:

(1) RTBM Resource Offers;

(2) Approved and tagged Export Interchange Transactions, Import Interchange Transactions and Through Interchange Transactions;

(3) Operating Reserve requirements (system-wide and Reserve Zone minimum and maximum);

(4) Resources selected to provide Regulation-Up Service or Regulation-Down Service from the most recent RUC. This set of Resources will remain on regulation control for the Operating Hour and will be used by SCED to clear Regulation-Up and Regulation-Down on a five (5) minute basis to meet the regulation requirements;

(5) Resource commitment from the Current Operating Plan. The Current Operating Plan includes Resource commitments and Resource de-commitments from the Multi-Day Reliability Assessment, Day-Ahead Market, Day-Ahead RUC and Intra-Day RUC;

(6) Maximum Emergency Capacity Operating Limits, Maximum Emergency Discharge Limits, and Minimum Emergency Charge Limits on Resources identified in the Day-Ahead RUC or Intra-Day RUC; and

(7) Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, and Maximum Emergency Charge Limits on Resources identified in the Day-Ahead RUC or Intra-Day RUC.

#### 6.2.1.2 Intra-Operating Hour Inputs

Intra-operating hour inputs to the RTBM will include the following:

(1) Latest State Estimator solution for:

(a) Distribution of load forecast throughout the Network Model;

(b) Latest transmission topology for the Network Model; and

(c) Backup initial Energy injection of Resources if SCADA not available;

(2) Real-Time Resource data from latest SCADA snapshot to determine initial Energy injection of Resources, Generator outages and Real-Time State of Charge (for MSR only);

(3) Active transmission constraints;

(4) Intra-operating hour adjustments to Interchange Transactions due to curtailments or initiation of a Reserve Sharing Event involving external Balancing Authorities;

(5) Intra-operating hour adjustments to Resource Offer physical operating parameters due to changes in a Resource's capability. Market Participants shall notify the Transmission Provider of a change in a Resource Offer physical operating parameter during an Operating Hour. For the current Operating Hour the Transmission Provider will make the requested modification to the Resource Offer physical operating parameter. For subsequent hours the Market Participant shall remain responsible for accurately reflecting Resource operating parameters in its Resource Offer submissions;

(6) Intra-hour adjustments to selection of Resources to provide Regulation-Up Service or Regulation-Down Service to the extent that Resources selected as described under Section 6.2.1.1(4) become unavailable to provide regulation service;

(7) Transmission Provider load forecast;

(8) The Transmission Provider's wind Resource MWh output forecast; and

(9) The Transmission Provider's estimate of Parallel Flows.

### 6.2.2 Real-Time Balancing Market Execution

The Transmission Provider will attempt to execute the RTBM every five (5) minutes for the next Dispatch Interval based on the inputs described above. In the event the Transmission Provider is unable to execute the RTBM or to approve a valid solution for the RTBM, the clearing from the last approved RTBM will carry forward until the approval of a new RTBM.

(1) A simultaneous co-optimization methodology utilizing a SCED algorithm is employed to calculate Resource Dispatch Instructions and clear Regulation-Up Service, Regulation Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, and Ramp Capability Down to meet the Transmission Provider load forecast and Operating Reserve requirements at minimum costs based upon submitted Offers while respecting Resource operating constraints and transmission constraints as described in Section 3.3.1 of this Attachment AE.

(2) The SCED algorithm includes marginal loss sensitivity factors that approximate the change in marginal system losses for a change in Energy dispatch.

(3) In certain situations, enforcing constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED.

(4) The co-optimization logic will provide through the Shadow Price calculation, MCPs for Operating Reserve that include lost opportunity costs incurred as a result of Operating Reserve clearing.

(5) Additionally, the Transmission Provider will execute a look-ahead SCED prior to the RTBM SCED process. The Transmission Provider will use the look-ahead SCED results to: (1) anticipate the need to adjust Dispatch Instructions for the current Dispatch Interval to prepare to meet forecasted changes in the load several Dispatch Intervals into the future and (2) determine commitment of Resources that can be on-line within the Operating Hour including Fast-Start Resources.

### 6.2.2.1 Emergency Operations – Capacity Shortage

(1) In addition to the incorporation of the capacity up to Resources' Maximum Emergency Capacity Operating Limits prior to the Operating Hour as described under Sections 5.1.2(1)(a)(i) and 5.2.2(2)(a) of this Attachment AE, the Transmission Provider may incorporate any remaining emergency capacity limits as needed during the Operating Hour. The Transmission Provider shall continue implementation of emergency procedures which may have been implemented prior to the Operating Hour or shall begin implementation of emergency procedures within the Operating Hour, as needed, in accordance with its authority as Reliability Coordinator.

(a) If there is an actual Operating Reserve shortage during a Dispatch Interval, either on a system-wide or a Reserve Zone basis, the system-wide or Reserve Zone Scarcity Prices will be implemented as specified in Sections 8.3.1 and 8.3.4.2 of this Attachment AE.

(b) If there is a shortage of available capacity to meet Energy requirements on a system-wide, LMPs will be set through Scarcity Pricing procedures as specified in Section 8.3.1 of this Attachment AE.

### 6.2.2.2 Emergency Operations – Excess Generation

(1) The Transmission Provider will take any or all of the following actions, as time permits, within the Operating Hour to address excess generation conditions on either a system-wide or Reserve Zone basis:

(a) Notify any remaining Resources not cleared for Regulation-Down Service and not notified prior to the Operating Hour that they will be dispatched down to their Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, or Maximum Emergency Charge Limits;

(b) De-commit any remaining Resources that were self-committed following the Day-Ahead RUC;

(c) Pro-rata curtail, on a MW basis, any remaining fixed non-firm Import Interchange Transactions;

(d) Pro-rata curtail, on a per MW basis, any fixed firm Import Interchange Transactions;

(e) Reduce Resources with cleared Regulation-Down Service economically, as needed, down to Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limits, or Maximum Emergency Charge Limits;

(f) Coordinate with generation Operators, SPP Balancing Authority Operator and SPP Reliability Coordinator to de-commit generation to meet power balance; and

(g) Commit any MSR that is available for charging.

(2) If actions taken under (1) above are not sufficient to relieve the excess generation condition in any Dispatch Interval either on a system-wide or Reserve Zone basis, LMPs will be set to the lesser of zero (0) or the Offer prices associated with Energy down to the minimum emergency limit, to the extent that the Regulation-Down requirement can be maintained. If the actions under (1) above create a Regulation-Down Service shortage during any Dispatch Interval either on a system-wide or Reserve Zone basis, the MCPs for Regulation-Down Service will reflect Scarcity Prices and LMPs will reflect negative Scarcity Prices.

(3) In parallel with the actions under (1) above, if there is a transmission constraint within a Reserve Zone occurring simultaneously with a Reserve Zone excess capacity event, the Transmission Provider may take any or all of the following additional actions:

(a) Identify and communicate with the Market Participant concerning Resources with greater than a five percent (5%) generation shift factor on the constraint and fixed Import Interchange Transactions with greater than a three percent (3%) transfer distribution factor on constraint;

(b) Issue Transmission Loading Relief ("TLR") provisions, in accordance with Attachment R, to curtail any Interchange Transactions that may be contributing to the loading;

(c) Commit Resources in the constrained area if they can be re-dispatched with other Resources in the constrained area to relieve constraint without contributing to the excess capacity situation.

### 6.2.2.3 Congestion Management

The Transmission Provider shall use the following process to coordinate the operations of the RTBM to manage congestion within the SPP Balancing Authority Area and between the SPP Balancing Authority Area and external Balancing Authority Areas:

(a) The Transmission Provider shall submit the Market Flow impact on each Coordinated Flowgate and Reciprocal Coordinated Flowgate to the IDC.

(b) The Transmission Provider shall assign curtailment priorities to the Market Flow on each flowgate in the following priority categories:

(i) Curtailment priorities for flowgates that have not been defined as a Coordinated Flowgate or a Reciprocal Coordinated Flowgate shall be assigned in accordance with NERC TLR procedures.

(ii) For Coordinated Flowgates, the Transmission Provider will assign Market Flow in the firm priority up to the firm limit with any excess Market Flow assigned as non-firm network.

(iii) For Reciprocal Coordinated Flowgates, the Transmission Provider will divide its Market Flows into firm, non-firm network, and non-firm hourly curtailment priorities. The Transmission Provider will first assign Market Flow in the firm priority up to the firm limit, then assign remaining Market Flow in the non-firm network priority up to the non-firm network limit, and finally assign any excess Market Flow as non-firm hourly.

(c) The Market Flow associated with operation of the RTBM shall be determined by the Transmission Provider. For Coordinated Flowgates, any Market Flow from RTBM operation in excess of that assigned to the firm priority shall be assigned a non-firm priority. For Reciprocal Coordinated Flowgates, any Market Flow from RTBM operation in excess

of amounts assigned to firm or non-firm network priorities shall be assigned a non-firm hourly priority.

(d) When congestion occurs on a flowgate that requires a TLR event, the IDC will identify the amount of relief required from Market Flows on the Coordinated Flowgate or Reciprocal Coordinated Flowgate.

(e) When congestion occurs on a flowgate that does not require a TLR event, the Transmission Provider shall manage such congestion using its security constrained dispatch software until the flowgate loading is within its applicable operating limits.

(f) The Transmission Provider shall achieve the required reduction in Market Flows provided by the IDC using its security constrained dispatch software in the following order until the desired reduction in Market Flows is achieved:

(i) To the extent that Market Flows are contributing to the constrained condition, the Transmission Provider shall restrict the ability of the market operating system from contributing further to the constrained condition by binding the Coordinated Flowgate or Reciprocal Coordinated Flowgate constraint. The security constrained dispatch of Dispatchable Resources shall continue within each priority level until the Market Flows within that priority level have been reduced to zero or the flowgate constraint is eliminated, whichever comes first.

### 6.2.3 Real-Time Balancing Market Results

Following execution of the RTBM SCED, the Transmission Provider shall communicate the results to Market Participants.

(1) The following results are communicated to each Market Participant for only its specific Resources prior to the start of the applicable Dispatch Interval:

(a) Resource Dispatch Instructions. The Dispatch Instruction is a MW output target for the end of the applicable Dispatch Interval.

(b) Cleared Regulation-Up Service, Regulation-Down Service, Spinning Reserve, Supplemental Reserve, Ramp Capability Up, and Ramp Capability Down MW by Resource.

(i) Cleared Regulation-Up Service MWs represent only those MWs cleared to meet the Regulation-Up Service requirement.

(ii) Cleared Regulation-Down Service MWs represent only those MWs cleared to meet the Regulation-Down Service requirement.

(iii) Cleared Spinning Reserve MWs represent the Spinning Reserve MWs cleared to meet the Spinning Reserve requirement and Regulation-Up Service MWs cleared to meet the Spinning Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(iv) Cleared Supplemental Reserve MWs represent the sum of Supplemental Reserve MWs cleared to meet the Supplemental Reserve requirement and Regulation-Up Service MWs and Spinning Reserve MWs cleared to meet the Supplemental Reserve requirement through product substitution as described under Section 3.1.7 of this Attachment AE.

(v) Cleared Ramp Capability Up MWs represent only those MWs cleared to meet the Ramp Capability Up requirement.

(vi) Cleared Ramp Capability Down MWs represent only those MWs cleared to meet the Ramp Capability Down requirement.

(2) The following pricing solution results are communicated to all Market Participants after the posting of the dispatch solution and are used for settlement purposes;

(a) LMPs for each Settlement Location, the MCC of LMP for each Settlement Location and the MLC of LMP for each Settlement Location.

(b) MCPs for Regulation-Up Service, Expected Regulation-Up Mileage, Regulation-Down Service, Expected Regulation-Down Mileage, Spinning Reserve and Supplemental Reserve for each Reserve Zone.

### 6.2.4 Out-of-Merit Energy Dispatch

The Transmission Provider may issue an OOME to any Resource not on outage. The Transmission Provider will make every effort to define and activate the appropriate constraints in RTBM SCED within one (1) hour of the time the OOME is issued.

A local transmission operator may 1) request the Transmission Provider to issue an OOME or 2) issue an OOME directly to the Resource(s) and will notify the Transmission Provider that it has done so. If the local transmission operator determines there is an adequate amount of time prior to issuing the OOME directly to the Resource, the local transmission operator will coordinate with the Transmission Provider to ensure the OOME is provided by the Transmission Provider. If the initial OOME is issued by the local transmission operator, the local transmission operator shall coordinate with the Transmission Provider to ensure subsequent OOMEs are provided by the Transmission Provider.

During the period of time an OOME is imposed, the Transmission Provider will take the following actions:

(1) The Transmission Provider will issue an OOME at either the fixed MW level or an OOME cap and/or OOME floor MW level the Resource is expected to produce until such time as the constraint can be resolved by SCED through the RTBM.

(2) For the current dispatch interval and all future dispatch intervals during the period of time an OOME is imposed, a Resource will receive Setpoint Instructions that are adjusted as specified in the Market Protocols.

(3) The Transmission Provider will notify the Market Participant when the OOME event ends.

(4) To the extent that the OOME is initiated directly by a local transmission operator, such OOME may also specify either the fixed MW level or an OOME cap and/or OOME floor MW level. Market Participants shall be compensated for such OOME in accordance with Section 8.6.6 of this Attachment AE as if they had been issued an OOME by the Transmission Provider; except that if the Market Monitor determines that the Resource selected pursuant to Section 6.2.4(4) of this Attachment AE was selected by the local transmission operator in a discriminatory manner and the Resource was affiliated with the local transmission

operator, such Resource shall not be eligible for compensation under Section 8.6.6 of this Attachment AE. Such determination shall be made using the same standards and procedures prescribed for Resource selection in the Intra-Day Reliability Unit Commitment process, as set forth in Section 6.1.2.1 of this Attachment AE. The recovery of the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(5) To the extent that the OOME was initiated by the Transmission Provider at the request of a local transmission operator, such Resources issued OOMEs shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. In such event, Market Participants shall be compensated for such OOMEs in accordance with Section 8.6.6 of this Attachment AE. The recovery of the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(6) To the extent that the OOME was initiated by the Transmission Provider, such Resources issued an OOME shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Recovery of compensation for Resources directly issued OOMEs by Transmission Provider that are received under Section 8.6.6 of this Attachment AE shall be collected regionally under Section 8.8 of this Attachment AE.

(7) The Transmission Provider, local transmission operator, and affected Resource owners shall develop operating guides to be applied to OOMEs made to relieve known and recurring reliability issues or to relieve known and recurring Emergency Conditions. Such Resources will be compensated in the same manner as any other Resource that is issued OOMEs. The recovery of the compensation paid by the Transmission Provider under Section 8.6.6 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

In addition to the actions listed above, if an OOME is issued in response to an Emergency Condition, the Transmission Provider will post the Emergency Condition on OASIS as soon as possible. The Transmission Provider shall displace the OOME with a market solution as soon as possible consistent with system safety and reliability.

## 6.3 Energy and Operating Reserve Deployment

The Transmission Provider will deploy Energy, Regulation-Up Service, Regulation-Down Service, Spinning Reserve and on-line Supplemental Reserve simultaneously through the issuance of Setpoint Instructions to each Resource in accordance with the technical requirements specified in the Market Protocols. Deployment of Supplemental Reserve from off-line Resources or an MCR that has cleared Supplemental Reserve on a higher capacity configuration is accomplished through the Transmission Provider issuance of a Commitment Instruction to start-up following a Contingency Reserve event.

(1) The Setpoint Instruction for a Resource that has indicated that it is dispatchable is equal to the sum of:

(a) The Resource MW Dispatch Instruction for the current Dispatch Interval either as developed by SCED or by OOMEs; for DVERs who are not being incrementally dispatched by RTBM but are selected for regulation, this Resource MW Dispatch Instruction will be replaced with the Real-Time Capability value submitted via ICCP;

(b) Regulation-Up Service deployment instruction for Resources with cleared Regulation-Up Service;

(c) Regulation-Down Service deployment instruction for Resources with cleared Regulation-Down Service;

(d) Spinning Reserve deployment instruction for Resources with cleared Spinning Reserve; and

(e) On-Line Supplemental Reserve deployment instruction for Resources with cleared on-line Supplemental Reserve.

(2) The Setpoint Instruction for a Resource that has indicated that it is non-dispatchable shall be equal to the most recently recorded actual telemetered Resource output.

### 6.3.1 Regulation Deployment

Regulation Deployment is limited to Resources that have cleared Regulation-Up Service or Regulation-Down Service. Regulation-Up Service and Regulation-Down Service are deployed on specific Resources through Setpoint Instructions via the automatic generation control system on a pro-rata basis based upon Regulation-Up Service or Regulation-Down Service cleared MW, adjusted as needed to ensure deliverability. No Regulation Deployment will occur on Resources that have not cleared Regulation-Up Service or Regulation-Down Service. Market Participants providing Regulation-Up Service or Regulation-Down Service during the Operating Hour are obligated to report to the Transmission Provider when their Resources are no longer capable of providing the service due to physical problems.

### 6.3.2 Contingency Reserve Deployment

Contingency Reserve procured in the RTBM will be deployed through a Contingency Reserve Deployment Instruction following a Reserve Sharing Event in accordance with the following rules:

(1) Contingency Reserve is deployed on Resources with cleared Contingency Reserve and Export Interchange Transactions providing Supplemental Reserve in the Dispatch Interval immediately following system events;

(2) Spinning Reserve and on-line Supplemental Reserve is deployed ahead of off-line Supplemental Reserve;

(3) If the amount of Spinning Reserve and on-line Supplemental Reserve cleared is greater than or equal to the Contingency Reserve amount required in response to a contingency, no off-line Supplemental Reserve is deployed;

(4) Spinning Reserve and on-line Supplemental Reserve is deployed in proportion to the amount of Spinning Reserve and on-line Supplemental Reserve cleared on each Resource, adjusted as needed to ensure deliverability; and

(5) Supplemental Reserve from off-line Resources or from online MCRs that have cleared Supplemental Reserve on a higher capacity configuration is deployed on Resources in merit order of Start-Up Offer, Transition State Offer, No-Load Offer, Energy Offer Curves and Minimum Run Time, adjusted as needed to ensure deliverability. For the purposes of deploying Supplemental Reserve supplied from Export Interchange Transactions, the merit order cost will be equal to zero (0).

(6) If a Resource fails all four of the tests described under Section 6.4.3 and the smallest Shortfall Quantity is greater than 25% of the Contingency Reserve Deployment Instruction, the amount of Contingency Reserve available to be cleared on that Resource will be reduced for the remainder of the Operating Day based on the (a) current Contingency Reserve Ramp Rate, for online deployment; (b) Maximum Off-line Supplemental Reserve Response Limit for offline deployments; or Maximum Transition State Supplemental Reserve Resource Response Limit for MCRs, supplying offline Supplemental Reserve by transitioning to a higher capacity configuration.

### 6.3.3 Reserve Sharing Group Scheduling Procedures

The Energy schedules implemented through the reserve sharing Contingency Reserve deployment, are created automatically by the Reserve Sharing System and are settled through the RTBM as either a fixed Export Interchange schedule or a fixed Import Interchange schedule in accordance with Attachment AK to the Tariff and Sections 8.6.17 and 8.6.18 of this Attachment AE. Except as provided in Attachment AK and in Sections 8.6.17 and 8.6.18 of this Attachment AE, the Integrated Marketplace rules and practices are not applicable to Reserve Sharing Group members.

Deployment of Contingency Reserve by the SPP Balancing Authority to provide assistance to a Reserve Sharing Group member will be in accordance with the deployment procedures specified in Section 6.3.2 of this Attachment AE.

### 6.3.4 Contingency Reserve Recovery

Following an Operating Reserve contingency, the SPP Balancing Authority will attempt to restore its Contingency Reserve to its Contingency Reserve requirement by the Dispatch Interval following the end of the Assistance Period. During an Assistance Period, Scarcity Pricing will apply only if the amount of Contingency Reserve cleared in the RTBM is less than the Contingency Reserve requirement reduced by the deployed amount.

## 6.4 Energy and Operating Reserve Deployment Failure

### 6.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation ("URD").

(1) For the purposes of determining URD exemptions for Resources that are part of a Common Bus as described under Section 6.4.1.1(6) of this Attachment AE, each Asset Owner's Resources' combined average ramped MW Setpoint Instruction and combined actual average MW output at the Common Bus will be used to calculate URD at the Common Bus for the Dispatch Interval for each Asset Owner.

(2) A Resource's URD is allocated a portion of the RUC make whole payment costs, as described under Section 8.6.7 of this Attachment AE, in any Dispatch Interval where Resource's URD is outside of its Operating Tolerance unless that Resource has been exempted from URD.

(a) A generating unit Resource's Operating Tolerance in each Dispatch Interval is equal to the Resource's Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(b) A Dispatchable Demand Response Resource's Operating Tolerance in each Dispatch Interval is equal to the resource's Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(c) A Block Demand Response Resource's Operating Tolerance in each Dispatch Interval is equal to the resource's Maximum Economic Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(d) The Common Bus Operating Tolerance for each Market Participant registered at a Common Bus is equal to the sum of that Market Participant's Resources' Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(e) If the absolute value of a Resource's URD is greater than the Resource's Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC make whole payment cost allocation. The Hourly URD amount is calculated as the sum of Dispatch Interval URD for the hour. Additionally, if that Resource was eligible to receive a RUC make whole payment, the payment may be reduced in accordance with Section 8.6.5 of this Attachment AE.

(f) An MSR's Operating Tolerance in each Dispatch Interval is equal to the greater of the absolute value of the Maximum Emergency Charge Limit and the Maximum Emergency Discharge Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

#### 6.4.1.1 Uninstructed Resource Deviation Exemptions

A. A Resource will receive a URD exemption in a Dispatch Interval under the following situations:

(1) The Resource is deployed for Contingency Reserve as described in Section 6.3.2 of this Attachment AE or is deployed for a Contingency Reserve test as described under Sections 2.10.1 and 2.10.2 of this Attachment AE; or

(2) The Resource trips off-line or is derated after receiving Dispatch Instructions; or

(3) There is missing or bad Resource SCADA data in the Dispatch Interval; or

(4) If during Emergency Conditions the URD is due to a Resource output above the Resource's Setpoint Instruction in a shortage condition or the URD is due to a Resource output below the Resource's Setpoint Instruction during an excess generation condition; or

(5) If a Dispatch Instruction is issued to a Resource beyond the reported capabilities due to the application of a VRL; or

(6) If the Resource is part of a Common Bus and the URD calculated at the Common Bus is less than the Operating Tolerance calculated at the Common Bus; or

(7) If the URD results from an event of force majeure or, in the case of a Variable Energy Resource, if the URD results from extremely high wind or other extreme weather-related conditions materially and directly impacting a Variable Energy Resource's ability to provide or reduce output of Energy. For purposes of this subsection, the term force majeure shall have the meaning described under Section 10.1 of this Tariff except that acts of Curtailment shall not qualify for exemption; or

(8) If the Resource has been issued an OOME for Energy.

B. In the event a Resource does not receive a URD exemption in a Dispatch Interval, the Transmission Provider shall determine through the dispute process, in accordance with the invoice dispute process as provided in Section 10.3 of this Attachment AE, whether an exemption to an Uninstructed Resource Deviation will be given. The Market Participant may provide the Transmission Provider with adequate documentation in order for the Market Participant to be eligible to avoid such Uninstructed Resource Deviation. Adequate documentation may include but is not limited to an audio file documenting a call between the Market Participant and the Transmission Provider.

### 6.4.1.2 Load Deviation Exemptions

A load is exempt from deviation based charges for cost allocation under Section 8.6.7 under the following situations:

(1) The RTBM billable metering for load is less than that load's Day-Ahead Market cleared quantity during a capacity shortage condition Emergency.

### 6.4.2 Regulation Deployment Failure Charges

In any Dispatch Interval, if the URD of a Resource with cleared Regulation-Up Service, Regulation-Down Service or both is outside of the Resource's Operating Tolerance, that Market Participant will incur a Regulation Deployment failure charge as described in Section 8.6.11 of this Attachment AE.

### 6.4.3 Contingency Reserve Deployment Failure Tests

A Market Participant receiving a Contingency Reserve Deployment Instruction must pass one of four tests described below in order to be in full compliance with the instruction. Each of these tests is performed by the Transmission Provider, either at the individual Resource level, or at a Common Bus level if the Market Participant's Resource receiving the Contingency Reserve Deployment Instruction is registered at a Common Bus. A Resource that fails all four tests will receive a Contingency Reserve deployment failure charge as described in Section 8.6.13 of this Attachment AE. The Setpoint Instructions used in these tests are calculated in accordance with Section 6.3(1).

(1) Test 1 compares the Resource expected output or Common Bus expected output at the end of the Contingency Reserve Deployment Period to the Resource actual output or Common Bus actual output as measured at the end of the Contingency Reserve Deployment Period using the instantaneous ramped Setpoint Instruction.

(2) Test 2 is the same as Test 1 except that the expected output is calculated using the instantaneous stepped Setpoint Instruction instead of the instantaneous ramped Setpoint Instruction.

(3) Test 3 compares the change in Resource expected output or Common Bus expected output between the beginning and the end of the Contingency Reserve Deployment Period to the change in Resource actual output or Common Bus actual output between the beginning and the end of the Contingency Reserve Deployment Period using the instantaneous ramped Setpoint Instruction.

(4) Test 4 is the same as Test 3 except that the expected output is calculated using the instantaneous stepped Setpoint Instruction instead of the instantaneous ramped Setpoint Instruction.

## 6.5 Inadvertent Management

The Transmission Provider will maintain inadvertent accounts and administer inadvertent payback for the SPP Balancing Authority Area. In doing so, the Transmission Provider will adhere to the following principles:

(1) Inadvertent payback will be administered in accordance with applicable NERC Reliability Standards, applicable joint operating agreements, and Good Utility Practice; and

(2) Inadvertent payback decisions will be made without regard to possible profits or losses resulting from changes in Energy costs over time.

### 6.5.1 Inadvertent Payback Reporting

The SPP Balancing Authority will report its Inadvertent Interchange balance with the applicable NERC interconnection. The Transmission Provider reporting will be consistent with applicable NERC Reliability Standards and timelines for Balancing Authorities.

Inadvertent payback will be initiated based on an objective and publicly available process that is triggered on balances exceeding statistical norms. Inadvertent payback will be done during periods and in amounts such that payback will not burden others or interfere with time corrections. Settlement impact will not factor into the decision to payback or recover inadvertent interchange.

## 6.6 Emergency Energy Assistance with Adjacent Balancing Authorities

The SPP Balancing Authority may request emergency energy assistance from an adjacent balancing authority, or an adjacent balancing authority may request emergency energy assistance from the SPP Balancing Authority. The definition of emergency energy and the procedures for emergency energy assistance between the SPP Balancing Authority and an adjacent balancing authority will be pursuant to the applicable joint operating agreement.

Import or export schedules related to emergency energy assistance will be settled similar to all other import or export schedules. The joint operating agreements may include additional market-related charges or credits for the provision of emergency energy assistance.

The settlement of additional market-related charges or credits for the provision of emergency energy assistance is distributed or collected through the Revenue Neutrality Uplift charge type as described in the Market Protocols, except for instances when the Transmission Provider implements a Local Reliability Issue Commitment in response to the request for emergency energy assistance.

When the Transmission Provider implements a Local Reliability Issue Commitment in response to the request for emergency energy assistance, the settlement of additional market-related credits paid to the Transmission Provider will first be allocated to load in the Settlement Area in which the Local Reliability Issue Commitments were implemented, up to the amount of the make whole payments made to Resources who received Local Reliability Issue Commitments in response to the request for emergency energy assistance. Any remaining market-related credits paid to the Transmission Provider will be distributed through the Revenue Neutrality Uplift charge type as described in the Market Protocols.

## 7.0 Transmission Congestion Rights Markets

The TCR Markets process includes an annual LTCR allocation, an annual ARR allocation, annual and monthly TCR auctions and a monthly ARR allocation in accordance with the timelines specified in the Market Protocols. The TCR Markets process is subject to review by the Market Monitor consistent with Attachment AG of this Tariff. LTCRs are obtained by Eligible Entities during the annual LTCR allocation and ILTCRs are obtained during the annual LTCR allocation. ARRs are obtained by Eligible Entities during the annual ARR allocation or the monthly ARR allocation. TCRs are obtained by Market Participants through the annual LTCR allocation and the annual and monthly TCR auctions.

There are eight (8) key processes associated with LTCRs, ILTCRs, ARRs and TCRs:

(1) Annual LTCR/ILTCR/ARR verification;

(2) Annual LTCR/ILTCR allocation;

(3) Annual ARR allocation;

(4) Annual TCR auction;

(5) Monthly ARR allocation;

(6) Monthly TCR auction;

(7) ARR allocation and TCR auction settlements; and

(8) TCR secondary markets.

Table 7-1 in Section 7.4.2 of this Attachment AE provides additional details related to auction timing and Transmission System capability available for the TCR auctions.

(b) Except as otherwise provided in this Section 7.0.b (ii), an entity taking firm transmission service under a GFA Carve Out will not be eligible to participate in the TCR Markets for the MW capacity associated with the GFA Carve Out.

(i) The MW capacity associated with each GFA Carve Out shall be included in the Transmission Provider's ARR allocation and TCR auction processes

in a manner that reflects the transmission service pursuant to the GFA Carve Out, provided, however, that (A) candidate ARRs associated with the GFA Carve Out service shall not be nominated for a product period if, based upon the twelve preceding months for which congestion data is available, such ARR, had it been converted to a TCR, would have resulted in a net charge to the holder of the TCR over that product period, and (B) until twelve months of Integrated Marketplace data are available, the Transmission Provider shall use relevant data from both the EIS Market and the Integrated Marketplace to estimate whether the result would have been a net charge to the TCR holder.

(ii) On an annual basis, the GFA Responsible Entity may elect, in writing, to cancel the GFA Carve Out treatment and will be eligible to participate in the TCR Markets pursuant to Section 7.0 of Attachment AE. The conversion of GFA Carve Out to the TCR Market is irrevocable.

(c) Firm transmission capacity associated with a FSE shall not be eligible to participate in the TCR Markets.

(i) The MW capacity associated with each FSE shall be included in the Transmission Provider's ARR allocation and TCR auction processes in a manner that reflects the transmission service pursuant to the FSE, provided, however, that Candidate ARRs associated with the FSE service shall not be nominated for a product period if, based upon the twelve preceding months for which congestion data is available, such ARR, had it been converted to a TCR, would have resulted in a net charge to the holder of the TCR over that product period.

(ii) For the MW capacity associated with each FSE, the sink for the ARR/TCR shall be the (1) load Settlement Location within the UMZ, (2) interface with an external Balancing Authority, or (3) FSE Transfer Point, as appropriate. For ARR/TCR activity from FSE Transfer Points to load external to the UMZ but internal to the Transmission Provider, the normal ARR/TCR process is available to the applicable Market Participants from

the FSE Transfer Point to the load consistent with the transmission service reservation.

## 7.1 Annual Long-Term Congestion Right/Incremental Long-Term Congestion Rights/Auction Revenue Right Verification

Only Eligible Entities are permitted to nominate candidate LTCRs and/or ARRs. Only Market Participants that have received candidate ILTCRs through the process described under Section IV of Attachment Z2 of this Tariff are eligible to nominate candidate ILTCRs. The following rules apply to verification of firm transmission service for conversion to LTCRs and/or ARRs and verification of candidate ILTCRs.

### 7.1.1 Transmission Service and Incremental Long-Term Congestion Rights Verification

In order for Eligible Entities to obtain candidate LTCRs and/or ARRs, the Transmission Provider must first verify existing transmission service entitlements, including transmission service entitlements that have been renewed in accordance with rollover rights since their initial term. An Eligible Entity's transmission service must span the entire monthly or seasonal period for which ARRs are allocated to qualify for candidate ARRs in a particular month or season. An Eligible Entity's transmission service must span the entire annual period for which LTCRs are allocated and must have rollover rights to qualify for candidate LTCRs. In order to qualify for candidate ILTCRs in the current LTCR allocation year, upgrades associated with the candidate ILTCRs must be in-service prior to the start of the annual LTCR/ILTCR/ARR verification process. For transmission service with rollover rights whose deadline for providing notice of rollover occurs after the annual LTCR/ARR verification but before June 1, the Transmission Provider shall assume that the rollover will occur and shall consider the transmission service entitlement to span the entire allocation year, provided, however, that, if rollover rights for such transmission service are not exercised by the applicable deadline, any ARRs, TCRs, or LTCRs associated with such transmission service shall revert to the Transmission Provider effective on the date such transmission service terminates. The Transmission Provider will verify Eligible Entity existing transmission service entitlements as follows:

(1) The following will be performed prior to each annual LTCR and ARR allocation for Eligible Entities taking Network Integration Transmission Service or Firm Point-To-Point Transmission Service under the Tariff:

(a) The Transmission Provider will obtain source, sink and Reservation Capacity information from the OASIS for each monthly and seasonal period for which ARRs are allocated in which the transmission service spans the entire period, or would if or when rolled over, for the current annual allocation and for the annual period for which LTCRs are allocated in which the transmission service spans the entire year;

(i) For a transmission service reservation with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Hub, the Transmission Provider will determine the load Settlement Location that most electrically corresponds to the source on the transmission service reservation that will be utilized as the source for candidate LTCRs and/or ARRs. In the alternative, Eligible Entities may create Resource specific transmission service reservations that represent their current transmission service reservations using the process described in Section 7.1.1.1 of this Attachment AE.

(ii) For a transmission service reservation with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for candidate LTCRs and/or ARRs.

(iii) For a transmission service reservation with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for candidate LTCRs and/or ARRs.

(iv) Eligible Entities taking Network Integration Transmission Service with rollover rights under this Tariff shall be considered to have met the definition of Load Serving Entity for purposes of LTCR allocation;

(v) Eligible Entities taking Firm Point-To-Point Transmission Service with rollover rights under this Tariff shall not be considered a Load Serving Entity for LTCR allocation purposes unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is a Load Serving Entity as defined in this Attachment AE;

(b) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(c) Eligible Entities will notify the Transmission Provider within 2 weeks following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified.

(d) For transmission service granted with a redispatch obligation, the Transmission Provider will verify the times of year and amounts of service that are not subject to redispatch in accordance with the limitations set forth in Sections 13.5 and 34.6 of this Tariff.

(2) The following will be performed prior to each annual LTCR and ARR allocation for the Eligible Entity taking GFA service:

(a) Each Transmission Owner shall register any GFA for which candidate LTCRs and/or ARRs are to be provided to the Transmission Owner or the transmission customer under the GFA on the Transmission Provider's OASIS. The Transmission Owner must provide the Transmission Provider with source, sink and Reservation Capacity information for each GFA on the Transmission Provider's OASIS by registering each GFA with the Transmission Provider. The Transmission Provider will use source, sink, and Reservation Capacity information from the GFA registration for each monthly and seasonal period for which LTCRs and/or ARRs are allocated and the annual period for which the LTCRs are allocated. If both parties to the GFA are Market Participants with respect to the GFA load, then the parties may jointly inform the Transmission Provider which Market Participant will be allocated the candidate ARRs. If the parties to the GFA do not so inform the Transmission Provider, or if only the Transmission Owner that sold the GFA service is a Market Participant, then the Transmission Owner that sold the GFA service will be allocated the candidate LTCRs and/or ARRs associated with the GFA.

(i) For a GFA with a source inside the SPP Balancing Authority Area that is not a specific Resource or Resource Hub, the Transmission

Provider will determine the load Settlement Location that most electrically corresponds to the source on the transmission service reservation that will be utilized as the source for candidate LTCRs and/or ARRs.

(ii) For a GFA with a source outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the source for the candidate LTCRs and/or ARRs.

(iii) For a GFA with a sink outside of the SPP Balancing Authority Area, the interface between the Transmission Provider and the first tier Balancing Authority Area associated with the transmission reservation will be utilized as the sink for the candidate LTCRs and/or ARRs.

(iv) An Eligible Entity under a GFA taking the equivalent of Network Integration Transmission Service with rollover rights shall be considered to have met the definition of Load Serving Entity for purposes of LTCR allocation;

(v) An Eligible Entity under a GFA taking the equivalent of Firm Point-To-Point Transmission Service with rollover rights shall not be considered a Load Serving Entity for the purposes of LTCR allocation unless the Eligible Entity provides an attestation to the Transmission Provider confirming that the Eligible Entity is an Load Serving Entity as defined in this Attachment AE;

(b) If the transmission customer under the GFA is receiving the candidate ARRs, to the extent that the transmission service specified in the GFA is identified as the equivalent of SPP Network Integration Transmission Service, the transmission customer under the GFA must provide the historical peak loads being served under the GFA for the previous three years.

#### 7.1.1.1 Transmission Service Reservation Modification for Resource Specific Source Points

For purposes of the Transmission Provider's verification of transmission service entitlements under this Section 7.1.1(1)(a)(i) of this Attachment AE, Eligible Entities may use their non-Resource specific transmission service that is inside the SPP market footprint by creating individual Resource specific transmission service reservations on OASIS. These individual Resource specific transmission service reservations will be used exclusively for the TCR Markets. The original transmission service reservations will remain on OASIS.

For an Eligible Entity's use of its original master Network Integration Transmission Service reservation to create Resource specific transmission service reservations, Appendix 1 of the Eligible Entity's current Network Integration Transmission Service Agreement will be used to validate the process. For an Eligible Entity's use of non-Resource specific transmission service other than its original master Network Integration Transmission Service reservation, the Eligible Entity involved in the transmission service transaction will be responsible for determining which Resources and Resource capacities should be used to create the Resource specific transmission service reservation. SPP shall not be required to determine which Resources the transmission service is intended to represent. The sum of all transmission service from each Resource must be less than or equal to the Maximum Capacity of the Resource.

Eligible Entities must use the following process to initiate and complete the TSR modification.

(1) Submit the "Non-Resource Specific TSR Breakout Form," found on www.spp.org, to SPP if more than one party is involved in the transmission service transaction; and

(2) Submit new transmission service requests with the new service code of "SPP FN-7 YEARLY NITS TCR", "SPP F-7 YEARLY PTP TCR", "SPP FN-7 MONTHLY NITS TCR", or "SPP F-7 MONTHLY PTP TCR", whichever is equivalent to the original transmission service type.

(a) The only difference between the original transmission service reservation and the new transmission service reservation should be the source, the capacity, and the subclass.

(i) For transmission service reservations utilizing the Eligible Entity's original master Network Integration Transmission Service, the capacity should be the highest value per Resource found in Appendix 1 of the Network Integration Transmission Service Agreement (including the comments column) rounded up to the nearest whole MW value. If the capacity in the Network Integration Transmission Service Agreement changes after the transmission service reservation has been granted, then this transmission service reservation may be recalled and a new transmission service reservation may be submitted to represent the new value in the Network Integration Transmission Service Agreement.

(ii) For other Non-Resource Specific transmission service reservations, the capacity should be the amount the parties have agreed to.

(b) Pre-confirm all submittals to allow for immediate confirmation after acceptance by SPP.

### 7.1.2 Candidate Long-Term Congestion Rights/Auction Revenue Rights

Following verification of an Eligible Entity transmission service, candidate LTCRs and/or ARRs associated with such transmission service, and candidate ILTCRs are assigned as follows:

(1) For each Eligible Entity with Network Integration Transmission Service, the Eligible Entity's Network Integration Transmission Service Candidate LTCRs and/or candidate ARRs from a specific source is equal to the source Reservation Capacity.

(a) An Eligible Entity may nominate Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2.4 of this Attachment AE from a specific source to one or more sinks up to the amount of its available Network Integration Transmission Service Candidate LTCRs associated with the source such that the total of such nominations does not exceed the lesser of the sum of Network Integration Transmission Service Candidate LTCRs or the limit described under Section 7.1.3(1)(b) for that Eligible Entity.

(b) An Eligible Entity may nominate Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE from a specific source to one or more sinks up to the amount of its Network Integration Transmission Service Candidate ARRs associated with the source subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(2) For each Eligible Entity with Firm Point-To-Point Transmission Service, the Eligible Entity's Firm Point-To-Point Candidate LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate Firm Point-To-Point Candidate LTCRs, as described in Section 7.2 of this Attachment AE, for this specific source and sink up to the amount of its available Firm Point-To-Point Candidate LTCRs such that the total of such nominations does not exceed the total Firm Point-To-Point Candidate LTCRs available for that Eligible Entity.

(b) Firm Point-To-Point Candidate ARRs may be nominated by an Eligible Entity, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(3) A holder of candidate ILTCRs may nominate the candidate ILTCRs up to the MW amount for the specific source and sink path documented through the process described in Section IV of Attachment Z2 of this Tariff less previously awarded ILTCRs issued subsequent to the initial allocation pursuant to Section 7.2.5 of this Attachment AE.

(4) For each Eligible Entity with equivalent Network Integration Transmission Service GFA service, the Eligible Entity's Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs and/or ARRs from a specific source is equal to the source Reservation Capacity.

(a) An Eligible Entity may nominate Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs, as described in Section 7.2 of this Attachment AE, from a specific source to one or more sinks up to the amount of its available Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs such that the total of such nominations does not exceed the lesser of the sum of Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs or the limit described under Section 7.3.1(3)(b) for that Eligible Entity.

(b) An Eligible Entity may nominate Grandfathered Agreement Network Integration Transmission Service Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, from a specific source to one or more sinks up to the amount of its Grandfathered Agreement Network Integration Transmission Service Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

(5) For each Eligible Entity with equivalent Firm Point-To-Point GFA service, the Eligible Entity's Grandfathered Agreement Firm Point-To-Point Candidate

LTCRs and/or ARRs for a specific source and sink is equal to the Reservation Capacity associated with that source and sink.

(a) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate LTCRs, as described in Section 7.2 of this Attachment AE, for this specific source and sink up to the amount of its available Grandfathered Agreement Firm Point-To-Point Candidate LTCRs such that the total of such nominations does not exceed the total Grandfathered Agreement Firm Point-To-Point Candidate LTCRs available for that Eligible Entity.

(b) An Eligible Entity may nominate Grandfathered Agreement Firm Point-To-Point Candidate ARRs, as described in Section 7.3.1 of this Attachment AE, for this specific source and sink up to the amount of its Grandfathered Agreement Firm Point-To-Point Candidate ARRs subject to the total nomination cap described in Section 7.1.3 of this Attachment AE.

### 7.1.3 Auction Revenue Right Nomination Cap

An Eligible Entity's ARR Nomination Cap will be as follows:

(1) For Network Integration Transmission Customers, the Network Integration Transmission Service ARR Nomination Cap for a particular month or season is equal to the lesser of (a) the sum of Network Integration Transmission Service Candidate ARRs and Network Integration Transmission Service Candidate LTCRs for that particular month or season as calculated in Section 7.1.2 of this Attachment AE and any additional Network Integration Transmission Service Candidate ARRs for that particular month or season as calculated in Section 7.6.1 of this Attachment AE or (b) One hundred and three percent (103%) of the average of that customer's three most recent annual peak Network Loads. This value will be adjusted by the Transmission Provider as required to account for wholesale load shifts between Transmission Customers. In addition, Network Integration Transmission Service Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(2) For Firm Point-To-Point Transmission Customers, the Firm Point-To-Point ARR Nomination Cap is equal to the sum of Firm Point-To-Point Candidate ARRs and Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Firm Point-To-Point Candidate ARRs as calculated in Section 7.6.1 of this Attachment AE. In addition, Firm Point-To-Point Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(3) For GFA customers taking the equivalent of SPP Network Integration Transmission Service, the Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap for that particular month or season is equal to the lesser of (a) the sum of Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs for that particular month or season as calculated in Section 7.1.2 of this Attachment AE and any

additional Grandfathered Agreement Network Integration Transmission Service Candidate ARRs for that particular month or season as calculated in Section 7.6.1 of this Attachment AE or (b) One hundred and three percent (103%) of the average of that GFA customer's three most recent annual peak Network Loads. This value will be adjusted by the Transmission Provider as required to account for wholesale load shifts between Transmission Customers. In addition, Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(4) For GFA customers taking the equivalent of SPP Firm Point-To-Point, the Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap is equal to the sum of Grandfathered Agreement Firm Point-To-Point Candidate ARRs and Grandfathered Agreement Firm Point-To-Point Candidate LTCRs as calculated in Section 7.1.2 of this Attachment AE and any additional Grandfathered Agreement Firm Point-To-Point Candidate ARRs as calculated in Section 7.6.1 of this Attachment AE. In addition, Grandfathered Agreement Firm Point-To-Point Candidate LTCRs and awarded LTCRs shall be transferred by the Transmission Provider as applicable to account for wholesale load shifts between Transmission Customers.

(5) An Eligible Entity's ARR Nomination Cap is equal the sum of its Network Integration Transmission Service ARR Nomination Cap, Firm Point-To-Point ARR Nomination Cap, Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap and Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap.

## 7.2 Annual Long-Term Congestion Right Allocation

Eligible Entities may nominate their candidate LTCRs and Market Participants may nominate their candidate ILTCRs that they wish to receive as described under Section 7.1.2 of this Attachment AE. The feasible portion of the nominated candidate LTCRs and nominated candidate ILTCRs are awarded during the LTCR annual allocation. Nominated candidate LTCRs and candidate ILTCRs are evaluated on an annual basis in a two-step, single round process; (i) nominated candidate LTCRs associated with Eligible Entities that are Load Serving Entities and nominated candidate ILTCRs issued subsequent to the initial allocation pursuant to Section 7.2.5 of this Attachment AE are evaluated in accordance with Section 7.2.2 and (ii) remaining nominated candidate LTCRs associated with Eligible Entities which are not Load Serving Entities are then evaluated in accordance with Section 7.2.3.

The Transmission Provider shall make available fifty percent (50%) of the projected maximum Transmission System capability for the purpose of LTCR and ILTCR allocation in the annual LTCR allocation process. No later than five (5) days prior to the start of the annual LTCR allocation process, the Transmission Provider shall post the Transmission System network topology, including the corresponding impacts from Parallel Flow, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocation.

### 7.2.1 Long-Term Congestion Right and Incremental Long-Term Congestion Right Surrender and Nomination

(a) Eligible Entities and holders of ILTCRs must confirm with the Transmission Provider their intent to retain previously awarded LTCRs and/or ILTCRs. Eligible Entities and holders of ILTCRs may surrender previously awarded LTCRs and ILTCRs in 0.1 MW increments. Prior to annual LTCR allocation, Eligible Entities and holders of ILTCRs surrendering previously awarded LTCRs and/or ILTCRs shall submit the following information:

(1) Source (valid candidate LTCR source Settlement Location);

(2) Sink (valid candidate LTCR sink Settlement Location);

(3) Surrendered LTCR MW (cannot exceed previously awarded LTCR);

(4) Surrendered ILTCR MW (cannot exceed previously awarded ILTCR).

(b) Eligible Entities and holders of candidate ILTCRs shall submit the following information in order to nominate LTCRs and ILTCRs that were not previously awarded in 0.1 MW increments:

(1) Source (valid candidate LTCR and/or ILTCR source Settlement Location);

(2) Sink (valid candidate LTCR and/or ILTCR sink Settlement Location);

(3) LTCR MW (total LTCR MW nominated from a source Settlement Location cannot exceed the source candidate LTCR MW as previously determined under Section 7.1.2 of this Attachment AE less previously awarded LTCRs plus surrendered LTCRs);

(4) ILTCR MW (total ILTCR MW nominated from a source Settlement Location cannot exceed the source candidate ILTCR MW as previously determined under Section 7.1.2 of this Attachment AE less previously awarded ILTCRs plus surrendered ILTCRs).

### 7.2.2 Available Long-Term Congestion Rights for Load Serving Entities and Incremental Long-Term Congestion Rights

A Simultaneous Feasibility Test is performed to determine the amount of awarded ILTCRs and LTCRs for Eligible Entities that are LSEs. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, nominated candidate ILTCRs and Load Serving Entities' nominated candidate LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition, all previously awarded ILTCRs and LTCRs issued subsequent to the initial allocation pursuant to Section 7.2.5 of this Attachment AE are modeled as fixed injections and withdrawals provided that such LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or such ILTCRs and LTCRs have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded ILTCRs and LTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution. If all nominated candidate ILTCRs and all Load Serving Entities' nominated candidate LTCRs are feasible, then all are awarded. If the nominated candidate ILTCRs and Load Serving Entities' nominated candidate LTCRs are not feasible, the amount of awarded ILTCRs and LTCRs will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual ILTCR and LTCR amounts and the candidate ILTCR and candidate LTCR amounts, weighted by the reciprocal of the candidate ILTCR and candidate LTCR amounts, which results in a higher percentage ILTCR and LTCR reduction for those nominations having the greatest impact on the constraints. ILTCR and LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

### 7.2.3 Available Long-Term Congestion Rights for Non-Load Serving Entities

A Simultaneous Feasibility Test is performed to determine the amount of awarded LTCRs for Eligible Entities that are not Load Serving Entities. The Simultaneous Feasibility Test is performed using the most current Network Model for the corresponding LTCR allocation period. For the Simultaneous Feasibility Test, all non-Load Serving Entity nominated candidate LTCRs are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. In addition, all Load Serving Entity awarded LTCRs as calculated under Section 7.2.2 of this Attachment AE are modeled as fixed injections and withdrawals and all previously awarded LTCRs and ILTCRs are modeled as fixed injections and withdrawals provided that such previously awarded LTCRs must meet the criteria as specified in Section 7.1.1 of this Attachment AE, or such LTCRs and ILCTRs have not been surrendered as described under Section 7.2.1 of this Attachment AE. To the extent that these previously awarded LTCRs and ILTCRs are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution.

If all non-Load Serving Entity nominated candidate LTCRs are feasible, then all non-Load Serving Entity LTCRs are awarded. If the non-Load Serving Entity nominated candidate LTCRs are not feasible, the amount of awarded LTCRs will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual LTCR amounts and the candidate LTCR amounts, weighted by the reciprocal of the candidate LTCR amounts , which results in a higher percentage LTCR reduction for those nominations having the greatest impact on the constraints. LTCR reductions associated with candidates that have an equal impact on the constraints are reduced by the same percentage.

### 7.2.4 Long-Term Congestion Right and Incremental Long-Term Congestion Right Awards

(1) All previously awarded LTCRs are automatically awarded as LTCRs for the current allocation year; provided that such LTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE; and were not surrendered as described under Section 7.2.1 of this Attachment AE.

(2) All previously awarded ILTCRs awarded pursuant to Section 7.2.2 of this Attachment AE are automatically awarded as LTCRs for the current allocation year provided that such ILTCRs meet the criteria specified in Section 7.1.1 of this Attachment AE; and were not surrendered as described under Section 7.2.1 of this Attachment AE.

(3) Additional Load Serving Entity LTCRs and/or ILTCRs are awarded as described under Section 7.2.2 of this Attachment AE.

(4) Additional non-Load Serving Entity LTCRs are awarded as described under Section 7.2.3 of this Attachment AE.

(5) Initial ILTCRs are awarded pursuant to Section 7.2.5 of this Attachment AE. ILTCRs awarded pursuant to Section 7.2.5 of this Attachment AE are not automatically awarded for the subsequent year(s). ILTCRs for subsequent years shall be awarded pursuant to Section 7.2 of this Attachment AE.

(6) All awarded LTCRs and ILTCRs as described in subsections (1) through (*4*) above are directly converted to TCRs prior to the annual ARR allocation for the current allocation year.

### 7.2.5 Initial Incremental Long-Term Congestion Right Awards

The initial ILTCR award process addresses how candidate ILTCRs will be nominated and awarded to an Upgrade Sponsor from the time when the upgrade is placed into service until the next annual LTCR allocation. The Upgrade Sponsor and/or Transmission Owner shall notify the Transmission Provider at least forty-five (45) calendar days in advance of the expected upgrade in-service date. When the upgrade is placed into service, the Upgrade Sponsor and/or Transmission Owner shall notify the Transmission Provider. Upon receipt of notification, the Transmission Provider will model the upgrade in the next feasible monthly TCR auction.

During the first full month that the upgrade is included in the transmission model for a monthly TCR auction, nominated candidate ILTCRs will be awarded as ILTCRs. These awarded ILTCRs will be directly converted to TCRs until they can be included in the next annual LTCR allocation process, and the TCRs will only be effective for the remainder of the current allocation year. Upgrades that are placed in-service after the annual LTCR/ILTCR/ARR verification process but before the next allocation year starts will receive TCRs for: (i) the remainder of the current allocation year, and (ii) the next allocation year.

At the start of the next annual LTCR/ILTCR/ARR verification process after the upgrade has been placed in-service, Market Participants will be issued candidate ILTCRs that may be nominated in the annual LTCR allocation process as described in Section 7.2 of this Attachment AE.

## 7.3 Annual Auction Revenue Right Allocation

The annual ARR allocation addresses how candidate ARRs verified in the annual LTCR/ARR verification may be nominated and awarded. Eligible Entities may nominate the candidate ARRs that they wish to receive up to their ARR nomination caps less any LTCRs awarded. Candidate ARRs are available from un-awarded candidate LTCRs and surrendered LTCRs. No candidate ARRs are available from un-awarded ILTCRs or surrendered ILTCRs. The portion of the nominated candidate ARRs that are simultaneously feasible are allocated to each Eligible Entity during the annual allocation. Candidate ARRs are nominated on a monthly and seasonal basis in a three round process.

The Transmission Provider shall make available one hundred percent (100%) of the Transmission System capability for the month of June, ninety percent (90%) of the Transmission System capability for the months of July through September, and sixty percent (60%) of the Transmission System capability for the Fall, Winter and Spring seasons. No later than five (5) days prior to the start of the annual ARR allocation process, the Transmission Provider will post the Transmission System network topology data for each of the monthly and seasonal On-Peak and Off-Peak models, including the corresponding Parallel Flow and transmission line outage assumptions, used to determine the projected maximum Transmission System capability that will be used in the upcoming allocations.

### 7.3.1 Auction Revenue Right Nominations

For each month and season included in the annual ARR allocation period, as defined in Table 7-1 in Section 7.4.2 of this Attachment AE, Eligible Entities may nominate candidate ARRs in 0.1 MW increments for specific source to sink pairs that total up to their ARR nomination caps as calculated in Section 7.1.3 of this Attachment AE less any LTCRs awarded. Nominations occur separately for On-Peak and Off-Peak periods. Prior to each ARR nomination round, Eligible Entities shall submit the following information:

(1) Source: valid candidate ARR source Settlement Location for rounds 1 and 2, and any applicable source Settlement Location for round 3;

(2) Sink: valid candidate ARR sink Settlement Location for rounds 1 and 2, and any applicable sink Settlement Location for round 3;

(3) Class: On-Peak or Off-Peak;

(4) Period: specific month or season; and

(5) Nominated ARR MW:

  (a) In round 1 and round 2, the total candidate ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less any awarded LTCRs associated with the source.

  (b) In round 3, any source to sink path may be nominated, subject to the limitation described in Section 7.3.2(3) of this Attachment AE.

### 7.3.2 Auction Revenue Right Allocation

ARRs are allocated in a three round process as follows:

(1) In round 1, Eligible Entities may nominate:

(a) ARRs from their Network Integration Transmission Service Candidate ARRs that total no more than fifty percent (50%) of their Network Integration Transmission Service ARR Nomination Cap less the sum of awarded LTCRs from their Network Integration Transmission Service Candidate LTCRs;

(b) ARRs from their Grandfathered Agreement Network Integration Transmission Service Candidate ARRs that total no more than fifty percent (50%) of their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap less the sum of awarded LTCRs from their Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs;

(c) ARRs from their Firm Point-To-Point Candidate ARRs that total no more than fifty percent (50%) of their Firm Point-To-Point Nomination Cap less the sum of awarded LTCRs from their Firm Point-To-Point Candidate LTCRs; and

(d) ARRs from their Grandfathered Agreement Firm Point-To-Point Candidate ARRs that total no more than fifty percent (50%) of their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap less the sum of awarded LTCRs from their Grandfathered Agreement Firm Point-to-Point Candidate LTCRs.

(2) In round 2, Eligible Entities may nominate:

(a) ARRs from their Network Integration Transmission Service Candidate ARRs that total no more than one hundred percent (100%) of their Network Integration Transmission Service ARR Nomination Cap less any nominated Network Integration Transmission Service Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Network Integration Transmission Service Candidate LTCRs;

(b) ARRs from their Grandfathered Agreement Network Integration Transmission Service Candidate ARRs that total no more than one hundred percent (100%) of their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap less any nominated Grandfathered Agreement Network Integration Transmission Service Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs;

(c) ARRs from their Firm Point-To-Point Candidate ARRs that total no more than one hundred percent (100%) of their Firm Point-To-Point ARR Nomination Cap less any nominated Firm Point-To-Point Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Firm Point-To-Point Candidate LTCRs; and

(d) ARRs from their Grandfathered Agreement Firm Point-To-Point Candidate ARRs that total no more than one hundred percent (100%) of their Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap less any nominated Grandfathered Agreement Firm Point-To-Point Candidate ARRs awarded in round 1 less the sum of awarded LTCRs from their Grandfathered Agreement Firm Point-To-Point Candidate LTCRs.

(3) In round 3, any Eligible Entity may nominate ARRs from any source to sink that total no more than one hundred percent (100%) of its ARR Nomination Cap less any nominated candidate ARR amounts awarded in rounds 1 and 2 less the sum of all awarded LTCRs. In this round an Eligible Entity is limited to a maximum combined submittal of two-thousand (2,000) ARR nominations for each Asset Owner it represents; and ARR nominations between Settlement Location pairs that are electrically equivalent will not be accepted.

### 7.3.3 Annual Auction Revenue Right Awards

A Simultaneous Feasibility Test is performed in each round of the ARR allocation to determine the amount of nominated ARRs to be awarded. The Simultaneous Feasibility Test is performed using the most current Network Model including planned transmission outages for the corresponding ARR allocation period. For the Simultaneous Feasibility Test, a nominated candidate ARR is modeled as a generation injection at the source and a corresponding load withdrawal at the sink. All directly converted TCRs from awarded LTCRs and awarded ILTCRs are modeled as fixed injections and withdrawals.

If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced using a weighted least squares method. The weighted least squares method minimizes the sum of the squared deviations between the actual ARR amounts and the nominated ARR amounts, weighted by the reciprocal of the nominated ARR amounts, which results in a higher percentage ARR reduction for those nominations having the greatest impact on the constraints. ARR reductions associated with nominations that have an equal impact on the constraints are reduced by the same percentage.

Every six (6) months for the first two (2) years after implementation of the Integrated Marketplace, the Transmission Provider will analyze the net funding of TCRs through the Day-Ahead Market. In the event the cumulative funding is at or below 90% or above 100%, the Transmission Provider may approve an additional adjustment of all subsequent monthly auctions and the month of June in the annual auction of the normal and emergency ratings of all flowgates and monitored transmission system elements.

## 7.4 Annual Transmission Congestion Right Auction

Market Participants may obtain TCRs by purchasing them in the annual TCR auction or through conversion of ARRs into TCRs. The percentages of the Transmission System capability made available during the annual TCR auction are listed in Table 7-1 in Section 7.4.2 of this Attachment AE. TCRs in the annual auction are auctioned in a single round process for all months and seasons. If there are any changes to the transmission system topology or Parallel Flow data after the conclusion of Annual ARR Allocation Process, the Transmission Provider will post such changes no later than three (3) Business Days prior to the start of the Annual TCR Auction Process.

### 7.4.1 Transmission Congestion Right Offer and Bid Submittal

(1) Market Participants that have satisfied the applicable credit requirements may participate in the annual TCR auction.

(2) Market Participants holding ARRs associated with a specific source and sink may elect to self-convert all or a portion of those ARRs into TCRs by specifying the self-convert option as part of the TCR Bid submittal.

(3) For each month and season included in the annual TCR auction, Market Participants may submit TCR Bids and/or Offers in 0.1 MW increments, for On-Peak and Off-Peak periods. A valid TCR Bid and/or Offer must contain the following information:

- (a) Source: any valid Settlement Location;
- (b) Sink: any valid Settlement Location;
- (c) Class: On-Peak or Off-Peak;
- (d) Period: specific month or season;
- (e) Type: Bid, Offer or self-convert;
- (f) TCR MW; and
- (g) TCR Price;
  - (i) TCR Bids and Offers cannot exceed $100,000/MW-Month;
  - (ii) TCR Bids and Offers cannot be less than negative $100,000/MW-Month;

(4) For each TCR round, a Market Participant is limited to a maximum of 2,000 TCR Bids and/or Offers for each Asset Owner it represents. TCR Bids between Settlement Location pairs that are electrically equivalent will not be included in the annual TCR auction.

### 7.4.2 Annual Transmission Congestion Right Auction

In the annual TCR auction, TCRs are made available in a single round for each month and season as follows:

(1) For the month of June, one hundred percent (100%) of the Transmission System capability is made available, for the July-September period ninety percent (90%) is made available, and for the Fall, Winter and Spring seasons sixty percent (60%) is made available. For additional details see Table 7-1;

(a) Only Eligible Entities holding ARRs may submit a self-convert TCR Bid.

(b) The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(c) The self-convert TCR Bid or Offer must specify the same source and sink as the associated ARR and the TCR MW must be less than or equal to the associated ARR MW.

(d) The self-convert type option will convert ARRs associated with the specified source to sink pair into the TCR MW specified subject to simultaneous feasibility.

## Table 7-1: TCR Auction Summary

| Auction Month | Auction Type | TCR Award Periods | | | | | | | TCR Products | Auction Rounds | Total Auctions |
|---|---|---|---|---|---|---|---|---|---|---|---|
| May | Annual (System Capability %) | Jun (100) | Jul (90) | Aug (90) | Sep (90) | Fall[1] (60) | Winter[2] (60) | Spring[3] (60) | On-Peak/ Off-Peak | 1 | 14 |
| Jun | Monthly (System Capability %) | Jul (100) | | | | | | | On-Peak/ Off-Peak | 1 | 2 |
| Jul | Monthly (System Capability %) | Aug (100) | | | | | | | On-Peak/ Off-Peak | 1 | 2 |
| Aug | Monthly (System Capability %) | Sep (100) | | | | | | | On-Peak/ Off-Peak | 1 | 2 |
| Sep | Monthly (System Capability %) | Oct (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Oct | Monthly (System Capability %) | Nov (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Nov | Monthly (System Capability %) | Dec (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Dec | Monthly (System Capability %) | Jan (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Jan | Monthly (System Capability %) | Feb (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Feb | Monthly (System Capability %) | Mar (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Mar | Monthly (System Capability %) | Apr (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |
| Apr | Monthly (System Capability %) | May (100) | | | | | | | On-Peak/ Off-Peak | 2 | 4 |

[1] October and November

[2] December, January, February, March

[3] April and May

### 7.4.3 Annual Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

The auction is performed with an objective of maximizing the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible. A Simultaneous Feasibility Test is performed in each round.

The Simultaneous Feasibility Test is performed using the most up to date Network Model including planned transmission outages for the corresponding ARR allocation period. For the Simultaneous Feasibility Test:

(1) TCR submittals of both the self-convert type and Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink.

(2) TCR submittals of the Offer type are modeled as a generation injection at the sink and a corresponding load withdrawal at the source; and

(3) Directly converted TCRs from LTCRs are modeled as fixed injections and withdrawals.

### 7.4.4 Annual Transmission Congestion Right Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-converted TCRs are evaluated concurrently with all other submitted TCR Bids and are given the highest priority subject to simultaneous feasibility. In the event there is a tie during the Simultaneous Feasibility Test, each competing TCR Bid and Offer will be awarded a TCR on a pro rata share based on the individual impact on the constraint. ACPs are calculated based on the shift factor for a specific bus to the Reference Bus with the corresponding Shadow Price for such bus, for each Settlement Location using the formula for the MCC as described in Section 8.3.1.2 of this Attachment AE.

## 7.5 Monthly Transmission Congestion Right Auctions

Market Participants may obtain TCRs, in addition to those obtained in the annual TCR auction, by purchasing TCRs in the monthly TCR auction or through conversion of ARRs awarded in the annual and monthly ARR allocations. Market Participants may also offer for sale TCRs awarded in the annual TCR auction. The TCRs for the months of July through September are auctioned in a single round. The TCRs for the months of October through May are auctioned in two rounds. No later than three (3) days prior to the monthly TCR auction, the Transmission Provider will post any changes to the Transmission System topology or input data assumptions that occurred after the conclusion of the annual ARR allocation.

### 7.5.1 Monthly Transmission Congestion Right Offer and Bid Submittal

(1) Market Participants that have satisfied the applicable credit requirements may participate in the monthly TCR auction.

(2) Market Participants may submit TCR Bids and Offers for On-Peak and Off-Peak eriods. The following information is submitted for a TCR Bid or Offer:

(a) Source: any valid Settlement Location;

(b) Sink: any valid Settlement Location;

(c) Class: On-Peak or Off-Peak;

(d) Type: Bid, Offer or self-convert;

(e) TCR MW: 0.1 MW increments, may not exceed ARR MW held on path if self-convert type selected; and

(f) TCR Price:

(i) TCR Bids cannot exceed $100,000/MW-Month;

(ii) TCR Bids cannot be less than negative $100,000/MW-Month;

(3) Market Participants may not submit more than a total of 2,000 TCR Bids and Offers in each TCR round for each Asset Owner it represents. TCR Bids between Settlement Location pairs that are electrically equivalent will not be included in the monthly TCR auction.

### 7.5.2 Monthly Transmission Congestion Right Auction

TCRs are auctioned in a single round for the months of July through September and one hundred percent (100%) of the Transmission System capability is made available. Any amounts of ARRs awarded in the monthly ARR allocation may be self-converted during this auction and any TCRs obtained in the annual TCR auction may be offered for sale.

TCRs are auctioned in a two round process for the months of October through May. In the two round process:

(1) Round 1 - Fifty percent (50%) of the Transmission System capability remaining following the annual TCR auction is made available;

(a) All ARRs awarded in the Monthly ARR Allocation Process may be submitted for self-conversion.

(i) ARRs obtained in the annual allocation may be submitted for self-conversion subject to the following limitations: Eligible Entities may submit the lesser of:

(a) ARR Award multiplied by the quantity of 1 minus (auction available Transmission System capability percentage divided by the allocation available Transmission System capability percentage); or

(b) the difference between the ARRs awarded in the annual ARR allocation and the quantity of self-converted TCRs awarded in the annual TCR auction.

Where the auction available Transmission System capability percentage is equal to: 60% - Fall, Winter, and Spring seasons.

Where the allocation available Transmission System capability percentage is equal to: 60% - Fall, Winter, and Spring seasons of the ARRs obtained in the annual ARR allocation.

(ii) A self-convert TCR Bid must specify the same source and sink as the associated ARR and must be less than or equal to the associated ARR MW.

(iii) The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(b) Any TCRs awarded in the annual TCR auction may be offered for sale by the TCR holder.

(c) Any Market Participant may also submit TCR Bids for any source-sink pair.

(2) Round 2 - The remaining Transmission System capability is made available;

(a) An Eligible Entity may submit self-convert TCR Bids in this round that are limited to the values calculated under Section 7.7(2)(c) of this Attachment AE. The self-convert TCR MWs are evaluated simultaneously with TCR Bids and Offers and are subject to reductions that may result from the Simultaneous Feasibility Test.

(b) Any TCRs awarded in round 1 or the annual TCR auction, including self-converted TCRs, may be offered for sale by the TCR holder.

(c) Any Market Participant may also submit TCR Bids for any source-sink pair.

### 7.5.3 Monthly Transmission Congestion Right Auction Clearing and Simultaneous Feasibility

The auction is performed with an objective of maximizing the total TCR auction value while ensuring that the cleared TCRs are also simultaneously feasible. A Simultaneous Feasibility Test is performed in each round using the most up to date Network Model including planned transmission outages for the corresponding monthly TCR auction period with all TCRs awarded in the annual TCR auction modeled as fixed injections and withdrawals. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution prior to the start of the monthly TCR auction solely for the purpose of the monthly TCR auction. The Transmission Provider will report to the stakeholders on a quarterly basis regarding the number of times that the transmission facility ratings had to be adjusted in the model to ensure feasibility.

For the Simultaneous Feasibility Test, monthly TCR submittals of the self-convert type and TCR Bid type are modeled as a generation injection at the source and a corresponding load withdrawal at the sink. A monthly TCR submittal of the Offer type is modeled as a generation injection at the sink and a load withdrawal at the source.

### 7.5.4 Monthly Transmission Congestion Right Awards

Simultaneously feasible TCRs are awarded based upon the TCR Bid prices such that the total TCR auction value is maximized. Self-converted TCRs are evaluated concurrent with all other submitted TCR Bids and are given the highest priority subject to simultaneous feasibility. ACPs are calculated for each Settlement Location using the formula for the MCC as described in Section 8.3.1.2 of this Attachment AE.

## 7.6 Monthly Auction Revenue Right Allocation

Monthly ARRs are nominated in a single-round nomination process but awarded in two steps as described in Section 7.6.3 of this Attachment AE. Eligible Entities are eligible to nominate candidate ARRs for: (i) any remaining candidate ARR capacities from the Annual ARR Allocation Process, (ii) firm Transmission Service that has been confirmed following the completion of the most recent annual TCR auction and prior to the next annual LTCR/ARR verification, (iii) firm Transmission Service confirmed prior to the Annual LTCR/ARR Verification Process that includes a partial season, or (iv) Transmission Service for which a redispatch obligation has been eliminated. To the extent that the Eligible Entity's firm Transmission Service term extends beyond the current annual ARR allocation period, such remaining service will be included in the next annual LTCR/ARR verification.

### 7.6.1 Monthly Auction Revenue Right Transmission Service Verification

In order to qualify for additional monthly candidate ARRs in a particular month, an Eligible Entity's Transmission Service must span the entire month within the applicable year. The Transmission Provider will verify Eligible Entity existing Transmission Service entitlements as follows:

(1) The Transmission Provider will obtain the source, sink and Reservation Capacity information from the Transmission Provider's OASIS for the applicable month;

(2) The Transmission Provider will provide this information to each Eligible Entity for verification; and

(3) Eligible Entities will notify the Transmission Provider within six (6) days following receipt of this information, identifying and correcting inaccurate data on the OASIS. Otherwise, the Transmission Provider provided data will be considered verified and additional monthly candidate ARRs will be assigned as described under Section 7.1.2.

## 7.6.2 Reserved for Future Use

### 7.6.3 Monthly Auction Revenue Right Nominations

At least five (5) days and no more than six (6) days prior to the start of the monthly TCR auction, Eligible Entities may nominate in a single round: (i) Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Network Integration Transmission Service ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Network Integration Transmission Service Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with Network Integration Transmission Service Candidate LTCRs in the annual allocation processes; (ii) Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Firm Point-To-Point ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Firm Point-To-Point Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with Firm Point-To-Point Candidate LTCRs in the annual allocation processes; (iii) Grandfathered Agreement Network Integration Transmission Service Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between (1) their Grandfathered Agreement Network Integration Transmission Service ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with Grandfathered Agreement Network Integration Transmission Service Candidate LTCRs in the annual allocation processes; and (iv) Grandfathered Agreement Firm Point-To-Point Candidate ARRs in 0.1 MW increments along specific source to sink paths that totals no more than the difference between their (1) Grandfathered Agreement Firm Point-To-Point ARR Nomination Cap and (2) the sum of (a) awarded ARRs associated with Grandfathered Agreement Firm Point-To-Point Candidate ARRs and (b) directly converted TCRs from awarded LTCRs associated with Grandfathered Agreement Firm Point-To-Point Candidate LTCRs in the annual allocation processes. Nominations occur separately for On-Peak and Off-Peak periods and occur in a single round two-step nomination process. Eligible Entities submit the following information:

(1) For step 1, ARRs are nominated in MWs.

(a) Source: valid candidate ARR source Settlement Location;

(b) Sink: valid candidate ARR sink Settlement Location;

(c) Class: On-Peak or Off-Peak; and

(d) Nominated ARR MW amount:

(i) The total ARR MW nominated from a source Settlement Location cannot exceed the source candidate ARRs less previously awarded source ARRs.

(2) For step 2, ARRs are nominated on any path in percentages of the Eligible Entities' residual nomination caps after step 1 allocations. The nominated MWs will be the specified percentage multiplied by the residual nomination cap from step 1.

(a) Source: any valid Settlement Location;

(b) Sink: any valid Settlement Location;

(c) Class: On-Peak or Off-Peak; and

(d) Nominated ARR MW percentage amount:

(i) Percentages shall range from 0 to 100%. For either On-Peak or Off-Peak period, the sum of percentages for nominated ARRs cannot exceed 100%.

(ii) In addition, Eligible Entities may elect to submit a MW limit to cap the maximum MW nomination for each ARR path.

A Market Participant is limited to a maximum combined submittal of 2,000 ARR Nominations per product and per step for each Asset Owner it represents. Market Participants cannot nominate ARRs between Settlement Location pairs that are electrically equivalent in step 2 of the allocation.

### 7.6.4 Monthly Auction Revenue Rights Awards

A Simultaneous Feasibility Test is performed to determine the amount of nominated candidate ARRs to be awarded. For the Simultaneous Feasibility Test a nominated candidate ARR is modeled as a generation injection at the source and a corresponding load withdrawal at the sink. The Simultaneous Feasibility Test is performed using the following assumptions.

(1) The Transmission System model used in will be the same Network Model to be used in the upcoming monthly TCR auction;

(2) One hundred percent (100%) of the projected maximum Transmission System capability, including any completed Network Upgrades, is made available; and

(3) All TCRs previously awarded in the annual TCR auction and all remaining ARRs not accounted for in the annual TCR auction (as defined in Section 7.7 of this Attachment AE) for the applicable month are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution solely for the purpose of assessing ARR feasibility. The Transmission Provider will report to the stakeholders on a quarterly basis regarding the number of times that the transmission facility ratings had to be adjusted in the model to ensure feasibility.

If the nominated candidate ARRs are not feasible, the amount of nominated candidate ARRs to be awarded will be reduced based on their relative impact on the constraint to produce a simultaneously feasible result.

## 7.7 Auction Revenue Right Allocation and Transmission Congestion Right Auction Settlements

The charges and payments to ARR and TCR holders will be calculated on a daily basis and included on the Settlement Statements consistent with the timing of the Energy and Operating Reserve Markets settlement as described in Section 8.7 of this Attachment AE. For the purposes of calculating charges and payments to ARR holders, the following amounts of ARR awards will be used:

(1) ARR Settlement for annual TCR auction will be the greater of (i) the annual ARR award multiplied by the auction available Transmission System capability percentage divided by the allocation available Transmission System capability percentage, or (ii) self-convert TCR award. Where the auction available Transmission System capability percentage is equal to: 100% - June; 90% - July through September; 60% - Fall, Winter, and Spring seasons.

Where the allocation available Transmission System capability percentage is equal to: 100% - June; 90% - July through September; 60% - Fall, Winter, and Spring seasons of the ARRs obtained in the annual ARR allocation.

(2) ARR Settlement for monthly TCR auction will be settled as follows:

(a) For the months of July through September, all monthly ARR awards;

(b) For the months of October through May for round 1, the greater of (i) fifty percent (50%) of monthly ARR awards plus: fifty percent (50%) of the difference between the annual ARR award and the ARRs accounted for in the annual TCR auction as described in (1) above or (ii) Self-convert TCR awards; and

(c) For the months of October through May for round 2, the difference between: (i) the sum of annual ARR awards and monthly ARR awards and (ii) the sum of ARR MW accounted for in (1) above and the ARR MW accounted for in Section (2)(b) above.

## 7.8 Transmission Congestion Right Secondary Market

The Transmission Provider will facilitate a secondary market for TCRs. Both purchaser and seller in the secondary market must be a Market Participant. The secondary market is described as follows:

(1) Bilateral trading of existing TCRs is facilitated through a bulletin board system;

(2) TCRs may be broken down into increments that are not smaller than 0.1 MW and that totals no more than the original TCR;

(3) TCRs may be traded daily, for On-Peak or Off-Peak periods;

(4) Trades must be completed no later than two (2) calendar days prior to the applicable Operating Day to which the TCR instrument applies.

(5) The TCR purchaser pays TCR seller directly;

(6) TCRs may not be reconfigured (path must remain the same);

(7) The Market Participants must inform the Transmission Provider of any proposed transfer and the Transmission Provider must confirm that the credit requirements in Attachment X of this Tariff have been met prior to the transfer of ownership of a TCR through a bilateral transaction; and

(8) The Transmission Provider records the transfer of TCR ownership.

## 7.9 Liquidation of Transmission Congestion Rights in the Event of Market Participant Default

In the event the Transmission Provider declares a Market Participant to be in default in accordance with Attachment X of this Tariff, the Transmission Provider shall initiate the following procedures to close out and liquidate the TCRs of the Market Participant as soon as practicable after such default is declared:

(1) Transmission Provider may close out the defaulting Market Participant's positions as of the date of default, by unilaterally accelerating and terminating all forward TCR positions.

(2) Transmission Provider shall post on its website all salient information relating to a closed out portfolio of TCRs.

(3) In liquidating the defaulting Market Participant's TCR portfolio, the Transmission Provider shall not allow the liquidated TCRs offered for sale to set price.

(4) Transmission Provider may offer for sale all of the TCR positions within the defaulting Market Participant's TCR portfolio in any or all upcoming regularly scheduled TCR auctions.

(5) Alternatively, the Transmission Provider may conduct one or more specially scheduled TCR auctions, in which all of the portfolio of the defaulting Market Participant's TCRs are offered for sale.

(6) If Transmission Provider elects not to, or is unable to, close out and liquidate a TCR position under these procedures, the close out shall be deemed void and the defaulting Market Participant shall remain liable for the full final value of its default, such full final value being based upon the results of the applicable Day-Ahead Market settlements.

## 7.10 Reserved for Future Use

## 7.11 Transitional ARR Allocation

A Transmission Owner joining the Integrated Marketplace as a Market Participant may request the Transmission Provider perform a Transitional ARR Allocation to the extent that the Transmission Owner is incorporating existing transmission facilities into the SPP Transmission System under the Tariff and the timing of such incorporation does not allow participation in the annual ARR allocation process described under Section 7.2 of this Attachment AE. Eligible Entities with firm transmission service on that Transmission Owner's facilities may participate in the allocation. The Transmission Provider shall conduct the Transitional ARR Allocation consistent with the processes described under Section 7.1 and Section 7.2 of this Attachment AE, provided that:

(1) The Transitional ARR Allocation shall be performed in a single round;

(2) At a minimum, the Transitional ARR Allocation must include the winter and spring season and align with the other annual ARR periods; and

(3) All TCRs previously awarded in the annual TCR auction and all remaining ARRs not accounted for in the annual TCR auction (as defined in Section 7.6 of this Attachment AE) for the applicable study period are modeled as fixed injections at the specified sources and fixed withdrawals at the specified sinks. To the extent that these fixed injections and withdrawals are no longer feasible, the Transmission Provider will make the minimum adjustments necessary to the ratings of the applicable transmission facilities in the model in order to allow the model to produce a feasible solution solely for the purpose of assessing transitional ARR feasibility.

## 8.0 Post Operating Day and Settlement Activities

Post Operating Day activities begin on the day immediately following the Operating Day. The Transmission Provider issues Scheduled Settlement Statements for each Operating Day based on the Settlement Statement process outlined in Section 10.1 of this Attachment AE to both Asset Owners and Market Participants. Settlement Invoices are issued to Market Participants on a weekly basis.

## 8.1 Settlement Sign Conventions

For the purposes of settlement calculation of charges and payments described under this Section 8, negative signs shall reflect payments to Market Participants and positive signs to shall reflect charges to Market Participants. Throughout the settlement calculations, multiplication by (-1) is used to attain the proper sign convention where needed. Injections to the Transmission System are negative values and withdrawals are positive values. Consistent with the injection and withdrawals, the following sign conventions for variables used in the settlement calculations are as follows:

(1) Cleared Resource MWh and Virtual Energy Offer MWh in the Day-Ahead Market is negative value;

(2) Cleared load MWh and Virtual Energy Bid MWh in the Day-Ahead Market is a positive value;

(3) Import Interchange Transaction MWh is a negative value;

(4) Export Interchange Transaction MWh is a positive value;

(5) Cleared Operating Reserve MWs in the Day-Ahead Market and RTBM are positive values;

(6) All MWs associated with TCRs are positive values;

(7) Actual Meter values and telemetered/State Estimator values for Resource injections are a negative value; and

(8) Actual meter values and telemetered/State Estimator values for load consumption or a Resource's Energy withdrawals exceeding energy production are positive values.

## 8.2 Bilateral Settlement Schedules, GFA Carve Outs and FSE

Market Participants may create Bilateral Settlement Schedules for Energy and Operating Reserve obligations by registering and confirming the parameters of the agreement between buyer and seller as described in the Market Protocols. Both the buyer and seller must confirm the Bilateral Settlement Schedule except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE. Either the buyer or seller may terminate the Bilateral Settlement Schedule at any time except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE.

Market Participants may submit Bilateral Settlement Schedule quantities for Energy and Operating Reserve obligation for use in the Day-Ahead Market and may submit Bilateral Settlement Schedule quantities for Energy for use in the Real-Time Balancing Market based on settlement timelines for data submittal defined in the Market Protocols. Submittals not confirmed by both parties will not be included in any settlement execution.

Transactions related to Bilateral Settlement Schedules for Energy must specify the Settlement Location, the MW amount, the buyer, the seller and which market it applies to (Day-Ahead Market or RTBM), and must be for the physical transfer of Energy, with title of the energy transferring from the seller to the buyer at the Settlement Location specified for the transaction. Market Participants that submit Bilateral Settlement Schedules for Energy shall use reasonable efforts to limit the megawatt hours of such transactions to amounts reflecting the expected load and other physical delivery obligations of the buyer under the bilateral contract. The seller receives an increase in load obligation equal to the specified MW amount and the buyer receives a reduction in load obligation equal to the specified MW amount (the equivalent of a Resource settlement) at the specified Settlement Location.

Transactions related to Bilateral Settlement Schedules for Operating Reserve obligation must specify the buyer, the seller, the Operating Reserve product, the MW obligation transfer and the Reserve Zone within which the obligation transfer applies and must be for the physical transfer of energy associated with the Operating Reserve

product, with title of the Operating Reserve product transferring from the seller to the buyer at the Reserve Zone specified for the transaction. The seller receives an increase in Operating Reserve obligation equal to the specified MW and the buyer receives a corresponding decrease in Operating Reserve obligation within the specified Reserve Zone.

### 8.2.1 Default Procedures for Pre-Existing Bilateral Contracts Transitioning to Integrated Marketplace

The procedures established under this Section 8.2.1 of Attachment AE shall apply to bilateral contracts entered into prior to the start of the Integrated Marketplace, where the buyer and seller have not agreed to the terms in the Bilateral Settlement Schedules corresponding to such pre-existing bilateral contracts:

(1) Upon request of the buyer, the Transmission Provider shall review and confirm that a particular bilateral contract exists between the buyer and seller. The Transmission Provider shall schedule a meeting between a designated senior representative of the buyer and seller within 30 days of such a request. The Transmission Provider shall conduct these discussions in accordance with Section 12 of the Tariff. Following confirmation, the buyer may register and confirm a Bilateral Settlement Schedule representing the parameters of the agreement. The Transmission Provider shall confirm that the buyer has submitted Bilateral Settlement Schedule parameters that are consistent with those specified in the bilateral contract;

(2) Subsequent submission by either the buyer or the seller of Bilateral Settlement Schedules for Energy and/or Operating Reserve associated with the registered Bilateral Settlement Schedule in either the Day-Ahead Market and/or RTBM must be consistent with the quantities specified in the bilateral contract. Only the buyer is required to confirm;

(3) Only the buyer may terminate the Bilateral Settlement Schedule;

(4) The Settlement Location for Bilateral Settlement Schedules for Energy shall be the source Settlement Location of the associated transmission service reservation as described under Section 7.1.1(1)(a) of this Attachment AE, as applicable;

(5) The Transmission Provider shall not be a party to Bilateral Settlement Schedules and nothing in this Section 8.2.1 of Attachment AE shall impose on the Transmission Provider any obligation regarding the settlement of financial rights and obligations between the parties to Bilateral Settlement Schedules; and

(6) Nothing in this Section 8.2.1 of Attachment AE shall alter the parties' rights and obligations under preexisting bilateral contracts, limit the right of either party to seek enforcement of such rights and obligations, and/or limit a party's right to obtain appropriate relief, pursuant to Section 206 of the FPA or as otherwise in accordance with the law.

### 8.2.2 GFA Carve Out

A Market Participant receiving GFA Carve Out shall not be charged for the cost of congestion and cost of marginal losses in the Day-Ahead Market for the amount of actual energy (MWh) transacted as specified in the GFA Carve Out Schedule.

(a) GFA Carve Out is only available to the extent that the Resources are offered into the Day-Ahead Market using a commit status as described in Section 4.1(10) (a) or (b) of this Attachment AE. To the extent the source is external, an Import Interchange Transaction must be submitted in the Day-Ahead Market with sufficient capacity to cover the GFA Carve Out Schedule.

(b) The Transmission Provider will remove charges for cost of congestion and cost of marginal losses from the Settlement Statement as provided in Section 10.1(5) of Attachment AE, only if the GFA Responsible Entity submits a GFA Carve Out Schedule and E-Tag (as applicable) according to the procedures specified in Section 8.2.2.1 of Attachment AE for the Day-Ahead Market for the GFA Carve Out transaction, consistent with the GFA Settlement Locations, and within the maximum MW Capacity permissible under the GFA Carve Out. The GFA Responsible Entity must update the GFA Carve Out Schedule after the close of the Day-Ahead Market with the actual energy transacted that corresponds to the GFA Carve Out.

(c) The Transmission Provider shall account for the GFA Carve Out in the TCR Markets, but shall not allocate ARR or assign TCR to the GFA Responsible Entity for a GFA Carve Out.

(d) The GFA Responsible Entity is responsible to coordinate the GFA Carve Out Schedule data and to ensure the consistency of the GFA Carve Out Schedules. The Market Monitor will monitor GFA Carve Out Schedules in accordance with Section 4.6 of Attachment AG.

#### 8.2.2.1 GFA Carve Out Schedules

The GFA Responsible Entity shall create GFA Carve Out Schedules for all energy transacted under the GFA, as described in the Market Protocols. The GFA Responsible Entity shall submit: (i) GFA Carve Out Schedules for both the

Resource Settlement Location and Load Settlement Location within the SPP BA; and (ii) an E-Tag for GFA Carve Out transactions with Resource Settlement Location or Load Settlement Location external to the SPP BA. Such submittal of the GFA Carve Out Schedule and E-Tag (as applicable) shall be consistent with the provisions set forth herein for any sales and purchases of Energy pursuant to a GFA Carve Out.

### 8.2.3 FSE

Western-UGP shall not be charged for the cost of congestion and marginal losses for actual energy (MWh) transacted from Federal Power-Western-UGP resources across the UMZ to Western-UGP's Statutory Load Obligations as stated in Section 39.3(e)(ii) of this Tariff.

(a) FSE treatment is only available to the extent that the Resources are offered and cleared in the Day-Ahead Market using a commitment status as described in Section 4.1(10) (a) or (b) of this Attachment AE. To the extent a Federal Power-Western-UGP resource is external to the Energy and Operating Reserve Markets, an Import Interchange Transaction must be submitted and cleared in the Day-Ahead Market with sufficient capacity to cover the FSE Schedule.

(b) The Transmission Provider will remove charges for cost of congestion and cost of marginal losses from the Settlement Statement as provided in Section 10.1(5) of Attachment AE, only if Western-UGP submits a FSE Schedule and E-Tag (if applicable) according to the procedures specified in Section 8.2.3.1 of Attachment AE for the Day-Ahead Market for the FSE transaction, consistent with the FSE Settlement Locations, and within the maximum MW capacity permissible under the FSE. Western-UGP must update the FSE Schedule with the lesser of (i) the cleared amount in the Day-Ahead Market or (ii) actual energy transacted that corresponds to the FSE.

(c) The Transmission Provider shall account for the FSE in the TCR Markets, but shall not allocate ARRs or assign TCRs to Western-UGP for a FSE.

(d) Western-UGP is responsible for coordinating the FSE Schedule data and ensuring the consistency of the FSE Schedules. The Market Monitor will monitor FSE Schedules in accordance with Section 4.6 of Attachment AG of this Tariff.

(e) The FSE Schedule associated with a Federal Power-Western-UGP resource will include provision of physical losses in accordance with Attachment M of this Tariff. The FSE Schedule associated with Statutory Load Obligations will not include the physical losses.

### 8.2.3.1 FSE Schedules

Western-UGP shall create FSE Schedules for all energy transacted under the FSE. For FSE Schedules, Western-UGP shall submit:

(i) FSE Schedules for the Resource Settlement Location within the Energy and Operating Reserve Markets.

(a) The FSE Schedule for the Resource shall be equal to the lesser of (1) the cleared amount in the Day-Ahead Market or (2) the submitted meter in Real-Time.

(ii) FSE Schedules for the Load Settlement Location or FSE Transfer Point within the Energy and Operating Reserve Markets.

(a) The FSE Schedule for Statutory Load Obligations shall be equal to the lesser of (1) the cleared amount in the Day-Ahead Market or (2) the submitted meter in Real-Time.

(iii) An E-Tag for FSE transactions with Resource Settlement Location or Load Settlement Location external to the Energy and Operating Reserve Markets.

(a) The FSE Schedule for an import shall be equal to the lesser of (1) Asset Owner's cleared import quantity in the Day-Ahead Market or (2) Asset Owner's cleared import quantity in Real-Time.

(b) The FSE Schedule for an export shall be equal to the lesser of (1) Asset Owner's cleared export quantity in the Day-Ahead Market or (2) Asset Owner's cleared export quantity in Real-Time.

(iv) Either the sum of the FSE Schedules for Resources or the sum of the FSE Schedules for Statutory Load Obligations shall be reduced to make the sum of the FSE Schedule for Resources plus Federal Power-Western-UGP resource imports as defined in Section 8.2.3.1 (iii)(a), excluding the losses submitted as described in Attachment M of the Tariff equal to the sum of the FSE Schedules for Statutory Load Obligations.

## 8.3 Calculation of Locational Marginal Prices, Locational Marginal Price Components, and Market Clearing Prices

An LMP shall be calculated for each Meter Settlement Location for the Day-Ahead Market and RTBM and shall be calculated as the price at that location based on the SCED and Operating Reserve clearing, the Dispatchable Resource Energy Offer Curve, Operating Reserve Offer prices and Resource characteristics submitted by Market Participants and data from the State Estimator. The following rules will be used in calculating the LMPs:

(1) LMPs are calculated by the Transmission Provider for each hour in the Day-Ahead Market as part of the SCED solution described under Sections 3.3.1 and 5.1.2 of this Attachment AE and each Dispatch Interval in the RTBM as part of the SCED solution described under Sections 3.3.1 and 6.2.2 of this Attachment AE. In performing these calculations, Dispatchable Resources will be eligible to set the LMP under the following conditions:

(a) The Dispatchable Resource must be operating below its maximum capacity limit;

(b) The Dispatchable Resource must be operating above its minimum capacity limit; and

(c) The Dispatchable Resource output must not be ramp rate constrained such that the Dispatchable Resource cannot achieve the optimal desired dispatch point under the economic dispatch.

(2) The Transmission Provider shall calculate LMPs, MCCs and MLCs for use in settlement as follows:

(a) An LMP, MCC and MLC shall be calculated for each Meter Settlement Location for each hour in the Day-Ahead Market and for every Dispatch Interval in the RTBM.

(b) The LMP, MCC and MLC for a load Settlement Location or a Demand Response Load location with multiple Meter Settlement Locations for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the load weighted average of LMPs calculated for Meter Settlement Locations aggregated to that Settlement Location or

Demand Response Load location for that hour or Dispatch Interval. The load weights utilized in this calculation for the Day-Ahead Market shall be based upon a historical Real-Time load calculated at each Meter Settlement Location by the State Estimator and for the RTBM shall be based upon the actual Real-Time load calculated at each Meter Settlement Location by the State Estimator in that Dispatch Interval.

(c) The LMP, MCC and MLC for a Resource Settlement Location for an hour in the Day-Ahead Market and for a Dispatch Interval in the RTBM shall equal the LMP, MCC and MLC calculated for that Settlement Location for the Resource or, in the case of a Block Demand Response Resource, the LMP, MCC and MLC calculated at the associated Demand Response Load location.

(d) The LMP, MCC and MLC for a Trading Hub Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the average of LMPs, MCCs and MLCs calculated for Price Nodes within the Trading Hub aggregated to that Trading Hub Settlement Location for that hour or Dispatch Interval.

(e) The LMP, MCC and MLC for a Resource Hub Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the weighted average of LMPs, MCCs and MLCs calculated for Price Nodes within the Resource Hub Settlement Location aggregated to that Resource Hub Settlement Location for that hour or Dispatch Interval. The weights utilized in this calculation shall be submitted by the Market Participant at the time the Resource Hub Settlement Location is created.

(f) The LMP, MCC and MLC for an External Interface Settlement Location for an hour within the Day-Ahead Market or a Dispatch Interval within the RTBM shall be equal to the weighted average of LMPs, MCCs and MLCs calculated for Price Nodes within the External Interface aggregated to that External Interface Settlement Location for that hour or Dispatch Interval. The weights utilized in this calculation for the Day-Ahead Market and

RTBM shall be determined by the Transmission Provider at the time the External Interface is created.

(3) If there is insufficient capacity to meet the Energy requirements on a system-wide basis, Energy requirements are reduced to meet available capacity and LMPs are calculated as described under Section 8.3.1.

(4) In the event a failure of the Day-Ahead Market systems results in the loss of the ability to clear the Day-Ahead Market in a timely manner, the TCR charge type described under Section 8.5.11 shall continue to be settled as part of the Day-Ahead Market settlement using the MCCs calculated for the corresponding Operating Day for the RTBM and the congestion revenue collected as part of the RTBM settlement. TCR uplift calculated under Section 8.5.12 shall be set equal to zero and the differences between amounts paid under Section 8.5.11 and available real-time congestion revenue shall be accounted for under Section 8.8. In the event a failure of the Day-Ahead Market systems results in the loss of the ability to clear the Day-Ahead Market, the Transmission Provider will set the Day-Ahead Market LMP, MLC, and MCP to zero.

(5) In the event a failure of the RTBM systems results in a loss of the ability to calculate LMPs, RTBM Energy will continue to be settled financially under this Tariff based upon estimated LMPs. The Transmission Provider shall notify Market Participants if RTBM Energy is to be settled using estimated prices.

(a) If the failure of the RTBM systems occurs for twelve (12) Dispatch Intervals or less, the estimated LMPs and LMP components shall be the most recently calculated LMPs, MCCs, and MLCs for each affected Settlement Location and shall be utilized for settlement purposes for each of the Dispatch Intervals in which LMP pricing data is missing.

(b) If the failure of the RTBM systems occurs for more than twelve (12) Dispatch Intervals, the Transmission Provider shall calculate LMPs, MCCs, and MLCs for the RTBM using mitigated Offers in a manner that reflects, as closely as practicable, the LMPs, MCCs, and MLCs that would have resulted but for the RTBM systems failure and shall use such LMPs, MCCs, and MLCs for settlement purposes for each of the Dispatch

Intervals in which LMP pricing data is missing. To the extent that the Transmission Provider is unable to calculate RTBM LMPs, MCCs, MLCs, and MCPs, the Transmission Provider shall use the LMPs, MCCs, MLCs, and MCPs generated in the Day-Ahead Market for RTBM settlement.

(6) If for any reason a portion of generation and load within the SPP Balancing Authority Area becomes isolated from the rest of the SPP Balancing Authority Area ("Island"), the Transmission Provider shall calculate LMPs, MCCs, and MLCs for the RTBM within the Island using mitigated Offers for Resources within the Island in a manner that reflects, as closely as practicable, the LMPs, MCCs, and MLCs within the Island that would have resulted as if the RTBM systems had calculated the values, and shall use such LMPs, MCCs, and MLCs for settlement purposes within the Island for each of the Dispatch Intervals.

## 8.3.1 Locational Marginal Price Calculations and Components

The LMP at a PNode is the cost of delivering an incremental MW of energy at that specific PNode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of energy causes a corresponding increase in shortage conditions where such Demand Curve prices and shortage conditions are as described under Section 8.3.4.2. The LMP at any PNode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC).

LMP Components at PNode i are calculated based upon the following formula:

LMPi = MEC + MLCi + MCCi

Where:

(1) MEC is the component of LMPi representing the marginal cost of Energy;

(2) MLCi is the component of LMPi representing the marginal cost of losses at PNode i relative to the Reference Bus;

(3) MCCi is the component of LMPi representing the marginal cost of congestion at ENode i relative to the Reference Bus; and

(4) The Reference Bus represents the network distributed load bus.

### 8.3.1.1 Marginal Losses Component Calculation

The MLCi at each Pnode i is defined by the following equations:

MLCi = -MLSFi * MEC

MLSFi = (SPP Losses) / Pi

Where:

(1) SPP Losses = SPP Transmission System losses;

(2) MLSFi = Marginal loss sensitivity factor at PNode i;

(3) MEC is the component of LMPi representing the marginal cost of Energy;

(4) Pi = Net injection at PNode i.

The MLSFi is a linearized estimate of the change in SPP transmission losses that will result from a 1 MW injection at PNode i coupled with a corresponding withdrawal at the Reference Bus to maintain global power balance. Marginal loss sensitivity factors are dependent on topology, node injections and node withdrawals.

### 8.3.1.2 Marginal Congestion Component Calculation

The MCC at each PNode i is defined by the following equations:

MCCi = - ( Sensik * SPk )

Sensik = Flowk / Pi

Where:

(1) K is the number of transmission constraints;

(2) Sensik is the linearized estimate of the change in the constraint k flow resulting from an incremental energy injection at PNode i coupled with an incremental energy withdrawal at the Reference Bus;

(3) Flowk = Calculated flow for constraint k;

(4) SPk = is the Shadow Price of constraint k;

(5) Pi = Net injection at PNode i.

### 8.3.1.3 Marginal Energy Component Calculation

The MEC is defined as the computed LMP at the Reference Bus. By definition, MCC and MLC components are zero (0) at the Reference Bus.

### 8.3.2 Violation Relaxation Limit

The Day-Ahead Market, RUC and RTBM SCED enforce a number of operating constraints in developing the co-optimized market solution. In certain situations, attempting to enforce all constraints may result in a solution that is not feasible at a Shadow Price less than an appropriately priced VRL. In such cases, the Transmission Provider must apply VRLs in SCED. The VRL values are listed in Addendum 1 to this Attachment AE.

There are five (5) categories of constraints and associated VRLs: (1) Resource capacity constraints; (2) Resource ramp constraints; (3) global power balance constraints; (4) operating constraints (which include Price Node ("Pnode"), Manual, Watch List, flowgate and Real-Time contingency analysis ("RTCA") constraints) and (5) Regulation-up plus spinning reserve requirement constraint. A higher VRL value is an indication of the relative priority for enforcing the constraint type. For example, the VRL value assigned to a ramp rate limit exceeds that assigned to a flowgate limit indicating that the flowgate constraint should be relaxed before the ramp rate constraint. If the VRL with the lowest value will not allow SCED to balance the Energy obligations, a higher VRL will be applied. In the case of the operating constraint VRLs, the values limit the cost of the dispatch needed to balance system injections and withdrawals by capping the Shadow Price depending upon the level of the violation. Similarly, the Spinning Reserve constraint VRL limits the costs of redispatch needed to meet the Spinning Reserve requirement by capping the Spinning Reserve Shadow Price.

## 8.3.3 Impact of Violation Relaxation Limits on Security Constrained Economic Dispatch

The applicable VRLs impact SCED in the following manner: VRLs are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE.

(1) When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is reached but not exceeded, it is referred to as "binding." In this state, VRLs are not applicable and LMPs/DLMPs are calculated through the normal SCED solution; and

(2) When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is exceeded and cannot be resolved, the applicable constraint is relaxed so that SCED can solve. The VRL values applied by SCED in this case act as a cap on the Shadow Price on the applicable constraint. LMPs/DLMPs are determined by the relaxed SCED solution.

### 8.3.3.1 Modifications to Violation Relaxation Limits

By August 1 of each year, the Transmission Provider shall produce a report with supporting documentation that will analyze the effectiveness of VRLs and associated values on reliability and prices. If changes are warranted, the Transmission Provider shall recommend changes to the appropriate stakeholder groups for consideration.

By November 1 of each year, taking into consideration the recommendations of stakeholders and staff, any changes to the VRLs or associated values must be approved for filing by the SPP Board of Directors and then filed with the Commission. The most recent Commission-approved VRLs and associated values shall be posted on the Transmission Provider's OASIS site and also are found in Addendum 1 to this Attachment AE.

### 8.3.4 Market Clearing Price Calculations

The MCP represents the cost of supplying an increment of Operating Reserve, taking into account lost opportunity cost and is composed of the marginal Operating Reserve costs and marginal costs associated with Operating Reserve scarcity. The Day-Ahead Market and RTBM MCPs at a Reserve Zone for Resources with cleared Regulation-Up Service, Regulation-Down Service, Spinning Reserve and/or Supplemental Reserve in that Reserve Zone are equal to the summation of the applicable Shadow Prices associated with the constraints as described in subsections (1) and (2) below. Calculation of MCPs for Expected Regulation-Up Mileage and Expected Regulation-Down Mileage are calculated as described in subsections (3) and (4) below:

(1) There are six sets of constraints which apply on both a system-wide basis and a Reserve Zone basis:

(a) A Contingency Reserve plus Regulation-Up constraint is equal to the sum of the Contingency Reserve requirement and the Regulation-Up requirement;

(b) A Regulation-Up plus Spinning Reserve constraint is equal to the sum of the Regulation-Up requirement and the Spinning Reserve requirement;

(c) A Regulation-Up constraint is equal to the Regulation-Up requirement;

(d) A Regulation-Down constraint is equal to the Regulation-Down requirement;

(e) A Ramp Capability Down constraint is equal to the Ramp Capability Down requirement; and

(f) A Ramp Capability Up constraint is equal to the Ramp Capability Up requirement.

(2) Operating Reserve MCPs for each Reserve Zone are calculated as follows:

(a) The Regulation-Up Service MCP is equal to sum of the Shadow Prices for the system-wide and zonal Regulation-Up constraints, system-wide and zonal Regulation-Up plus Spinning Reserve constraints and the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

(b) The Spinning Reserve MCP is equal to the sum of the Shadow Prices for the system-wide and zonal Regulation-Up plus Spinning Reserve

constraints and the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

(c) The Supplemental Reserve MCP is equal to the sum of the Shadow Prices for the system-wide and zonal Contingency Reserve plus Regulation-Up constraints;

(d) The Regulation-Down MCP is equal to the Shadow Price for the system-wide and zonal Regulation-Down constraint;

(e) The Ramp Capability Down MCP is equal to the Shadow Price for the system-wide and zonal Ramp Capability Down constraint; and

(f) The Ramp Capability Up MCP is equal to the Shadow Price for the system-wide and zonal Ramp Capability Up constraint.

(3) RTBM MCPs for Expected Regulation-Up Mileage are set equal to the highest Regulation-Up Mileage Offer of all Resources economically cleared to provide Regulation-Up Service in a particular Dispatch Interval. For Resources submitting a Regulation-Up Service dispatch status as described under Section 4.1(11)(c) of this Attachment AE, the cleared amount of Regulation-Up Service MW must be greater than the submitted self-schedule MW in order to be considered economically cleared;

(4) RTBM MCPs for Expected Regulation-Down Mileage are set equal to the highest Regulation-Down Mileage Offer of all Resources economically cleared to provide Regulation-Down Service in a particular Dispatch Interval. For Resources submitting a Regulation-Down Service dispatch status as described under Section 4.1(11)(c) of this Attachment AE, the cleared amount of Regulation-Down Service MW must be greater than the submitted self-schedule MW in order to be considered economically cleared;

(5) In the event a system-wide failure of the RTBM systems results in a loss of the ability to calculate MCPs, RTBM Operating Reserve will continue to be settled financially under this Tariff based upon estimated MCPs. The Transmission Provider shall notify Market Participants if RTBM Operating Reserve is to be settled using estimated prices.

(a) If the failure of the RTBM systems occurs for twelve (12) Dispatch Intervals or less, the estimated MCPs shall be the most recently calculated MCPs for each affected Reserve Zone and shall be utilized for settlement purposes for each of the Dispatch Intervals in which MCP pricing data is missing.

(b) If the failure of the RTBM systems occurs for more than twelve (12) Dispatch Intervals, the Transmission Provider shall calculate MCPs using mitigated Offers for the RTBM in a manner that reflects, as closely as practicable, the MCPs that would have resulted but for the RTBM systems failure, and shall use such MCPs for settlement purposes for each of the Dispatch Intervals in which MCP pricing data is missing. To the extent that the Transmission Provider is unable to calculate RTBM MCPs, the Transmission Provide shall use the MCPs generated in the Day-Ahead Market for RTBM settlement.

(6) If for any reason a portion of generation and load within the SPP Balancing Authority Area becomes isolated from the rest of the SPP Balancing Authority Area ("Island"), RTBM MCPs will not be calculated and procurement of Operating Reserve within the Island will not be performed.

### 8.3.4.1 Impact of Violation Relaxation Limits on Security Constrained Economic Dispatch (MCP)

The applicable VRLs impact SCED in the following manner: VRLs are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE.

(1) When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is reached but not exceeded, it is referred to as "binding." In this state, VRLs are not applicable and MCPs are calculated through the normal SCED solution; and

(2) When a Resource capacity, global power balance, Resource ramp, Spinning Reserve, or operating constraint is exceeded and cannot be resolved, the applicable constraint is relaxed so that SCED can solve. The VRL values applied

by SCED in this case act as a cap on the Shadow Price on the applicable Operating Constraint. MCPs are determined by the relaxed SCED solution.

**8.3.4.2 Impact of Scarcity Pricing on Locational Marginal Prices and Market Clearing Prices**

(1) Demand Curves are applied independently in the dispatch solution and pricing solution described in Section 3.3.1 of this Attachment AE. The Transmission Provider shall use Demand Curves to reflect Scarcity Prices in both the Day-Ahead Market and RTBM during times of Energy and/or Operating Reserve shortages, either on a system-wide and/or Reserve Zone basis.

(2) Scarcity Prices are reflected in MCPs using the following Demand Curves:

(a) The Contingency Reserve Demand Curve Price is applied on both a system-wide basis and zonal basis and is equal to the product of the applicable Contingency Reserve Scarcity Factor, defined in accordance with the Market Protocols, and the sum of the safety-net Energy Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE.

(b) The Regulation-Up Service Scarcity Pricing is determined in accordance with the following subparagraphs – 8.3.4.2(2)(b)(i) and (ii) – provided that maximum Regulation-Up Demand Curve Price is equal to the sum of the Regulation-Up Service Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE and is applied on a system-wide basis.

(i) If Regulation-Up shortages are caused by insufficient ramping capabilities, then the Regulation-Up Demand Curve Price is equal to the product of the applicable Regulation-Up Scarcity Factor and the Regulation Base Demand Price.

(ii) If Regulation-Up shortages are the result of insufficient capacity, then the Regulation-Up Demand Curve Price is equal to the greater of (a) the marginal Resource clearing cost or (b) the product of the applicable Regulation-Up Scarcity Factor and the Regulation Base Demand Price.

(c) The Regulation-Down Service Scarcity Pricing is determined in accordance with the following subparagraphs – 8.3.4.2(2)(c)(i) and (ii) – provided that maximum Regulation-Down Demand Curve Price is equal to the sum of the Regulation-Down Service Offer cap and the Contingency Reserve Offer cap as specified in Section 4.1.1 of this Attachment AE and is applied on a system-wide basis.

(i) If Regulation-Down shortages are caused by insufficient ramping capabilities, then the Regulation-Down Demand Curve Price is equal to the product of the applicable Regulation-Down Scarcity Factor and the Regulation Base Demand Price.

(ii) If Regulation-Down shortages are the result of insufficient capacity, then the Regulation-Down Demand Curve Price is equal to the greater of (a) the marginal Resource clearing cost and (b) the product of the applicable Regulation-Down Scarcity Factor and the Regulation Base Demand Price.

(d) Ramp Capability Up – The Transmission Provider calculates and posts Ramp Capability Up Scarcity Pricing in accordance with the following rules:

(i) The maximum Scarcity Price is calculated as the average cost per MW for all eligible Resources to recover their qualified cold Start-Up Offer , No-Load Offer, and Energy at minimum cost at their Maximum Normal Operating Limit. Eligible Resources are Resources which offer a cold start-up time of 10 minutes or less, a Minimum Run Time of 60 minutes or less, and are not on outage. The maximum Scarcity Price is equal to the cold Start-Up Offer plus the product of the Minimum Run Time and the No-Load Offer plus the Energy at minimum cost all divided by the Resource's Maximum Normal Capacity Operating Limit or Maximum Discharge Limit as applicable. (ii) The maximum Scarcity Price will be calculated each month using the previous three months offer data.

(iii) The Demand Curve levels for Ramp Capability Up will be equal to:

1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.

2. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, 1/3 of the maximum Scarcity Price.

3. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 1/2 of the maximum Scarcity Price.

4. Shortages greater than 15% but less than or equal to 25% of the requirement will equal, to the nearest dollar, 2/3 of the maximum Scarcity Price.

5. Shortages greater than 25% but less than or equal to 40% of the requirement will equal, to the nearest dollar, 5/6 of the maximum Scarcity Price.

6. Shortages greater than 40% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

(iv) The minimum amount for the Ramp Capability Up Demand Curve prices will be limited to $10.

(e) Ramp Capability Down – The Transmission Provider calculates and posts Ramp Capability Down Scarcity Pricing in accordance with the following rules:

(i) The maximum Scarcity Price is calculated as the average cost per MW for all eligible Resources to recover their qualified cold Start-Up Offer, No-Load Offer, and Energy at minimum cost at their Maximum Normal Operating Limit. Eligible Resources are Resources which offer a cold Start-Up Time of 10 minutes or less, a Minimum Run Time of 60 minutes or less, and are not on outage. The maximum Scarcity Price is equal to the cold Start-Up Offer plus the product of the Minimum Run Time and the No-Load Offer plus the Energy at minimum cost all divided by the Resource's Maximum Normal Capacity Operating Limit or Maximum Discharge Limit as applicable.

(ii) The maximum Scarcity Price will be calculated each month using the previous three months offer data.

(iii) The Demand Curve levels for Ramp Capability Down will be equal to:

1. Shortages up to or equal to 5% of the requirement will equal, to the nearest dollar, 1/6 of the maximum Scarcity Price.

2. Shortages greater than 5% but less than or equal to 10% of the requirement will equal, to the nearest dollar, 1/3 of the maximum Scarcity Price.

3. Shortages greater than 10% but less than or equal to 15% of the requirement will equal, to the nearest dollar, 1/2 of the maximum Scarcity Price.

4. Shortages greater than 15% but less than or equal to 25% of the requirement will equal, to the nearest dollar, 2/3 of the maximum Scarcity Price.

5. Shortages greater than 25% but less than or equal to 40% of the requirement will equal, to the nearest dollar, 5/6 of the maximum Scarcity Price.

6. Shortages greater than 40% of the requirement will equal, to the nearest dollar, the maximum Scarcity Price.

(iv) The minimum amount for the Ramp Capability Down Demand Curve prices will be limited to $0.

(3) Scarcity Prices will be reflected in LMPs when serving an incremental MW of energy worsens the Operating Reserve capacity shortage condition.

(4) During Operating Reserve shortage conditions on a system wide basis and/or zonal basis, Market Clearing Prices are impacted by Demand Curves as follows:

(a) If there is a system-wide shortage of Contingency Reserve, no shortage of Regulation-Up or Regulation-Down, and all zonal minimum requirements have been met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up and Regulation-Down constraint Shadow Prices are calculated normally and do not reflect the Regulation-Up or Regulation-Down Demand Curve Prices;

(iv) the Supplemental Reserve MCP shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE; and

(v) the Spinning Reserve MCP and the Regulation-Up MCP shall also reflect the Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE respectively.

(b) If there is a system-wide shortage of Contingency Reserve, a shortage of Regulation-Up, no shortage of Regulation-Down, and all zonal minimum requirements have been met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the system-wide Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(iii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iv) the Regulation-Down constraint Shadow Price is calculated normally and does not reflect the Regulation-Down Demand Curve Price;

(v) the Supplemental Reserve MCP shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP shall also reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(b) of this Attachment AE; and

(vii) the Regulation-Up MCP shall reflect the summation of the Contingency Reserve Demand Curve Price and the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(c) If there is a system-wide shortage of Contingency Reserve, no shortage of Regulation-Up or Regulation-Down, and zonal minimum requirements cannot not be met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up and Regulation-Down constraint Shadow Prices are calculated normally and do not reflect the Regulation-Up or Regulation-Down Demand Curve Prices;

(iv) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(v) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP and Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall

reflect the Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE respectively; and

(vii) the Spinning Reserve MCP and Regulation-Up MCPs in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculations described under Sections 8.3.4(2)(b) and 8.3.4(2)(a) of this Attachment AE, respectively.

(d) If there is a system-wide shortage of Contingency Reserve, a shortage of Regulation-Up, no shortage of Regulation-Down, and zonal minimum requirements cannot not be met:

(i) the system-wide Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(ii) the zonal Regulation-Up plus Contingency Reserve constraint Shadow Price is set equal to the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(iv) the Regulation-Down constraint Shadow Price is calculated normally and does not reflect the Regulation-Down Demand Curve Price;

(v) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(vi) the Spinning Reserve MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the Contingency Reserve Demand Curve price through the

calculations described under Section 8.3.4(2)(b) of this Attachment AE;

(vii) the Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the summation of the Regulation-Up Demand Curve Price and the Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE;

(viii) the Supplemental Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(c) of this Attachment AE;

(ix) the Spinning Reserve MCP in all Reserve Zones in which the minimum requirements have not been met shall reflect the summation of the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(b) of this Attachment AE; and

(x) the Regulation-Up MCP in all Reserve Zones in which the minimum requirements have been met shall reflect the summation of the Regulation-Up Demand Curve Price, the system-wide Contingency Reserve Demand Curve Price and the zonal Contingency Reserve Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(e) If there is a system-wide shortage of Regulation-Up, no shortage of Regulation-Down, no shortage of Contingency Reserve, and all zonal minimum requirements have been met:

(i) the Regulation-Up constraint Shadow Price is set equal to the Regulation-Up Demand Curve Price;

(ii) the Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Supplemental Reserve MCP and Spinning Reserve MCP shall not reflect the Contingency Reserve Demand Curve Price through the calculation described under Sections 8.3.4(2)(c) and 8.3.4(b) of this Attachment AE respectively; and

(iv) the Regulation-Up MCP shall reflect the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE.

(f) If there is a system-wide shortage of Regulation-Down, no shortage of Regulation-Up, no shortage of Contingency Reserve, and all zonal minimum requirements have been met:

(i) the Regulation-Down constraint Shadow Price is set equal to the Regulation-Down Demand Curve Price;

(ii) the Regulation-Up plus Contingency Reserve constraint Shadow Price is calculated normally and does not reflect the Contingency Reserve Demand Curve Price;

(iii) the Regulation-Up constraint Shadow Price is calculated normally and does not reflect the Regulation-Up Demand Curve Price;

(iv) the Supplemental Reserve MCP and Spinning Reserve MCP shall not reflect the Contingency Reserve Demand Curve Price through the calculation described under Sections 8.3.4(2)(c) and 8.3.4(b) of this Attachment AE respectively;

(v) the Regulation-Up MCP shall not reflect the Regulation-Up Demand Curve Price through the calculation described under Section 8.3.4(2)(a) of this Attachment AE; and

(vi) the Regulation-Down MCP shall reflect the Regulation-Down Demand Curve Price through the calculation described under Section 8.3.4(2)(d) of this Attachment AE.

(g) If there is a system-wide shortage of Ramp Capability Up, the Ramp Capability Up MCP will be set equal to the Ramp Capability Up Demand Curve price. The Ramp Capability Up Demand Curve price will be reflected in the LMP.

(h) If there is a system-wide shortage of Ramp Capability Down, the Ramp Capability Down MCP will be set equal to the Ramp Capability Down Demand Curve price. The Ramp Capability Down Demand Curve price will be reflected in the LMP.

### 8.3.4.3 Operating Reserve Scarcity Factors

The Transmission Provider calculates and posts Contingency Reserve Scarcity Factors, Regulation-Up Scarcity Factors and Regulation-Down Scarcity Factors as described below.

(1) The Contingency Reserve Scarcity Factor varies based on the MW amount of Contingency Reserve shortage. The Contingency Reserve shortage MW values that result in changes to the scarcity price values are calculated by the Transmission Provider based on the projected Most Severe Single Contingency (MSSC) for the Operating Day in accordance with the following rules:

a. For Contingency Reserve shortages less than or equal to one-half of the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Reserve Scarcity Factor will be set to 0.25.

b. For Contingency Reserve Shortages greater than one-half the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC but less than or equal to SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Contingency Reserve Scarcity Factor will be set to 0.5.

c. For Contingency Reserve Shortages greater than the SPP Reserve Sharing Group Contingency Reserve requirement above the MSSC, the Contingency Reserve Scarcity Factor will be set to 1.

(2) The Regulation-Up Scarcity Factor varies based on the MW amount of Regulation-Up shortage. The Regulation-Up shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Up deployment data in accordance with the following rules:

a. For Regulation-Up reserve shortages less than or equal to 30 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 1.

b. For Regulation-Up reserve shortages greater than 30 percent but less than or equal to 50 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 2.

c. For Regulation-Up reserve shortages greater than 50 percent but less than or equal to 70 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 3.

d. For Regulation-Up reserve shortages greater than 70 percent but less than or equal to 80 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 4.

e. For Regulation-Up reserve shortages greater than 80 percent but less than or equal to 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 5.

f. For Regulation-Up Reserve shortages greater than 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(b).

(3) The Regulation-Down Scarcity Factor varies based on the MW amount of Regulation-Down shortage. The Regulation-Down shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission

Provider using historical Regulation-Down deployment data in accordance with the following rules:

a. For Regulation-Down reserve shortages less than 30 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 1.

b. For Regulation-Down reserve shortages greater than 30 but less than or equal to 50 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 2.

c. For Regulation-Down reserve shortages greater than 50 but less than or equal to 70 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 3.

d. For Regulation-Down reserve shortages greater than 70 but less than or equal to 80 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 4.

e. For Regulation-Down reserve shortages greater than 80 but less than or equal to 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 5.

f. For Regulation-Down reserve shortages greater than 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(c) of this Attachment AE.

### 8.3.4.4 Regulation Base Demand Price

On a monthly basis, the Transmission Provider calculates and posts a Regulation Base Demand Price as a function of the cost to commit a Resource to provide ramp or capacity to the market in accordance with the following rules:

(1) Regulation Base Demand Price is the average cost per MW for all Resources to recover their qualified cold start-up, no-load, and Energy costs at their Minimum Normal Operating Limit or Minimum Discharge Limit, as applicable.

(2) For each interval and Resource, a cold start-up time must be less than or equal to 10 minutes and the Real-Time commitment status must be Market, Reliability, or Self for the Resource costs to qualify for inclusion in the calculation.

(3) By interval and Resource, the average cost per MW is based on the costs (cold start-up, no-load, and Energy) that would be incurred at the minimum load and minimum run time from three months of historical offer data.

The Transmission Provider may re-calculate the Regulation Base Demand Price more frequently than once a month as needed in order to reflect the operational cost of Resources if projected to be significantly different than historical based offer data.

## 8.4 Price Corrections

There may be instances in which Software Errors and/or Data Errors affect the prices in a manner that is inconsistent with economic efficiency. If such an instance occurs, price corrections in the Day-Ahead and Real-Time Balancing Markets may be performed in accordance with paragraph (1) of this Section 8.4 of this Attachment AE.

(1) The Transmission Provider, in its sole discretion, may make LMP and MCP corrections, and such corrections shall be made in accordance with this Section 8.4. Such price corrections may only be performed if the underlying causes result in a significant Day-Ahead or Real-Time Balancing Market impact. In the exercise of its discretion pursuant to this Section 8.4, the Transmission Provider may consider all relevant facts, including, but not limited to, the degree of the economic impact to the market results in terms of production cost. For purposes of this section, "production cost" is defined as the settlement cost for the market and can be calculated as the sum of the cleared MW * LMP plus cleared OR * MCP plus Start-Up and No-Load costs for all Resources.

(2) If the Transmission Provider, in its sole discretion, determines that an error requiring correction has occurred, the Transmission Provider shall address such errors in accordance with the following procedures:

(a) The Transmission Provider shall notify Market Participants of the contemplated price correction.

(b) If the Transmission Provider provides the notification described in (3)(a) later than 1700 hours five (5) calendar days following the operating day in which the LMPs and MCPs would be affected by the contemplated price correction, the Transmission Provider shall request Commission approval prior to making the price correction.

(c) If the Transmission Provider performs a price correction for the Day-Ahead Market, it shall recalculate LMPs, MCPs, and Day-Ahead Market cleared amounts in a manner that reflects, as closely as practicable, the

LMPs and MCPs that would have resulted but for the relevant Software Error or Data Error while maintaining the original Day-Ahead Market unit commitment. The Transmission Provider shall perform any necessary Resettlement using the recalculated Day-Ahead Market results. Such recalculated Day-Ahead Market results shall be provided to Market Participants in the same manner as the original Day-Ahead Market results determined in the ordinary course of business.

(d) If the Transmission Provider performs a price correction for the RTBM, it shall recalculate LMPs and MCPs for the RTBM in a manner that reflects, as closely as practicable, the LMPs and MCPs that would have resulted but for the relevant Software Error or Data Error and shall perform any necessary Resettlement using these recalculated values. Such recalculated LMPs and MCPs shall be provided to Market Participants in the same manner as LMPs and MCPs determined in the ordinary course of business. Compensation to Market Participants in connection with recalculated prices in the RTBM shall be as follows:

(i) For instances where the recalculated RTBM LMP is less than a Resource's Energy Offer Curve price, compensation shall be as described under Section 8.6.6(1) of this Attachment AE;

(ii) For instances where a Resource's recalculated RTBM LMP is greater than the Day-Ahead Market LMP and the Market Participant is buying back its Day-Ahead Market position as a result of a Dispatch Instruction, compensation shall be as described under Section 8.6.6(2) of this Attachment AE except that the MW amount eligible for compensation shall be equal to the difference between the Resource's Day-Ahead Market MW position and the greater of (1) that Resource's actual MW output in the Dispatch Interval or (2) the Resource's average Setpoint Instruction in the Dispatch Interval;

(iii) For instances where a Resource's recalculated RTBM Operating Reserve product MCP is greater than the Day-Ahead Market

Operating Reserve product MCP and the Market Participant is buying back its Day-Ahead Market Operating Reserve product position resulting from the Transmission Provider clearing all or a portion of that Operating Reserve product on a different Resource in the market solution, compensation shall be as described under Section 8.6.6(3) of this Attachment AE.

## 8.5 Day-Ahead Market Settlement

Settlement calculations for Energy and Operating Reserve in the Day-Ahead Market are based upon the results of the Day-Ahead Market clearing for that Operating Day as described in Section 5.1.3 of this Attachment AE.

The following Subsections describe the Day-Ahead Market settlement charge types. For each charge type, the calculation is performed at the hourly level for each Asset Owner at each Settlement Location. The Transmission Provider shall calculate hourly summations for each Market Participant for all Asset Owners it represents and shall calculate daily summations as specified in the Market Protocols.

### 8.5.1 Day-Ahead Energy Amount

A Day-Ahead Market charge or payment for cleared Energy is calculated at each Settlement Location for each Asset Owner for each hour as follows:

(1) For Energy associated with loads and Self-Charging MSRs:

The Day-Ahead Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Load Energy Hourly Quantity) - (Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules)]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with that load Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Load Energy Hourly Quantity is the MW quantity associated with cleared Demand Bids at that load Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner's Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that load Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(2) For Energy associated with Resources and MSRs providing a market service:

The Day-Ahead Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Resource Energy Hourly Quantity) - (Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules)]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with that Resource Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Resource Energy Hourly Quantity is the MW quantity associated with cleared Resource Offers at that Resource Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner's Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that Resource Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(3) For Energy associated with Import Interchange Transactions:

Day-Ahead Non-Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Import Energy Hourly Quantity) – (Day-Ahead Non-Asset Energy Bilateral Settlement Schedules)]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Import Energy Hourly Quantity is the MW quantity associated with cleared Import Interchange Transaction Offers at that External Interface Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner's Day-Ahead Non-Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(4) For Energy associated with Export Interchange Transactions:

Day-Ahead Non-Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Cleared Export Energy Hourly Quantity) – (Day-Ahead Non-Asset Energy Bilateral Settlement Schedules)]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Export Energy Hourly Quantity is the MW quantity associated with cleared Export Interchange Transaction Offers at that External Interface Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner's Day-Ahead Non-Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(5) For Energy associated with remaining Bilateral Settlement Schedules:

Day-Ahead Non-Asset Energy Hourly Amount =

(Day-Ahead LMP) * [(Day-Ahead Non-Asset Energy Bilateral Settlement Schedules) * (-1)]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Non-Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at Settlement Locations other than External Interface Settlement Locations, that Asset Owner's load Settlement Locations or that Asset Owner's Resource Settlement Locations, as submitted in accordance with Section 8.2.1 of this Attachment AE.

(6) For Energy associated with Virtual Energy Bids:

Day-Ahead Virtual Energy Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Cleared Virtual Energy Bid Hourly Quantity)

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Virtual Energy Bid Hourly Quantity is the MW quantity associated with cleared Virtual Energy Bids at that Settlement Location as described under Section 5.1.3 of this Attachment AE.

(7) For Energy associated with Virtual Energy Offers:

Day-Ahead Virtual Energy Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Cleared Virtual Energy Offer Hourly Quantity)

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Virtual Energy Offer Hourly Quantity is the MW quantity associated with cleared Virtual Energy Offers as described under Section 5.1.3 of this Attachment AE at that Settlement Location.

### 8.5.2 Day-Ahead Regulation Service Amount

A Day-Ahead Market payment for cleared Regulation-Up Service and cleared Regulation-Down Service will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

(1) Regulation-Up Service

Day-Ahead Regulation-Up Service Hourly Amount =

[(Day-Ahead MCP) * (Day-Ahead Cleared Regulation-Up Service Hourly Quantity)] * (-1)

(a) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Regulation-Up Service associated with the Reserve Zone in which the applicable Resource is located.

(b) An Asset Owner's Day-Ahead Cleared Regulation-Up Service Hourly Quantity is the MW quantity associated with cleared Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE.

(2) Regulation-Down Service

Day-Ahead Regulation-Down Service Hourly Amount =

[(Day-Ahead MCP) * (Day-Ahead Cleared Regulation-Down Service Hourly Quantity)] * (-1)

(a) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Regulation-Down Service associated with the Reserve Zone in which the applicable Resource is located.

(b) An Asset Owner's Day-Ahead Cleared Regulation-Down Service Hourly Quantity is the MW quantity associated with cleared Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE.

### 8.5.3 Day-Ahead Spinning Reserve Amount

A Day-Ahead Market payment for cleared Spinning Reserve will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

Day-Ahead Spinning Reserve Hourly Amount =

[(Day-Ahead MCP) * (Day-Ahead Cleared Spinning Reserve Hourly Quantity)] * (-1)

(1) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Spinning Reserve associated with the Reserve Zone in which the applicable Resource is located.

(2) An Asset Owner's Day-Ahead Cleared Spinning Reserve Hourly Quantity is the MW quantity associated with cleared Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE.

### 8.5.4 Day-Ahead Supplemental Reserve Amount

A Day-Ahead Market payment for cleared Supplemental Reserve will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

Day-Ahead Supplemental Reserve Hourly Amount =

[(Day-Ahead MCP) * (Day-Ahead Cleared Supplemental Reserve Hourly Quantity)] * (-1)

(1) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Supplemental Reserve associated with the Reserve Zone in which the applicable Resource is located.

(2) An Asset Owner's Day-Ahead Cleared Supplemental Reserve Hourly Quantity is the MW quantity associated with cleared Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE.

### 8.5.5 Day-Ahead Regulation-Up Service Distribution Amount

A Day-Ahead Market charge for Regulation-Up Service procurement costs calculated under Section 8.5.2(1) will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Regulation-Up Service Hourly Distribution Amount =
[(Day-Ahead Regulation-Up Service Obligation) * (Day-Ahead Regulation-Up Procurement Rate)]

(1) An Asset Owner's Day-Ahead Regulation-Up Service Obligation in each Reserve Zone is equal to the system wide total of all cleared Regulation-Up Service multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Regulation-Up Service.

(2) For a Reserve Zone that clears more Regulation-Up Service than the sum of Asset Owners' Day-Ahead Regulation-Up Service Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Regulation-Up Service Procurement Rate is equal to the Regulation-Up Service MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Regulation-Up Service than the sum of Asset Owners' Day-Ahead Regulation-Up Service Obligations for that Reserve Zone, the Day-Ahead Regulation-Up Service Procurement Rate is as follows:

Day-Ahead Regulation-Up Service Procurement Rate =
{(Reserve Zone Regulation-Up Service MCP * Total of cleared Regulation-Up Service for that Reserve Zone) + [(Weighted Average Regulation-Up Service MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Regulation-Up Service Obligations for that Reserve Zone - Total of cleared Regulation-Up Service for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Regulation-Up Service Obligations for that Reserve Zone).

### 8.5.6 Day-Ahead Regulation-Down Service Distribution Amount

A Day-Ahead Market charge for Regulation-Down Service procurement costs calculated under Section 8.5.2(2) will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Regulation-Down Service Hourly Distribution Amount =
[(Day-Ahead Regulation-Down Service Obligation) * (Day-Ahead Regulation-Down Service Procurement Rate)]

(1) An Asset Owner's Day-Ahead Regulation-Down Service Obligation in each Reserve Zone is equal to the system wide total of all cleared Regulation-Down Service multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Regulation-Down.

(2) For a Reserve Zone that clears more Regulation-Down Service than the sum of Asset Owners' Day-Ahead Regulation-Down Service Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Regulation-Down Service Procurement Rate is equal to the Regulation-Down Service MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Regulation-Down Service than the sum of Asset Owners' Day-Ahead Regulation-Down Service Obligations for that Reserve Zone, the Day-Ahead Regulation-Down Service Procurement Rate is as follows:

Day-Ahead Regulation-Down Service Procurement Rate =
{(Reserve Zone Regulation-Down Service MCP * Total of cleared Regulation-Down Service for that Reserve Zone) + [(Weighted Average Regulation-Down Service MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Regulation-Down Service Obligations for that Reserve Zone - Total of cleared Regulation-Down Service for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Regulation-Down Service Obligations for that Reserve Zone).

### 8.5.7 Day-Ahead Spinning Reserve Distribution Amount

A Day-Ahead Market charge for Spinning Reserve procurement costs calculated under Section 8.5.3 will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Spinning Reserve Hourly Distribution Amount =

[(Day-Ahead Spinning Reserve Obligation) * (Day-Ahead Spinning Reserve Procurement Rate)]

(1) An Asset Owner's Day-Ahead Spinning Reserve Obligation in each Reserve Zone is equal to the system wide total of all cleared Spinning Reserve multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Spinning Reserve and Spinning Reserve being supplied pursuant to Section 4.3.3(3) and of this Attachment AE.

(2) For a Reserve Zone that clears more Spinning Reserve than the sum of Asset Owners' Day-Ahead Spinning Reserve Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Spinning Reserve Procurement Rate is equal to the Spinning Reserve MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Spinning Reserve than the sum of Asset Owners' Day-Ahead Spinning Reserve Obligations for that Reserve Zone, the Day-Ahead Spinning Reserve Procurement Rate is as follows:

Day-Ahead Spinning Reserve Procurement Rate =

{(Reserve Zone MCP * Total of cleared Spinning Reserve for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Spinning Reserve Obligations for that Reserve Zone - Total of cleared Spinning Reserve for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Spinning Reserve Obligations for that Reserve Zone).

### 8.5.8 Day-Ahead Supplemental Reserve Distribution Amount

A Day-Ahead Market charge for Supplemental Reserve procurement costs calculated under Section 8.5.4 will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Supplemental Reserve Hourly Distribution Amount =

[(Day-Ahead Supplemental Reserve Obligation) * (Day-Ahead Supplemental Reserve Procurement Rate)]

(1) An Asset Owner's Day-Ahead Supplemental Reserve Obligation in each Reserve Zone is equal to the system wide total of all cleared Supplemental Reserve multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Supplemental Reserve and Supplemental Reserve being supplied pursuant to Section 4.3.3(3) of this Attachment AE.

(2) For a Reserve Zone that clears more Supplemental Reserve than the sum of Asset Owners' Day-Ahead Supplemental Reserve Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Supplemental Reserve Procurement Rate is equal to the Supplemental Reserve MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Supplemental Reserve than the sum of Asset Owners' Day-Ahead Supplemental Reserve Obligations for that Reserve Zone, the Day-Ahead Supplemental Reserve Procurement Rate is as follows:

Day-Ahead Supplemental Reserve Procurement Rate =

{(Reserve Zone MCP * Total of cleared Supplemental Reserve for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Supplemental Reserve Obligations for that Reserve Zone - Total of cleared Supplemental Reserve for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Supplemental Reserve Obligations for that Reserve Zone).

### 8.5.9 Day-Ahead Make Whole Payment Amount

(1) The Day-Ahead make whole payment amount is a payment to an Asset Owner and is calculated for each Resource with an associated Day-Ahead Market Commitment Period that was committed by the Transmission Provider including commitments from the Multi-Day Reliability Assessment as defined under Section 4.5.3 of this Attachment AE. Asset Owners of Resources previously committed by a local transmission operator to address a Local Emergency Condition are eligible to receive a Day-Ahead Market make whole payment if such commitment is included in the Day-Ahead Market; except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a Day-Ahead Market make whole payment. A payment is made to an Asset Owner when a Resource's costs are greater than the Day-Ahead Market revenues received during the Resource's Day-Ahead Market make whole payment eligibility period. The make whole payment is equal to this difference between those costs and revenues.

(2) A Resource's Day-Ahead Market make whole payment eligibility period is equal to a Resource's Day-Ahead Market Commitment Period except as defined herein. For Resources with an associated Day-Ahead Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two (2) Day-Ahead Market make whole payment eligibility periods are created. The first period begins in the first Operating Day in the hour that the Day-Ahead Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the Day-Ahead Market Commitment Period.

(3) The following cost recovery rules apply to each Day-Ahead Market make whole payment eligibility period. Offer costs are calculated using the Day-Ahead Market Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b)(iiv) below.

(a) There may be more than one Day-Ahead Market make whole payment eligibility period for a Resource in a single Operating Day for which a charge or payment is calculated. A single Day-Ahead Market make whole payment eligibility period is contained within a single Operating Day.

(b) A Resource's Day-Ahead Market commitment level offer costs include Start-Up Offer, Transition State Offer, and RUC remainder amount (as described in Section 8.5.9(3)(b)(v) of this Attachment AE) for a Day-Ahead Market make whole payment eligibility period in which that Resource is committed with a Day-Ahead Market Resource Offer commitment status under Section 4.1(10)(a), (b) or (c) of this Attachment AE, including commitments from the Multi-Day Reliability Assessment as described under Section 4.5.3 of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting all Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as described under Sections 4.1(10)(a) of this Attachment AE from all eligible commitment level Offer costs required to execute the Day-Ahead schedule associated with the Day-Ahead Market make whole payment eligibility period. The resulting difference represents either a charge or a payment and is a cost component when determining a Day-Ahead Market make whole payment.

(i) In any Day-Ahead Market make whole payment eligibility period for which the Day-Ahead Market SCUC algorithm did not consider the Resource's Start-Up Offer in the original commitment decision, except Day-Ahead Start-Up Offer costs associated with the commitments made under Sections 4.5 and 5.1.2(1)(b) of this Attachment AE that caused an additional scheduled start, the Resource's Start-Up Offer shall equal zero.

(ii) A Resource's Day-Ahead Market Start-Up Offer cost is not eligible for recovery in the following Day-Ahead Market make whole payment eligibility periods:

(1) For any Day-Ahead make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource's Day-Ahead Market Commit Time in addition to the Resource's Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource's Sync-To-Min Time; or

(2) For any Day-Ahead make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource's Day-Ahead Market Commit Time in addition to the Resource's Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource's Sync-To-Min Time.

(iii) When a RUC commitment is made at a point in time after the existing Day-Ahead Market commitment was made, but the RUC commitment is scheduled for a time adjacent and prior to the existing Day-Ahead Market commitment, the cost considered at the point of adjacency between the RUC and Day-Ahead Market commitments will be allocated between the two commitments for make whole payment purposes as described in (1) and (2) below.

(1) The cost allocated to the RUC make whole payment will not be greater than the difference between: (a) the Day-Ahead Market Start-Up Offer and Transition State Offer costs at the adjacency point of the RUC and Day-Ahead Market commitment; and (b) Day-Ahead Market Start-Up

Offer and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitment at the adjacency point.

(2) The commitment level cost in the Day-Ahead Market make whole payment is reduced by the non-negative cost allocated to the RUC make whole payment.

(iv) A Resource's Day-Ahead Market Transition State Offer costs for a Day-Ahead Market commitment are eligible for recovery in the Day-Ahead Market make whole payment eligibility period except when the Day-Ahead Market SCUC algorithm did not consider the Resource's Transition State Offer in the Day-Ahead commitment decision unless Transition State Offers costs are associated with manual commitments as described under Sections 4.5.2 and 5.1.2 of this Attachment AE.

(v) As described under Section 8.6.5(3)(g) of this Attachment AE, to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the adjacent RUC make whole payment eligibility period, any remaining RTBM Start-Up cost is carried forward for recovery in the adjacent Day-Ahead make whole payment eligibility period.

(vi) When a Resource loses eligibility to recover a Day-Ahead Market Start-Up Offer cost for the reason described in Section 8.5.9(3)(b)(ii)(1) of this Attachment AE, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (a) the Resource's Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitments; or (b) the ineligible Day-Ahead Market Start-Up Offer cost.

(vii) For each Day-Ahead Market make whole payment eligibility period within an Operating Day, a Resource's eligible Start-Up cost is divided by the lesser of (1) the Resource's applicable Minimum Run Time rounded down to the nearest hour or (2) twenty-four (24) hours, to achieve an hourly proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead commitments.

(1) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period meets or exceeds the duration of the divisor as described in (vii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the Day-Ahead Market make whole payment eligibility period.

(2) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period is less than the duration of the divisor as described in (vii) above, the hourly proration is multiplied by the number of participating hours to achieve a single Start-Up Offer amount to be included in the commitment level cost for that Day-Ahead Market make whole payment eligibility period. Any remaining Day-Ahead Market Start-Up Offer cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period in the next Operating Day.

(c) For an MCR, additional costs or revenues are incurred when the Resource has cleared Contingency Reserve, Ramp Capability Up, or Ramp Capability Down in the Day-Ahead Market and must buy back that position in Real-Time at an average hourly Real-Time MCP. These costs or revenues will be considered as an adjustment when determining a Day-Ahead Market make whole payment. These costs or revenues must be incurred during a time period in the Day-Ahead Market make whole

payment eligibility period in which the Resource is transitioning in Real-Time due to a Day-Ahead scheduled transition that is not forced by the Resource Offer. The Market Participant may also be eligible for adjustments to a Day-Ahead Market make whole payment for costs or revenues incurred during transition if the Resource is transitioning in Real-Time in response to a local transmission operator to address a Local Emergency Condition, (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE) then such Resources are not eligible to receive an adjustment to a Day-Ahead make whole payment for these costs or revenues. In such cases, the adjustment is equal to the Real-Time MCP multiplied by the Day-Ahead Market cleared Contingency Resource, Ramp Capability Up, or Ramp Capability Down MW amounts. Recovery of these costs of revenues is limited to the dispatch interval time periods defined by the Transition State Time submitted in the Resource Offer.

(d) If a Resource's self-commitment period is less than the Resource's Minimum Run Time, the Transmission Provider will relax the Resource's Minimum Run Time to equal the self-commit period.

(e) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the Day-Ahead Market, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.5.9(4)(a) of this Attachment AE for that period in the Day-Ahead Market make whole payment eligibility period.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given Day-Ahead Market make whole payment eligibility period is calculated as follows:

Day-Ahead Make Whole Payment Amount =

Maximum of [Either Zero or Sum of ((Day-Ahead Make Whole Payment Cost Amount in the Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Revenue Amount in the

Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Commitment Cost))] * (-1)

(a) An Asset Owner's Day-Ahead Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Day-Ahead Market No-Load Offer,

(ii) Energy cost associated with cleared Resource Energy, including MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Resource Energy by the cost of such Energy as calculated from the Resource's Day-Ahead Market Energy Offer Curve,

(iii) Regulation-Up Service cost associated with cleared Regulation-Up Service from Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up Service by the cost of such Regulation-Up Service as calculated from the Resource's Day-Ahead Market Regulation-Up Service Offer,

(iv) Regulation-Down Service cost, associated with cleared Regulation-Down Service from Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Down Service by the cost of such Regulation-Down Service as calculated from the Resource's Day-Ahead Market Regulation-Down Service Offer,

(v) Spinning Reserve cost, associated with: (1) cleared Spinning Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve by the Day-Ahead Spinning Reserve offer; and (2) cleared Spinning Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Spinning Reserve by the

Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Spinning Reserve requirement. Such costs shall exclude Spinning Reserve and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vi) Supplemental Reserve cost, associated with: (1) cleared Supplemental Reserve from Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Supplemental Reserve by the Day-Ahead Supplemental Reserve Offer; (2) cleared Supplemental Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve for Supplemental Reserve by the Day-Ahead Spinning Reserve offer to the extent that Spinning Reserve was cleared to meet the Supplemental Reserve requirement; and (3) cleared Supplemental Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Supplemental Reserve by the Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Supplemental Reserve requirement. Such costs shall exclude Supplemental Reserve, Spinning Reserve, and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vii) Day-Ahead Potential Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(1)(b) of this Attachment AE, and

(viii) Day-Ahead Potential Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(1)(b) of this Attachment AE,

(ix) Day-Ahead Combined Cycle Spinning Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Spinning Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period, and

(x) Day-Ahead Combined Cycle Supplemental Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Supplemental Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period.

(b) An Asset Owner's Day-Ahead Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Energy revenue associated with cleared Resource Energy, and MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, calculated by multiplying Resource Energy by Day-Ahead LMP at that Resource Settlement Location, and

(ii) The sum of the revenues calculated under Section 8.5.2, 8.5.3, 8.5.4, 8.5.26, 8.6.19(1) and 8.6.20(1) of this Attachment AE for that eligible Resource.

(c) An Asset Owner's Day-Ahead Make Whole Payment Commitment Cost Amount for each eligible Resource in the Day-Ahead Market Make Whole Payment Eligibility Periods is equal to:

(i) Day-Ahead Market Start-Up Offer or any RUC remainder amount as described in Section 8.6.5(3)(f) of this Attachment AE, plus

(ii) Day-Ahead Transition State Offer (for an MCR), plus

(iii) Any amount of Start-Up costs where the Resource loses eligibility to recover as described in Section 8.5.9(3)(b)(v) of this Attachment AE, minus

(iv) Any amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(ii) of this Attachment AE, minus

(v) All Start-Up and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE.

### 8.5.10 Day-Ahead Make Whole Payment Distribution Amount

A Day-Ahead Market system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.5.9 of this Attachment AE. The system-wide amount will be determined by multiplying an Asset Owner's system-wide distribution volume by a daily system-wide Day-Ahead Market make whole payment rate as described in this Section 8.5.10. The local amount for each Local Settlement Area impacted by a Local Reliability Issue will be determined as described in Section 8.6.7(B) of this Attachment AE.

The Day-Ahead System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

Day-Ahead System-Wide Make Whole Payment Distribution Amount =
(Day-Ahead SPP System-Wide Make Whole Payment Distribution Rate) * (Day-Ahead System-Wide Make Whole Payment Distribution Quantity))

(1) The Day-Ahead SPP System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.5.9, excluding make whole payments made to Resources committed to address a Local Reliability Issue or a Local Emergency Condition, divided by the sum of all Asset Owners' Day-Ahead System-Wide Make Whole Payment Distribution Quantities for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner's Day-Ahead System-Wide Make Whole Payment Distribution Quantity at a Settlement Location for an hour is equal to that Asset Owner's cleared Energy withdrawals at that Settlement Location for that hour. An Asset Owner's Energy withdrawal at a Settlement Location is calculated as the sum of cleared Demand Bids, cleared Self-Charging MSR Offers, Export Interchange Transaction Bids and Virtual Energy Bids at that Settlement Location.

### 8.5.11 Transmission Congestion Rights Funding Amount

The TCR funding amount can be either a charge or a payment to an Asset Owner and is calculated for each TCR instrument held by the Asset Owner. The TCR instruments funding amount is calculated for each hour as follows:

TCR Hourly Funding Amount =

TCR Hourly Quantity * [(Day-Ahead MCC at the source) – (Day-Ahead MCC at the sink)]

(1) Day Ahead MCC is as defined under Section 1 of this Attachment AE.

(2) TCR Hourly Quantity is the amount TCR MWs held on a particular source to sink path as awarded to that Asset Owner in the annual TCR auction, monthly TCR auctions or secondary market as described under Section 7 of the Attachment AE.

### 8.5.12 Transmission Congestion Rights Daily Uplift Amount

A Day-Ahead Market daily charge will be calculated as follows for each Asset Owner holding TCRs for each Operating Day to the extent that congestion revenues collected over the Operating Day are not sufficient to fund the net of the total charges and payments calculated under Section 8.5.11 over the Operating Day:

TCR Daily Uplift Amount =

(TCR Daily Shortfall Amount) * (TCR Uplift Ratio Amount)

(1) The TCR Daily Shortfall Amount is equal to the positive difference between (i) the net of the total charges and payments calculated under Section 8.5.11 over the Operating Day multiplied by (-1) and (ii) Total Congestion Revenues collected over the Operating Day.

(2) The Total Congestion Revenues collected over the Operating Day is equal to the sum for all hours and Settlement Locations in the Operating Day of (total Day-Ahead cleared Energy MW * Day-Ahead MCC) at each Settlement Location.

(3) An Asset Owner's TCR Uplift Ratio Amount shall be equal to the sum of the absolute value of each of the hourly charges and payments calculated under Section 8.5.11 for that Asset Owner over the Operating Day divided by the sum of the absolute value of each of the charges and payments calculated under Section 8.5.11 for all Asset Owners over the Operating Day.

### 8.5.13 Transmission Congestion Rights Monthly Payback Amount

A Day-Ahead Market monthly payment will be calculated as follows for each Asset Owner receiving a charge under Section 8.5.12 in any Operating Day of the month:

TCR Monthly Payback Amount =

Minimum of [(TCR Monthly Uplift Amount) or ((Excess Congestion Fund Monthly Amount) * (TCR Monthly Uplift Amount / Total TCR Monthly Uplift Amount))] * (-1)

(1) An Asset Owner's TCR Monthly Uplift Amount is equal to the sum of that Asset Owner's charges calculated under Section 8.5.12 for the month.

(2) Total TCR Monthly Uplift Amount is equal to the sum of all Asset Owners' TCR Monthly Uplift Amounts for the month.

(3) The Excess Congestion Fund Monthly Amount is equal to the sum of the Excess Congestion Fund Daily Amount for the month.

(a) The Excess Congestion Fund Daily Amount is equal to the positive difference between the (i) Total Congestion Revenue collected for the Operating Day and (ii) the net of the total charges and payments calculated under Section 8.5.11 over the Operating Day multiplied by (-1).

(b) The Total Congestion Revenues collected over the Operating Day is equal to the sum for all hours and Settlement Locations in the Operating Day of (Total Day-Ahead cleared Energy MW * Day-Ahead MCC) at each Settlement Location.

### 8.5.14 Transmission Congestion Rights Annual Payback Amount

A Day-Ahead Market annual payment will be calculated as follows for each Asset Owner receiving payments under Section 8.5.13 that were not sufficient to cover charges received under Section 8.5.12 over the year in order to ensure full funding of TCRs to the extent possible:

TCR Annual Payback Amount =

Minimum of [(TCR Net Uplift Annual Amount) or ((Excess Congestion Fund Yearly Amount) * (TCR Net Uplift Annual Amount / Total TCR Net Uplift Annual Amount))] * (-1)

(1) An Asset Owner's TCR Net Uplift Annual Amount is equal the difference between (i) the sum of that Asset Owner's charges calculated under Section 8.5.12 for the year and (ii) the sum of that Asset Owner's payments made under Section 8.5.13 for the year multiplied by (-1).

(2) Total TCR Net Uplift Annual Amount is equal to the sum of all Asset Owners' TCR Net Uplift Annual Amounts for the month.

(3) The Excess Congestion Fund Yearly Amount is equal to the difference between the total Excess Congestion Fund Monthly Amount for the year, as described under Section 8.5.13(3), and the total payments made under Section 8.5.13 for the year.

### 8.5.15 Transmission Congestion Rights Annual Closeout Amount

A Day-Ahead Market annual payment will be calculated as follows for each Asset Owner with ARR Nomination Caps established under Section 7.1.3 of this Attachment AE to the extent that there are any funds remaining once all payments are made under Section 8.5.14. The calculations below can result in residual amounts due to rounding. The Transmission Provider will uplift the annual residual amounts to all of the Asset Owners as specified in the Market Protocols.

TCR Annual Closeout Amount =

[(Excess Congestion Fund Yearly Amount + TCR Annual Payback Total) * (Annual ARR Nomination Cap / Total Annual ARR Nomination Cap)] * (-1)

(1) Excess Congestion Fund Yearly Amount is equal to the value calculated under Section 8.5.14 of this Attachment.

(2) TCR Annual Payback Total is equal to the sum of all payments made under Section 8.5.14.

(3) An Asset Owner's Annual ARR Nomination Cap is equal to the sum of all of that Asset Owner's daily ARR nomination caps, as calculated under Section 7.1.3 of this Attachment AE, for the year.

(4) Total Annual ARR Nomination Cap is equal to the sum of all Asset Owners' Annual ARR Nomination Caps for the year.

### 8.5.16 Day-Ahead Over-Collected Losses Distribution Amount

The MLC of the Day-Ahead Market LMP creates an over collection of funds related to payment for losses ("Day-Ahead Market Over-Collected Losses") that is calculated and distributed to Asset Owners, as described in Section 8.6.16 of this Attachment AE.

## 8.5.17 Reserved for Future Use

### 8.5.18 Day-Ahead GFA Carve Out and FSE Daily Amount

A Day-Ahead Market credit or charge for exclusion of transactions associated with GFA Carve Outs and FSEs from Marketplace settlement of congestion, losses and hedging instruments as described under Section 8.2.2 of this Attachment AE, is calculated each day for every Asset Owner modeled to represent a GFA Carve Out or FSE. This Day-Ahead GFA Carve Out Daily Amount is calculated as follows:

Day-Ahead GFA Carve Out Daily Amount per Asset Owner = ((-1) * (Day-Ahead Asset Energy Amount + Day-Ahead Non-Asset Energy Amount + Transmission Congestion Rights Funding Amount + Transmission Congestion Rights Daily Uplift + Over-Collected Losses Distribution Amount + Transmission Congestion Rights Auction Daily Amount + Auction Revenue Rights Daily Amount + Auction Revenue Rights Daily Uplift Amount))

Where:

(1) Day-Ahead Asset Energy Amount is equal to the daily sum of the hourly values calculated under Section 8.5.1(1) and 8.5.1(2) of this Attachment AE;

(2) Day-Ahead Non-Asset Energy Amount is equal to the daily sum of the hourly values calculated under Section 8.5.1(3) of this Attachment AE;

(3) Transmission Congestion Rights Funding Amount is equal to the daily sum of the hourly values calculated under Section 8.5.11 of this Attachment AE;

(4) Transmission Congestion Rights Daily Uplift Amount is equal to the daily value calculated under Section 8.5.12 of this Attachment AE;

(5) Over-Collected Losses Distribution Amount is equal to the daily sum of the hourly values calculated under Section 8.6.16 of this Attachment AE;

(6) Transmission Congestion Rights Auction Daily Amount is equal to the daily value calculated under Section 8.7.1 of this Attachment AE;

(7) Auction Revenue Rights Daily Amount is equal to the daily value calculated under Section 8.7.2 of this Attachment AE; and

(8) Auction Revenue Rights Daily Uplift Amount is equal to the daily value calculated under Section 8.7.3 of this Attachment AE.

### 8.5.19 Day-Ahead GFA Carve Out and FSE Monthly Amount

A Day-Ahead Market credit or charge for exclusion of GFA Carve Outs and FSEs from Marketplace settlement of Transmission Congestion Rights Monthly Payback Amount and Auction Revenue Rights Monthly Payback Amount, as described under Sections 8.5.13 and 8.7.4 of this Attachment AE, is calculated each month for every Asset Owner modeled to represent a GFA Carve Out or FSE. This Day-Ahead GFA Carve Out Monthly Amount is calculated as follows:

Day-Ahead GFA Carve Out Monthly Amount per Asset Owner = ((-1) * (Transmission Congestion Rights Monthly Payback Amount + Auction Revenue Rights Monthly Payback Amount))

Where:

(1) Transmission Congestion Rights Monthly Payback Amount is equal to the monthly value calculated under Section 8.5.13 of this Attachment AE; and

(2) Auction Revenue Rights Monthly Payback Amount is equal to the monthly value calculated under Section 8.7.4 of this Attachment AE.

### 8.5.20 Day-Ahead GFA Carve Out and FSE Yearly Amount

A Day-Ahead Market credit or charge for exclusion of GFA Carve Outs and FSEs from Marketplace settlement of Transmission Congestion Rights Yearly Payback Amount, Transmission Congestion Rights Yearly Closeout Amount, Auction Revenue Rights Yearly Payback Amount and Auction Revenue Rights Yearly Closeout Amount, as described under Sections 8.5.14, 8.5.15, 8.7.5 and 8.7.6 of this Attachment AE, is calculated each year for every Asset Owner modeled to represent a GFA Carve Out or FSE. This Day-Ahead GFA Carve Out Yearly Amount is calculated as follows:

Day-Ahead GFA Carve Out Yearly Amount per Asset Owner = ((-1) * (Transmission Congestion Rights Yearly Payback Amount + Transmission Congestion Rights Yearly Closeout Amount + Auction Revenue Rights Yearly Payback Amount + Auction Revenue Rights Yearly Closeout Amount))

Where:

(1) Transmission Congestion Rights Yearly Payback Amount is equal to the yearly value calculated under Section 8.5.14 of this Attachment AE;

(2) Transmission Congestion Rights Yearly Closeout Amount is equal to the yearly value calculated under Section 8.5.15 of this Attachment AE;

(3) Auction Revenue Rights Yearly Payback Amount is equal to the yearly value calculated under Section 8.7.5 of this Attachment AE; and

(4) Auction Revenue Rights Yearly Closeout Amount is equal to the yearly value calculated under Section 8.7.6 of this Attachment AE.

### 8.5.21 GFA Carve Out and FSE Distribution Daily Amount

The Transmission Provider shall perform the following calculation for each day for each Asset Owner and Settlement Location to ensure that the Day Ahead GFA Carve Out Daily Amount is distributed to all non GFA Carve Out load and non FSE load on a daily load ratio share basis, and that the Transmission Provider is revenue neutral.

GFA Carve Out Distribution Daily Amount =

GFA Revenue Inadequacy Daily Amount * Asset Owner Daily Distribution Factor * (-1)

Where:

(1) The GFA Revenue Inadequacy Daily Amount is equal to the sum of all GFA Carve Out charges and payments calculated under Section 8.5.18 of this Attachment AE for that day; and

(2) An Asset Owner's Daily Distribution Factor is equal to:

(a) The sum for all hours in the Operating Day of the Maximum of (i) zero or (ii) the Asset Owner's hourly Reported Load and an MSR's hourly Self-Charging MW, plus hourly Export Interchange Transactions minus the Asset Owner's hourly GFA Carve Out load minus the Asset Owner's hourly FSE load;

Divided by,

(b) The sum for all Asset Owners and Settlement Locations of the values calculated in Section 8.5.21(2)(a).

### 8.5.22 GFA Carve Out and FSE Distribution Monthly Amount

The Transmission Provider shall perform the following calculation for each month for each Asset Owner and Settlement Location to ensure the Day Ahead GFA Carve Out Monthly Amount is distributed to all non GFA Carve Out load and non FSE load on a monthly load ratio share basis and that the Transmission Provider is revenue neutral.

GFA Carve Out Distribution Monthly Amount =
GFA Revenue Inadequacy Monthly Amount * Asset Owner Monthly Distribution Factor * (-1)

Where:

(1) The GFA Revenue Inadequacy Monthly Amount is equal to the sum of all GFA Carve Out charges and payments calculated under Section 8.5.19 of this Attachment AE; and

(2) An Asset Owner's Monthly Distribution Factor is equal to:

(a) The sum for all hours in the month of the Maximum of (i) zero or (ii) the Asset Owner's hourly Reported Load and an MSR's hourly Self-Charging MW, plus hourly Export Interchange Transactions minus the Asset Owner's hourly GFA Carve Out load minus the Asset Owner's hourly FSE load;

Divided by,

(b) The sum for all Asset Owners and Settlement Locations of the values calculated in Section 8.5.22(2)(a).

### 8.5.23 GFA Carve Out and FSE Distribution Yearly Amount

The Transmission Provider shall perform the following calculation for each year for each Asset Owner and Settlement Location to ensure the Day Ahead GFA Carve Out Yearly Amount is distributed to all non GFA Carve Out load and non FSE load on an annual load ratio share basis and that the Transmission Provider is revenue neutral.

GFA Carve Out Distribution Yearly Amount =
GFA Revenue Inadequacy Yearly Amount * Asset Owner Yearly Distribution Factor * (-1)

Where:

(1) The GFA Revenue Inadequacy Yearly Amount is equal to the sum of all GFA Carve Out charges and payments calculated under Section 8.5.20 of this Attachment AE; and

(2) An Asset Owner's Yearly Distribution Factor is equal to:

(a) The sum for all hours in the year of the Maximum of (i) zero or (ii) the Asset Owner's hourly Reported Load and an MSR's hourly Self-Charging MW, plus hourly Export Interchange Transactions minus the Asset Owner's hourly GFA Carve Out load minus the Asset Owner's hourly FSE load,

divided by:

(b) The sum for all Asset Owners and Settlement Locations of the values calculated in Section 8.5.23(2)(a) of this Attachment AE.

### 8.5.24 Day-Ahead Demand Reduction Amount

A Day-Ahead Market payment will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with cleared Demand Response Resource Offers for each applicable Settlement Location and each hour as follows:

Day-Ahead Demand Reduction Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Total Demand Response Resource Hourly Quantity)

(1) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, for a load Settlement Location containing one or more Demand Response Loads associated with cleared Demand Response Resources Offers.

(2) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the sum of the MW quantities for cleared Demand Response Resources in the Day-Ahead Market, as described under Section 5.1.3 of this Attachment AE, that are associated with one or more Demand Response Loads contained within the load Settlement Location referenced in (1) above.

### 8.5.25 Day-Ahead Demand Reduction Distribution Amount

The Day-Ahead demand reduction distribution amount is an hourly charge to Asset Owners at each Settlement Location to recover the sum of the demand reduction payments made under Section 8.5.24 of this Attachment AE and is calculated as:

Day-Ahead Demand Reduction Distribution Amount =
(Day-Ahead Demand Reduction Distribution Rate) * (Day-Ahead Demand Reduction Distribution Quantity))

(1) The Day-Ahead Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.5.24 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owners' Day-Ahead Demand Reduction Distribution Quantities for all Settlement Locations for the Hour.

(2) An Asset Owner's Day-Ahead Demand Reduction Distribution Quantity at a Settlement Location for an hour is equal to that Asset Owner's net cleared Energy withdrawals at that Settlement Location for that hour. An Asset Owner's net cleared Energy withdrawal at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner's cleared Demand Bids, cleared Self-Charging MSR Offers, the positive MWh value for the Asset Owner's net cleared Export and Import Interchange Transactions, the positive MWh value for the Asset Owner's net cleared Virtual Energy Bids and Offers at that Settlement Location.

### 8.5.26 Day-Ahead Ramp Capability Amount

A Day-Ahead Market payment for cleared Ramp Capability Up and Ramp Capability Down will be calculated at each Settlement Location for each Asset Owner for each hour as follows:

1) Day-Ahead Ramp Capability Up Hourly Amount =

   [(Day-Ahead MCP) * (Day-Ahead Cleared Ramp Capability Up Hourly Quantity)] * (-1)

   (a) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Up associated with the Reserve Zone in which the applicable Resource is located.

   (b) An Asset Owner's Day-Ahead Cleared Ramp Capability Up Hourly Quantity is the MW quantity associated with cleared Ramp Capability Up as described under Section 5.1.3 of this Attachment AE.

2) Day-Ahead Ramp Capability Down Hourly Amount =

   [(Day-Ahead MCP) * (Day-Ahead Cleared Ramp Capability Down Hourly Quantity)] * (-1)

   (a) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Down associated with the Reserve Zone in which the applicable Resource is located.

   (b) An Asset Owner's Day-Ahead Cleared Ramp Capability Down Hourly Quantity is the MW quantity associated with cleared Ramp Capability Down as described under Section 5.1.3 of this Attachment AE.

### 8.5.27 Day-Ahead Ramp Capability Up Distribution Amount

A Day-Ahead Market charge for Ramp Capability Up procurement costs calculated under Section 8.5.25 of this Attachment AE will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Ramp Capability Up Hourly Distribution Amount =

[(Day-Ahead Ramp Capability Up Obligation) * (Day-Ahead Ramp Capability Up Procurement Rate)]

(1) An Asset Owner's Day-Ahead Ramp Capability Up Obligation in each Reserve Zone is equal to the system wide total of all cleared Ramp Capability Up multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Ramp Capability Up and Ramp Capability Up being supplied pursuant to Section 4.3.3(3) of this Attachment AE.

(2) For a Reserve Zone that clears more Ramp Capability Up than the sum of Asset Owners' Day-Ahead Ramp Capability Up Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Ramp Capability Up Procurement Rate is equal to the Ramp Capability Up MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Ramp Capability Up than the sum of Asset Owners' Day-Ahead Ramp Capability Up Obligations for that Reserve Zone, the Day-Ahead Ramp Capability Up Procurement Rate is as follows:

Day-Ahead Ramp Capability Up Procurement Rate =

{(Reserve Zone MCP * Total of cleared Ramp Capability Up for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Ramp Capability Up Obligations for that Reserve Zone - Total of cleared Ramp Capability Up for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Ramp Capability Up Obligations for that Reserve Zone).

### 8.5.28 Day-Ahead Ramp Capability Down Distribution Amount

A Day-Ahead Market charge for Ramp Capability Down procurement costs calculated under Section 8.5.26 of this Attachment AE will be calculated at each Reserve Zone for each Asset Owner for each hour as follows:

Day-Ahead Ramp Capability Down Hourly Distribution Amount =
[(Day-Ahead Ramp Capability Down Obligation) * (Day-Ahead Ramp Capability Down Procurement Rate)]

(1) An Asset Owner's Day-Ahead Ramp Capability Down Obligation in each Reserve Zone is equal to the system wide total of all cleared Ramp Capability Down multiplied by the Asset Owner Reserve Zone Load Ratio Share, adjusted up or down to account for any Bilateral Settlement Schedules for Ramp Capability Down and Ramp Capability Down being supplied pursuant to Section 4.3.3(3) and of this Attachment AE.

(2) For a Reserve Zone that clears more Ramp Capability Down than the sum of Asset Owners' Day-Ahead Ramp Capability Down Obligations for that Reserve Zone, the zone is deemed an exporting zone and the Day-Ahead Ramp Capability Down Procurement Rate is equal to the Ramp Capability Down MCP for that Reserve Zone.

(3) For a Reserve Zone that clears less Ramp Capability Down than the sum of Asset Owners' Day-Ahead Ramp Capability Down Obligations for that Reserve Zone, the Day-Ahead Ramp Capability Down Procurement Rate is as follows:

Day-Ahead Ramp Capability Down Procurement Rate =
{(Reserve Zone MCP * Total of cleared Ramp Capability Down for that Reserve Zone) + [(Weighted Average MCP of all Exporting Zones) * (Sum of Asset Owners' Day-Ahead Ramp Capability Down Obligations for that Reserve Zone - Total of cleared Ramp Capability Down for that Reserve Zone)]} / (Sum of Asset Owners' Day-Ahead Ramp Capability Down Obligations for that Reserve Zone).

## 8.6 Real-Time Balancing Market Settlement

Settlement calculations for the RTBM are performed on a Dispatch Interval basis for each Operating Day and are based upon the difference between the results of the RTBM and the Day-Ahead Market clearing for that Operating Day. To calculate RTBM actual Energy in a Dispatch Interval for Market Participants that have not directly submitted five (5) minute interval meter data, the Transmission Provider allocates the submitted hourly meter data for Resources and loads into five (5) minute values using five (5) minute telemetered or State Estimator profiles for the corresponding hour. The profiling of the hourly meter data maintains the shape of the five (5) minute telemetered or State Estimator values even if there are both positive and negative values contained within the twelve (12) intervals.

The following Subsections describe the RTBM settlement charge types. For each charge type, the calculation is performed either at the Dispatch Interval level or hourly level for each Asset Owner at each Settlement Location. The Transmission Provider shall calculate hourly summations for each Market Participant for all Asset Owners it represents and shall calculate daily summations as specified in the Market Protocols.

### 8.6.1 Real-Time Energy Amount

An RTBM payment or charge for Energy is calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

(1) For Energy associated with loads, and Self-Charging MSRs:

(a) Real-Time Asset Energy Dispatch Interval Amount =

Real-Time LMP * [((Real-Time Load Billing Meter Quantity) – (Day-Ahead Cleared Load Energy Quantity)) – (Real-Time Asset Energy Bilateral Settlement Schedules)] / 12

(i) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with that load, Self-Charging MSR, or station power from offline generation Settlement Location.

(ii) An Asset Owner's Real-Time Load Billing Meter Quantity at that Settlement Location is (i) the five (5) minute Reported Load submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly Reported Load profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data. The Transmission Provider shall make any necessary adjustments to the submitted Reported Load, as described under Section 8.6.1.1 of this Attachment AE.

(iii) An Asset Owner's Day-Ahead Cleared Load Energy Quantity is the MW quantity associated with cleared Demand Bids and cleared Self-Charging MSR Offers at that Settlement Location as described under Section 5.1.3 of this Attachment AE.

(iv) An Asset Owner's Real-Time Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that load Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(b) Real-Time Asset Energy Hourly Amount =

Sum of Real-Time Asset Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(2) For Energy associated with Resources:

(a) Real-Time Energy Dispatch Interval Amount =

Real-Time LMP * [((Real-Time Resource Billing Meter Quantity) – (Day-Ahead Cleared Resource Energy Hourly Quantity)) – (Real-Time Asset Energy Bilateral Settlement Schedules)] / 12

(i) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with that Resource Settlement Location.

(ii) An Asset Owner's Real-Time Resource Billing Meter Quantity at that Resource Settlement Location, excluding Self-Charging MSRs is (i) the five (5) minute actual meter MWh Resource output quantity submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly actual meter MWh Resource injection or withdrawal quantity profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data.

(iii) An Asset Owner's Day-Ahead Cleared Resource Energy Hourly Quantity is the MW quantity associated with cleared Resource Offers excluding Self-Charging MSRs at that Resource Settlement Location as described under Section 5.1.3 of this Attachment AE.

(iv) An Asset Owner's Real-Time Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that Resource Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(b) Real-Time Energy Hourly Amount =

Sum of Real-Time Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(3) For Energy associated with Interchange Transactions:

(a) Real-Time Non-Asset Energy Dispatch Interval Amount =

Real-Time LMP * [((Real-Time Import Energy Quantity) – (Day-Ahead Import Energy Quantity) – (Real-Time Non-Asset Energy Bilateral Settlement Schedules))] / 12

(i) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(ii) An Asset Owner's Real-Time Import Energy Quantity is the five (5) minute Dispatch Interval MW quantity scheduled for use in the RTBM, adjusted for curtailments, at that External Interface Settlement Location.

(iii) An Asset Owner's Day-Ahead Import Energy Quantity is the five (5) minute Dispatch Interval MW quantity calculated by the Transmission Provider for each Dispatch Interval by multiplying the scheduled MW in the Dispatch Interval by the ratio of (a) hourly scheduled amount for use in the Day-Ahead Market and (b) the MW amount of cleared Import Interchange Transaction Offers, as described under Section 5.1.3 of this Attachment AE, at that External Interface Settlement Location.

(iv) An Asset Owner's Real-Time Non-Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(4) For Energy associated with Export Interchange Transactions:

(a) Real-Time Non-Asset Energy Dispatch Interval Amount =

Real-Time LMP * [((Real-Time Export Energy Quantity) – (Day-Ahead Export Energy Quantity) – (Real-Time Non-Asset Energy Bilateral Settlement Schedules))] / 12

(i) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(ii) An Asset Owner's Real-Time Export Energy Quantity is the five (5) minute Dispatch Interval MW quantity scheduled for use in the RTBM, adjusted for curtailments, at that External Interface Settlement Location.

(iii) An Asset Owner's Day-Ahead Export Energy Quantity is the five (5) minute Dispatch Interval MW quantity calculated by the Transmission Provider for each Dispatch Interval by multiplying the scheduled MW in the Dispatch Interval by the ratio of (a) hourly scheduled amount for use in the Day-Ahead Market and (b) the MW amount of cleared Export Interchange Transaction Bids, as described under Section 5.1.3 of this Attachment AE, at that External Interface Settlement Location.

(iv) An Asset Owner's Real-Time Non-Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(b) Real-Time Non-Asset Energy Hourly Amount =

Sum of Real-Time Non-Asset Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(5) For Energy associated with remaining Bilateral Settlement Schedules:

Real-Time Non-Asset Energy Hourly Amount =

(Real-Ahead LMP) * [(Real-Time Non-Asset Energy Bilateral Settlement Schedules for Energy) * (-1)]

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner's Real-Time Non-Asset Energy Hourly Bilateral Settlement Schedules for Energy are those Bilateral Settlement Schedules that settle at Settlement Locations other than External Interface Settlement Locations, that Asset Owner's load Settlement Locations or that Asset Owner's Resource Settlement Locations, as submitted in accordance with Section 8.2.1 of this Attachment AE.

(6) For Energy associated with Day-Ahead Market cleared Virtual Energy Bids:

Real-Time Virtual Energy Dispatch Interval Amount =

[(Real-Time LMP) * ((Day-Ahead Cleared Virtual Energy Bid Hourly Quantity) / 12)] * (-1)

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Virtual Energy Bid Hourly Quantity is the MW quantity associated with cleared Virtual Energy Bids as described under Section 5.1.3 of this Attachment AE at that Settlement Location.

(7) For Energy associated with Day-Ahead Market cleared Virtual Energy Offers:

Real-Time Virtual Energy Dispatch Interval Amount =

[(Real-Time LMP) * ((Day-Ahead Cleared Virtual Energy Offer Hourly Quantity) / 12)] * (-1)

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner's Day-Ahead Cleared Virtual Energy Offer Hourly Quantity is the MW quantity associated with cleared Virtual Energy Offers as described under Section 5.1.3 of this Attachment AE at that Settlement Location.

### 8.6.1.1 Adjustments to Reported Load

The Transmission Provider shall make any necessary adjustments to the Asset Owner submitted Reported Load values as follows:

(1) The sum of the Reported Load within a Settlement Area must equal the Settlement Area Net Load. To the extent that the Transmission Provider observes that a difference exists, the Transmission Provider shall adjust each Asset Owner's Reported Load within the Settlement Area on a pro rata basis such that the sum of Reported Load within the Settlement Area is equal to the Settlement Area Net Load. To the extent that the Reported Load is associated with Statutory Load Obligations, the Reported Load shall not be adjusted.

(2) To the extent that the Reported Load is associated with a Meter Data Submittal Location that includes a Demand Response Load, the Transmission Provider shall adjust such Reported Load by adding all associated calculated or submitted Demand Response Resource output to such Reported Load, where the calculated Demand Response Resource output is as described under Section 4.1.2.1(1)(b) of this Attachment AE.

(3) To the extent that the Reported Load for a specific Meter Data Submittal Location is the Residual Load for the Settlement Area, the Transmission Provider shall reduce such Reported Load by the associated State Estimator Settlement Area losses.

### 8.6.2 Real-Time Regulation Service Amount

(1) An RTBM payment or charge for the sum of (i) deviations between cleared RTBM Regulation-Up Service and cleared Day-Ahead Market Regulation-Up, (ii) Excess Regulation-Up Mileage and (iii) Unused Regulation-Up Mileage, will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

(a) Real-Time Regulation-Up Service Dispatch Interval Amount = [[(Real-Time MCP) * ((Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity) - (Day-Ahead Regulation-Up Hourly Quantity)) / 12] - Unused Regulation-Up Mileage Dispatch Interval Amount + Excess Regulation-Up Mileage Dispatch Interval Amount] * (-1)

(i) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Regulation-Up Service associated with the Reserve Zone in which the applicable Resource is located.

(ii) An Asset Owner's Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity is the MW quantity associated with cleared RTBM Regulation-Up Service Offers as described under Section 6.2.3 of this Attachment AE.

(iii) An Asset Owner's Day-Ahead Cleared Regulation-Up Service Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE.

(iv) An Asset Owner's Unused Regulation-Up Mileage Dispatch Interval Amount is equal to the Asset Owner's Unused Regulation-Up Mileage multiplied by the MCP for Expected Regulation-Up Mileage, as defined under Section 8.3.4(3) of this Attachment AE, divided by 12. An Asset Owner's Unused Regulation-Up Mileage is equal to the amount by which Expected Regulation-Up Mileage exceeds Actual Regulation-Up Mileage except that, if Actual Regulation-Up Mileage is greater than or equal to Instructed

Regulation-Up Mileage multiplied by a factor equal to one minus Regulation Mileage Operating Tolerance, then Unused Regulation-Up Mileage is equal to the amount by which Expected Regulation-Up Mileage exceeds Instructed Regulation-Up Mileage.

(v) An Asset Owner's Excess Regulation-Up Mileage Dispatch Interval Amount is equal to the Asset Owner's Excess Regulation-Up Mileage multiplied by the MCP for Expected Regulation-Up Mileage, as defined under Section 8.3.4(3) of this Attachment AE, divided by 12. An Asset Owner's Excess Regulation-Up Mileage is the amount by which Actual Regulation-Up Mileage exceeds Expected Regulation-Up Mileage except that, if Actual Regulation-Up Mileage is greater than or equal to Instructed Regulation-Up Mileage multiplied by a factor equal to one minus Regulation Mileage Operating Tolerance, Excess Regulation-Up Mileage is equal to the amount by which Instructed Regulation-Up Mileage exceeds Expected Regulation-Up Mileage.

(b) Real-Time Regulation-Up Service Hourly Amount =

Sum of Real-Time Regulation-Up Service Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(2) An RTBM payment or charge for the sum of (i) deviations between cleared RTBM Regulation-Down Service and cleared Day-Ahead Market Regulation-Down, (ii) Excess Regulation-Down Mileage and (iii) Unused Regulation-Down Mileage, will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

(a) Real-Time Regulation-Down Service Dispatch Interval Amount =

[[(Real-Time MCP) * ((Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity) – (Day-Ahead Regulation-Down Service Hourly Quantity)) / 12] - Unused Regulation-Down Mileage Dispatch Interval Amount + Excess Regulation-Down Mileage Dispatch Interval Amount] * (-1)

(i) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Regulation-Down Service associated with the Reserve Zone in which the applicable Resource is located.

(ii) An Asset Owner's Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity is the MW quantity associated with cleared Regulation-Down Service Offers as described under Section 6.2.3 of this Attachment AE.

(iii) An Asset Owner's Day-Ahead Cleared Regulation-Down Service Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE.

(iv) An Asset Owner's Unused Regulation-Down Mileage Dispatch Interval Amount is equal to the Asset Owner's Unused Regulation-Down Mileage multiplied by the MCP for Expected Regulation-Down Mileage, as defined under Section 8.3.4(4) of this Attachment AE, divided by 12. An Asset Owner's Unused Regulation-Down Mileage is equal to the amount by which Expected Regulation-Down Mileage exceeds Actual Regulation-Down Mileage except that, if Actual Regulation-Down Mileage is greater than or equal to Instructed Regulation-Down Mileage multiplied by a factor equal to one minus Regulation Mileage Operating Tolerance, then Unused Regulation-Down Mileage is equal to the amount by which Expected Regulation-Down Mileage exceeds Instructed Regulation-Down Mileage.

(v) An Asset Owner's Excess Regulation-Down Mileage Amount is equal to the Asset Owner's Excess Regulation-Down Mileage multiplied by the MCP for Expected Regulation-Down Mileage, as defined under Section 8.3.4(4) of this Attachment AE, divided by 12. An Asset Owner's Excess Regulation-Down Mileage is the amount by which Actual Regulation-Down Mileage exceeds Expected Regulation-Down Mileage except that, if Actual

Regulation-Down Mileage is greater than or equal to Instructed Regulation-Down Mileage multiplied by a factor equal to one minus Regulation-Mileage Operating Tolerance, Excess Regulation-Down Mileage is equal to the amount by which Instructed Regulation-Down Mileage exceeds Expected Regulation-Down Mileage.

(b) Real-Time Regulation-Down Service Hourly Amount =

Sum of Real-Time Regulation-Down Service Dispatch Interval Amount over all Dispatch Intervals in the Hour.

### 8.6.3 Real-Time Spinning Reserve Amount

An RTBM payment or charge for deviations between cleared RTBM Spinning Reserve and cleared Day-Ahead Market Spinning Reserve will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

(1) Real-Time Spinning Reserve Dispatch Interval Amount =

[(Real-Time MCP) * ((Real-Time Cleared Spinning Reserve Dispatch Interval Quantity) – (Day-Ahead Spinning Reserve Hourly Quantity)) / 12] * (-1)

(a) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Spinning Reserve associated with the Reserve Zone in which the applicable Resource is located.

(b) An Asset Owner's Real-Time Cleared Spinning Reserve Dispatch Interval Quantity is the MW quantity associated with cleared Spinning Reserve Offers as described under Section 6.2.3 of this Attachment AE.

(c) An Asset Owner's Day-Ahead Cleared Spinning Reserve Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE.

(2) Real-Time Spinning Reserve Hourly Amount =

Sum of Real-Time Spinning Reserve Dispatch Interval Amount over all Dispatch Intervals in the Hour.

### 8.6.4 Real-Time Supplemental Reserve Amount

An RTBM payment or charge for deviations between cleared RTBM Supplemental Reserve and cleared Day-Ahead Market Supplemental Reserve will be calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

(1) Real-Time Supplemental Reserve Dispatch Interval Amount =

[(Real-Time MCP) * ((Real-Time Cleared Supplemental Reserve Dispatch Interval Quantity) – (Day-Ahead Supplemental Reserve Hourly Quantity)) / 12] * (-1)

(a) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Supplemental Reserve associated with the Reserve Zone in which the applicable Resource is located.

(b) An Asset Owner's Real-Time Cleared Supplemental Reserve Dispatch Interval Quantity is the MW quantity associated with cleared Supplemental Reserve Offers as described under Section 6.2.3 of this Attachment AE.

(c) An Asset Owner's Day-Ahead Cleared Supplemental Reserve Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE.

(2) Real-Time Supplemental Reserve Hourly Amount =

Sum of Real-Time Supplemental Reserve Dispatch Interval Amount over all Dispatch Intervals in the Hour.

### 8.6.5 Reliability Unit Commitment Make Whole Payment Amount

(1) Asset Owners of Resources committed by the Transmission Provider during the RUC processes, are eligible to receive a RUC make whole payment. Asset Owners of Resources committed by a local transmission operator during the RUC processes to address a Local Emergency Condition are eligible to receive a RUC make whole payment, except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a RUC make whole payment. A RUC make whole payment is made to the Asset Owner when the sum of a Resource's costs associated with actual Energy and cleared RTBM Operating Reserve is greater than the RTBM revenues received over the Resource's RUC make whole payment eligibility period. Recovery of such compensation shall be collected in accordance with Section 8.6.7 of this Attachment AE.

(2) A Resource's RUC make whole payment eligibility period is equal to the set of a Resource's contiguous RUC Commitment Periods and adjacent Day-Ahead Market commitment periods except;

(a) For Resources with a set of contiguous Day-Ahead and RUC Commitment Periods that continue from one Operating Day to the next Operating Day, a RUC make whole payment eligibility period is created for each Operating Day in which there is a RUC commitment. A RUC make whole payment eligibility period is created for each Operating Day with a RUC commitment. The start of a RUC make whole payment eligibility period is the later of (1) beginning of the Operating Day or (2) the beginning of the set of contiguous Day-Ahead Market and RUC commitments. The end of a RUC make whole payment eligibility period is the earlier of (1) the end of the set of contiguous Day-Ahead Market and RUC commitments or (2) the end of the Operating Day; or

(b) For an MCR that cleared in the Day-Ahead Market and was transitioned to a different configuration in Real-Time by the Transmission Provider or by

a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), the costs in the intervals preceding the RUC commitment for the purpose of buying back Operating Reserve products while the Resource transitions to the RUC committed configuration, as defined by the Transition State Time of the Resource's offer parameters in Section 4.1(9) of this Attachment AE, are included in the RUC make whole payment calculation.

(3) The following cost recovery rules apply to each RUC make whole payment eligibility period. Resource production costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made for start-up, transitions, no-load, and minimum-energy; and the RTBM Offer price in effect at the solving of a dispatch interval for the Energy above minimum energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.

(a) If the Transmission Provider cancels a Commitment Instruction prior to the start of the associated RUC make whole payment eligibility period, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource's RTBM Start-Up Offer unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(b) In order to receive the full amount of Start-Up Offer recovery within a RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in at least one Dispatch Interval in the RUC make whole payment eligibility period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource's RUC commitment level offer costs include Start-Up Offer cost and Transition State Offer cost for a RUC make whole payment eligibility period in which that Resource is committed with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting: (1) all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period; from (2) all eligible commitment level offer costs associated with the final Resource schedule in a RUC make whole payment eligibility period. The resulting difference can represent a charge or a payment and is considered as an adjustment when determining a RUC make whole payment.

(i) Except for an MCR that is committed by RUC in a different configuration than in the Day-Ahead Market, when a RUC make whole payment eligibility period is created after a Day-Ahead make whole payment eligibility period and is adjacent and preceding that Day-Ahead make whole payment eligibility period where the Day-Ahead Start-Up Offer Amount defined in Section 8.5.9(3)(b)(i) of this Attachment AE was considered, the Day-Ahead Start-up Offer Amount is used in place of the RUC Start-up costs.

(ii) In any RUC make whole payment eligibility period for which the RUC SCUC did not consider the Resource's Start-Up Offer in the original commitment decision, except for commitments made as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Resource's Start-Up Offer shall equal zero.

(iii) A Resource's RTBM Start-Up costs are not eligible for recovery in the following RUC make whole payment eligibility periods:

(1) Any RUC make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource's RUC Commit Time in addition to the Resource's Sync-To-Min Time unless the RUC make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource's Sync-To-Min Time; or

(2) For any RUC make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource's RUC Commit Time in addition to the Resource's Sync-To-Min Time unless the RUC market whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource's Sync-To-Min Time.

(iv) When there is a cost transferred from the Day-Ahead Market make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE, the commitment level cost in the RUC make whole payment is increased by the amount allocated to the RUC make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE.

(v) In any RUC make whole payment eligibility period for which the RUC SCUC considered the Resource's Transition State Offer in the original commitment decision, or the RTBM Transition State Offer is associated with a manual commitment as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Transition State Offer cost is eligible for recovery when the following conditions are met:

(1) In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target "from" configuration and the Resource must be a Synchronized Resource; and

(2) In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target "to" configuration and the Resource must be a Synchronized Resource.

(vi) If the Transmission Provider cancels a transition between configurations prior to the scheduled transition associated with a RUC make whole payment eligibility period, the Asset Owner will be eligible to recover a time-based pro-rata share of the Resource's RTBM Transition State Offer through the RUC make whole payment unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

(vii) When a Resource loses eligibility to recover a Start-Up Offer cost for the reason described in Section 8.6.5(3)(e)(iii)(1) of this Attachment AE, or loses eligibility to recover Transition State Offer costs for the reason described in Section 8.6.5(3)(v) of this

Attachment AE, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (1) its Start-Up Offer cost and Transition State Offer cost associated with commitments that have a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE; or (2) the ineligible RTBM Start-Up Offer cost plus the ineligible Transition State Offer costs.

(viii) For each RUC make whole payment eligibility period within an Operating Day, a Resource's eligible Start-Up cost is divided by the lesser of (1) the hours of RUC commitment within the Resource's applicable Minimum Run Time multiplied by twelve (12), rounded down to the nearest whole interval, or (2) twenty-four (24) hours multiplied by twelve (12), to achieve a Dispatch Interval proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead Market or RUC make whole payment eligibility periods.

(1) If the number of participating Dispatch Interval meets or exceeds the duration of the divisor as described in (viii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the RUC make whole payment eligibility period.

(2) If the number of participating Dispatch Intervals is less than the duration of the divisor as described in (viii) above, the proration is multiplied by the number of participating Dispatch Intervals to achieve a single Start-Up Offer amount to be included in the commitment level cost for that RUC make whole payment eligibility period. Any remaining eligible RUC Start-Up cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period as described in Section 8.6.5(3)(f) of this Attachment AE or

the following and adjacent RUC make whole payment eligibility period in the next Operating Day.

(f) If the Resource has been committed in the Day-Ahead Market in a period adjacent to and following a RUC make whole payment eligibility period to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the RUC make whole payment eligibility period, any remaining eligible RTBM Start-Up cost is carried forward for recovery in the Day-Ahead make whole payment eligibility period.

(g) If a Resource has operated outside of its Operating Tolerance in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource's economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(h) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource's economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(i) (1) If a Resource's minimum operating limit is increased above the Resource's minimum operating limit that was used to make the commitment decision, the increase is greater than the Resource's Operating Tolerance and the Resource remains dispatchable in any Dispatch Interval, any cost associated with energy injection or withdrawal above the Resource's economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE, or (2) if a Resource is committed and subsequent to that commitment, the Resource's originally submitted limits are modified such that the Resource's availability switches from injection to withdrawal, any cost associated with energy withdrawal below the Resource's economic operating point resulting from changing its availability from injection to withdrawal is not eligible for

recovery for the Dispatch Interval for which such cost is calculated. If a Resource is committed and subsequent to that commitment, the Resource's originally submitted limits are modified such that the Resource's availability switches from withdrawal to injection, any cost associated with energy injection above the Resource's economic operating point resulting from changing its availability from withdrawal to injection is not eligible for recovery for the Dispatch Interval for which such cost is calculated.

(j) If a Resource's self-commitment period is less than the Resource's Minimum Run Time, the Transmission Provider will relax the Resource's Minimum Run Time to equal the self-commit period.

(k) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the RTBM, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.6.5(4)(b) of this Attachment AE for that period in the RUC make whole payment eligibility period.

(l) For an MCR, additional costs of revenues incurred when the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time will be considered as an adjustment when determining a RUC make whole payment. These costs or revenues must be incurred during time periods in which the Resource is ineligible to clear Operating Reserve products due to transitioning between configurations in Real-Time where at least one configuration is the result of a RUC commitment, and the transition is not forced by the Resource Offer. The Market Participant may also be eligible to recover Operating Resource product buy back costs or revenue incurred during a Real-Time transition if the Resource is transitioned by a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), then such Resources are not eligible to recover any costs or revenues associated with the transition as part of a RUC make whole

payment. In such cases, the adjustment is equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs. For Contingency Reserve, Ramp Capability Up, and Ramp Capability Down the adjustment is limited to the time period defined as the transition State Time submitted in the Resource Offer. For Regulation-Up and/or Regulation-Down, the adjustment is limited to all Dispatch Intervals within the transition hour.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given RUC make whole payment eligibility period is calculated as follows:

RUC Make Whole Payment Amount =

Maximum of [Either Zero or (RUC Make Whole Payment Commitment Cost Amount + RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period + RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period – Uninstructed Resource Deviation Cost Disallowance – Non-Dispatchable Cost Disallowance – Minimum Limit Cost Disallowance + Real-Time Combined Cycle Operating Reserve Adjustment Amounts)]

(a) An Asset Owner's Real-Time Make Whole Payment Commitment Cost Amount for each eligible Resource in the RUC make whole payment eligibility period is equal to:

(i) Start-Up Offer used to make the commitment decision which was committed by the Transmission Provider or by a local transmission operator to address a Local Emergency Condition (unless such commitment instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus

(ii) The Transition State Offer used to make the transition decision for an MCR that cleared in the Day-Ahead Market or committed by the RUC process that were transitioned by the Transmission Provider into a different configuration in Real-Time or transitioned

by a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus

(iii) Real-Time Cancelled Transition Amount as described in Section 8.6.5(3)(e)(vi) of this Attachment AE; plus

(iv) Amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(iii) of this Attachment AE; plus

(v) Amount of costs where the Resource loses eligibility to recover as describe in Section 8.6.5(3)(e)(vii) of this Attachment AE, minus

(vi) The sum of all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining (1) all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and (2) all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period.

(b) An Asset Owner's RUC Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC commitment of:

(i) No-Load Offer used to make the RUC commitment decision, less any Day-Ahead Market No-Load from an MCR resulting from a different Day-Ahead Market committed configuration;

(ii) Energy cost at minimum injection or withdrawal as calculated from the Energy Offer Curve used to make the commitment decision;

(iii) Energy cost above minimum injection or withdrawal as calculated from the Energy Offer Curve that applied to the current Dispatch Interval;

(iv) For MCRs, the Energy cost shall be calculated from the Energy Offer Curve used in the Day-Ahead Market from zero to the lesser of (1) Day-Ahead Market cleared Energy or (2) the submitted meter in Real-Time, multiplied by (-1);

(v) For Resources (other than MCRs cleared in the Day-Ahead Market that were committed into a different configuration in Real-Time), Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with cleared Real-Time Operating Reserve. Excess Regulation-Up Mileage and Excess Regulation-Down Mileage as calculated from the Operating Reserve Offers, except when those costs are associated with self-scheduled Operating Reserve which is greater than or equal to the amount of Operating Reserve cleared, in which case all three of these costs shall be set equal to zero;

(vi) For an MCR that was cleared in the Day-Ahead Market and was committed into a different configuration in Real-Time and is not transitioning into that configuration, the Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with cleared Real-Time Operating Reserve minus Day-Ahead Operating Reserve cost, including the impact from product substitution as described under Section 3.1.7 of this Attachment AE, associated with the lesser of (1) cleared Real-Time Operating Reserve or (2) cleared Day-Ahead Operating Reserve, except when self-scheduled Operating Reserve is less than or equal to the amount of Real-Time Operating Reserve cleared then the Operating Reserve cost shall be set equal to zero;

(vii) Real-Time Potential Regulation-Up Unused Mileage Make Whole Payment as calculated under Section 8.6.19(2)(b) of this Attachment AE; and

(viii) Real-Time Potential Regulation-Down Unused Mileage Make Whole Payment as calculated under Section 8.6.20(2)(b) of this Attachment AE.

(c) An Asset Owner's RUC Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum of the following for all Dispatch Intervals in the RUC commitment:

(i) Dispatch Interval revenue associated with Energy calculated by multiplying actual Dispatch Interval Energy injection or withdrawal by Real-Time LMP, except for MCRs that cleared in the Day-Ahead Market and were transitioned into a different configuration in Real-Time, in which case such revenue is calculated by multiplying Real-Time LMP by the incremental increase of the actual Dispatch Interval Energy injection or withdrawal above the Day-Ahead cleared Energy;

(ii) the sum of the revenues calculated under Sections 8.6.3 and 8.6.4 of this Attachment AE for that eligible Resource;

(iii) Energy revenue associated with payments made under Section 8.6.6 of this Attachment AE;

(iv) amounts associated with settlement made under Section 8.6.15 of this Attachment AE;

(v) Real-Time Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(2) of this Attachment AE;

(vi) Real-Time Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(2) of this Attachment AE;

(vii) Real-Time Regulation-Up Service Revenue as calculated under Section 8.6.19(2)(a)(i) of this Attachment AE;

(viii) Real-Time Regulation-Down Service Revenue as calculated under Section 8.6.20(2)(a)(i) of this Attachment AE;

(ix) Excess Regulation-Up Mileage Dispatch Interval Amount as calculated under Section 8.6.2(1)(a)(v) of this Attachment AE, multiplied by (-1);

(x) Excess Regulation-Down Mileage Dispatch Interval Amount as calculated under Section 8.6.2(2)(a)(v) of this Attachment AE, multiplied by (-1); and

(xi) the sum of the revenues calculated under Section 8.6.26 of this Attachment AE.

(d) An Asset Owner's Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource's Energy cost at actual injection or withdrawal as calculated from the Resource's current Dispatch Interval Energy Offer Curve and the Resource's Energy cost at the Resource's economic operating point as calculated from the Resource's current Dispatch Interval Energy Offer Curve.

(e) A Resource's economic operating point is the MW injection or withdrawal where the cost on the Resource's current Dispatch Interval Energy Offer Curve first exceeds the Real-Time DLMP for that Resource.

(f) For MCRs that have been transitioned into a different configuration in Real-Time and are transitioning into that configuration, the Real-Time Combined Cycle Operating Reserve Adjustment Amount shall be equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs.

### 8.6.6 Real-Time Out-of-Merit Amount

An RTBM OOME payment will be made for each Asset Owner with a Resource that passes a primary Contingency Reserve deployment test as described in Section 2.10.1 of this Attachment AE and/or receives an OOME from the Transmission Provider or local transmission operator that creates a cost to the Asset Owner or that adversely impacts the Asset Owner's Day-Ahead Market position for Energy and/or Operating Reserve. Resources issued an OOME by the Transmission Provider or a local transmission operator that the Market Monitor determines were selected in a discriminatory manner, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the issuing party are not eligible to receive a RTBM OOME payment. RTBM OOME payments made to Asset Owners that received an OOME to address a Local Reliability Issue including Local Emergency Condition shall be recovered locally as described under Section 8.6.7(B). RTBM OOME payments made to Asset Owners that received an OOME to address a reliability issue other than a Local Reliability Issue shall be recovered regionally under Section 8.8. The amount will be calculated on a Dispatch Interval basis as follows:

(1) If the OOME is for Energy above the Resource's economic operating point and the Energy Offer Curve cost associated with the Resource's additional injection or withdrawal attributable to its response ("OOME MW") floor or fixed is greater than the RTBM LMP, the Asset Owner will receive a payment for the difference multiplied by the OOME MW floor or fixed. The payment shall be limited to the amount necessary to compensate the Asset Owner for any under-recovery resulting from the Resource's response to the OOME. The OOME MW is calculated as the positive difference between (i) the lesser of the actual Resource injection or withdrawal or the Resource's OOME floor or fixed MW and (ii) the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 8.6.5(4)(d) of this Attachment AE;

(2) If the OOME is for Energy below the Resource's economic operating point (including a Resource de-commitment or movement of an MCR to a configuration with a lower applicable maximum capacity operating limit) and the RTBM LMP is greater than the Day-Ahead Market LMP, the Asset Owner will

receive a payment equal to the difference multiplied by the Resource's reduction in output or increased withdrawal attributable to its response ("OOME MW") cap or fixed. The payment shall be limited to the amount necessary to compensate the Asset Owner for any increase in net settlement costs resulting from its response to the OOME. The OOME MW is calculated as the maximum of zero (0) or the difference between the Resource's Day-Ahead Market cleared Energy MW and the greater of (i) actual Resource injection or withdrawal or (ii) the Resource's OOME cap or fixed MW;

(3) If an OOME (including a Resource de-commitment instruction or movement of an MCR to a configuration with a lower applicable maximum capacity operating limit) causes the RTBM cleared amount of an Operating Reserve product to be less than the Day-Ahead Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the Day-Ahead Market MCP, the Asset Owner will receive a payment for the difference multiplied by the OOME Operating Reserve MW. The OOME Operating Reserve MW is calculated as the maximum of zero (0) or the difference between the Resource's Day-Ahead Market cleared Operating Reserve MW and the Resource's RTBM cleared Operating Reserve MW.

(4) To the extent that additional costs are incurred as a direct result of an OOME that are not addressed through the compensation mechanisms described in (1) through (3) above, Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

### 8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount

An RTBM system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.6.5 and payments made under Section 8.5.9 of this Attachment AE to Resources committed to address a Local Reliability Issue or Local Emergency Condition. The system-wide amount will be determined by multiplying an Asset Owner's system-wide distribution volume by a daily system-wide RUC make whole payment rate as described in Section 8.6.7(A) of this Attachment AE. The local amount for each Local Settlement Area impacted by a Local Reliability Issue will be determined by multiplying an Asset Owner's Local Settlement Area distribution volume by the Local Settlement Area Make Whole Payment Distribution Rate as described in Section 8.6.7(B) of this Attachment AE.

A. The RUC System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

The RUC System-Wide Make Whole Payment Distribution Amount =
[(RUC System-Wide Make Whole Payment Distribution Rate) *
(RUC System-Wide Make Whole Payment Distribution Volume)]

(1) The RUC System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.6.5 excluding make whole payments made to Resources committed to address a Local Reliability Issue by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Emergency Condition, divided by the sum of Asset Owners' RUC System-Wide Make Whole Payment Distribution Volumes for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner's RUC System-Wide Make Whole Payment Distribution Volume at a Settlement Location for an hour is equal to the sum of following values that are calculated for each Dispatch Interval within the hour:

(a) The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, cleared Self-Charging MSR Offers, virtual offer transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition due to a capacity shortage, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations associated with actual Real-Time load and actual Real-Time Self-Charging MSRs in excess of amounts cleared in the Day-Ahead Market;

(b) For Resources cleared in the Day-Ahead Market, except MCRs with an RTBM Resource Offer commitment status as defined under Section 4.1(10)(b) or (c) of this Attachment AE, that have been transitioned in Real-Time by the Transmission Provider or local transmission operator into a Real-Time configuration with a higher applicable minimum capacity operating limit than the Day-Ahead Market committed configuration, (a) the positive difference between the RTBM Resource applicable minimum limits and Day-Ahead Market Resource cleared Energy quantity; or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the RTBM Resource regulation minimum limit and (2) the greater of the Day-Ahead Market Resource cleared Energy quantity or the Resource's Day-Ahead Market regulation minimum limit, provided that:

(i) The applicable RTBM Resource minimum limit is greater than the comparable Day-Ahead Market Resource minimum limit by more than the Resource's Operating Tolerance; and

(ii) The applicable RTBM Resource minimum limit is greater than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour.

(c) For Resources cleared in the Day-Ahead Market, except combined cycle Resources with an RTBM Resource Offer commitment status as defined under Section 4.1(10)(b) or (c) of this Attachment AE that have been transitioned in Real-Time by the Transmission Provider or local transmission operator into a Real-Time configuration with a lower applicable maximum capacity operating limit than the Day-Ahead Market committed configuration, (a) the positive difference between the Resource Day-Ahead Market cleared Energy quantity and the RTBM Resource applicable maximum limit or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the lesser of the Resource's RTBM regulation maximum limit or the Resource's Day-Ahead Market Resource cleared Energy quantity and (2) the Resource's RTBM regulation maximum limit, provided that:

(i) The applicable RTBM Resource maximum limit is less than the comparable Resource maximum limit submitted for use in the Day-Ahead Market by more than the Resource's Operating Tolerance; and

(ii) The applicable RTBM Resource maximum limit is less than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction greater than or equal to the RTBM applicable maximum limit for at least one Dispatch Interval in the hour.

(d) For Resources cleared in the Day-Ahead Market, the Resource's Day-Ahead Market cleared amount if that Resource is off-line in the RTBM and if the Resource has not been de-committed or dispatched to zero by the Transmission Provider;

(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Instructions, including an MCR that is not in its committed configuration, the absolute value of the difference between a Resource's actual injection or withdrawal and the Resource's economic operating point. The Resource's economic operating point is calculated as described under Section 8.6.5(4)(e) of this Attachment AE;

(f) For Resources that were not offered in the Day-Ahead Market and that self-committed following the close of the Day-Ahead Market, and for Resources that were offered and not cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead RUC, the actual Resource injection or withdrawal if the Resource received a Dispatch Instruction with an absolute value less than or equal to the RTBM applicable minimum charge or discharge limit for at least one Dispatch Interval in the hour;

(g) A Resource's economic operating point, as calculated as described under Section 8.6.5(4)(e) of this Attachment AE, for Resource or MCR configuration that was committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Transmission Provider including, for an MCR, the amount of the incremental MWs from Day-Ahead Market cleared Energy to Real-Time economic operating point; and

(h) The absolute value of a Resource's URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 6.4.1.1 of this Attachment AE.

B. Local Settlement Area Make Whole Payment Distribution Amount shall be calculated as follows:

Local Settlement Area Make Whole Payment Distribution Amount =

[(Local Settlement Area Make Whole Payment Distribution Rate) * (Local Settlement Area Make Whole Payment Distribution Volume)]

(1) The Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day for a Local Settlement Area as calculated under Sections 8.6.5, 8.6.6, and 8.5.9 of this Attachment AE for Resources committed by the Transmission Provider at the request of a local transmission operator or by a local transmission operator to address a Local Reliability Issue in the Local Settlement Area, divided by the sum of Asset Owners' Local Settlement Area Make Whole Payment Distribution Volumes within the impacted Local Settlement Area for the entire Operating Day.

(2) An Asset Owner's Local Settlement Area Make Whole Payment Distribution Volume for the impacted Local Settlement Area for an hour is equal to that Asset Owner's Reported Load and Self-Charging MSRs in that Local Settlement Area for that hour.

### 8.6.8 Real-Time Regulation Service Distribution Amount

An RTBM charge will be calculated for each Asset Owner at each Settlement Location for each hour for the purposes of funding payments made under Section 8.6.2 as follows:

(1) Real-Time Regulation-Up Service Distribution Amount =

[(Real-Time Regulation-Up Service Amount) * (Real-Time Load Ratio Share)] * (-1)

(a) The Real-Time Regulation-Up Service Amount shall be equal to the sum of the all payments made under Section 8.6.2(1) for Regulation-Up Service procurement and the sum of all payments made under Section 8.6.19 for Unused Regulation-Up Mileage Make Whole Payments for the hour.

(b) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

(2) Real-Time Regulation-Down Service Distribution Amount =

[(Real-Time Regulation-Down Service Amount) * (Real-Time Load Ratio Share)] * (-1)

(a) The Real-Time Regulation-Down Service Amount shall be equal to the sum of the all payments made under Section 8.6.2(2) for Regulation-Down Service procurement and the sum of all payments made under Section 8.6.20 for Unused Regulation-Down Mileage Make Whole Payments for the hour.

(b) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.9 Real-Time Spinning Reserve Distribution Amount

An RTBM charge will be calculated for each Asset Owner at each Settlement Location for each hour for the purposes of funding the payments made under Section 8.6.3 as follows:

Real-Time Spinning Reserve Distribution Amount =

[(Real-Time Spinning Reserve Amount) * (Real-Time Load Ratio Share)] * (-1)

(1) The Real-Time Spinning Reserve Amount shall be equal to the sum of the all payments made under Section 8.6.3 for Spinning Reserve procurement for the hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.10 Real-Time Supplemental Reserve Distribution Amount

An RTBM charge will be calculated for each Asset Owner at each Settlement Location for each hour for purposes of funding the payments made under Section 8.6.4 as follows:

Real-Time Supplemental Reserve Distribution Amount =

[(Real-Time Supplemental Reserve Amount) * (Real-Time Load Ratio Share)] * (-1)

(1) The Real-Time Supplemental Reserve Distribution Amount shall be equal to the sum of the all payments made under Section 8.6.4 for Supplemental Reserve procurement for the hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.11 Real-Time Regulation Service Non-Performance Amount

An RTBM charge will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Regulation-Up Service, Regulation-Down Service or both operates outside of its Operating Tolerance. The amount will be determined as follows:

Real-Time Regulation Service Non-Performance Amount =

[[{Maximum of [Either Zero or ((Day-Ahead MCP for Regulation-Up Service) * (Day-Ahead Cleared Regulation-Up Service Hourly Quantity) + (Real-Time MCP for Regulation-Up Service) * (Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity – Day-Ahead Cleared Regulation-Up Service Hourly Quantity))]} +

{Maximum of [Either Zero or ((Day-Ahead MCP for Regulation-Down Service) * (Day-Ahead Cleared Regulation-Down Service Hourly Quantity) + (Real-Time MCP for Regulation-Down Service) * (Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity – Day-Ahead Cleared Regulation-Down Hourly Quantity))]}] / 12] - Unused Regulation-Up Mileage Dispatch Interval Amount + Excess Regulation-Up Mileage Dispatch Interval Amount - Unused Regulation-Down Mileage Dispatch Interval Amount + Excess Regulation-Down Mileage Dispatch Interval Amount.

(1) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Regulation-Up Service associated with the Reserve Zone in which the applicable Resource is located.

(2) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Regulation-Down Service associated with the Reserve Zone in which the applicable Resource is located.

(3) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Regulation-Up Service associated with the Reserve Zone in which the applicable Resource is located.

(4) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Regulation-Down Service associated with the Reserve Zone in which the applicable Resource is located.

(5) An Asset Owner's Day-Ahead Cleared Regulation-Up Service Hourly Quantity is the MW quantity associated with cleared Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE.

(6) An Asset Owner's Day-Ahead Cleared Regulation-Down Service Hourly Quantity is the MW quantity associated with cleared Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE.

(7) An Asset Owner's Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity is the MW quantity associated with cleared Regulation-Up Service Offers as described under Section 6.2.3 of this Attachment AE.

(8) An Asset Owner's Real-Time Cleared Regulation-Down Dispatch Interval Quantity is the MW quantity associated with cleared Regulation-Down Service Offers as described under Section 6.2.3 of this Attachment AE.

(9) An Asset Owner's Unused Regulation-Up Mileage Dispatch Interval Amount is the amount calculated under Section 8.6.2(1)(a)(iv) of this Attachment AE.

(10) An Asset Owner's Excess Regulation-Up Mileage Dispatch Interval Amount is the amount calculated under Section 8.6.2(1)(a)(v) of this Attachment AE.

(11) An Asset Owner's Unused Regulation-Down Mileage Dispatch Interval Amount is the amount calculated under Section 8.6.2(2)(a)(iv) of this Attachment AE.

(12) An Asset Owner's Excess Regulation-Down Mileage Dispatch Interval Amount is the amount calculated under Section 8.6.2(2)(a)(v) of this Attachment AE.

### 8.6.12 Real-Time Regulation Service Non-Performance Distribution Amount

An RTBM payment will be calculated for each Asset Owner at each Settlement Location for each hour in order to distribute the funds collected under Section 8.6.11. The Asset Owner amount is calculated as follows:

Real-Time Regulation Service Non-Performance Distribution Amount =

[(Real-Time Regulation Service Non-Performance Amount) * (Real-Time Load Ratio Share)] * (-1)

(1) The Real-Time Regulation Service Non-Performance Amount shall be equal to the sum of all charges made under Section 8.6.11 for hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.13 Real-Time Contingency Reserve Deployment Failure Amount

If the amount of Contingency Reserve specified in the Contingency Reserve Deployment Instruction is not provided, as determined through failure of the tests described in Section 6.4.3 of this Attachment AE, an RTBM charge will be assessed to the Asset Owner. The charge amount will be determined by multiplying the RTBM LMP (absolute value) for the Dispatch Interval in which the Contingency Reserve Deployment Period ends by the minimum of all shortfall quantity amounts calculated from each of the four tests.

### 8.6.14 Real-Time Contingency Reserve Deployment Failure Distribution Amount

An RTBM payment will be calculated for each Asset Owner at each Settlement Location for each hour in order to distribute the funds collected under Section 8.6.13. The Asset Owner amount is calculated as follows:

Real-Time Contingency Reserve Deployment Failure Distribution Amount =

[(Real-Time Contingency Reserve Deployment Failure Amount) * (Real-Time Load Ratio Share)] * (-1)

(1) The Real-Time Contingency Reserve Deployment Failure Amount shall be equal to the sum of all charges made under Section 8.6.13 for the hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.15 Real-Time Regulation Service Deployment Adjustment Amount

A Real-Time regulation deployment adjustment amount charge or payment will be calculated for each Asset Owner for each Dispatch Interval when a Resource with cleared Real-Time Regulation-Up Service and/or Regulation-Down Service is deployed. The amount will be determined as one-twelfth of the sum of:

(1) For Regulation-Up Service deployment, the amount is equal to the difference between (1) actual Regulation-Up Service deployment MW multiplied by Real-Time LMP at that Resource Settlement Location; and (2) Lesser of (i) as-dispatched Energy Offer Curve cost of actual Regulation-Up Service deployment MW, and (ii) Mitigated Energy Offer Curve cost of actual Regulation-Up Service deployment MW.

(i) The actual Regulation-Up Service deployment MW is calculated as the difference between the lesser of (1) Dispatch Instruction plus the average Regulation-Up Service deployment or (2) actual Resource output, and the Resource's average Dispatch Instruction for Energy. If the absolute value of the Resource's actual output is less than or equal to the absolute value of the Resource's average Dispatch Instruction for Energy, then the actual Regulation-Up Service deployment MW is equal to zero (0).

(2) For Regulation-Down Service deployment, the amount is equal to the difference between (1) Greater of (i) as-dispatched Energy Offer Curve cost of actual Regulation-Down Service deployment MW, and (ii) Mitigated Energy Offer Curve cost of actual Regulation-Down Service deployment MW; and (2) actual Regulation-Down Service deployment MW multiplied by RTBM LMP.

(i) The actual Regulation-Down Service deployment MW is calculated as the difference between the Resource's average Dispatch Instruction for Energy and the greater of (1) Average Dispatch Instruction minus the average Regulation-Down Service deployment or (2) actual Resource output. If the absolute value of the Resource's actual output is greater than or equal to the absolute value of the Resource's average Dispatch Instruction for Energy, then the actual Regulation-Down Service deployment MW is equal to zero (0).

Distribution of such charges and recovery of such payments shall be made in accordance with Section 8.8 of this Attachment AE.

### 8.6.16 Over-Collected Losses Distribution Amount

The MLC of the Day-Ahead Market LMP and RTBM LMP creates an over collection of funds (or under collection of funds as a result of the Real-Time deviation accounting) related to the payment for losses ("Over-Collected Losses") that must be refunded (or charged) as described below. Over-Collected Losses refunds associated with a GFA Carve Out and FSE are calculated pursuant to this Section 8.6.16 and included as a credit to the GFA Carve Out costs and FSE costs under Section 8.5.18 of this Attachment AE. Over-Collected Losses refunds associated with a GFA Carve Out shall not be credited to a GFA Carve Out Responsible Entity to the extent of load it serves under GFA Carve Out Schedule(s). Over-Collected Losses refunds associated with a FSE shall not be credited to Western-UGP for the amount of load served under an FSE Schedule(s).

(1) A payment or charge for the portion of such Over-Collected Losses allocable to each Asset Owner ("Over-Collected Losses Distribution Amount") shall be calculated for each hour at each Settlement Location for which an Asset Owner has a net RTBM Energy withdrawal within a Loss Pool and such Loss Pool contributed positively to the Over-Collected Losses or were charged for Real-Time pseudo-tie losses at the Settlement Location of the sink of the pseudo-tie path for use of the SPP Transmission System according to the following calculations:

(a) Each Loss Pool's contribution to the Over-Collected Losses is calculated based on transactional activity in that Loss Pool where such transactional activity shall include: actual Resource Energy, actual load consumption, and actual Real-Time Self-Charging MSRs, RTBM Import Interchange Transactions and RTBM Export Interchange Transactions.

(b) A "Real-Time Loss Pool loss rebate factor" is calculated hourly for each Loss Pool. The Real-Time Loss Pool loss rebate factor is equal to the sum of the positive loss rebate factors calculated in the RTBM at each withdrawal Settlement Location in the Loss Pool (the "Real-Time Withdrawal Settlement Location loss rebate factor"). Real-Time Withdrawal Settlement Location loss rebate factors are calculated hourly

as the sum of i) the difference between the Real-Time MLC at a withdrawal Settlement Location in the Loss Pool and the injection weighted average Real-Time MLC for the Loss Pool, multiplied by the withdrawal quantity at that Settlement Location and ii) the sum of charges for Real-Time pseudo-tie losses at the Settlement Location of the sink of the pseudo-tie path.

(i) For any Settlement Location that is contained within more than one Settlement Area Loss Pool, any injections or withdrawals associated with such Settlement Location shall be allocated pro rata to the applicable Settlement Area Loss Pools based upon actual submitted real-time meter values for the Meter Data Submittal Locations contained within each applicable Settlement Area Loss Pool.

(ii) The total withdrawal quantity at a Settlement Location is calculated as the positive value of the sum of: (1) actual Resource injection or withdrawal; (2) actual load consumption, and actual Real-Time Self-Charging MSRs; (3) RTBM scheduled Import Interchange Transactions; and (4) RTBM scheduled Export Interchange Transactions at that Settlement Location.

(c) The injection weighted average Real-Time MLC for a Loss Pool is calculated assuming that net RTBM injection in a Loss Pool first serves net RTBM withdrawals in the Loss Pool and then goes to meet the net RTBM withdrawal in Loss Pools that do not have sufficient Net RTBM injections to meet all net RTBM withdrawals.

(d) A Real-Time Loss Pool Unitized Loss Rebate Factor is calculated for each Loss Pool and is equal to that Real-Time Loss Pool loss rebate factor, as calculated in subsection (1)(b) above, divided by the sum of all Real-Time Loss Pool loss rebate factors.

(2) An Over-Collected Losses Distribution Amount shall be calculated hourly for each Asset Owner for each Loss Pool and Settlement Location with a net withdrawal within each Loss Pool as follows:

Asset Owner Settlement Location Over-Collected Losses Distribution Amount = [(Real-Time Loss Pool Unitized Loss Rebate Factor) * (Real-Time Over-Collected Losses Amount + Day-Ahead Over-Collected Losses Amount) * Asset Owner Settlement Location Withdrawal in Loss Pool / Total Asset Owner Settlement Location Withdrawals in Loss Pool] * (-1)

(a) The Real-Time Over-Collected Losses Amount in an hour is equal to the sum for all Settlement Locations of [(Real-Time LMP – Real-Time MCC)] * the difference between actual Energy and Day-Ahead Market cleared Energy MW at each Settlement Location plus the sum of the losses for all Resources or loads that are pseudo-tied out of the SPP Balancing Authority.

(b) The Day-Ahead Over-Collected Losses Amount in an hour is equal to the sum for all Settlement Locations of an amount equal to [(Day-Ahead LMP – Day-Ahead MCC)] * Total cleared Day-Ahead Market Energy MW at each Settlement Location.

(c) The Asset Owner Settlement Location Withdrawal in Loss Pool is equal to the positive value of the sum for that Asset Owner at that Settlement Location in that Loss Pool of: (i) actual Resource injection or withdrawal; (ii) actual load consumption, and actual Real-Time Self-Charging MSRs; (iii) RTBM scheduled Import Interchange Transactions; (iv) RTBM scheduled Export Interchange Transactions; (v) RTBM Bilateral Settlement Schedules where the buyer is the Asset Owner of the net withdrawal at that Settlement Location, capped at the actual withdrawal, adjusted by Sections 8.6.16(2)(c)(vii) and 8.6.16(2)(c)(viii) of this Attachment AE, as described in the Market Protocols; (vi) Day-Ahead Market Bilateral Settlement Schedules where the buyer is the Asset Owner of the net withdrawal at that Settlement Location, capped at the actual withdrawal, adjusted by Sections 8.6.16(2)(c)(vii) and 8.6.16(2)(c)(viii) of this Attachment AE, as described in the Market Protocols; (vii) GFA Carve Out Schedules; and (viii) FSE Schedules.

(d) Real-Time Loss Pool Unitized Loss Rebate Factor is the factor calculated as described in subsection (1)(d) above.

### 8.6.17 Real-Time Reserve Sharing Group Amount

A Real-Time Reserve Sharing Group amount for requested assistance provided between Reserve Sharing Group members following a Resource contingency will be calculated for each counterparty for each hour as specified in the Market Protocols.

### 8.6.18 Real-Time Reserve Sharing Group Distribution Amount

A Real-Time Reserve Sharing Group distribution amount charge or payment will be calculated for each Asset Owner at each Settlement Location for each hour in order to fund payments made or distribute funds collected under Section 8.6.17 as follows:

Real-Time Reserve Sharing Group Distribution Amount =

(Real-Time Reserve Sharing Group Amount) * (Real-Time Load Ratio Share)

(1) Real-Time Reserve Sharing Group Amount is equal to the sum of all charges and payments made under Section 8.6.17.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.19 Unused Regulation-Up Mileage Make Whole Payment

A payment will be made to each Asset Owner with a Resource that is charged for Unused Regulation-Up Mileage at a rate that is in excess of that Resource's Regulation-Up Mileage Offer to the extent that Regulation-Up Service margin is not sufficient to offset such excess. The amount will be calculated on a Dispatch Interval basis as follows:

Unused Regulation-Up Mileage Make Whole Payment Amount =
Day-Ahead Unused Regulation-Up Mileage Make Whole Payment Amount + Real-Time Unused Regulation-Up Mileage Make Whole Payment Amount

(1) Day-Ahead Unused Regulation-Up Mileage Make Whole Payment = Maximum of [zero or (Day-Ahead Regulation-Up Service Margin + Day Ahead Potential Regulation-Up Unused Make Whole Payment Amount)] * (-1)

(a) Day-Ahead Regulation-Up Service Margin = Minimum of [zero or [(Day-Ahead Regulation-Up Service Hourly Amount (as calculated under Section 8.5.2 of this Attachment AE) plus Day-Ahead Regulation-Up Service Cost), divided by 12]

minus

Minimum of [zero or (Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity (as defined under Section 8.6.2(1)(a)(ii) of this Attachment AE) - Day-Ahead Regulation-Up Service Hourly Quantity)] * (Real-Time MCP (as defined under Section 8.6.2(1)(a)(i) of this Attachment AE) – Day-Ahead Regulation-Up Offer ), divided by 12]

(i) If the Resource has cleared Regulation-Up Service that is greater than the amount of self-scheduled Regulation-Up Service on that Resource, then Day-Ahead Regulation-Up Service Cost is equal to the cost calculated as described under Section 8.5.9(4)(a)(iv) of this Attachment AE. If the Resource is not eligible for a Day-Ahead Make Whole Payment Amount as described under Section 8.5.9 of this Attachment AE and the Resource has cleared

Regulation-Up Service that is less than or equal to the amount of self-scheduled Regulation-Up Service on that Resource then Day-Ahead Regulation-Up Service Cost is equal zero for the purposes of this calculation.

(ii) If the Resource has cleared Regulation-Up Service that is greater than the amount of self-scheduled Regulation-Up Service on that Resource, then Day-Ahead Regulation-Up Service Hourly Quantity is equal to the value described under Section 8.6.2(1)(a)(iii) of this Attachment AE. If the Resource is not eligible for a Day-Ahead Make Whole Payment Amount as described under Section 8.5.9 of this Attachment AE and the Resource has cleared Regulation-Up Service that is less than or equal to the amount of self-scheduled Regulation-Up Service on that Resource then Day-Ahead Regulation-Up Service Hourly Quantity is equal zero for the purposes of this calculation.

(b) Day-Ahead Potential Regulation-Up Unused Mileage Make Whole Payment =

[Maximum of [zero or (Expected Regulation-Up Mileage MCP – Day-Ahead Regulation-Up Mileage Offer)]] * Day-Ahead Unused Regulation-Up Mileage divided by 12

(i) Regulation-Up Mileage Offer and Regulation-Up Offer are defined under Section 1 of this Attachment AE. (Regulation-Up Mileage Offer for Day-Ahead Market and Regulation-Up Offer for Day-Ahead Market are the terms used here);

(ii) Expected Regulation-Up Mileage MCP is defined under Section 8.3.4(3) of this Attachment AE;

(iii) If Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity (as described under Section 8.6.2(1)(a)(ii) of this Attachment AE) is equal to zero, then Day-Ahead Unused Regulation-Up Mileage = Maximum of [zero or (Regulation-Up Unused Mileage (as calculated under Section

8.6.2(1)(a)(iv) of this Attachment AE), otherwise Day Ahead Unused Regulation-Up Mileage = Regulation-Up Unused Mileage * Minimum of [one or (Day-Ahead Cleared Regulation-Up Service Hourly Interval Quantity (as described under Section 8.6.2(1)(a)(ii) of this Attachment AE) divided by Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity (as described under Section 8.6.2(1)(a)(ii) of this Attachment AE))])].

(2) Real-Time Unused Regulation-Up Mileage Make Whole Payment = Maximum of [zero or (Real-Time Regulation-Up Service Margin + Real-Time Potential Regulation-Up Unused Make Whole Payment Amount)] * (-1)

(a) Real-Time Regulation-Up Service Margin = Minimum of [zero or Real-Time Regulation-Up Service Revenue plus Real-Time Regulation-Up Service Cost];

(i) Real-Time Regulation-Up Service Revenue = (Real-Time MCP as defined under Section 8.6.2(1)(a)(i) of this Attachment AE) * Maximum of [ zero or ((Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity as defined under Section 8.6.2(1)(a)(ii) of this Attachment AE) - (Day-Ahead Regulation-Up Service Hourly Quantity as defined under Section 8.6.2(1)(a)(iii) of this Attachment AE)) ] / 12) * (-1);

(ii) Real-Time Regulation-Up Service Cost = (Real-Time Regulation-Up Service Offer) * ((Real-Time Cleared Regulation-Up Service Dispatch Interval Quantity) - (Day-Ahead Regulation-Up Service Hourly Quantity)) / 12; except that Real-Time Regulation-Up Service Costs associated with self-scheduled Regulation-Up Service where such self-schedules are less than or equal to the amount of Real-Time Regulation-Up Service cleared shall be set equal to zero.

(b) Real-Time Potential Regulation-Up Unused Mileage Make Whole Payment = {[Maximum of [zero or (Expected Regulation-Up Mileage

MCP – Real-Time Regulation-Up Mileage Offer)]] * (Real-Time Unused Regulation-Up Mileage – Day-Ahead Unused Regulation-Up Mileage) + (For any MCR committed with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(b) or (c) of this Attachment AE, [ (Maximum of [zero or (Expected Regulation-Up Mileage MCP – Real-Time Regulation–Up Mileage Offer) ] ) – (Maximum of [zero or (Expected Regulation-Up Mileage MCP – Day-Ahead Regulation-Up Mileage Offer) ] ) * Day-Ahead Unused Regulation-Up Mileage] ) }, divided by 12

(i) Regulation-Up Mileage Offer is defined under Section 1 of this Attachment AE. (Regulation-Up Mileage Offer for Real-Time Balancing Market is the term used here);

(ii) Expected Regulation-Up Mileage MCP is defined under Section 8.3.4(3) of this Attachment AE;

(iii) Real-Time Unused Regulation-Up Mileage is calculated under Section 8.6.2(1)(a)(iv) of this Attachment AE;

(iv) Day-Ahead Unused Regulation-Up Mileage is calculated under Section 8.6.19(1)(b)(iii) of this Attachment AE;

(v) Day-Ahead Regulation-Up Mileage Offer as defined under Section 8.6.19(1)(b)(i) of this Attachment AE.

### 8.6.20 Unused Regulation-Down Mileage Make Whole Payment

A payment will be made to each Asset Owner with a Resource that is charged for Unused Regulation-Down Mileage at a rate that is in excess of that Resource's Regulation-Down Mileage Offer to the extent that Regulation-Down Service margin is not sufficient to offset such excess. The amount will be calculated on a Dispatch Interval basis as follows:

Unused Regulation-Down Mileage Make Whole Payment Amount =
Day-Ahead Unused Regulation-Down Mileage Make Whole Payment Amount + Real-Time Unused Regulation-Down Mileage Make Whole Payment Amount

(1) Day-Ahead Unused Regulation-Down Mileage Make Whole Payment = Maximum of [zero or (Day-Ahead Regulation-Down Service Margin + Day Ahead Potential Regulation-Down Unused Make Whole Payment Amount)] * (-1)

(a) Day-Ahead Regulation-Down Service Margin = Minimum of [ zero or [(Day-Ahead Regulation-Down Service Hourly Amount (as calculated under Section 8.5.2 of this Attachment AE) plus Day-Ahead Regulation-Down Service Cost, divided by 12],

minus

Minimum of [zero or (Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity (as defined under Section 8.6.2(1)(a)(ii) of this Attachment AE) -Day-Ahead Regulation-Down Service Hourly Quantity) ] * (Real-Time MCP (as defined under Section 8.6.2(2)(a)(i) of this Attachment AE) – Day-Ahead Regulation-Down Offer ), divided by 12]

(i) If the Resource has cleared Regulation-Down Service that is greater than the amount of self-scheduled Regulation-Down Service on that Resource, then Day-Ahead Regulation-Down Service Cost is equal to the cost calculated as described under Section 8.5.9(4)(a)(v) of this Attachment AE. If the Resource is

not eligible for a Day-Ahead Make Whole Payment Amount as described under Section 8.5.9 of this Attachment AE and the Resource has cleared Regulation-Down Service that is less than or equal to the amount of self-scheduled Regulation-Down Service on that Resource then Day-Ahead Regulation-Down Service Cost is equal zero for the purposes of this calculation.

(ii) If the Resource has cleared Regulation-Down Service that is greater than the amount of self-scheduled Regulation-Down Service on that Resource, then Day-Ahead Regulation-Down Service Hourly Quantity is equal to the value described under Section 8.6.2(2)(a)(iii) of this Attachment AE. If the Resource is not eligible for a Day-Ahead Make Whole Payment Amount as described under Section 8.5.9 of this Attachment AE and the Resource has cleared Regulation-Up Service that is less than or equal to the amount of self-scheduled Regulation-Up Service on that Resource then Day-Ahead Regulation-Up Service Hourly Quantity is equal zero for the purposes of this calculation.

(b) Day-Ahead Potential Regulation-Down Unused Mileage Make Whole Payment = [Maximum of [zero or (Expected Regulation-Down Mileage MCP - Day-Ahead Regulation-Down Mileage Offer]] * Day-Ahead Unused Regulation-Down Mileage, divided by 12

(i) Regulation-Down Mileage Offer and Regulation-Down Offer are defined under Section 1 of this Attachment AE. (Regulation-Down Mileage Offer for Day-Ahead Market and Regulation-Down Offer for Day-Ahead Market are the terms used here);

(ii) Expected Regulation-Down Mileage MCP is defined under Section 8.3.4(4) of this Attachment AE;

(iii) If Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity (as described under Section 8.6.2(2)(a)(ii) of this Attachment AE) is equal to zero then Day-Ahead Unused

Regulation-Down Mileage = Maximum of [zero or (Regulation-Down Unused Mileage (as calculated under Section 8.6.2(2)(a)(iv) of this Attachment AE), otherwise Day-Ahead Unused Regulation-Down Mileage = Regulation-Down Unused Mileage * Minimum of [one or (Day-Ahead Cleared Regulation-Down Service Hourly Interval Quantity (as described under Section 8.6.2(2)(a)(ii) of this Attachment AE) divided by Real-Time Cleared Regulation-Down Service Hourly Quantity (as described under Section 8.6.2(2)(a)(ii) of this Attachment AE))])].

(2) Real-Time Unused Regulation-Down Mileage Make Whole Payment = Maximum of [zero or (Real-Time Regulation-Down Service Margin + Real-Time Potential Regulation-Down Unused Make Whole Payment Amount)] * (-1)

(a) Real-Time Regulation-Down Service Margin = Minimum of [zero or Real-Time Regulation-Down Service Revenue plus Real-Time Regulation-Down Service Cost];

(i) Real-Time Regulation-Down Service Revenue = (Real-Time MCP as defined under Section 8.6.2(2)(a)(i) of this Attachment AE) * Maximum of [ zero or ((Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity as defined under Section 8.6.2(2)(a)(ii) of this Attachment AE) - (Day-Ahead Regulation-Down Service Hourly Quantity as defined under Section 8.6.2(2)(a)(ii) of this Attachment AE) ] / 12 * (-1);

(ii) Real-Time Regulation-Down Service Cost = (Real-Time Regulation-Down Service Offer) * ((Real-Time Cleared Regulation-Down Service Dispatch Interval Quantity) - (Day-Ahead Regulation-Down Service Hourly Quantity)) / 12; except that Real-Time Regulation-Down Service Costs associated with self-scheduled Regulation-Down Service where such self-schedules are less than or equal to the amount of Real-Time Regulation-Down Service cleared shall be set equal to zero.

(b) Real-Time Potential Regulation-Down Unused Mileage Make Whole Payment = { [Maximum of [zero or (Expected Regulation-Down Mileage MCP – Real-Time Regulation-Down Mileage Offer)]] * (Real-Time Unused Regulation-Down Mileage – Day-Ahead Unused Regulation-Down Mileage) + (For any MCR committed with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(b) or (c) of this Attachment AE, [ (Maximum of [zero or (Expected Regulation-Down Mileage MCP – Real-Time Regulation-Down Mileage Offer) ] ) – (Maximum of [zero or (Expected Regulation-Down Mileage MCP – Day-Ahead Regulation-Down Mileage Offer) ] ) * Day-Ahead Unused Regulation-Down Mileage] ) }, divided by 12

(i) Regulation-Down Mileage Offer is defined under Section 1 of this Attachment AE. (Regulation-Down Mileage Offer for Real-Time Balancing Market is the term used here);

(ii) Expected Regulation-Down Mileage MCP is defined under Section 8.3.4(4) of this Attachment AE;

(iii) Real-Time Unused Regulation-Down Mileage is calculated under Section 8.6.2(2)(a)(iv) of this Attachment AE;

(iv) Day-Ahead Unused Regulation-Down Mileage is calculated under Section 8.6.20(1)(b)(iii) of this Attachment AE;

(v) Day-Ahead Regulation-Down Mileage Offer as defined under Section 8.6.20(1)(b)(i) of this Attachment AE.

### 8.6.21 Real-Time Demand Reduction Amount

A Real-Time Balancing Market payment or charge will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with the difference between actual Demand Response Resource output and cleared Day-Ahead Market Demand Response Resource Offers for each applicable Settlement Location and each Dispatch Interval as follows:

(1) Real-Time Demand Reduction Dispatch Interval Amount =

[(Real-Time LMP) * (Real-Time Total Demand Response Resource Billing Meter Quantity – Day-Ahead Total Demand Response Resource Hourly Quantity)] / 12

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, for a load Settlement Location containing one or more Demand Response Loads associated with committed and dispatched Demand Response Resources.

(b) An Asset Owner's Real-Time Total Demand Response Resource Billing Meter Quantity is equal to the sum of that Asset Owner's Real-Time Demand Response Resource Billing Meter Quantities for each Demand Response Resource associated with the load Settlement Location referenced in (1) above.

(c) An Asset Owner's Real-Time Demand Response Resource Billing Meter Quantity for each Demand Response Resource Settlement Location is:

(i) For a Dispatchable Demand Response Resource selecting the submitted Resource production option as described under Section 4.1.2.1(1)(a) of this Attachment AE, either (i) the five (5) minute actual meter MWh Resource output quantity submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12); or (ii) the hourly actual meter MWh Resource output quantity profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data; or

(ii) For a Dispatchable Demand Response Resource selecting the calculated Resource production option as described under Section 4.1.2.1(1)(b) of this Attachment AE and Block Demand Response Resources, either (i) the five (5) minute actual meter MWh output quantity of the associated Demand Response Load submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly actual meter MWh output quantity of the associated Demand Response Load profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data. The Transmission Provider then calculates the Demand Response Resource output as described under Section 4.1.2.1(1)(b)(ii) and multiplies the result by (-1).

(d) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the value calculated under Section 8.5.24(2) of this Attachment AE for the applicable load Settlement Location.

(2) Real-Time Demand Reduction Hourly Amount =

Sum of Real-Time Demand Reduction Dispatch Interval Amount over all Dispatch Intervals in the Hour.

### 8.6.22 Real-Time Demand Reduction Distribution Amount

The Real-Time demand reduction distribution amount is an hourly payment or charge to Asset Owners at each Settlement Location to account for the sum of the demand reduction amounts calculated under Section 8.6.21 of this Attachment AE and is calculated as:

Real-Time Demand Reduction Distribution Amount =
(Real-Time Demand Reduction Distribution Rate) * (Real-Time Demand Reduction Distribution Quantity)

(1) Real-Time Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.6.21 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owner's Real-Time Demand Reduction Distribution Quantities for all Settlement Locations for the hour.

(2) An Asset Owner's Real-Time Demand Reduction Distribution Quantity for an hour is equal to that Asset Owner's net actual Energy withdrawals at that Settlement Location for that hour. The net actual Energy withdrawal at a Settlement Location is calculated as the sum of an Asset Owner's load consumption and the Real-Time Self-Charging MSRs and the positive MWh value for the Asset Owner's net Export and Import Interchange Transactions.

### 8.6.23 Real-Time Pseudo-Tie Congestion Amount

A RTBM charge or credit will be calculated for each Resource or load that is pseudo-tied out of the SPP Balancing Authority for each Dispatch Interval of the Operating Day. The amount is calculated as follows:

Real-Time Pseudo-Tie Congestion Amount =

(Real-Time Pseudo-Tie Quantity)

* [(Real-Time MCC at the sink) - (Real-Time MCC at the source)]

(1) Real-Time Pseudo-Tie Quantity is the telemetered value of the Resource or load that is pseudo-tied out of the SPP Balancing Authority.

(2) Real-Time MCC is as defined under Section 1 of this Attachment AE.

### 8.6.24 Real-Time Pseudo-Tie Losses Amount

A RTBM charge or credit will be calculated for each Resource or load that is pseudo-tied out of the SPP Balancing Authority for each Dispatch Interval of the Operating Day. The amount is calculated as follows:

Real-Time Pseudo-Tie Losses Amount =

(Real-Time Pseudo-Tie Quantity) * [(Real-Time MLC at the sink) - (Real-Time MLC at the source)]

(1) Real-Time Pseudo-Tie Quantity is the telemetered value of the Resource or load that is pseudo-tied out of the SPP Balancing Authority.

(2) Real-Time MLC is as defined under Section 1 of this Attachment AE.

### 8.6.25 Real-Time Ramp Capability Amount

(1) An RTBM payment or charge for deviations between cleared RTBM Ramp Capability Up and cleared Day-Ahead Market Ramp Capability Up will be calculated at each Settlement Location by Asset Owner for each Dispatch Interval and hour as follows:

(a) Real-Time Ramp Capability Up Dispatch Interval Amount =
[(Real-Time MCP) * ((Real-Time Cleared Ramp Capability Up Dispatch Interval Quantity) – (Day-Ahead Ramp Capability Up Hourly Quantity)) / 12] * (-1)

(i) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Up associated with the Reserve Zone in which the applicable Resource is located.

(ii) Asset Owner Real-Time Cleared Ramp Capability Up Dispatch Interval Quantity is the MW quantity associated with cleared Ramp Capability Up as described under Section 6.2.3 of this Attachment AE.

(iii) Asset Owner Day-Ahead Cleared Ramp Capability Up Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Ramp Capability Up as described under Section 5.1.3 of this Attachment AE.

(b) Real-Time Ramp Capability Up Hourly Amount =
Sum of Real-Time Ramp Capability Up Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(2) An RTBM payment or charge for deviations between cleared RTBM Ramp Capability Down and cleared Day-Ahead Market Ramp Capability Down will be calculated at each Settlement Location by Asset Owner for each Dispatch Interval and each hour as follows:

(a) Real-Time Ramp Capability Down Dispatch Interval Amount =
[(Real-Time MCP) * ((Real-Time Cleared Ramp Capability Down Dispatch Interval Quantity) – (Day-Ahead Ramp Capability Down Hourly Quantity)) / 12] * (-1)

(i) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Down associated with the Reserve Zone in which the applicable Resource is located.

(ii) Asset Owner Real-Time Cleared Ramp Capability Down Dispatch Interval Quantity is the MW quantity associated with cleared Ramp Capability Down as described under Section 6.2.3 of this Attachment AE.

(iii) Asset Owner Day-Ahead Cleared Ramp Capability Down Hourly Quantity is the MW quantity associated with cleared Day-Ahead Market Ramp Capability Down as described under Section 5.1.3 of this Attachment AE.

(b) Real-Time Ramp Capability Down Hourly Amount =

Sum of Real-Time Ramp Capability Down Dispatch Interval Amount over all Dispatch Intervals in the Hour.

### 8.6.26 Real-Time Ramp Capability Distribution Amount

(1) An RTBM charge will be calculated by Asset Owner at each Settlement Location for each hour for the purposes of funding the payments made under Section 8.6.25 of this Attachment AE as follows:

Real-Time Ramp Capability Up Distribution Amount =

[(Real-Time Ramp Capability Up Amount) * (Real-Time Load Ratio Share)] * (-1)

(a) The Real-Time Ramp Capability Up Amount shall be equal to the sum of the all payments made under Section 8.6.25 of this Attachment AE for Ramp Capability Up procurement for the hour.

(b) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

(2) An RTBM charge will be calculated by Asset Owner at each Settlement Location for each hour for the purposes of funding the payments made under Section 8.6.25 of this Attachment AE as follows:

Real-Time Ramp Capability Down Distribution Amount =

[(Real-Time Ramp Capability Down Amount) * (Real-Time Load Ratio Share)] * (-1)

(a) The Real-Time Ramp Capability Down Amount shall be equal to the sum of all payments made under Section 8.6.25 of this Attachment AE for Ramp Capability Down procurement for the hour.

(b) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

### 8.6.27 Real-Time Ramp Capability Non-Performance Amount

An RTBM charge will be calculated at each Resource Settlement Location for each Asset Owner for each Dispatch Interval when a Resource with cleared RTBM Ramp Capability Up, Ramp Capability Down or both operates outside of its Operating Tolerance. The amount will be determined as follows:

Real-Time Ramp Capability Up Non-Performance Amount =

[[{Maximum of [Either Zero or ((Day-Ahead MCP for Ramp Capability Up) * (Day-Ahead Cleared Ramp Capability Up Hourly Quantity) + (Real-Time MCP for Ramp Capability Up) * (Real-Time Cleared Ramp Capability Up Dispatch Interval Quantity – Day-Ahead Cleared Ramp Capability Up Hourly Quantity))]} +

{Maximum of [Either Zero or ((Day-Ahead MCP for Ramp Capability Down) * (Day-Ahead Cleared Ramp Capability Down Hourly Quantity) + (Real-Time MCP for Ramp Capability Down) * (Real-Time Cleared Ramp Capability Down Dispatch Interval Quantity – Day-Ahead Cleared Ramp Capability Down Hourly Quantity))]}] / 12]

(1) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Up associated with the Reserve Zone in which the applicable Resource is located.

(2) Day-Ahead MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Down associated with the Reserve Zone in which the applicable Resource is located.

(3) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Up associated with the Reserve Zone in which the applicable Resource is located.

(4) Real-Time MCP, as defined under Section 1 of this Attachment AE, for Ramp Capability Down associated with the Reserve Zone in which the applicable Resource is located.

(5) An Asset Owner’s Day-Ahead Cleared Ramp Capability Up Hourly Quantity is the MW quantity associated with cleared Ramp Capability Up as described under Section 5.1.3 of this Attachment AE.

(6) An Asset Owner's Day-Ahead Cleared Ramp Capability Down Hourly Quantity is the MW quantity associated with cleared Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE.

(7) An Asset Owner's Real-Time Cleared Ramp Capability Up Dispatch Interval Quantity is the MW quantity associated with cleared Ramp Capability as described under Section 6.2.3 of this Attachment AE.

(8) An Asset Owner's Real-Time Cleared Ramp Capability Down Dispatch Interval Quantity is the MW quantity associated with cleared Ramp Capability as described under Section 6.2.3 of this Attachment AE.

### 8.6.28 Real-Time Ramp Capability Non-Performance Distribution Amount

An RTBM payment will be calculated for each Asset Owner at each Settlement Location for each hour in order to distribute the funds collected under Section 8.6.27 of this Attachment AE. The Asset Owner amount is calculated as follows:

Real-Time Ramp Capability Non-Performance Distribution Amount =

[(Real-Time Ramp Capability Non-Performance Amount) * (Real-Time Load Ratio Share)] * (-1)

(1) The Real-Time Ramp Capability Non-Performance Amount shall be equal to the sum of all charges made under Section 8.6.27 of this Attachment AE for each hour.

(2) Real-Time Load Ratio Share is as defined under Section 1 of this Attachment AE.

## 8.7 Auction Revenue Rights and Transmission Congestion Rights Auction Settlement

The charges and payments to ARR holders and TCR holders resulting from the annual and monthly TCR auctions described in Section 7 of this Attachment AE are calculated on a daily basis and included on the Settlement Statements consistent with the timing of the Day-Ahead Market settlement and RTBM settlement.

The following Subsections describe the ARR/TCR auction settlement charge types. For each charge type, the calculation is performed each Asset Owner. The Transmission Provider shall calculate daily summations to each Market Participant for all Asset Owners it represents as specified in the Market Protocols.

### 8.7.1 Transmission Congestion Rights Auction Transaction Amount

A TCR auction daily charge or payment to each Asset Owner is calculated as the sum of charges and payments associated with that Asset Owner's TCRs purchased or sold on a particular source to sink path, for each TCR auction period and round in the annual and monthly TCR auctions, as follows:

TCR Auction Daily Amount =

Sum of [(TCR Auction Quantity) * (Auction Clearing Price at source - Auction Clearing Price at sink)] / Number of Days in the Period

(1) An Asset Owner's TCR Quantity is the total MWs of TCRs purchased on a particular source to sink path in the annual TCR auctions or the net total MWs of TCRs purchased or sold on a particular source to sink path in round 1 and round 2 in the monthly TCR auctions by that Asset Owner.

(2) Auction Clearing Price at source is the Auction Clearing Price in the applicable auction period and round at the source Settlement Location of the TCR Quantity source to sink path as calculated as described under Sections 7.4.4 and 7.5.4 of this Attachment AE.

(3) Auction Clearing Price at sink is the Auction Clearing Price in the applicable auction period and round at the sink Settlement Location of the TCR Quantity source to sink path as calculated as described under Sections 7.4.4 and 7.5.4 of this Attachment AE.

(4) Number of Days in the Period is either number of days in the applicable monthly period or number of days in the applicable seasonal period.

### 8.7.2 Auction Revenue Rights Funding Amount

ARRs are valued at the prices from the annual and monthly TCR auctions during the lifetime of the instrument. An ARR auction daily charge or payment to each Asset Owner is calculated for each applicable ARR quantity held on a particular source to sink path, for each TCR auction period and round in the annual and monthly TCR auctions as follows:

ARR Daily Amount =

[(ARR Quantity) * (Auction Clearing Price at Source - Auction Clearing Price at Sink)] / Number of Days in the Period * (-1)

(1) An Asset Owner's ARR Quantity is the total applicable MWs of ARRs on a particular source to sink path for the corresponding TCR auction period and round where such quantities are described under Section 7.7 of this Attachment AE.

(2) Auction Clearing Price at Source is the Auction Clearing Price in the applicable auction period and round at the source Settlement Location of the ARR Quantity source to sink path as calculated as described under Sections 7.4.4 and 7.5.4 of this Attachment AE.

(3) Auction Clearing Price at Sink is the Auction Clearing Price in the applicable auction period and round at the sink Settlement Location of the ARR Quantity source to sink path as calculated as described under Sections 7.4.4 and 7.5.4 of this Attachment AE.

(4) Number of Days in the Period is either number of days in the applicable monthly period or number of days in the applicable seasonal period.

### 8.7.3 Auction Revenue Rights Uplift Amount

A daily charge will be calculated for each Asset Owner holding ARRs for each TCR auction period and round to the extent that the associated TCR auction revenues calculated under Section 8.7.1 are not sufficient to fund the total of the amounts calculated under Section 8.7.2 for each associated TCR auction period and round. The daily amount will be calculated as follows:

ARR Daily Uplift Amount =

[(ARR Under Funding Amount) * (ARR Net Daily Amount) / Total ARR Net Daily Amount)]

(1) ARR Under Funding Amount is equal to the difference between: (a) the sum of all charges and payments made under Section 8.7.2 for that TCR auction period and round for that day, multiplied by (-1); and (b) the sum of all charges and payments made under Section 8.7.1 for that TCR auction period and round for that day, to the extent that such difference is a positive value. Otherwise, the ARR Under Funding Amount shall be equal to zero (0).

(2) An Asset Owner's ARR Net Daily Amount is equal to the sum of the absolute value of amounts calculated under Section 8.7.2 for that Asset Owner for that day.

(3) The Total ARR Net Daily Amount is equal to the sum of all of the Asset Owner values calculated in (2) above for that day.

### 8.7.4 Auction Revenue Rights Monthly Payback Amount

A monthly payment will be calculated as follows for each Asset Owner assessed charges under Section 8.7.3 during the month:

ARR Monthly Payback Amount =

Minimum of [(ARR Monthly Uplift Amount) or ((Excess TCR Revenue Fund Monthly Amount) * (ARR Monthly Uplift Amount) / (Total ARR Monthly Uplift Amount))] * (-1)

(1) An Asset Owner's ARR Monthly Uplift Amount is equal to the sum of that Asset Owner's charges calculated under Section 8.7.3 for the month.

(2) Total ARR Monthly Uplift Amount is equal to the sum of all Asset Owners' ARR Monthly Uplift Amounts for the month.

(3) The Excess TCR Revenue Fund Monthly Amount is equal to the sum of Excess TCR Revenue Fund Daily Amount for the month.

(a) The Excess TCR Revenue Fund Daily Amount is equal to the positive difference between: (i) the total of all charges and payments calculated under Section 8.7.1 for the Operating Day and (ii) the total charges and payments calculated under Section 8.7.2 for the Operating Day multiplied by (-1).

### 8.7.5 Auction Revenue Rights Annual Payback Amount

An annual payment will be calculated as follows for each Asset Owner assessed charges under Section 8.7.3 over the year that were not fully reimbursed in the monthly payback process:

ARR Annual Payback Amount =

Minimum of [(ARR Net Uplift Annual Amount) or ((Excess TCR Auction Revenue Fund Yearly Amount) * (ARR Net Uplift Annual Amount) / (Total ARR Net Uplift Annual Amount))]

(1) An Asset Owner's ARR Net Uplift Annual Amount is equal the difference between (i) the sum of that Asset Owner's charges calculated under Section 8.7.3 for the year and (ii) the sum of that Asset Owner's payments made under Section 8.7.4 for the year multiplied by (-1).

(2) Total ARR Net Uplift Annual Amount is equal to the sum of all Asset Owners' TCR Net Uplift Annual Amounts for the month.

(3) The Excess TCR Revenue Fund Yearly Amount is equal to the difference between the total Excess TCR Revenue Fund Monthly Amount for the year, as described under Section 8.7.4(3), and the total payments made under Section 8.7.4 for the year.

### 8.7.6 Auction Revenue Rights Annual Closeout Amount

An annual payment will be calculated as follows for each Asset Owner with ARR Nomination Caps established under Section 7.1.3 of this Attachment AE to the extent that there are any funds remaining once all payments are made under Section 8.7.4. The calculations below can result in residual amounts due to rounding. The Transmission Provider will uplift the annual residual amounts to all of the Asset Owners as specified in the Market Protocols.

ARR Annual Closeout Amount =
[(Excess TCR Revenue Fund Yearly Amount + ARR Annual Payback Total) * (Annual ARR Nomination Cap / Total Annual ARR Nomination Cap)] * (-1)

(1) Excess TCR Revenue Fund Yearly Amount is equal to the value calculated under Section 8.7.5 of this Attachment.

(2) ARR Annual Payback Total is equal to the sum of all payments made under Section 8.7.5.

(3) An Asset Owner's Annual ARR Nomination Cap is equal to the sum of all of that Asset Owner's daily ARR nomination caps, as calculated under Section 7.1.3 of this Attachment AE, for the year.

(4) Total Annual ARR Nomination Cap is equal to the sum of all Asset Owners' Annual ARR Nomination Caps for the year.

## 8.8 Revenue Neutrality Uplift Distribution Amount

The Transmission Provider shall perform the following calculation for each hour of the Operating Day for each Asset Owner and Settlement Location to ensure that the Transmission Provider is revenue neutral over the Operating Day. The Transmission Provider shall calculate hourly summations to each Market Participant for all Asset Owners it represents and shall calculate daily summations as specified in the Market Protocols. The calculations below can result in residual amounts due to rounding. The Transmission Provider will sum up those residual amounts per Operating Day and include them in the Transmission Provider budgeted expenses used to calculate the rate specified under Schedule 1-A of the Tariff.

Revenue Neutrality Uplift Distribution Amount =

Daily RNU Distribution Rate * RNU Distribution Volume * (-1)

(1) The Daily RNU Distribution Rate is equal to the Daily RNU Distribution Amount divided by the Daily RNU Distribution Volume.

(a) The Daily RNU Distribution Amount is equal to:

(i) The sum of all Asset Owners' charges and payments calculated under Section 8.5, excluding payments under Section 8.5.13 for the Operating Day; plus

(ii) The sum of all Asset Owners' charges and payments calculated under Section 8.6 for the Operating Day; plus

(iii) The sum of all Asset Owners' charges and payments calculated under Section 8.7, excluding payments under Section 8.7.4; plus

(iv) The sum of all charges and payments for emergency purchases and sales entered into by the Transmission Provider in its Balancing Authority role in order to alleviate a capacity shortage inside the SPP Balancing Authority Area or to assist an external balancing authority in alleviating a capacity shortage. Payments for Local Reliability Issue Commitments are allocated in accordance with Section 6.6 of this Attachment AE; plus

(v) Any other charges and credits not accounted for in subsections (i) through (iv) above; minus

(vi) The Excess Congestion Fund Daily Amount calculated under Section 8.5.13(3)(a) for the Operating Day; plus

(vii) The Excess Congestion Fund Yearly Amount calculated under Section 8.5.14(3) for the year corresponding with the annual TCR auction; minus

(viii) The Excess TCR Revenue Fund Daily Amount calculated under Section 8.7.4(3)(a) for the Operating Day; plus

(ix) The Excess TCR Revenue Fund Yearly Amount calculated under Section 8.7.5(3) for the Operating Day.

(b) The Daily RNU Distribution Volume is equal to the sum of all Asset Owners' RNU Distribution Volumes for the Operating Day.

(2) An Asset Owner's RNU Distribution Volume at a Settlement Location for an hour is equal to the sum of:

(a) The absolute value of actual metered generation or load in the hour; and

(b) The absolute value of scheduled Interchange Transactions in the hour; and

(c) The absolute value of cleared Virtual Energy Offers and Bids in the hour.

## 8.9 GFA Carve Out or FSE Uplift

The Transmission Provider shall determine the congestion charges and marginal loss charges related to the GFA Carve Outs or FSE. Subject to Section 7.0(b)(i) of this Attachment AE, these charges will be offset by the ARR/TCR settlement that would have been claimed for each GFA Carve Out or FSE under the normal ARR/TCR process and by the distribution of associated Marginal Loss Overcollection funds. The Transmission Provider shall perform calculations in accordance with Sections 8.5.18 through 8.5.23 of this Attachment AE to ensure that the Transmission Provider is revenue neutral for the expense or credit attributed to GFA Carve Out Schedules or FSE Schedules. The Transmission Provider shall calculate uplift charges or credits on a load ratio share basis to each Market Participant for all load Asset Owners it represents, excluding from such calculations all load served under GFA Carve Out Schedules or FSE Schedules. The Daily, Monthly, and Yearly GFA Carve Out Uplift Distribution Amounts shall not be charged or credited to a GFA Carve Out Responsible Entity to the extent of load it serves under GFA Carve Out Schedules. The Daily, Monthly, and Yearly Uplift Distribution Amounts associated with FSE Schedules shall not be charged or credited to Western-UGP for the amount of load served under FSE Schedules.

## 8.10 Market Administration Services Amount

The Transmission Provider will perform calculations for each Asset Owner for each hour consistent with Schedule 1-A2 of this Tariff. The Transmission Provider will perform calculations at each Settlement Location for each hour consistent with Schedules 1-A3 and 1-A4 of this Tariff.

## 9.0 Release of Offer Curve Data

The Transmission Provider will release data on all Day-Ahead Offers and Bids, RTBM Energy Offer Curves and Operating Reserves ninety (90) days after the day for which they were submitted. Such information released by the Transmission Provider will not be provided by Settlement Location or include the identity of the Market Participant, Resource or load.

## 10.0 Billing

The Transmission Provider shall prepare a billing statement each billing cycle in accordance with this section of Attachment AE. Such billing statements shall be prepared for each Market Participant in accordance with the charges and payments specified in Section 8 of this Attachment AE, and showing the net amount to be paid or received by the Market Participant in accordance with Sections 10.6 and 10.7 of this Attachment AE. Billing statements shall provide sufficient detail, as specified in the Market Protocols, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Unresolved billing disputes shall be settled in accordance with procedures specified in Section 12 of the Tariff.

## 10.1 Settlement Statements

(1) The Transmission Provider shall issue a preliminary Scheduled Settlement Statement for an Operating Day no later than seven (7) calendar days following the applicable Operating Day unless the seventh (7) day following the applicable Operating Day is not a business day, in which case, the preliminary Settlement Statement shall be issued on the first business day thereafter. This preliminary Scheduled Settlement Statement is defined as an S7 Scheduled Settlement Statement.

(2) The Transmission Provider shall issue a second Scheduled Settlement Statement for an Operating Day no later than fifty-three (53) calendar days following the applicable Operating Day unless the fifty-third (53) calendar day following the applicable Operating Day is not a business day, in which case, the S53 Scheduled Settlement Statement shall be issued on the first business day thereafter. This second Scheduled Settlement Statement is defined as an S53 Scheduled Settlement Statement.

(3) The Transmission Provider shall issue a final Scheduled Settlement Statement for an Operating Day no later than one hundred and twenty (120) calendar days following the applicable Operating Day unless the one hundred and twentieth (120) calendar day following the applicable Operating Day is not a business day, in which case, the S120 Scheduled Settlement Statement shall be issued on the first (1) business day thereafter. This final Scheduled Settlement Statement is defined as an S120 Scheduled Settlement Statement.

(4) The Transmission Provider shall make corrections to Settlement Statements for an Operating Day for Data Errors, Software Errors, and Settlement Statement disputes in accordance with Section 10.1.1 of this Attachment AE. Settlement associated with a specific Operating Day shall be considered final at the end of the three hundred sixty-fifth (365) calendar day following the applicable Operating Day.

(5) To the extent that a Market Participant, or its designated Meter Agent, does not submit meter data representing that Market Participant's actual Resource output

and load consumption, either on a five (5) minute basis or an hourly basis in accordance with the timelines specified in the Market Protocols, the Transmission Provider shall use estimated data for that Market Participant that is equal to that Market Participant's telemetered generation and load for the applicable intervals or State Estimator values if telemetered values are not available for the purposes of calculating the preliminary statements specified under Section 10.1(1) of this Attachment AE. To the extent a Meter Agent does not submit data representing the metering of each interconnecting tie-line between Settlement Areas, the Transmission Provider will substitute State Estimator values. In the event that actual meter data is not submitted prior to the issuance of an S120 Scheduled Settlement Statement, the Transmission Provider shall use the best available data, which may include estimated meter data as developed by the Transmission Provider, for the purposes of calculating S120 Scheduled Settlement Statements.

(6) The Transmission Provider shall remove from the GFA Responsible Entity's Settlement Statement all charges associated with the cost of congestion and the cost of losses for GFA Carve Out transactions based on the Day-Ahead Market for the designated Settlement Locations, as set forth in Section 8.2.2 of this Attachment AE. The Transmission Provider removal of all charges associated with the cost of congestion and the cost of losses for GFA Carve Out is subject to the GFA Responsible Entity's compliance with the requirements of Section 8.2.2.1 of this Attachment AE.

(7) The Transmission Provider shall remove from Western-UGP's Settlement Statement all charges associated with the cost of congestion and the cost of losses for FSE transactions based on the Day-Ahead Market for the designated Settlement Locations, as set forth in Section 8.2.3 of this Attachment AE. Such removal is subject to Western-UGP's compliance with the requirements of Section 8.2.3.1 of this Attachment AE.

### 10.1.1 Resettlements

Resettlements for a given Operating Day will be considered by the Transmission Provider for the following reasons:

(1) Software Errors and Data Errors

(a) The Transmission Provider, in its discretion, may correct its Software Errors and/or Data Errors and resettle the relevant Operating Day(s), as closely as practicable, to the outcome that would have resulted but for the relevant Software Error or Data Error based on the following:

(i) Software Errors and/or Data Errors that are identified by the Transmission Provider or submitted through the dispute process within ninety (90) calendar days of the affected Operating Day will be considered for Resettlement.

(ii) Software Errors and/or Data Errors that result in incremental differences between any two consecutive Settlement Statements subsequent to S7 Scheduled Settlement Statement will be considered for Resettlement if identified by the Transmission Provider or submitted through the dispute process within thirty (30) calendar days of the posting of the applicable Settlement Statement.

(b) If the correction of the relevant Software Error and/or Data Error would require Day-Ahead or Real-Time Balancing Market price corrections, the Transmission Provider will address such errors in accordance with the procedures in Section 8.4 of this Attachment AE.

(2) Granted Disputes

(a) The Transmission Provider will resettle Operating Days for a granted dispute in accordance with the guidelines in Section 10.3 of this Attachment AE.

(3) Per FERC or court order

(a) The Transmission Provider will resettle Operating Days as required by FERC or court order.

## 10.2 Invoices

(1) The Transmission Provider shall issue an invoice detailing all charges and payments specified in Section 8 of this Attachment AE on a weekly basis in accordance with the invoice issue dates specified in the Market Protocols.

(2) The Transmission Provider shall make payments to the Market Participant for any net credit shown on the invoice and the Market Participant shall make payment to the Transmission Provider for any net charge shown or the invoice, including disputed amounts. Resolution of disputed amounts shall be shown as an adjustment on future invoices.

(3) Market Participants shall make payment to the Transmission Provider that is equal to the net charge shown on the invoice by no later than 5:00 PM on the 4th business day following the day the invoice was issued.

(4) The Transmission Provider shall make payment to the Market Participant that is equal to the net credit shown on the invoice by no later than 5:00 PM on the 6th business day following the day the invoice was issued subject to the procedures specified under Section V of Attachment L.

(5) All payments to the Market Participant and all payments to the Transmission Provider shall be made by electronic funds transfer in U.S. dollars.

## 10.3 Invoice Disputes

In the event that a dispute arises between the Market Participant and the Transmission Provider concerning any Settlement Statements contained within an invoice that cannot be resolved to the Market Participant's satisfaction, such disputes shall be resolved as follows:

(1) Disputes relating to an S7 Scheduled Settlement Statement or S53 Scheduled Settlement Statement:

The Market Participant must notify the Transmission Provider within ninety (90) calendar days of the applicable Operating Day of the items that the Market Participant wishes to dispute.

(2) Disputes relating to the S120 Scheduled Settlement Statement, or any subsequent Settlement Statement:

a. Must relate only to material incremental changes between issuance of the relevant consecutive Settlement Statements. Material for the purpose of this section is defined as a dispute wherein more than $2,000.00 is at issue for the Market Participant for the impacted Operating Day. The Market Participant must submit documentation supporting the materiality of the dispute for consideration.

b. Must be filed within thirty (30) calendar days following the posting of the applicable Settlement Statement that the Market Participant wishes to dispute.

(3) The notice of dispute must contain the following minimum information:

- Request Type
- Subject
- Full Description
- Statement Type
- Charge Type
- Settlement Location
- Operating Day
- Start Interval
- End Interval

- Dispute Amount
- Proposed Resolution
- Market Participant
- Asset Owner

(4) If the Transmission Provider determines that additional information is required concerning a submitted notice of dispute, the Transmission Provider shall notify the Market Participant no later than thirty (30) days following the date the notice of dispute was submitted to the Transmission Provider. The Market Participant must then submit additional information to the Transmission Provider within thirty (30) days in order to have the notice of dispute considered valid.

(5) The Transmission Provider shall use its best efforts to notify the Market Participant of approval or denial of the submitted notice of dispute within twenty (20) business days following the close of the applicable ninety (90) day or thirty (30) day window specified under Subsection 10.3(1) or Subsection 10.3(2). If the Transmission Provider estimates that it will take longer than the twenty (20) business day window to analyze a specific billing dispute, the Transmission Provider shall notify the Market Participant and provide an estimate of the amount of time required to complete the analysis.

(6) If the Transmission Provider denies a Market Participant's notice of dispute or the Market Participant is not satisfied that it is receiving timely consideration of the dispute, the Market Participant may initiate the dispute resolution procedures specified under Section 12 of the Tariff.

## 10.4 Interest on Unpaid Balances

Interest on any unpaid amounts shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the invoice to the date of payment.

## 10.5 Market Participant Default

Defaults by a Market Participant will be handled in accordance with Attachments L (Treatment of Revenues) and X (SPP Credit Policy) of the Tariff.

## 10.6 Further Clarification Regarding Right to Net

The Integrated Marketplace Counterparty and the Market Participant shall discharge mutual debts and payment obligations for multiple transactions due and owing to each other on the same date through netting, in which case all amounts a party owes to the other party under Attachment AE shall be replaced by a single payment obligation and netted so that only the net amount remaining due shall be paid by the owing party.

## 10.7 Integrated Marketplace Counterparty Limitation of Liability

The liability of the Integrated Marketplace Counterparty to settle Integrated Marketplace transactions shall be limited such that the aggregate of payments owed to a Market Participant shall not exceed the aggregate amount of payments that has been paid to or recovered by the Integrated Marketplace Counterparty, from that Market Participant (including by way of realization of financial security) in respect of that settlement period.

## 11.0 Confidentiality Provisions

This Section 11 shall apply to Confidential Information disclosed by a Market Participant to the Transmission Provider or by the Transmission Provider to a Market Participant or its designee, the Market Monitor, the Commission, the CFTC, or an Authorized Requestor and shall only be applicable to Confidential Information referenced within this Attachment AE, Attachment AF and Attachment AG.

## 11.1 Restrictions on Confidential Information Provided to Receiving Party

The Transmission Provider or any Market Participant ("Receiving Party") may not disclose Confidential Information received from the other ("Disclosing Party") to any person, corporation, or any other entity except as specifically permitted in this Section 11 of this Attachment AE.

A Market Participant that is subject to a freedom of information or similar statute must, prior to receiving Confidential Information, provide the Transmission Provider a statement identifying and forwarding copies of the particular statute, rule or regulation, protective order, or practice that will allow that Market Participant to keep Confidential Information received by it hereunder confidential and non-public, and of limited distribution within the Market Participant as described above. In the event that such Market Participant receives a request pursuant to the applicable freedom of information or similar statute for information deemed confidential pursuant to this section, the Market Participant shall promptly notify the Disclosing Party of such request.

### 11.1.1 Procedures for Confidential Information

Receiving Party shall adopt procedures within its organization to maintain the confidentiality of all Confidential Information. Such procedures must provide that:

(1) The Confidential Information will be disclosed to Receiving Party's directors, officers, employees, representatives and agents only on a "need to know" basis;

(2) Receiving Party shall make its directors, officers, employees, representatives and agents aware of Receiving Party's obligations under this Section 11;

(3) Receiving Party shall cause any copies of the Confidential Information that it creates or maintains, whether in hard copy, electronic format, or other form, to identify the Confidential Information as such; and to retain such confidential marking;

(4) Before disclosing Confidential Information to a representative or agent of Receiving Party, Receiving Party shall require a non-disclosure agreement with each such representative or agent. Such nondisclosure agreement shall contain confidentiality provisions substantially similar to the terms of this Section 11.

Any Receiving Party seeking to dispute the designation of information as Confidential Information may challenge such designation through the SPP dispute resolution process as established in Section 12 of this Tariff, unless the Receiving Party has received Confidential Information in connection with a proceeding at the Commission or in connection with a state regulatory proceeding. Any challenge to the confidentiality of Confidential Information obtained in connection with an administrative or legal proceeding shall be presented for consideration to the appropriate regulatory authority, court or tribunal.

### 11.1.2 Exceptions

Without violating the confidentiality provisions of this Section 11, a Receiving Party may disclose certain Confidential Information:

(1) As required by any law, regulation, or order, or expressly required or permitted by this Tariff, provided that the Receiving Party must make reasonable efforts to restrict public access to the disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(2) If the Disclosing Party that supplied the Confidential Information to the Receiving Party has given its prior written consent to the disclosure as set forth in Subsection 11.1.4(3), which consent may be given or withheld in Disclosing Party's sole discretion; or

(3) If, before it is furnished to Receiving Party, the Confidential Information is in the public domain; or

(4) If, after it is furnished to Receiving Party, the Confidential Information enters the public domain other than through a manner inconsistent with the provisions of this section; or

(5) If reasonably deemed by the Receiving Party to be required to be disclosed in connection with a dispute between Receiving Party and Disclosing Party; provided that the Receiving Party must make reasonable efforts to restrict public access to the disclosed Confidential Information by protective order, by aggregating information, or otherwise if reasonably possible; or

(6) To a vendor or prospective vendor of goods and services to Transmission Provider so long as such vendor or prospective vendor: (i) is not a Market Participant and (ii) executes a confidentiality agreement with terms substantially similar to those in this Section 11.

### 11.1.3 Injunctive Relief and Specific Performance

It may be impossible or very difficult to measure in terms of money the damages that would accrue due to any breach by Receiving Party of this Section 11, or any failure to perform any obligation contained in this Section 11, and, for that reason, among others, a Disclosing Party affected by a disclosure or threatened disclosure is entitled to injunctive relief, including specific performance, of this Section 11 (but is not hereby precluded from seeking other forms of relief). In the event that a Disclosing Party institutes any proceeding to enforce any part of this Section 11, the affected Receiving Party, by entering any agreement incorporating this Tariff, now waives any claim or defense that an adequate remedy at law exists for such a breach.

### 11.1.4 Market Participant Access and Transmission Provider Use of Confidential Information

(1) No Market Participant shall have a right hereunder to receive or review any documents, data, or other information of another Market Participant, including documents, data, or other information provided to the Transmission Provider, to the extent such documents, data, or information have been designated as Confidential Information under this Section 11; provided, however, a Market Participant may receive and review any composite documents, data, and other information that may be developed based on such Confidential Information if the composite does not, directly or by its nature, disclose any individual Market Participant's Confidential Information.

(2) The Transmission Provider shall collect and use Confidential Information only in connection with its authority under this Tariff and the retention of such information shall be in accordance with the Transmission Provider's retention policies. Except as otherwise provided in Sections 11.1.2, 11.1.5, 11.2 and 11.3, the Transmission Provider shall not disclose to a Market Participant or to any third party, any Confidential Information of a Market Participant or a Market Participant Applicant; provided that nothing contained herein shall prohibit the Transmission Provider from providing a Market Participant's Confidential Information to requesting entities to the extent that: (i) the Transmission Provider determines, in its reasonable discretion, that the exchange of such information is required to enhance and/or maintain reliability within the SPP Region and/or its neighboring Balancing Authorities; (ii) such receiving entity is bound by a written agreement to maintain such confidentiality; and (iii) the Transmission Provider has notified the affected Market Participant of its intention to release such information no less than five (5) business days prior to the release.

(3) Nothing contained herein shall prevent the Transmission Provider from releasing a Market Participant's Confidential Information to a third party provided that the Market Participant has delivered to the Transmission Provider specific, written authorization for such release setting forth the data or information to be released, to whom such release is authorized, and the period of time for which such release

shall be authorized. The Transmission Provider shall limit the release of a Market Participant's Confidential Information to that specific authorization received from the Market Participant. Nothing herein shall prohibit a Market Participant from withdrawing such authorization upon written notice to the Transmission Provider who shall cease such release as soon as practicable after receipt of such withdrawal notice.

### 11.1.5 Required Disclosure

(1) Notwithstanding anything in this Section 11 to the contrary except Section 11.2, Section 11.3 and Section 11.4, if a Receiving Party is required by applicable law, or in the course of administrative or judicial proceedings, other than Commission, CFTC, or state regulatory proceedings or investigations, to disclose to third parties, other than to the Commission, the CFTC, or their staffs, Confidential Information that is otherwise required to be maintained in confidence pursuant to this Tariff, the Receiving Party subject to such disclosure requirement may disclose such information; provided, however, that the Receiving Party shall not release the data until the affected Disclosing Party(ies) provide written consent or until the affected Disclosing Party's(ies') legal avenues to prevent the disclosure are exhausted. As soon as the Receiving Party learns of the disclosure requirement and prior to making disclosure, it shall notify the affected Disclosing Party(ies) of the requirement and the terms thereof and the date on which it may be required to disclose the information. The affected Disclosing Party(ies) may direct, at their sole discretion and cost, any challenge to or defense against the disclosure requirement. The Receiving Party shall cooperate with such affected Disclosing Party(ies) to the maximum extent practicable to minimize the disclosure of the Confidential Information consistent with applicable law. To the extent reasonably possible, the confidentiality of Confidential Information subject to this Section 11.1.5 will be maintained with (a) a protective order, (b) other procedures available for protecting confidential data or (c) by aggregating data to prevent disclosure of Confidential Information. Each Receiving Party shall cooperate with the affected Disclosing Party(ies) to obtain proprietary or confidential treatment of such Confidential Information by the person to whom such information is disclosed prior to any such disclosure.

(2) Section 11.1.5(1) does not apply to disclosure of information to the Commission or its staff, the CFTC or its staff, or to a state regulator or its staff.

### 11.1.6 Limitations

Nothing contained in Section 11.1 through and including Section 11.1.5 shall require any Receiving Party to violate any law or file a lawsuit in order to prevent disclosure of Confidential Information.

## 11.2 Confidentiality Provisions Applicable to the Market Monitor Reporting to the Board of Directors

For the purposes of this Section 11.2, references to the Market Monitor shall mean the Market Monitor as defined under Section 3.1 of Attachment AG.

(1) Notwithstanding anything in this Section 11 to the contrary, in order to enable the Market Monitor to discharge its duties, the Transmission Provider is authorized to provide Market Participant Confidential Information and any other information, data or materials that constitutes Confidential Information under this Tariff to the Market Monitor. For purposes of Confidential Information provided by the Transmission Provider to the Market Monitor, the Transmission Provider will be considered to be a Disclosing Party, and for purposes of this Section 11.2, the Market Monitor will treat both the Transmission Provider and, if known to the Market Monitor, the Market Participant originally providing specific Confidential Information as Disclosing Parties in the event the Market Monitor receives a request for Confidential Information under this Section 11.2.

(2) The Market Monitor shall use all reasonable procedures necessary to protect and preserve the confidentiality of all Confidential Information as defined in Section 11.1 received by it in connection with the discharge of its duties.

(3) Except as may be required by subpoena or other compulsory process or as set forth in Sections 11.3(1) and 11.3(2) and 11.3(3), the Market Monitor shall not disclose Confidential Information to any person or entity except to the Commission or its staff or the CFTC or its staff, without prior written consent. Upon receipt of a subpoena or other compulsory process from a source other than the Commission or its staff or the CFTC or its staff for the disclosure of Confidential Information, the Market Monitor shall promptly notify the affected Disclosing Party(ies) that originally provided the data and shall provide all reasonable assistance requested by the affected Disclosing Party(ies) to prevent disclosure, and if possible under the terms of the subpoena or other compulsory process shall not release the data until the affected Disclosing Party(ies) provide written consent or until the affected Disclosing Party(ies') legal avenues to prevent disclosure are exhausted. To the extent reasonably possible, the

confidentiality of Confidential Information subject to this Subsection 11.2(2) will be maintained with (i) a protective order, (ii) other procedures available for protecting confidential data, or (iii) by aggregating data to prevent disclosure of Confidential Information.

### 11.3 Disclosure to Commission or CFTC

(1) Notwithstanding any provisions of this Section 11 to the contrary, if the Commission or CFTC or their respective staffs during the course of an investigation or otherwise, requests Confidential Information from the Transmission Provider and/or the Market Monitor that is otherwise required to be maintained in confidence pursuant to this Tariff, the Transmission Provider and/or the Market Monitor, as applicable shall provide the requested information to the Commission, CFTC, or their respective staffs within the time provided for in the request for information. Should the Transmission Provider and/or the Market Monitor require additional time to provide the information requested due to logistical matters such as the volume of information requested or technical complexity involved, the Transmission Provider and/or the Market Monitor will promptly communicate that need to the entity requesting the information and shall establish the time for production of the requested information.

(2) In providing the information to the Commission or its staff, the Transmission Provider and the Market Monitor shall, consistent with 18 C.F.R. §§ 1b.20 and/or 388.112, request that the Confidential Information be treated as confidential and non-public by the Commission and its staff and that the Confidential Information be withheld from public disclosure. The Transmission Provider and/or the Market Monitor shall promptly notify the affected Disclosing Party(ies) that originally submitted the requested Confidential Information when it receives from the Commission or its staff a request for disclosure of Confidential Information.

(3) In providing the information to the CFTC or its staff, the Transmission Provider and the Market Monitor shall, consistent with 17 C.F.R §§ 11.3 and 145.9, request that the Confidential Information be treated as confidential and non-public by the CFTC and its staff and that the Confidential Information be withheld from public disclosure. If the Transmission Provider and/or the Market Monitor receives notice from the CFTC or its staff that Confidential Information provided by the Transmission Provider and/or the Market Monitor is to be released, it shall promptly notify the affected Disclosing Party(ies) in order to afford the affected

Disclosing Party(ies) an opportunity to respond before such information would be made public.

## 11.4 Disclosure to Authorized Agencies

### 11.4.1 Basic Requirements for Disclosure

For the purposes of this Section 11.4 Authorized Agency is a state regulatory commission that is authorized (or will be authorized upon satisfaction of the requirements herein) to receive confidential information pursuant to this section. The term Authorized Agency also includes state commissions acting jointly either through a regional state committee or otherwise. An Authorized Requestor is a representative of an Authorized Agency.

The Transmission Provider and/or Market Monitor shall only disclose Confidential Information, otherwise required to be maintained in confidence pursuant to Attachment AE of this Tariff, to an Authorized Requestor solely under the following conditions:

(1) The Authorized Requestor has executed a non-disclosure agreement with the Transmission Provider, stating:

(a) The position he or she holds within or the relationship he or she has with the Authorized Agency for which he or she will be an Authorized Requestor;

(b) That he or she is authorized to enter into and perform the obligations of the non-disclosure agreement;

(c) That the relevant Authorized Agency has practices or procedures adequate to protect against the unauthorized release of any Confidential Information received pursuant to the non-disclosure agreement;

(d) That he or she is familiar with, and will comply with, any applicable practices or procedures of the Authorized Agency that the Authorized Requestor represents; and

(e) That he or she is not in breach of any non-disclosure agreement entered into with the Transmission Provider.

(2) The Transmission Provider is able to verify that the Authorized Agency employing or retaining the Authorized Requestor has provided the Transmission Provider with the following information pursuant to Section 2.2 of Attachment AL (Form of Non-Disclosure Agreement for Authorized Requestors) to this Tariff:

(a) A list of authority (including statutory) specifying the particular Authorized Agency's duty, responsibility or authority in fulfillment of which it will make requests to the Transmission Provider or the Market Monitor under this section for information, including, but not limited to, that enumerated and described as available to the Market Monitor in Attachment AG of this Tariff; or, in the case of a regional state committee, an order of the Commission prohibiting the release of Confidential Information by the regional state committee, except in accordance with the terms of the non-disclosure agreement;

(b) A statement notifying and identifying to the Transmission Provider that the Authorized Agency has practices or procedures in place adequate to protect against the unauthorized release of Confidential Information; and

(c) Confirmation in writing that the Authorized Requestor is authorized by the Authorized Agency to enter into the non-disclosure agreement and to receive Confidential Information under Attachment AE of this Tariff.

(3) The Authorized Agency has provided either an order or a certification from counsel to such Authorized Agency or some other means acceptable to Transmission Provider, confirming that:

(a) The Authorized Agency has statutory authority (or in the case of a regional state committee is in receipt of and bound by a Commission Order referred to in Subsection (2)(a) above) to protect the confidentiality of any Confidential Information received pursuant to the non-disclosure agreement from public release or disclosure and from release or disclosure to any other entity, including other agencies of state government, except to the extent that such disclosure is required or permitted by state law;

(b) Except as provided in Subsection (4) below, the Authorizing Agency will defend against any disclosure of Confidential Information pursuant to any third party request through all available legal process, including, but not limited to, obtaining any necessary protective orders;

(c) The Authorizing Agency will provide the Transmission Provider with prompt notice of any such third party request or legal proceedings and will consult and cooperate with the Transmission Provider and/or any affected Market Participant in its efforts to deny the third party request or defend against such legal process;

(d) In the event a protective order or other remedy is denied, the Authorizing Agency will direct Authorized Requestors authorized by it to furnish only that portion of the Confidential Information that its legal counsel advises the Transmission Provider in writing is legally required to be furnished;

(e) The Authorizing Agency will exercise its best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information;

(f) The Authorizing Agency has adequate practices or procedures in place to protect against the release of such Confidential Information; and

(g) The Authorizing Agency has authorized the Authorized Requestor to enter into the non-disclosure agreement and to receive Confidential Information pursuant to this Attachment AE to this Tariff and under the non-disclosure agreement, and can provide a written copy of such authorization.

(4) The certification from counsel for the Authorized Agency referred to in Subsection (3)(b) above must affirmatively disclose any state law that will prohibit or prevent the Authorized Agency from defending against any disclosure of Confidential Information pursuant to any third party request as otherwise required by Subsection (3)(b). In an instance where there is such a state law disclosed, such certification shall confirm that the Transmission Provider would have notice of the third party request and standing to pursue legal processes, including obtaining a protective order, before the forum in which state law prohibits or prevents the Authorized Agency from taking such actions itself.

### 11.4.2 Schedule of Authorized Requestors

The Transmission Provider shall maintain a schedule of all Authorized Requestors and the Authorized Agencies they represent, which shall be made available on its website or by written request. The schedule shall include phone numbers and e-mail addresses. Such schedule shall be compiled by the Transmission Provider, based on information provided by any Authorized Requestor and/or Authorized Agency. The Transmission Provider shall update the schedule promptly upon receipt of information from an Authorized Requestor or Authorized Agency, but shall have no obligation to verify or corroborate any such information, and shall not be liable or otherwise responsible for any inaccuracies in the schedule due to incomplete or erroneous information conveyed to and relied upon by the Transmission Provider in the compilation and/or maintenance of the schedule.

### 11.4.3 Use of Confidential Information

The Authorized Requestor shall use the Confidential Information solely for the purpose of assisting an Authorized Agency in discharging its duty, responsibility or authority in fulfillment of which it authorizes Authorized Requestors to make requests for Confidential Information and for no other purpose. Any and all Authorized Requestors sponsored by the same Authorized Agency may have access to the Confidential Information that is provided to the sponsoring Authorized Agency pursuant to an information request described in Section 11.4.5.

### 11.4.4 Limited Oral Disclosures

(1) The Transmission Provider or the Market Monitor may, in the course of discussions with an Authorized Requestor or Authorized Requestors in meetings or teleconferences, orally disclose information otherwise required to be maintained in confidence, without the need for a prior information request. Such oral disclosures shall provide enough information to enable the Authorized Requestors or their Authorized Agency to determine whether additional information requests are appropriate. The Transmission Provider or the Market Monitor will not make any written or electronic disclosures of Confidential Information to the Authorized Requestor pursuant to this section. In any such discussions, the Transmission Provider or the Market Monitor shall ensure that the individual or individuals receiving such Confidential Information are Authorized Requestors, any Confidential Information disclosed is orally designated as Confidential Information and any specific affected Market Participant whose information is disclosed is not identified. The Transmission Provider or Market Monitor shall also be authorized to assist Authorized Requestors in interpreting Confidential Information that is disclosed.

(2) The Transmission Provider or the Market Monitor shall provide any affected Market Participant with oral notice of any oral disclosure promptly, but not later than one (1) business day after the oral disclosure. Such oral notice to the affected Market Participant shall include the substance of the oral disclosure, but shall not reveal any Confidential Information of any other entity and must be received by the affected Market Participant before the name of the affected Market Participant is released to the Authorized Requestor; provided, however, the identity of the affected Market Participant must be made available to the Authorized Requestor within two (2) business days of the initial oral disclosure.

### 11.4.5 Information Requests

(1) Form: Information requests to the Transmission Provider or the Market Monitor shall be in writing, and shall include electronic communications addressed to the Transmission Provider or to the Market Monitor as appropriate.

(2) Content: Each information request shall describe, in as much detail as possible, the particular information sought, including the time period for the requested information; provide a description of the purpose for which the information is being sought, and state the time period for which it is expected that the information will need to be retained by the Authorized Requestor.

(3) Notice:

(a) The Transmission Provider or the Market Monitor shall provide an affected Market Participant with notice of and a copy of an information request by an Authorized Requestor as soon as possible, but not later than two (2) business days after the receipt of the information request.

(b) The Transmission Provider shall maintain all information requests of a general nature in an electronic form accessible by Market Participants and Authorized Requestors. Such list shall not include those information requests that sought information of or about a named Market Participant or that would, in the Transmission Provider's view, otherwise be readily ascertainable as being directed toward Confidential Information from or about an individual Market Participant. On at least an annual basis the Transmission Provider shall delete from the list all information requests for which the Confidential Information has been returned or destroyed by the Authorized Requestor.

(4) Disclosure: Subject to the provisions of Section 11.4.5(6) and (7) below, the Transmission Provider or the Market Monitor shall supply the information sought to the Authorized Requestor in response to any information request within five (5) business days after the receipt of the information request, or within such longer period as may be specified by the information request, unless a timely objection has been made to the information request, or unless the requested information can only reasonably be made available within an extended time period.

To the extent that the Transmission Provider or the Market Monitor cannot reasonably prepare and deliver the requested information within the five (5) business day period or any longer period specified in the information request, it shall, within such period, hold discussions with the Authorized Requestor and provide the Authorized Requestor with a mutually agreed upon written schedule for the provision of such remaining information. Upon providing the requested information to the Authorized Requestor, the Transmission Provider or the Market Monitor shall provide a copy of the disclosed information to the Affected Participant(s), or provide a listing of the Confidential Information disclosed; provided, however, that the Transmission Provider or the Market Monitor shall not reveal any affected Market Participant's Confidential Information to any other Market Participant.

(5) Objection and Clarification: Notwithstanding Section 11.4.5(4) above, should the Transmission Provider, the Market Monitor or an affected Market Participant object to an information request or any portion thereof, any of them or the Authorized Requestor may, within four (4) business days following the Transmission Provider's or the Market Monitor's receipt of the information request, request, in writing, a conference with the Authorized Agency, or the Authorized Agency's Authorized Requestor, to resolve differences concerning the scope or time period covered by the information request; provided, however, nothing herein shall require the Authorized Agency to participate in any conference.

Any party to the conference may seek assistance from FERC staff in resolution of the dispute. Should such conference be refused by any participant, or not resolve the dispute, then the Transmission Provider, the affected Market Participant or the Authorized Agency may initiate appropriate legal action at FERC within three (3) business days following receipt of written notice from any participant refusing or terminating such conference. Any complaints filed at FERC objecting to a particular information request shall be designated by the party as a "fast track" complaint and each party shall bear its own costs in connection with such FERC proceeding.

If no FERC proceeding regarding the information request is commenced within such three-day period, the Transmission Provider or the Market Monitor shall respond to the Information Request within five (5) business days or any longer period that may be specified by the information request, counted from the expiration of such three-day period.

When an information request pertains to a Market Participant, the affected Market Participant may request that clarifying information be included in the response.

(6) Opportunity to Respond to Confidentiality Claims: If the affected Market Participant, the Transmission Provider or the Market Monitor considers the information sought by the information request as Confidential Information, the Authorized Requestor shall be provided an opportunity to challenge the designation or classification of the requested information as Confidential Information.

(7) Response to Tailored Request for Information from State Commissions: Market Monitor may respond to tailored requests for information from state commissions regarding general market trends and the performance of the wholesale market, but not for information designed to aid state enforcement actions. Granting or refusing such requests will be at the Market Monitor's discretion, based on agreements worked out between the Transmission Provider and the states, or otherwise based on time and resource availability.

(8) Limitation On Disclosure Obligation: The Transmission Provider or the Market Monitor shall not be required to make disclosure in response to an information request:

(a) In circumstances where an electronic data link, dedicated communication circuit or other hardware or third party services would be necessary to effectuate the disclosure;

(b) That is of a scope or extent materially similar to the flow of data from Market Participants to the Transmission Provider or from the Transmission Provider to the Market Monitor;

(c) That is unduly burdensome; or

(d) That is not pertaining to general market trends or the performance of the Transmission Provider.

### 11.4.6 Limited Discussion of Confidential Information Among Authorized Requestors Sponsored By Different Authorized Agencies

Authorized Requestors who are parties to non-disclosure agreements but who are sponsored by different Authorized Agencies may discuss Confidential Information with each other, provided that:

(1) They have each requested and received from the Transmission Provider or the Market Monitor such Confidential Information;

(2) At least one of such Authorized Requestors notifies the Transmission Provider in advance of the identity of the other Authorized Requestor(s) with whom such Confidential Information will be discussed; and

(3) The Transmission Provider confirms that the Authorized Requestors who will participate in the discussion received the Confidential Information as provided in Subsection (1) above. The Transmission Provider shall respond to a notification under Subsection (2) above within two (2) business days from receipt of the notification.

The Transmission Provider shall provide an affected Market Participant with notice of the planned discussion within two (2) business days from receipt of notification of the planned discussion. Such discussion among Authorized Requestors shall not change the status of the Confidential Information. It shall remain Confidential Information.

### 11.4.7 Breach of Non-Disclosure Obligations

In the event of any breach of a non-disclosure agreement:

(1) The Authorized Requestors and/or their respective Authorized Agency shall promptly notify the Transmission Provider or the Market Monitor, who shall, in turn, promptly notify any affected Market Participant of any unauthorized release of Confidential Information provided pursuant to any non-disclosure agreement.

Upon notification, the Transmission Provider will cease disclosure to the Authorized Requestor pursuant to any information requests and will make no disclosure pursuant to any information request pending from the Authorized Requestor until it can be determined after consultation with the Authorized Requestor, his or her Authorized Agency and the affected Market Participant that an appropriate combination of the following factors justifies resumption of the Authorized Requestor's access to Confidential Information: (i) the unauthorized disclosure was not due to the intentional, reckless or negligent action or omission of the Authorized Requestor; (ii) there was no harm or economic damage suffered by the Affected Participant; (iii) there are now practices or procedures in place adequate to prevent a recurrence of the unauthorized disclosure; and/or (iv) similar good cause shown.

(2) If the Transmission Provider or the Market Monitor receives from an Authorized Requestor or Authorized Agency a written notice that a breach has occurred, or FERC has made a ruling that a breach has occurred, the Transmission Provider and/or the Market Monitor shall terminate the non-disclosure agreement and require either the immediate return of all Confidential Information obtained by the Authorized Requestor pursuant to the non-disclosure agreement or a certification of its destruction.

The Transmission Provider shall verify the breach in consultation with the Authorized Agency. If it is subsequently determined that there was no breach, or if otherwise justified by circumstances described in Subsection (2) above, the Transmission Provider shall restore the status of the Authorized Requestor. Any other rights and remedies shall be pursuant to the terms of the non-disclosure agreement.

(3) No Authorized Requestor, who is an employee of an Authorized Agency, shall have responsibility or liability whatsoever under the non-disclosure agreement or Attachment AE to this Tariff for any and all liabilities, losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with the release of Confidential Information to persons not authorized to receive it.

However, nothing in this Section 11.4.7(3) is intended to limit the liability of any person who is not an employee of or a member of an Authorized Agency, to the degree not granted limitations as to liability under applicable state law of the Authorized Agency's state, when such a person is under contract to perform services for the Authorized Agency, for any and all economic losses, damages, demands, fines, monetary judgments, penalties, costs and expenses caused by, resulting from, or arising out of or in connection with such unauthorized release.

## 11.5 Preservation of Rights

Notwithstanding any provision in this Section 11, a Disclosing Party shall have the right to pursue all appropriate actions to prevent or contest any attempt to remove the confidential status or any order removing such confidential status of its Confidential Information.

### 11.6 Notice

Notwithstanding any provision in this Section 11 (except as detailed in Section 11.4), the Transmission Provider shall provide at least five (5) business days notice to the Disclosing Party of its intent to provide Confidential Information to any other entity other than the Commission and its staff or the CFTC or its staff. The Transmission Provider shall not be required to provide such notice if such disclosure is prohibited by law or Order or required by law or Order prior to five (5) business days.

# Addendum 1 to Attachment AE

## Violation Relaxation Limit Values

This Addendum 1 to Attachment AE sets forth the VRL values to be used in conjunction with the operation of the SPP Energy and Operating Reserve Markets.

| Constraint Type | Description | VRL [$/MW] |
|---|---|---|
| (1) Resource Capacity | The minimum and maximum MW dispatchable output of a resource as indicated in a Resource Offer. | 100,000 |
| (2) Global Power Balance | Energy needed to balance resources and load. | 50,000 |
| (3) Resource Ramp | The ramp capability of a resource as indicated in the resource plan. | 5,000 |
| (4a) Operating Constraint not subject to Market-to-Market coordination | A MW limit that can be imposed on SPP related to MW flow across a market node, a manually-identified transmission constraint, a Watch List transmission constraint, a flowgate constraint, or a transmission constraint identified by SPP's Real-Time contingency analysis. | $750 when the loading is greater than 100% and less than or equal to 101% at each network constraint at each Operating Constraint. |
| | | $750 when the loading is greater than 101% and less than or equal to 102% at each network constraint |
| | | $1,000 when the loading is greater than 102% and less than or equal to 103% at each network constraint |
| | | $1,250 when the loading is greater than 103% and less than or equal to 104% at each network constraint |
| | | $1,500 when the loading is greater than 104% at each network constraint |
| (4b) Operating Constraint subject to Market-to-Market coordination | A MW limit that can be imposed on SPP related to MW flow across a market node, a manually-identified transmission constraint, a Watch List transmission constraint, a flowgate constraint, or a transmission constraint identified by SPP's Real-Time contingency analysis. | MISO's Shadow Price as further defined in Section 3.1 of Attachment 2 of the SPP-MISO JOA |
| (5) Regulation-up plus Spinning Reserve Constraint | A MW value representing the sum of the Regulation-Up requirement and Spinning Reserve requirement | $200 |

## Addendum 2 to Attachment AE

### Bilateral Settlement Schedule Example

### System Power Sale

This Addendum 2 to Attachment AE provides an example showing how Market Participants may make use of Bilateral Settlement Schedules to account for a bilateral contract for a system power sale. This transaction and all related values are for illustrative purposes only and assume Market Participant A does not own any Resources and is purchasing from Market Participant B through a "slice-of-system" power sale. Market Participant A's peak load is equal to 35 MWs and Market Participant B's total Resource Capacity is equal to 400 MW. Therefore, Market Participant A has sufficient capacity and energy under contract (10% of 400 MWs = 40 MW) to meet its peak load with 5 MW available for reserve. The following examples are representative of a single hour in which Market Participant A's load is 15 MWh and only a portion of Market Participant B's Resources have been committed and dispatched. The examples show how a Bilateral Settlement Schedule may be used to remove Market Participant A's load consumption from the Marketplace Settlement for that hour. Assuming such an annual "slice-of-system" sale contract, the parties would need to enter a Bilateral Settlement Schedule for every hour of the year.

Market Participant A enters into a system power sales agreement with Market Participant B to purchase Energy from 10% of Market Participant B's Resources at $40/MWh. Market Participant B owns four 100 MW Resources. Market Participant A owns a 5 MW TCR from Resource 1 to its load, a 5 MW TCR from Resource 2 to its load, and a 5 MW TCR from Resource 3 to its load. Market Participant A submits a fixed Demand Bid of 15 MW and Market Participant B submits Resource Offers for its four Resources resulting in the following Day-Ahead Market results:

**Day-Ahead Market Results**

| | Market Participant A | | Market Participant B | |
|---|---|---|---|---|
| | **MWh** | **LMP-$/MWh** | **MWh** | **LMP - $/MWh** |
| **Load** | 15 | 60 | | |
| **Resource 1** | | | 50 | 40 |
| **Resource 2** | | | 50 | 45 |

| | | | | |
|---|---|---|---|---|
| **Resource 3** | | | 50 | 50 |
| **Resource 4** | | | 0 | 50 |

For simplicity, RTBM actual MW amounts are assumed to exactly match those amounts cleared in the Day-Ahead Market and losses are ignored (i.e. the MLC of LMP is assumed to be zero).

**Settlement Results with no Bilateral Settlement Schedule**

If there is no Bilateral Settlement Schedule submitted to account for the system power sales agreement, the combined Marketplace settlement and bilateral contract settlement would be as follows:

MP A Marketplace load settlement = 15MWh * $60/MWh = $900
MP A TCR Settlement for Resource 1 = 5 MWh * ($40/MWh – $60/MWh) = (-$100)
MP A TCR Settlement for Resource 2 = 5 MWh * ($45/MWh – $60/MWh) = (-$75)
MP A TCR Settlement for Resource 3 = 5 MWh * ($50/MWh – $60/MWh) = (-$50)
MP A bilateral contract payment = 15 MWh * $40/MWh = $600

Total Market Participant A Net Settlement = $1275 Cost

MP B Resource 1 Marketplace settlement = (-50 MWh) * $40/MWh = (-$2000)
MP B Resource 2 Marketplace settlement = (-50 MWh) * $45/MWh = (-$2250)
MP B Resource 3 Marketplace settlement = (-50 MWh) * $50/MWh = (-$2500)
MP B bilateral contract payment = (-15 MWh) * $40/MWh = (-$600)

Total Market Participant B Net Settlement = (-$7350) Payment

Because there is no Bilateral Settlement Schedule, Market Participant A is overcharged for its load consumption and Market Participant B is overpaid for its Resource output.

**Settlement Results with Bilateral Settlement Schedule**

Both Parties agree to enter into a Bilateral Settlement Schedule, reflecting their maximum sale amount of 40 MWhs (10% of MP B's Resource capacity). Because MP A owns TCRs from MP B's Resources to MP A's load, the agreed upon Settlement Location for the Bilateral Settlement Schedule is MP B's Resource Settlement Location. Because the bilateral contract involves multiple Resources, the Parties agree to create a Resource Hub that contains each of MP B's Resources and the Resource Hub will then be used as the Bilateral Settlement Schedule Settlement Location (a weighted average LMP at the Resource Hub is calculated as shown below). Creation of the Resource Hub allows a single Bilateral Settlement Schedule to be

created (as opposed to creating four separate Bilateral Settlement Schedules). Keeping with the previous 15 MWh example above, the combined Marketplace settlement and bilateral contract settlement would be as follows:

LMP at Resource Hub =

[[(50 MWh * $40/MWh) + (50 MWh * $45/MWh) + (50 MWh * $50/MWh)] / 150 MWh] = $45/MWh

| | |
|---|---|
| MP A Marketplace load settlement = | $15/MWh * $60/MWh = $900 |
| MP A TCR Settlement for Resource 1 = | 5 MWh * ($40/MWh – 60/MWh) = (-$100) |
| MP A TCR Settlement for Resource 2 = | 5 MWh * ($45/MWh – 60/MWh) = (-$75) |
| MP A TCR Settlement for Resource 3 = | 5 MWh * ($50/MWh – 60/MWh) = (-$50) |
| MP A Bilateral Settlement Schedule = | (-15 MWh) * $45/MWh = ($675) |
| MP A bilateral contract payment = | 15 MWh * $40/MWh = $600 |

Total Market Participant A Net Settlement = $600 Cost

| | |
|---|---|
| MP B Resource 1 Marketplace settlement = | (-50 MWh) * 40/MWh = (-$2000) |
| MP B Resource 2 Marketplace settlement = | (-50 MWh) * 45/MWh = (-$2250) |
| MP B Resource 3 Marketplace settlement = | (-50 MWh) * 50/MWh = (-$2500) |
| MP B Bilateral Settlement Schedule = | 15 MWh * $45/MWh = $675 |
| MP B bilateral contract payment = | (-15 MWh) * $40/MWh = (-$600) |

Total Market Participant B Net Settlement = (-$6675) Payment

As illustrated above, the Bilateral Settlement Schedule allows for correct accounting of the underlying bilateral contract. MP A now only pays MP B based on the bilateral contract terms and MP A's Marketplace load settlement obligation is reduced (in this case, removed). In a like manner, MP B's Marketplace revenue for its Resource output is reduced to account for the fact that it is receiving revenue from MP A under the bilateral contract terms.

# ATTACHMENT AF
# MARKET POWER MITIGATION PLAN

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Addendum 1 Reserved for Future Use

## 1. Purpose and Objective

The Market Mitigation Measures (the "Measures") contained within this Market Power Mitigation Plan provide for mitigation of the exercise of horizontal and vertical market power by Market Participants in certain specified circumstances. The Transmission Provider shall implement the Market Power Mitigation Plan as defined in this Attachment AF.

## 2. Definitions

For purposes of this Plan, capitalized terms shall have the meanings specified below:

### 2.1 Frequently Constrained Areas

As defined in Section 3.1.1 of this Attachment AF.

### 2.2 Measures

SPP's Market Mitigation Measures set forth in this document.

### 2.3 Performance Factor

The calculated ratio of actual fuel burn to either theoretical fuel use (design heat input) or the most recent heat rate performance test, consistent with the Market Protocols.

### 2.4 Plan

SPP's Market Power Mitigation Plan set forth in this Attachment AF.

### 2.5 Resource-to-Load Distribution Factor (RLDF)

The simulated impact of incremental power output from a specific Resource ("source") on the loading of a specific flowgate based on delivery to a representation of the locational weighting of all loads within all Settlement Locations ("sink").

### 2.6 Transmission/Generation Owners

Any Market Participant owning or controlling both transmission and generation assets in the SPP Region.

## 3. Mitigation Measures for Economic Withholding – Market Power in Energy and Operating Reserve

This section sets forth the market power mitigation measures that are applied in the Day-Ahead Market, Reliability Unit Commitment processes and the Real-Time Balancing Energy Markets, collectively referred to as the Energy and Operating Reserve Markets.

### 3.1 Local Market Power Test

A Resource satisfying at least one of the following conditions is determined to have local market power:

(1) The Resource is located in a Frequently Constrained Area, as described in Section 3.1.1, and one or more of the transmission constraints that define the Frequently Constrained Area is binding or the Reserve Zone that defines the area is binding;

(2) The Resource is not in a Frequently Constrained Area and

(a) has a Resource-to-Load-Distribution factor less than or equal to negative five percent (-5%) relative to a binding transmission constraint; or

(b) is located in a binding Reserve Zone;

(3) The Resource is committed, or the Multi-Configuration Resource ("MCR") is transitioned, as defined in Attachment AE, to address a Local Reliability Issue.

#### 3.1.1 Frequently Constrained Areas

A Frequently Constrained Area is an electrical area identified by the Market Monitor that is defined by one or more binding transmission constraints or binding Reserve Zone constraints that are expected to be binding for at least five-hundred (500) hours during a given twelve (12)-month period and within which one (1) or more suppliers are pivotal. All Frequently Constrained Area designations along with supporting analysis shall be posted on the Transmission Provider's website.

##### 3.1.1.1 Pivotal Supplier Test

A supplier is pivotal when the energy output or provision of operating reserves by any or some of its Resources jointly must be

increased or decreased to resolve the binding transmission constraint or binding Reserve Zone constraint during some or all hours. This will be determined utilizing transmission load flow cases or RTBM market cases reflecting a variety of market conditions.

These load flow or market cases will be used to estimate: (i) the generation shift factors for all relevant Resources and relevant resources outside the SPP Balancing Authority Area relative to each potentially constrained flowgate; (ii) the capability of all Resources to meet the requirements of each binding Reserve Zone constraint; (iii) the base loadings of Resources; (iv) the base allocation of Operating Reserves on Resources; and (v) the base flows on each flowgate. A supplier is pivotal when a binding transmission constraint or a binding Reserve Zone constraint cannot be relieved by changing the base loadings for other suppliers' Resources.

**3.1.1.2 Initial Designation of Frequently Constrained Areas**

The Market Monitor will define and recommend the Frequently Constrained Areas to the SPP Board of Directors prior to the start of the Integrated Marketplace.

**3.1.1.3 Changes to Frequently Constrained Area Designation**

The Market Monitor shall reevaluate the Frequently Constrained Areas at least annually. A reevaluation may be performed more frequently if the Market Monitor believes that conditions have changed with respect to the binding transmission constraints or binding Reserve Zone constraints that define a Frequently Constrained Area, or if congestion on constraints that are not designated as a Frequently Constrained Area warrant a new analysis. The Transmission Provider may also propose an area be designated or undesignated as a Frequently Constrained Area to the Market Monitor. The Market Monitor will post the updated

Frequently Constrained Area information along with the associated analysis on the Transmission Provider's website at least 14 calendar days prior to the Frequently Constrained Area updates becoming effective and will notify Market Participants of the posting. Market Participants may contact the MMU within the 14 day posting period if there are concerns with the Market Monitor's proposed updates. The Market Monitor will consider and respond to Market Participant concerns and will make updates if needed. The Market Monitor will notify Market Participant when updates become effective.

### 3.2 Mitigation Measures for Energy Offer Curves

Mitigated Energy Offer Curves shall be submitted on a daily basis by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs, for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Energy Offer Curve may be updated up to the close of the Day-Ahead Market as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Energy Offer Curve may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Energy Offer Curve submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.2(J) of this Attachment AF; for all other Resources the mitigated Energy Offer Curve submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day, and the Intra-Day RUC processes and the RTBM on the Operating Day. For the pricing SCED, the composite Energy Offer Curve and mitigated composite Energy Offer Curve will be calculated and used by the Transmission Provider for FSRs in the

Day-Ahead Market and RTBM as described in Section 3.3.1 of Attachment AE of this Tariff.

A. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that was not committed to address a Local Reliability Issue, the conduct thresholds are as follows:

(1) For a Resource located in a Frequently Constrained Area, the conduct threshold is a 17.5% increase above the mitigated Energy Offer Curve;

(2) For a Resource not located in a Frequently Constrained Area, the conduct threshold is a 25% increase above the mitigated Energy Offer Curve.

B. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Energy Offer Curve with the mitigated Energy Offer Curve if:

(1) The Resource's Energy Offer Curve exceeds the mitigated Energy Offer Curve by the applicable conduct threshold; and

(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:

(a) Fails the Market Impact Test as described in Section 3.7, or

(b) Is manually committed by the Transmission Provider or by a local transmission operator.

A Resource with an Energy Offer Curve below $25/MWh shall not be subject to mitigation measures on its Energy Offer Curve for economic withholding.

C. For a Resource with an Energy Offer Curve greater than or equal to $25/MWh that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Energy Offer Curve of 10% above the mitigated Energy Offer Curve. A Resource with an Energy Offer Curve below $25/MWh shall

not be subject to mitigation measures on its Energy Offer Curve for economic withholding.

D. The mitigated energy offer shall be the Resource's short-run marginal cost of producing energy as determined by the unit's heat rate or similar production efficiency ratio; fuel costs and the costs related to fuel usage, such as transportation and emissions costs ("total fuel related costs"); and Energy Offer Curve ("EOC") variable operations and maintenance costs ("VOM") as detailed in the Market Protocols and the charges incurred from Schedules 1-A3 and 1-A4 of this Tariff.

E. For Resources that are not ESRs, opportunity cost shall be an estimate of the Energy and Operating Reserve Markets revenues net of short run marginal costs for the marginal forgone run time during the timeframe when the Resource experiences the run-time restrictions as detailed in the Market Protocols. The run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available, consistent with the Market Protocols. The Market Participant may include in the calculation of its mitigated Energy Offer Curve an amount reflecting the resource-specific opportunity costs expected to be incurred under the following circumstances:

(1) Externally imposed environmental run-hour restrictions; or

(2) Physical equipment limitations on the number of starts or run-hours, as verified by the Market Monitoring Unit and determined by reference to the manufacturer's recommendation or bulletin, or a documented restriction imposed by the applicable insurance carrier; or

(3) Fuel Supply Limitations.

Resource specific opportunity costs are calculated by forecasting Locational Marginal Prices based on futures contract prices for natural gas and the historical relationship between the SPP system marginal Energy component of LMP and the price of natural gas, as determined by the SPP Market Monitoring Unit. The formulas and instructions in the price

forecast model shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Such forecasts of LMPs shall take into account historical variability, and basis differentials affecting the Settlement Location at which the Resource is located for the three-year period immediately preceding the period of time in which the Resource is bound by the referenced restrictions, and shall subtract therefrom the forecasted costs to generate energy at the Settlement Location at which the Resource is located, as specified in more detail in Appendix G of the Market Protocols. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting opportunity cost shall be zero. The Market Monitoring Unit will verify all Market Participants' opportunity cost calculations for consistency and accuracy. When the Market Monitoring Unit determines that the market price for any period was not competitive, it will adjust the LMP forecasting process used in the opportunity cost calculations to ensure that forecasted LMPs do not reflect non-competitive market conditions.

The following formula shall apply to all mitigated Energy Offer Curves unless specified otherwise in this Section 3.2(E) of this Attachment AF:

Mitigated Energy Offer ($/MWh) = HeatRate (mmBtu/MWh) * Performance Factor * Total Fuel Related Costs ($/mmBtu) + EOC VOM ($/MWh) + Opportunity Costs ($/MWh) + Schedule 1-A3 Charge ($/MWh) + Schedule 1-A4 Charge ($/MWh)

F. The Market Participant shall submit heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM to the Market Monitoring Unit. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the

mitigated Energy Offer Curve and shall include, among other data, the following information:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants' fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

Further details associated with the development, validation, and updating of these costs are included in Appendix G of the Market Protocols.

G. For Demand Response Resources utilizing Behind-The-Meter Generation, the mitigated Energy Offer Curve shall be developed in the same manner as any other generating Resource as described above. For Demand Response Resources utilizing load reduction, the mitigated Energy Offer Curve shall reflect the quantifiable opportunity costs associated with the reduction, net of related offsetting increases in usage.

H. For Dispatchable Variable Energy Resources, the mitigated Energy Offer Curve may include, but shall not exceed, any quantifiable costs that vary by MWh output, including short-run incremental VOM. Mitigation will not apply to Non-Dispatchable Variable Energy Resources in the Real-Time Balancing Market; monitoring of Energy Offers for Non-Dispatchable Variable Energy Resources will occur.

I. For an ESR, the mitigated Energy Offer Curve may include, but shall not exceed, (i) charging cost and (ii) opportunity cost, both adjusted for round-trip efficiency. Charging cost is the cost at which the ESR charged, and opportunity cost is the average profit in the next hour forgone by charging or discharging in the current hour. The sum of the charging cost and opportunity cost is the average LMP that is expected for the next Operating Hour. This expected average LMP for the next Operating Hour is the unweighted average of the LMPs for the most recent 45 days comparing like Operating Hours. The mitigated Energy Offer Curve for MSRs shall have at least two breakpoints: one for charging and another for discharging. More breakpoints may be added to the extent that other costs vary.

The following formula shall apply to mitigated Energy Offer Curves for ESRs:

Charging Mitigated Energy Offer ($/MWh) =

Performance Factor * Average LMP Expected for the Next Hour ($/mmBtu) * Round-Trip Efficiency - EOC VOM ($/MWh)

Discharging Mitigated Energy Offer ($/MWh) =

Performance Factor * Average LMP Expected for the Next Hour ($/mmBtu) / Round-Trip Efficiency + EOC VOM ($/MWh)

J. Intra-day changes to the mitigated Energy Offer Curve are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Energy Offer Curve that reflects the procurement of higher cost fuel;

(2) A Resource must switch fuels due to unforeseen operating conditions; or

(3) The Resource is an ESR.

Intra-day changes to the mitigated Energy Offer Curve must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

K. A Market Participant that has a Resource with short-run marginal costs greater than the Safety-net Energy Offer Cap specified in Section 4.1.1 of Attachment AE of this Tariff may submit an Energy Offer Curve using the same guidelines for development of the Resource's Mitigated Energy Offer Curve established in Appendix G of the Market Protocols. The Energy Offer Curve above $1,000/MWh must be equal to the Mitigated Energy Offer Curve and may include an adder with a maximum of $100/MWh due to the uncertainty of expected costs. For purposes of LMP calculation, the Energy Offer Curve will be limited to a maximum of $2,000/MWh and will have to be verified by the Market Monitor prior to the start of the applicable market clearing process. If the Energy Offer Curve cannot be verified prior to the start of the applicable market clearing process, then the Resource may be eligible to receive make-whole payments for its actual costs after verification by the Market Monitor. The default value is $1,000/MWh for any offer above $1,000/MWh until the offer can be verified. If the verified Energy Offer Curve is greater than $2,000/MWh, the Energy Offer Curve will be capped at $2,000/MWh in the applicable market clearing process, and the Resource may be eligible for make-whole payments for actual costs exceeding $2,000/MWh. Market Participants must submit evidence of actual costs to the Market Monitor. The Market Monitor shall verify the actual costs for use in make-whole payments. In order to include the costs in the make-whole payments of the final Settlement Statement, the submission must occur within 35 calendar days after the Operating Day and the verification must be complete no later than noon on the business day prior to 45 calendar days after the Operating Day.

L. In all cases under this Section 3.2, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the

confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

### 3.3 Mitigation Measures for Start-Up Offers and No-Load Offers

A mitigated Start-Up Offer and a mitigated No-Load Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. The mitigated Start-Up and No-Load Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the Start-Up and No-Load Offers may be updated until the Day-Ahead RUC begins. The mitigated Start-Up and No-Load Offers submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day and the Intra-Day RUC on the Operating Day unless an exception is allowed in Section 3.3(G) of this Attachment AF.

A. For a Resource that was not committed to address a Local Reliability Issue, the Start-Up and No-Load Offer conduct threshold is a 25% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable.

B. For a Resource that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Start-Up or No-Load Offer with the applicable mitigated Start-Up or No-Load Offer if:

(1) The Resource's Start-Up or No-Load Offer exceeds the mitigated Start-Up or mitigated No-Load Offer, as applicable, by the applicable conduct threshold; and

(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:

(a) Fails the Market Impact Test as described in Section 3.7, or

(b) Is manually committed by the Transmission Provider or by a local transmission operator.

C. For a Resource that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Start-Up Offer or No-Load Offer of 10% above the mitigated Start-Up Offer or No-Load Offer, as applicable.

D. The mitigated Start-Up Offer shall represent the cost per start as determined from start fuel usage and the costs related to that fuel usage, Performance Factor, cost of electricity for station use to start ("Station Service"), start-up VOM cost, start major maintenance cost, and start additional labor costs, if required above normal station staffing levels. Further guidelines for the mitigated Start-Up Offer are documented in Appendix G of the Market Protocols.

The mitigated Start-Up Offer for Demand Response resources shall be the cost to shut down or curtail load for a given period, which varies with the number of deployments rather than the amount of response, and/or the start cost of Behind-The-Meter Generation utilizing the mitigated Start-Up Offer calculation applicable to other generation Resources as defined above.

The mitigated Start-Up Offer for Variable Energy Resources shall be zero.

E. The mitigated No-Load Offer shall be the hourly fixed cost, represented in $/hr, required to operate the Resource at zero electricity output to the grid. The mitigated No-Load Offer can be calculated using either (1) the no-load fuel approach that includes no-load fuel (mmBtu/hour), Performance Factor, no-load VOM cost ($/mmBtu), total fuel related cost ($/mmBtu), and no-load major maintenance cost ($/hr); or (2) calculated using the no-load cost approach that includes heat input at Minimum Economic Capacity Operating Limit (mmBtu), Performance Factor, total fuel related cost ($/mmBtu), no-load VOM cost ($/mmBtu), incremental cost up to Minimum Economic Capacity Operating Limit ($/MWh), Minimum Economic Capacity Operating Limit (MW), and no-load major maintenance cost ($/hr). Further guidelines for the mitigated No-Load Offer are documented in Appendix G of the Market Protocols.

The mitigated No-Load Offer for Demand Response Resources utilizing Behind-The-Meter Generation shall adhere to the same definition above as a generating Resource. For Demand Response Resources utilizing load reduction, the mitigated No-Load Offer shall not exceed the quantifiable ongoing hourly costs associated with load reduction.

The mitigated No-Load Offer for Variable Energy Resources shall be zero.

F. The Market Participant shall submit all inputs used in calculating mitigated Start-Up and mitigated No-Load Offers to permit the Market Monitor to verify submitted offers. Required information includes: heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM cost. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. Information to be provided by the Market Participant shall include the following:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants' fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs reflecting short-run marginal costs, exclusive of fixed costs.

(4) For start and no-load major maintenance cost, Market Participants may include these costs as a component of the mitigated Start-Up

Offer and the mitigated No-Load Offer. Such cost must be based solely on resource-specific information derived from actual variable maintenance costs, when available, or estimated variable maintenance costs. The maintenance period for start major Maintenance cost must be tied to the number of starts, and the maintenance period for no-load major maintenance cost must be tied to the number of Resource run hours.

Further details associated with the development, validation and updating of these costs are included in Appendix G of the Market Protocols.

G. Intra-day changes to the mitigated Start-Up and mitigated No-Load Offers are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit updated mitigated Start-Up and mitigated No-Load Offers that reflect the procurement of higher cost fuel;

(2) A Resource must switch fuels due to unforeseen operating conditions; or

(3) The Resource is an ESR.

Intra-day changes to the mitigated Start-Up and mitigated No-Load offers must follow the mitigated offer development guidelines Appendix G of in the Market Protocols. Any such changes will be validated by the Market Monitor.

H. In all cases under this Section 3.3, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

### 3.3.1 Mitigation Measures for Transition State Offers

The mitigation measures in this section apply only to MCRs. A mitigated Transition State Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines specified in the Market Protocols for each potential transition state changes. The

mitigated Transition State offer may be updated up to the close of the Day-Ahead Market before the Operating Day as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Transition State Offer may be updated until the Day-Ahead RUC process begins. The mitigated Transition State Offer submitted at the time the Day-Ahead RUC process begins will apply to the Day-Ahead RUC process on the day before the Operating Day and Intra-Day RUC processes on the Operating Day.

A. For an MCR that was not transitioned to address a Local Reliability Issue, the Transition State Offer conduct threshold is a 25% increase above the mitigated Transition State Offer.

B. For an MCR that was not transitioned to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Transition State Offer with the mitigated Transition State Offer if:

(1) The Resource's Transition State Offer exceeds the mitigated Transition State Offer by the applicable conduct threshold; and

(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:

(a) Fails the Market Impact Test as described in Section 3.7, or

(b) Is manually committed by the Transmission Provider or by a local transmission operator.

C. For an MCR that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Transition State Offer of 10% above the mitigated Transition State Offer.

D. The mitigated Transition State Offer for an MCR shall represent the costs of moving from the current configuration to another configuration as determined from the fuel costs incurred during the transition, the costs related to that fuel usage, Performance Factor, and additional maintenance and labor costs incurred during the transition, including transition VOM cost and transition major maintenance cost. Further guidelines for the mitigated Transition State Offer are documented in Appendix G of the Market Protocols.

The Market Participant shall submit documentation of the method and any cost data for calculating the mitigated Transition State Offer that is necessary to allow the Market Monitor to validate submitted offers. Further details associated with the development of these costs are included in the Market Protocols.

E. Intra-day changes to the mitigated Transition State Offers are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit an updated mitigated Transition State Offer that reflects the procurement of higher cost fuel; or

(2) A Resource must switch fuels due to unforeseen operating conditions.

Intra-day changes to the mitigated Transition State Offers must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

F. In all cases under this Section 3.3.1, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of the Tariff.

### 3.4 Mitigation Measures for Operating Reserve Offers

A mitigated offer for each Operating Reserve product shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Operating Reserve Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Operating Reserve Offers may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Operating Reserve Offers submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.4(G) of this Attachment AF; for all other Resources, the mitigated Operating Reserve Offers submitted at the time the Day-Ahead RUC begins will apply to the RTBM on the Operating Day.

A. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that was not committed to address a Local Reliability Issue, the offer conduct threshold for each of the Operating Reserve products is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that was not committed to address a Local Reliability Issue, the Transmission Provider shall apply mitigation measures by replacing the Operating Reserve Offer with the applicable mitigated Operating Reserve Offer if:

(1) The Resource’s Operating Reserve Offer exceeds the applicable mitigated offer by the conduct threshold; and

(2) The Resource has local market power as determined in Sections 3.1(1) or 3.1(2); and

(3) The Resource either:

(a) Fails the Market Impact Test as described in Section 3.7, or

(b) Is manually committed by the Transmission Provider or by a local transmission operator.

A Resource with an Operating Reserve Offer below $10/MWh shall not be subject to mitigation measures on its applicable Operating Reserve Offer for economic withholding.

C. For a Resource with an Operating Reserve Offer greater than or equal to $10/MWh that has local market power as determined in Section 3.1(3), the Transmission Provider shall apply mitigation measures by placing a cap on the Operating Reserve Offer of 10% above the applicable mitigated Operating Reserve Offer. A Resource with an Operating Reserve Offer below $10/MWh shall not be subject to mitigation measures on its applicable Operating Reserve Offer for economic withholding.

D. The mitigated Spinning Reserve Offer shall be equal to zero for Resources other than combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser. No known incremental costs are incurred for providing Spinning Reserves from other resource types.

Total mitigated Spinning Reserve Offer for combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser shall not exceed any additional fuel related costs, maintenance costs and power consumption costs necessary for the Resource to be prepared for deployment of Spinning Reserve:

Mitigated Spinning Reserve Offer ($/MW) ≤
(Additional Fuel Cost($/Hr) + Additional Maintenance Cost ($/Hr) + Condensing Power Cost ($/Hr) ) /
Spinning Reserve MW

The mitigated Supplemental Reserve Offer shall not exceed labor costs necessary for the Resource to be prepared for deployment of Supplemental Reserve:

Mitigated Supplemental Reserve Offer ($/MW) ≤

Additional Labor Cost($) / Average Supplemental Reserve MW

E. The mitigated Regulation-Up Service Offer shall not exceed the sum of the cost increase due to:

(1) the heat rate increase during non-steady state operation,

(2) increase in VOM due to non-steady state operation,

(3) uncompensated costs, as described in the Market Protocols:

Where:

Mitigated Regulation-Up Service Offer = Mitigated Regulation-Up Offer ($/MW) + Mitigated Regulation-Up Mileage Offer ($/MW),

Mitigated Regulation-Up Offer ($/MW) ≤ Uncompensated Cost ($/MW), and

Mitigated Regulation-Up Mileage Offer ($/MW) ≤

(Cost Increase due to a decreased energy conversion efficiency (e.g., Heat Rate Increase)) during non-steady state operation + Cost Increase in VOM) * Regulation-Up Mileage Factor

F. The mitigated Regulation-Down Service Offer shall not exceed the sum of the cost increase due to:

(1) the heat rate increase during non-steady state operation,

(2) increase in VOM due to non-steady state operation,

(3) uncompensated costs, as described in the Market Protocols:

Where:

Mitigated Regulation-Down Service Offer = Mitigated Regulation-Down Offer ($/MW) + Mitigated Regulation-Down Mileage Offer ($/MW),

Mitigated Regulation-Down Offer ($/MW) ≤ Uncompensated Cost ($/MW), and

Mitigated Regulation-Down Mileage Offer ($/MW) ≤

(Cost Increase due to a decreased energy conversion efficiency (e.g., Heat Rate Increase)) during non-steady state operation + Cost Increase in VOM) * Regulation-Down Mileage Factor

Further details associated with the development of the exact costs in the formulas above are included in the Market Protocols.

G. Intra-day changes to the mitigated Operating Reserve Offers are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource that is supplying Operating Reserves remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Operating Reserve offer curve that reflects the procurement of higher cost fuel;

(2) A Resource must switch fuels due to unforeseen operating conditions; or

(3) Intra-day changes to the mitigated Regulation-Up and mitigated Regulation-Down Offers are allowed after the Day-Ahead RUC clears on the day before the Operating Day under the following condition:

a. The Resource incurs the uncompensated cost in Section 3.4(E)(3) of this Attachment AF, for which the mitigated offer calculation is described in Appendix G of the Market Protocols.

Intra-day changes to the mitigated Operating Reserve Offer curve must follow the mitigated offer development guidelines in Appendix G and Section 8.2.2 of the Market Protocols. Any such changes will be validated by the Market Monitor.

H. The Market Participant may include in the calculation of its mitigated Operating Reserve Offer an amount reflecting the Resource-specific opportunity costs if the Market Participant is able to demonstrate to the satisfaction of the SPP Market Monitoring Unit that such costs are legitimate and verifiable and not otherwise included in market outcomes. To the extent such costs include run-time restrictions, such run-time

restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available, consistent with the Market Protocols. The formulas and instructions in the price forecast model for any such opportunity costs shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Opportunity costs for mitigated Operating Reserve Offers shall not include Energy and Operating Reserve Markets revenues associated with forgone Energy or other types of Operating Reserve production to the extent that such costs are included in market outcomes.

I. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the mitigated Operating Reserve Offers and shall include, among other data, the following information:

(1) For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants' fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

(2) For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

(3) For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

J. In all cases under this Section 3.4, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the

confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

### 3.5 Validation of Mitigated Resource Offer Parameters

The Market Monitor shall review the costs included in each mitigated Resource Offer on an ex-post basis relative to the relevant Operating Day in order to ensure that the Market Participant has correctly applied the formulas and definitions in Sections 3.2, 3.3.1, and 3.4 of this Attachment AF and in the Market Protocols and that the level of the mitigated offer is otherwise acceptable. If the mitigated offer determined by the Market Monitor and the Market Participant differ, Market Participant shall use the mitigated offer calculated by the Market Monitor going forward. If a Market Participant submits a dispute over its mitigated offer, the previously approved mitigated offer shall be used from the time the dispute is submitted until the dispute is resolved. The procedures for submitting and processing disputes related to mitigated offers shall be those specified in the Market Protocols. The Transmission Provider shall remedy mitigated offer disputes resolved in favor of the Market Participant by providing make whole payments, as necessary, to the Market Participant whose mitigated offer was improperly determined by the Market Monitor.

Each Market Participant is obligated to provide to the Market Monitor any cost data necessary to allow the Market Monitor to validate its mitigated Resource Offer.

The Market Monitor shall keep such data confidential, and all cost data submitted under this Section 3.5, including any opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff. The Market Monitor shall develop and maintain on the Transmission Provider's website the mechanism and procedures to allow Market Participants to submit such cost data.

### 3.6 Additional Mitigation Measures for Resource Offer Parameters

The mitigation measures in this section apply to all Resource Offer parameters expressed in units other than dollars and will only apply in the presence of local market power as described in Section 3.1 of this Attachment AF. A reference level for each applicable Resource Offer parameter that reflects the physical capability of the Resource shall be determined prior to the start of the Energy and Operating Reserve Markets by

one or both of the following methods: (i) the reference levels will be determined through consultation between the Market Participant and the Market Monitor; and/or (ii) the reference levels will be based on averages of Resource Offer parameters from similar Resources. This methodology for setting reference levels for Offer parameters shall apply to all Resources at the start of the Energy and Operating Reserve Markets and to all Resources that register subsequent to the start of the Energy and Operating Reserve Markets. The Transmission Provider's output forecast for a wind-powered Variable Energy Resource shall be used as the reference maximum output limit for the wind-powered Variable Energy Resource.

The following thresholds shall be used by the Transmission Provider to identify Resource Offers that may warrant mitigation and shall be determined with respect to the corresponding reference level:

Time-based Resource Offer parameters: An increase of three (3) hours, or an increase of six (6) hours in total for multiple time-based Resource Offer parameters.

Resource Offer parameters expressed in units other than time or dollars: One hundred percent (100%) increase for Resource Offer parameters that are minimum values, or a fifty percent (50%) decrease for Resource Offer parameters that are maximum values.

Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) increase.

Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) decrease.

In the case that a Resource Offer fails the thresholds described above, the Market Monitor shall determine the impact on prices or make whole payments. If an impact exceeds the LMP, MCP or make whole payment thresholds in Section 3.7, the Market Monitor will initiate a discussion with the Market Participant concerning an explanation of the parameter changes. The Market Monitor will inform the Transmission Provider of any potential issue. If the Transmission Provider, in consultation with the Market

Monitor, concludes that the Market Participant has demonstrated the validity of the submitted Resource Offer parameter, no further action will be taken. If not, the Transmission Provider shall replace the Resource Offer parameter with the corresponding reference level. Mitigation measures will remain in place until such time that the Market Participant demonstrates the validity of the Resource Offer parameter or the Market Participant notifies the Market Monitor that the Resource Offer parameter has been changed to a value that is within the tolerance range as described above, and the Market Monitor has verified that this change has occurred. In the event that the Market Participant submits a dispute, the mitigation measure will remain in place until the resolution of the dispute.

In all cases under this Section 3.6, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

### 3.7 Market Impact Test

The Transmission Provider will apply the following market impact test in the Day-Ahead Market, Day-Ahead RUC, Intra-Day RUC and Real-Time Balancing Market in the event the conditions described in Section 3.1 of this Attachment AF are satisfied:

After an initial market solution is computed with no mitigation measures in place, a second market solution, called the mitigated market solution, will be computed with the appropriate mitigation measures applied. With the exception of Ramp Capability Up and Ramp Capability Down, if an LMP or MCP at a Settlement Location from the initial market solution exceeds the corresponding price from the mitigated market solution by the applicable impact test threshold, or a make whole payment for any Resource from the initial market solution exceeds the corresponding make whole payment from the mitigated market solution by make whole payment impact test threshold, then the mitigated market solution will be used for commitment and determining LMPs and MCPs.

The LMP impact threshold is twenty-five dollars ($25) per megawatt hour, the MCP impact threshold is twenty-five dollars ($25) per megawatt hour, and the make whole payment impact threshold is twenty-five dollars ($25) per megawatt hour.

### 3.8 Mitigation Exceptions

A. The Market Monitor shall, as soon as practicable and if warranted in light of the information available to the Market Monitor, contact a Market Participant to request an explanation of its actions in cases when an impact threshold in Section 3.7 of this Attachment AF is exceeded and the Market Participant's offer exceeded the mitigated offer by more than the applicable conduct threshold, as specified in Section 3.2, 3.3, 3.3.1, or 3.4 of this Attachment AF.

### 3.9 Sanctions for Noncompliance with the Day-Ahead Market Must Offer Requirement

A. In the case that a Market Participant is found to be noncompliant for an Asset Owner as determined by the conditions set forth in Section 2.11.1 of Attachment AE, the Market Participant shall be assessed a penalty for that Asset Owner by the Transmission Provider for each megawatt of withheld capacity below the 10% tolerance band. The penalty amount shall be equal to the Day-Ahead Market LMP associated with the withheld capacity.

B. The Market Monitor will monitor for, and report to the Commission's Office of Enforcement, or its successor organization, manipulative behavior associated with Day-Ahead Offers, including (but not limited to) monitoring load-serving Market Participants who do not offer enough net resource capacity to meet their maximum hourly Reported Load. The Market Monitor will also report to the Commission's Office of Enforcement or its successor organization any locational problems, such as deliverability issues, associated with load-serving Market Participants' offers in the Day-Ahead Market, any identified efforts by Market Participants to raise prices in the RTBM by limiting Day-Ahead Offers, and the effects of any such efforts upon make whole payments.

## 4. Mitigation Measures for Virtual Energy Bids and Virtual Energy Offers

If a determination is made, as specified in Section 4.6.3 of Attachment AG, that excessive divergence exists and the divergence is the result of the Virtual Energy Bids or Virtual Energy Offers of one or more Market Participants, the Transmission Provider shall impose mitigation measures. The mitigation measures will restrict the Market Participants that caused the divergence from submitting any Virtual Energy Bids or Virtual Energy Offers at the Settlement Locations where the Market Participant's Virtual Energy Bids or Virtual Energy Offers caused the excessive divergence. The mitigation measures shall be imposed for a period of three (3) months after which time the restriction will no longer apply.

# 5. Miscellaneous Provisions

## 5.1 Rights and Remedies

The Plan does not restrict the Transmission Provider and Market Participants from asserting any rights they may have under state and federal regulation and laws, including initiating proceedings before the FERC regarding any matter which is subject to this Plan.

Except as otherwise stated in this Plan, disputes as to the implementation of, or compliance with, this Plan shall be subject to the dispute resolution procedures under this Tariff or the SPP Bylaws as applicable or may be raised with the FERC.

# Addendum 1 to Attachment AF

## Reserved for Future Use

# ATTACHMENT AG
# MARKET MONITORING PLAN

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# 1. Purpose and Objective

## 1.1 Purpose of the Plan

This Market Monitoring Plan (the "Plan") is intended to provide for the monitoring of Markets and Services and submissions of recommendations to the FERC and the SPP Board of Directors.

## 1.2 Market Monitoring Plan

The Plan shall be developed, implemented and maintained by SPP's Market Monitor. The Market Monitor has the responsibility for implementing the Plan by (a) continuously monitoring Markets and Services, (b) recommending compliance and corrective actions per this Tariff, (c) collecting and retaining the data and information necessary for the performance of the Plan, (d) recommending updates to the monitoring plan contained within Attachment AG to this Tariff, and (e) periodically reporting on Markets and Services.

## 1.3 Mission Statement and Objectives of the Market Monitor

### 1.3.1 Mission Statement

The mission of the Market Monitor is to (a) monitor and report on possible abuses of horizontal and vertical market power and gaming in Markets and Services by any Market Participant (b) identify market design flaws and recommend any changes in design to improve the operation of Markets and Services for the benefit of consumers and Market Participants and (c) monitoring Market Participants' compliance with market rules.

### 1.3.2 Objectives

The Market Monitor will work to ensure that its functions and activities are implemented fairly and consistently, and that it protects and fosters competition while minimizing interference with open and competitive markets. Making recommendations to improve the operation of markets and preventing the exercise of market power in advance rather than punishing offenders afterward shall be the preferred approach.

The Market Monitor will evaluate existing and proposed market rules, Tariff provisions, and market design elements and recommend proposed rules and Tariff changes to the Transmission Provider, the Commission's Office of Energy Market

Regulation (or its successor organization) staff, and other interested entities such as state commissions and Market Participants. The Market Monitor will limit distribution of its identifications and recommendations to the Transmission Provider and the Commission's Office of Energy Market Regulation (or its successor organization) staff in the event that the Market Monitor believes that broader dissemination could lead to exploitation, with an explanation of why further dissemination should be avoided.

The Market Monitor will review the performance of the wholesale market and provide an annual report on the state of the market as provided in Section 7 of this Attachment AG.

The Market Monitor will recognize that entities otherwise identified as having market power may engage in conduct giving the impression of market power but, after analysis by the Market Monitor, may prove to be pro-competitive and efficient. In making this distinction, the Market Monitor will generally focus on an analysis of the identified conduct and associated market impacts, rather than seeking to determine the intent of the Market Participant (e.g., conducting profitability analyses that would require comprehensive information on all the physical and final positions of a participant).

### 1.4 Independence of the Market Monitor

The Market Monitor shall be independent from Market Participants to perform those activities necessary to provide impartial and effective market monitoring within the scope of the Plan. Notwithstanding the foregoing, in the normal course the Market Monitor shall verify information with affected Market Participants prior to making recommendations or reports.

### 1.5 Resolution of Conflicts

In the event there is a conflict between this Attachment AG and any other provision of this Tariff, this Attachment AG will control.

## 2. Definitions

For purposes of this Plan, capitalized terms shall have the meanings specified below:

### 2.1 Confidential Information

The term defined under Attachment AE to this Tariff.

### 2.2 Data and Information

Writings, documents and records of every type, including audio recordings and electronic files.

### 2.3 FERC Staff

The responsible office within FERC designated to receive reports submitted by market monitors.

### 2.4 Interested Government Agencies

The FERC and any state regulatory commission or agency with regulatory oversight responsibilities for SPP Transmission Owners.

### 2.5 Markets and Services

Integrated Marketplace (as defined in Attachment AE) and SPP's Transmission Services (as defined in the Tariff)

### 2.6 Plan

The Market Monitoring Plan set forth in this Attachment AG.

## 3. Market Monitor

The Market Monitor is responsible for implementing the Market Monitoring Plan as defined in this Tariff.

### 3.1 Staffing and Resources

The Market Monitor shall be an organization within SPP reporting to the Board of Directors, excluding any SPP management representatives serving on the Board of Directors. The Market Monitor shall be comprised of employees of SPP with the necessary experience and qualifications to perform the duties of the Market Monitor. The duties and responsibilities of the Market Monitor shall be assigned by the Board of Directors. However, the Market Monitor's duties and responsibilities will not include purely administrative matters (e.g., enforcement of late fees and the untimely submission of outage reports and meter data). SPP management representatives on the Board of Directors will be excluded from the Board of Directors' oversight of the Market Monitor. SPP shall establish and provide appropriate staffing and/or resources for the Market Monitor and shall ensure that the Market Monitor has such adequate employees, funding and/or other resources, access to required information, and the full cooperation of SPP Staff, Organizational Groups, and other persons, as necessary, for the effective functioning of the Market Monitor and implementation of this Plan. The Market Monitor shall have full responsibility for implementing Attachment AG.

### 3.2 Relationships and Notifications

As a general principle, the Market Monitor may obtain input from the SPP, FERC Staff, SPP Staff, the RSC, and affected state regulatory authorities for the purpose of executing its duties. However, in accordance with this Tariff, the Market Monitor shall at any time bring any instances of market behavior that may require investigation (including, but not limited to, suspected Tariff violations, suspected violations of Commission-approved rules and regulations, suspected market manipulation, and inappropriate dispatch) to the attention of FERC's Office of Enforcement (or its successor organization) staff. After any initial investigation of market design/policies, the Market Monitor shall also provide notification to the Board of Directors, the President of SPP, and FERC's Office of Enforcement

(or its successor organization) staff, and other interested entities such as relevant state regulatory commissions and Market Participants, as soon as practicable in the event it identifies a significant market problem that may require (a) further investigation, (b) a change to this Tariff, or (c) referral to FERC. In the event the Market Monitor believes broader dissemination could lead to exploitation, it may limit distribution of its identifications and recommendations to the Board of Directors, the President of SPP, and FERC Staff with an explanation of why further dissemination should be avoided at that time.

The Market Monitor shall also interface with FERC Staff and other RTO and ISO market monitors in adjacent regions as needed for the purpose of addressing electricity market issues in a comprehensive manner. The Market Monitor shall promptly notify the President of SPP of all such notifications, communications or reports.

### 3.3 Independence and Ethics Standards

The Market Monitor and its employees shall abide by SPP's Standards of Conduct, which shall be appropriate for establishing the professional and financial independence of the Market Monitor.

Consistent with this requirement, the Market Monitor and its employees shall:

(a) have no material affiliation with any Market Participant or any affiliate of a Market Participant;

(b) not serve as an officer, employee, or partner of a Market Participant;

(c) have no material financial interest in any Market Participant or any affiliate of a Market Participant (allowing for such potential exceptions as mutual funds and non-directed investments);

(d) not engage in any market transactions other than the performance of their duties under this Tariff;

(e) not be compensated, other than by SPP, for any expert witness testimony or other commercial services to SPP or to any other party in connection

with any legal or regulatory proceeding or commercial transaction relating to SPP;

(f) not accept anything of value from a Market Participant in excess of a de minimis amount;

(g) advise their relevant supervisor (or, in the case of the Market Monitoring management, SPP's Board of Directors) in the event they seek employment with a Market Participant, and must disqualify themselves from participating in any matter that would have an effect on the financial interest of such Market Participant.

These restrictions are not exclusive of the other requirements specified in SPP's Standards of Conduct. In the event there is a conflict between this Attachment AG and SPP's Standards of Conduct, this Attachment AG will control.

The Market Monitor shall certify compliance with such policies to the President of SPP. The Market Monitor shall require any external consultants or experts to certify compliance with these policies.

# 4. Market Monitoring

## 4.1 Markets to be Monitored

The Market Monitor will monitor Markets and Services. The Market Monitor will not monitor bilateral energy, transmission or capacity markets and services not administered, coordinated or facilitated by SPP, except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these unmonitored markets. Similarly, the Market Monitor will not monitor the energy, transmission or capacity markets and services in regions adjacent to the SPP Region except to assess the effect of these markets and services on Markets and Services, or the effects of Markets and Services on these adjacent markets.

## 4.2 Market Monitoring Scope

The Market Monitor will implement the Plan. The markets will require continuous monitoring by the Market Monitor. The Market Monitor will monitor Markets and Services by reviewing and analyzing market data and information including, but not limited to:

(a) Resource registration data;

(b) Resource Offer data including non-price related offer parameters required for use in either the Day-Ahead Market, Reliability Unit Commitment process and/or Real-Time Balancing Market;

(c) Demand Bids for the purchase of Energy in the Day-Ahead Market;

(d) Virtual Energy Bids for the purchase of Energy in the Day-Ahead Market and Virtual Energy Offers for the sale of Energy in the Day-Ahead Energy Market;

(e) Export Interchange Transaction Bids and Import Interchange Transaction Offers for the purchase and sale of Energy in the Day-Ahead Market and the Real-Time Balancing Market;

(f) Actual commitment and dispatch of Resources, including but not limited to Resource MW capability and output, MVAR capability and output, status, and outages;

(g) Locational Marginal Prices and zonal Market Clearing Prices at all Settlement Locations in or affecting any of Markets and Services;

(h) SPP Balancing Authority Area data, including but not limited to demand, area control error, Net Scheduled Interchange, actual total net interchange, and forecasts of operating reserves and peak demand;

(i) Conditions or events both inside and outside the SPP Balancing Authority Area affecting the supply and demand for, and the quantity and price of, products or services sold or to be sold in Markets and Services;

(j) Information regarding transmission services and rights, including the estimating and posting of Available Transfer Capability ("ATC") or Available Flowgate Capability ("AFC"), administration of this Tariff, the operation and maintenance of the transmission system, any auctions or other markets for transmission rights, and the reservation and scheduling of transmission service;

(k) Information regarding the nature and extent of transmission congestion in the region and, to the extent practicable, transmission congestion on any other system that affects Markets and Services, including but not limited to causes of, costs of and charges for transmission congestion, transmission facility loading, MVA capability, line status and outages;

(l) Settlement data for the Markets and Services;

(m) Any information regarding collusive or other anticompetitive or inefficient behavior in or affecting any of Markets and Services;

(n) Generation resource operating cost data for estimating resource incremental cost, including fuel input costs, heat rates where applicable, start-up fuel requirements, environmental costs and variable operating and maintenance expenses;

(o) Logs of transmission service requests and Generation Interconnection Requests along with the disposition of each request and the explanation of any refused requests;

(p) Any additional Resource and transmission facility outage data not otherwise provided for in this Section 4.2;

(q) GFA Carve Out Schedules; and

(r) FSE Schedules.

#### 4.2.1 Additional Market Monitor Duties

(a) In addition to the monitoring of market Data and Information, the Market Monitor may communicate with SPP Staff and Market Participants at any time for the purpose of monitoring and assessing market conditions.

(b) The Market Monitor shall evaluate the effectiveness of Markets and Services in signaling the need for investment in new generation, transmission or demand response infrastructure and report on its findings at least annually.

### 4.3 Referrals to the Commission

(a) The Market Monitor shall report suspected market violations, as defined in 18 CFR 35.28(b)(8), to FERC's Office of Enforcement (or its successor organization) staff in accordance with the FERC's reporting protocols for referrals by market monitors as specified in 18 C.F.R. § 35.28(g)(3)(iv) in a timely manner. Any such reports by the Market Monitor to FERC Staff shall be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release, unless such information and documents are already in the public domain.

### 4.4 Monitoring for Potential Integrated Marketplace Manipulation

The Market Monitor will monitor for potential instances of market manipulation in the Integrated Marketplace. Such actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices (including actions resulting in excessive day-ahead clearing prices), market conditions, or market rules for electric energy or electric products are prohibited. As listed by the FERC, prohibited behavior includes (a) wash trades, (b) submission of false data, (c) actions to cause artificial congestion

and (d) collusive acts. The Market Monitor will report any market manipulation in the Integrated Marketplace in a timely manner.

### 4.5 Monitoring for Potential Transmission Market Power Activities

The Market Monitor shall monitor Markets and Services for the exercise of transmission market power by reviewing and analyzing data and information related to the availability of transmission facilities that impact access to services under this Tariff. The Market Monitor will monitor for activities particularly with respect to the withholding of transmission facilities or transmission capacity, including activities such as but not limited to, the following:

(a) Physical withholding by Transmission Owners by providing improper information related to the availability of transmission, such as information related to the capability or other modeling data used by SPP for use in system operations;

(b) Economic withholding by Transmission Owners through the use of methods and data for estimating costs of interconnection and system upgrades that is not comparable for affiliates and non-affiliates;

(c) Unavailability of transmission facilities through planned and unplanned maintenance outages that routinely exceed historical baselines; and

(d) Withholding of transmission capacity through excess reservations that are not actually used.

The Market Monitor shall refer any perceived market design flaws and recommended Tariff language changes to the Commission's Office of Energy Market Regulation (or its successor office/organization). In addition, the Market Monitor shall refer any instance(s) of the suspected exercise of transmission market power directly to the Commission's Office of Enforcement (or its successor organization) utilizing the protocols for referrals to the Commission for suspected instances of the exercise of market power that may be part of a suspected market violation, such as manipulation, in accordance with 18 C.F.R. § 35.28(g)(3)(iv). Where appropriate, the Market Monitor shall also provide the FERC with an estimate of damages equal to (i) the effect on prices multiplied by

(ii) the affected energy produced by the Transmission/Generation Owner. The Market Monitor may also request the FERC to impose additional sanctions and penalties, which may consist of a fixed dollar amount based on each instance, or an amount up to (i) the effect on prices multiplied by (ii) the affected energy produced by Market Participants other than the Transmission/Generation Owner. All such referrals by the Market Monitor to FERC will be on a confidential basis, and all information and documents included in such reports will not be released to any other party except to the extent FERC directs or authorizes such release.

## 4.6 Monitoring for Market Participant Behavior Possibly Warranting Mitigation

The Market Monitor shall monitor Markets and Services for potential abuse associated with the following categories of Market Participant behavior: (1) economic withholding; (2) uneconomic production; (3) physical withholding; (4) uneconomic Virtual Bids and Virtual Offers; (5) gaming related to GFA Carve Out Schedules; and (6) gaming related to FSE Schedules. The mitigation measures for each of the behaviors identified in items (1) through (4) of this paragraph are described in Attachment AF. When the Market Monitor determines that there is sufficient credible information about a specific abusive practice, the issue will be referred to the Commission's Office of Enforcement (or its successor organization). Nothing in this section shall limit the Market Monitor's obligation to refer other suspected market violations to the Commission's Office of Enforcement, even where suspected behavior does not fall explicitly within the abovementioned categories or descriptions.

### 4.6.1 Uneconomic Production

The Market Monitor will monitor for cases where uneconomic production by a Resource causes congestion on transmission facilities or price separation between Reserve Zones that is not justified by reliability concerns. For an MSR, both charging and discharging are considered production. The provisions of this Section 4.6.1 shall not apply to Demand Response Resources.

(a) Potential uneconomic production will be indicated, and subject to further analysis as described in (b) of this Section 4.6.1, when the Resource has a positive Resource-to-Load Distribution Factor and any of the following conditions are met:

(1) a Resource is identified with an incremental energy offer price less than 50 percent of the applicable reference level; or

(2) a Resource is determined to be generating outside of its Operating Tolerance; or

(3) a Resource is subject to a time-based or other resource offer parameter (non-time and non-dollar based) that appears to facilitate production that is otherwise uneconomic.

(b) For any Resource meeting the conditions described in (a) of this Section 4.6.1, the Market Monitor shall determine whether: (i) the MW impact from uneconomic production associated with such Resource is exacerbating the transmission congestion or binding a Reserve Zone; and (ii) the uneconomic production is not obviously justified by reliability or other operational concerns.

The Market Monitor will conduct evaluations as specified above and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

### 4.6.2 Monitoring for Virtual Energy Bids and Virtual Energy Offers

The Market Monitor will monitor the level of divergence between the Day-Ahead Market LMPs and the Real-Time Balancing Market LMPs. Section 4.6.3 defines the monitoring metric and thresholds to be used in determining the existence of excessive LMP divergence. In the case that there is excessive LMP divergence, the Market Monitor will determine if the LMP divergence is attributable to the Virtual Energy Bid and Virtual Energy Offer behavior of one or more Market Participants. If the Market

Monitor identifies one or more Market Participants as having caused the excessive LMP divergence through Virtual Energy Bid and Virtual Energy Offer behavior, then the Transmission Provider shall impose mitigation measures described in Section 4.0 of Attachment AF.

### 4.6.3 Metric and Threshold Specifications

The Market Monitor will compute the hourly LMP deviation between the Day-Ahead Market and Real-Time Balancing Market using the following formula: $[(LMP_{RTBM} / LMP_{DA\ Market}) - 1] * 100$. The average hourly LMP deviation is computed over a rolling four (4) week period or any other period that the Market Monitor determines is appropriate. If the four (4) week rolling average is below negative ten percent (-10%) or in excess of ten percent (10%), then the divergence is considered excessive and additional analysis is required.

### 4.6.4 Physical Withholding

(1) The Market Monitor will monitor for physical withholding of capacity from the Energy and Operating Reserve Markets, and unavailability of facilities. Physical withholding and unavailability of facilities may include:

(a) Declaring that a Resource has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified;

(b) Refusing to provide offers or schedules for a Resource when it would otherwise have been in the economic interest to do so without market power;

(c) Operating a Resource in real-time to produce an output level that is less than the Dispatch Instruction minus the Resource's Operating Tolerance defined in Section 6.4.1 of Attachment AE to this Tariff and the Resource is not exempt from URD under Section 6.4.11 of Attachment AE to this Tariff;

(d) Derating a transmission facility for technical reasons that are not true or verifiable;

(e) Operating a transmission facility in a manner that is not economic and that causes a binding transmission constraint or binding reserve zone or local reliability issue; and

(f) Declaring that the magnitude of the capability of a Resource is reduced for reasons that are not true or verifiable. This capability includes but is not limited to the following:

(i) The capability to provide Energy;

(ii) The capability to provide Operating Reserves;

(iii) In the case of MSRs, the capability to charge and/or to discharge.

(2) Market Participant will not be deemed to be physically withholding if:

(a) They are following the directions of the SPP Balancing Authority, Reliability Coordinator, or applicable reliability standards;

(b) They are selling into another market at a higher price;

(c) Their Variable Energy Resources are withheld in the Day-Ahead Market under the conditions in Sections 4.6.4(a), 4.6.4(b), or 4.6.4(f); or

(d) The Market Participant is reducing the magnitude of the MSR's maximum capability, either charging or discharging, from its true and verifiable physical or environmental limitations in order to provide that capability for the duration of the minimum clearable commitment period.

**4.6.4.1 Thresholds for Identifying Physical Withholding of Resource Capacity**

4.6.4.1.1 A Market Participant is deemed to be physically withholding capacity in a Frequently Constrained Area if all of the following conditions exist:

(a) One or more of the transmission constraints or Reserve Zone constraints that define the Frequently Constrained Area are binding; and

(b) The Market Participant controls or owns a Resource that satisfies condition 4.6.4(a), 4.6.4(b), 4.6.4(c), or 4.6.4(f) of this Attachment AG and is located in the Frequently Constrained Area identified in (a).

4.6.4.1.2 A Market Participant is deemed to be physically withholding capacity in an area not designated as a Frequently Constrained Area if all of the following conditions exist:

(a) One or more transmission constraints are binding or a Reserve Zone is binding; and

(b) The Market Particiant owns or controls one of more Resources that have local market power as defined in Section 3.1 of Attachment AF of this Tariff; and

(c) One of the following conditions apply:

(1) Such Resource(s) satisfy one of the conditions in Sections 4.6.4(a), 4.6.4(b), or 4.6.4(f) of this Attachment AG and the total withheld capacity exceeds the lower of 5 percent of the total capability owned or controlled by the Market Participant or 200 MW; or

(2) Where the real-time output of each such Resource is less than the Dispatch Instruction minus the Resource's Operating Tolerance defined in Attachment AE, Section 6.4.1 of this Tariff and the Resource is not exempt from Uninstructed Resource Deviation under Attachment AE, Section 6.4.1.1 of this Tariff.

#### 4.6.4.2 Thresholds for Screening of Potential Physical Withholding of Transmission Facilities

A transmission facility fails the physical withholding screen if either of the following conditions is met:

(a) The transmission facility satisfies a condition in Section 4.6.4(d) or 4.6.4(e) of this Attachment AG; or

(b) The Market Monitor identifies a pattern of scheduling outages resulting in increased market costs compared to an alternative and lower cost impact outage schedule.

#### 4.6.4.3 Sanctions

The Market Monitor will record instances where Market Participants have failed the screens in Sections 4.6.4.1 and 4.6.4.2 of this Attachment AG. The Market Monitor will notify the Commission's Office of Enforcement, or successor organization, of suspected physical withholding behavior. In the event the Market Monitor determines there is credible evidence of a market violation, the Market Monitor shall make a referral to the Commission as described in Section 4.3 of this Attachment AG.

# 5. Review of Market Activity

## 5.1 Requests

Any Market Participant or Interested Government Agency may raise any issue with the Market Monitor and request that the Market Monitor consider the issue in its monitoring and reporting. The Market Monitor may include this issue in its monitoring or reporting if it determines it is appropriate to do so. The Market Monitor should not monitor or report on any complaint pertaining to issues not related to Markets and Services or activities not monitored and overseen by the Market Monitor.

Any requests by Market Participants and Interested Government Agencies to the Market Monitor may be made confidentially. The Market Monitor shall maintain the confidentiality to the extent practicable.

# 6. Compliance and Corrective Actions

## 6.1 Compliance

The Market Monitor shall administer the Market Monitoring Plan as described in this Attachment AG and report any actual or potential abuse of market power or market design inefficiencies as part of its monitoring process. However, the Market Monitor's activities are limited to matters that (i) are expressly set forth in this Tariff; (ii) involve objectively-identifiable behavior; and (iii) do not subject the Market Participant to sanctions or other consequences other than those expressly approved by the Commission and set forth in this Tariff.

As part of the monitoring process, the Market Monitor may issue a demand letter requesting Market Participants causing the issue to arise to change actions as the Market Monitor deems proper to achieve compliance and the Market Monitor may also engage in discussions with persons or entities other than Market Participants as necessary as part of any investigatory or compliance process.

## 6.2 Corrective Actions for Market Design

If the Market Monitor discerns any weaknesses or failures in market design and market rules, including the determination that Markets and Services are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure, the Market Monitor shall advise the appropriate Organizational Group of SPP, the President of SPP, the RSC, appropriate state authorities, FERC Staff, and relevant Market Participants. In the event the Market Monitor believes providing such information could lead to exploitation, it will restrict such notification to the President of SPP, the Chairman of the SPP Oversight Committee, and FERC Staff, and will provide a justification for such limited notification.

Should SPP not respond within 60 days, the Market Monitor may recommend changes in market design and market rules to the Board of Directors, FERC and the RSC as needed. If SPP responds, but does not recommend changes to market design and market rules that are acceptable to the Market Monitor, the Market Monitor shall report to the Board of Directors and the appropriate regulatory body or bodies as needed, and then SPP may file a petition or submission seeking

appropriate action from FERC or any other appropriate enforcement agency. The Market Monitor shall make recommendations for changes to this Tariff as necessary to correct weaknesses or failures in Markets and Services.

In the event that any weaknesses or failures in market design require immediate corrective action to ensure just and reasonable prices, the Market Monitor may request the President of SPP to authorize an immediate FERC filing requesting implementation of a corrective action while the appropriate Organizational Group of SPP responds to the Market Monitor's notification as described above. The requested immediate corrective action should be the method least intrusive or disruptive to Markets and Services necessary to resolve the market weakness or failure as determined by the Market Monitor. Prior to making such a request to the President of SPP, the Market Monitor will make reasonable efforts to discuss with affected Market Participants and the staff of affected Interested Government Agencies the market weakness or failure potentially requiring immediate corrective action, unless the Market Monitor determines that such discussions would lead to exploitation.

# 7. Periodic Reports and Updates to SPP, Government Agencies, and Market Participants

## 7.1 Reports and Updates to the Board of Directors

The Market Monitor shall prepare and submit to the Board of Directors periodic reports on an annual basis (and any other reports required by the Board of Directors) relating to its activities. In such reports, the Market Monitor may make recommendations regarding any matter within its purview. The reports to the Board of Directors shall include recommendations as to whether changes are necessary to the Market Monitor, this Plan, this Tariff, the SPP Bylaws, agreements between SPP and its Members, or any other policies, procedures, and standards under the Market Monitor's purview. Any such reports may be subject to confidentiality provisions consistent with Section 8.1.

**7.1.1** The Market Monitor shall also prepare and submit to the Board of Directors updates of the reports, at least quarterly, which will emphasize any issues of concern to the Market Monitor.

**7.1.2** SPP and Market Participants may comment on any reports made pursuant to this section, through the appropriate stakeholder process. The Market Monitor shall be free to disregard suggestions with which it disagrees.

## 7.2 Reports to Government Agencies, the Transmission Provider, and Market Participants

After an annual review of the performance of the wholesale markets as discussed in Section 1.3.2 of this Attachment AG, the Market Monitor shall provide its annual State of the Market Report to the Commission, the SPP Board of Directors, the Transmission Provider, state commissions, Market Participants, and other interested entities. The Market Monitor shall also make available, as described below, the reports provided to the Board of Directors and other such reports as may be requested by the FERC Staff or such authorities subject to protection of confidential, proprietary and commercially sensitive information and the protection of the confidentiality of ongoing monitoring activities.

**7.2.1** The Market Monitor shall submit such reports to the FERC Staff and other affected regulatory authorities, including the Regional State Committees.

**7.2.2** The Market Monitor reports shall be made available on the SPP Website.

**7.2.3** Conference calls related to the Market Monitor reports may be attended by the Transmission Provider, the Board of Directors, FERC Staff and other affected regulatory authorities, Regional State Committee, and Market Participants regardless of which party initiates the conference call. The Market Monitor shall make one or more of its staff members available for regular conference calls.

## 8. Data Access, Collection and Retention

The Market Monitor shall regularly collect and maintain Data and Information necessary for monitoring Markets and Services and implementing mitigation protocols.

### 8.1 Confidentiality

SPP and Market Participants may designate Data and Information as Confidential Information consistent with the terms of SPP's Membership Agreement and Section 11 of Attachment AE. If the designation of Confidential Information appears to be unreasonable, the Market Monitor may challenge such designation of Confidential Information consistent with Section 11 of Attachment AE.

The Market Monitor shall provide Confidential Information to Interested Government Agencies consistent with the terms of Section 11.4 of Attachment AE.

### 8.2 Access to SPP Data and Information

The Market Monitor shall have access to all Data and Information gathered or generated by SPP in the course of its operations. This Data and Information shall include, but not be limited to, that listed in Section 4 of this Plan. All Data and Information listed in Section 4 of this Plan shall be retained by SPP for a minimum period of three years.

### 8.3 Access to Market Participant Data and Information

Market Participants shall retain all Data and Information listed below, and in Section 4 of this Plan as applicable, that is in the custody and control of Market Participants, for a minimum of three years and will promptly provide any such Data and Information to the Market Monitor upon request.

Market Participants shall be capable of providing the Data and Information to the Market Monitor, upon request, in the Market Participant's native format along with a description of the native data format used. If necessary, due to proprietary format restrictions, the Market Participant shall be capable of providing the data to the Market Monitor in a non-proprietary format, such as CSV or XML format along with a description of the data format used. Any such request will be

accompanied by an explanation of the need for such Data and Information. Market Participants may designate such Data and Information as Confidential Information, but such Data and Information may not be redacted or modified in any manner prior to delivery to the Market Monitor by the Market Participant.

Data and Information to be retained by Market Participants and provided to the Market Monitor upon request:

(a) All Data and Information relating to the costs of operating a generating unit, including but not limited to, heat rates, start-up fuel requirements, fuel purchase costs, environmental costs, and operating and maintenance expenses;

(b) All Data and Information regarding opportunity costs of a generating unit, including but not limited to, regulatory, environmental, technical, or other restrictions that limit the run-time or other generating unit operating characteristics;

(c) All Data and Information relating to the operating status of a generating facility, including generator logs showing the generating status of a specified unit, including information relating to a forced outage, planned outage or derating of a generating unit;

(d) All Data and Information relating to the operating status of a transmission facility, a contingency, or other operating consideration, including forced outages, planned outages or derating of a transmission system component;

(e) All Data and Information relating to transmission system planning, including studies, reports, plans, models, analyses, and filings with FERC or any state regulatory commission;

(f) All Data and Information relating to the ability of a Market Participant or its Affiliate to determine the pricing or output level of generating capacity owned by another entity, including but not limited to any document setting forth the terms or conditions of such ability.

(g) All Data and Information used in the course of business operations in arriving at a decision by a Reserve Sharing Group member to call an Operating Reserve Contingency and to request assistance.

If any additional Data and Information not listed above or in Section 4 of this Plan is required from Market Participants by the Market Monitor for the purpose of fulfilling its responsibilities, the Market Monitor may request such Data and Information from Market Participants. Such Data and Information shall be provided in a timely manner by Market Participants. Any such request shall be accompanied by an explanation of the need for such data or other information, a specification of the form or format in which the data is to be produced, and an acknowledgement of the obligation of the Market Monitor to maintain the confidentiality of the data. If a Market Participant receiving a request for Data and Information not listed above or in Section 4 of this Plan believes that production of the requested Data and Information would impose a substantial burden or expense, or would require the party to produce information that is not relevant to achieving the purposes or objectives of this Plan, the Market Participant receiving the request shall promptly so notify the Market Monitor. The Market Monitor shall review the request with the receiving Market Participant to determine whether, without unduly compromising the objectives of this Plan, the request can be narrowed or otherwise modified to reduce the burden or expense of compliance, and if so shall so modify the request. No party that is the subject of a data request shall be required to produce any summaries, analyses or reports of the data that do not exist at the time of the data request.

If the Market Monitor determines that the requested Data and Information has not or will not be provided in a timely manner, the Market Monitor may utilize (a) the dispute resolution procedures under this Tariff or under the SPP Bylaws as applicable or (b) a filing with the appropriate regulatory or enforcement agency to compel the production of the requested information.

### 8.4 Data Created by Market Monitor

Any data created by the Market Monitor, including any reconfiguration of Data and Information obtained from SPP or Market Participants, will remain within the Market Monitor's exclusive control. Such data may be shared with SPP and Market Participants at the Market Monitor's sole discretion and on a non-discriminatory basis, subject to the confidentiality provisions specified in this Attachment AG and Section 11 of Attachment AE.

# 9. Miscellaneous Provisions

## 9.1 Rights and Remedies

This Plan does not restrict SPP and Market Participants from asserting any rights they may have under state and federal regulation and laws, including initiating proceedings before the FERC regarding any matter which is subject to this Plan.

## 9.2 Disputes

Disputes as to the implementation of, or compliance with, this Plan shall be subject to the dispute resolution procedures under this Tariff or under the SPP Bylaws as applicable or subject to review by FERC.

## 10. Review of Market Monitor

The activities of the Market Monitor shall be reviewed from time to time by the Board of Directors.

# ATTACHMENT AH
# MARKET PARTICIPANT SERVICE AGREEMENT

**FORM OF SERVICE AGREEMENT FOR MARKET PARTICIPANTS IN THE INTEGRATED MARKETPLACE**

1. This Service Agreement dated as of _____ is entered into by and between _____ (Transmission Provider) and _____ (Customer).
2. The Customer has submitted an application for participation in the Integrated Marketplace and desires to register as a Market Participant in accordance with the market application and asset registration procedures specified in the Market Protocols and has provided the information specified in Appendix 1 to this Service Agreement.
3. The Customer represents and warrants that it has met all applicable requirements set forth in the Transmission Provider's Tariff and has complied with all applicable procedures under the Tariff.
4. The Transmission Provider agrees to provide and the Customer agrees to take and pay for, or to supply to the Transmission Provider, any or all of the products defined in the Integrated Marketplace in accordance with the provisions of the Transmission Provider's Tariff and to satisfy all obligations under the terms and conditions of the Transmission Provider's Tariff, as may be amended from time-to-time, filed with the Commission.
5. The Transmission Provider and the Customer agree that this Service Agreement shall be subject to, and shall incorporate by reference, all of the terms and conditions of the Transmission Provider's Tariff.
6. It is understood that, in accordance with the Transmission Provider's Tariff, the Transmission Provider may amend the terms and conditions of this Service Agreement by notifying the Customer in writing and making the appropriate filing with the Commission.
7. The Customer represents and warrants that:
   (a) At any time it has registered one or more Resources that the Customer intends to offer for sale into the Energy and Operating Reserve Markets in accordance with procedures specified in the Market Protocols, the participation of its Resource(s) in the Energy and Operating Reserve Markets is not precluded under the laws or regulations of the relevant electric retail regulatory authority, including state-approved retail tariff(s), and it either (a) has on file with the Commission for each

of such Resources market-based rate authority and/or other Commission-approved basis for setting prices in the Energy and Operating Reserve Markets, or (b) is exempt from the requirement to have rates for services on file with the Commission;

(b) This Service Agreement, or any Transaction entered into pursuant to the Service Agreement, as applicable, has been duly authorized;

(c) This Service Agreement is the legal, valid, and binding obligation of the Customer enforceable in accordance with its terms, except as it may be rendered unenforceable by reason of bankruptcy or other similar laws affecting creditors' rights, or general principles of equity.

8. The Customer warrants and covenants that, during the term of the Service Agreement, the Customer shall be in compliance with all federal, state, and local laws, rules, and regulations related to the Customer's performance under the agreement.

9. Service under this Service Agreement shall commence on the later of the date of execution of the Service Agreement, or such other date as it is permitted to become effective by the Commission. Service under this Service Agreement shall terminate in accordance with Section 12 below.

10. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below:

Transmission Provider: _____

Customer: _____

11. Cancellation Rights:

If the Commission or any regulatory agency having authority over this Service Agreement determines that any part of this Service Agreement must be changed, the Transmission Provider shall offer to the Customer within fifteen (15) days of such determination an amended Service Agreement reflecting such changes. In the event that the Customer does not execute such an amendment within thirty (30) days, or longer if

the Parties mutually agree to an extension, after the Commission's action, this Service Agreement and the amended Service Agreement shall be void.

12. Termination:

(a) The Customer may terminate service under this Service Agreement no earlier than ninety (90) days after providing the Transmission Provider with written notice of the Customer's intention to terminate. The Customer's provision of notice to terminate service under this Service Agreement shall not relieve the Customer of its obligation to pay any rates, charges, or fees due under this Service Agreement, and which are owed as of the date of termination.

(b) The Transmission Provider may terminate service under this Service Agreement if the Customer is in default, such default condition as defined under Section 8.1 of the SPP Credit Policy, in accordance with the procedures specified under Section 7.4 of the Transmission Provider's Tariff or Section 10.5 of Attachment AE to the Transmission Provider's Tariff, as applicable.

13. The Customer hereby appoints the Transmission Provider as its agent for the limited purpose of effectively transacting on the Customer's behalf in accordance with the terms and conditions of the Transmission Provider's Tariff. The Customer agrees to pay all amounts due and chargeable to the Customer and the Transmission Provider agrees to pay all amounts creditable to the Customer in accordance with the terms of the Transmission Provider's Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

| **Transmission Provider:** | **Customer:** |
|---|---|
| By: _____ | By: _____ |
| Dated: _____ | Dated: _____ |
| Title: _____ | Title: _____ |

# Appendix 1 to Attachment AH

**MARKET PARTICIPANT INFORMATION:**

| Requested Change Type [1] (Add, Modify, Terminate) | Market Participant Name [2] | Market Participant Acronym [3] (4 characters) | Registered in EIR? [4] (yes/no) | Credit Customer Name[5] |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |

**ASSET OWNER AND TC INFORMATION:**

| Requested Change Type [1] (Add, Modify, Terminate) | Asset Owner Name [6] | Asset Owner Acronym [7] (4 characters) | Registered in EIR? [8] (yes/no) | Resource Owner [9] (yes/no) | Load Serving Entity [10] (yes/no) |
|---|---|---|---|---|---|
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |
| | | | | | |

**TRANSMISSION CUSTOMER TO ASSET OWNER RELATIONSHIPS:**

| Requested Change Type [1] (Add, Modify, Terminate) | Transmission Customer (TC) Acronym [11] (4 characters) | Asset Owner Acronym [7] (4 characters) |
|---|---|---|
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |
| | | |

**METER AGENT INFORMATION:**

| Requested Change | Meter Agent Name [12] | Meter Agent Acronym [13] | Registered in EIR? [14] |
|---|---|---|---|

| Type [1] (Add, Modify, Terminate) | | (4 characters) | (yes/no) |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

**CONTACT INFORMATION:**

| Contact Last Name | Contact First Name | Contact Type[15] (A,B,C) | Phone Number (nnn) nnn-nnnn | Email Address |
|---|---|---|---|---|
| | | | | |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

**PROPOSED EFFECTIVE DATE[16]: _____**

1 **Requested Change Type –** Indication of the type of change for each record. For adding an entity or relationship this will be Add. To terminate an entity or relationship from the Integrated Marketplace, enter Terminate. For requesting a modification or name change of an entity, enter Modify. When requesting a name change to an entity, enter the existing name followed by a forward slash "/" and then the new name.

2 **Market Participant Name** - Full name of the Market Participant.

3 **Market Participant Acronym** - The NAESB Electric Industry Registry ("EIR") acronym that will be used for the Market Participant. If the entity is not registered in the EIR, the acronym should conform to the EIR format of no more than four (4) alpha numeric characters. Any acronym for an entity that is not registered in EIR must also be unique from any abbreviation that is registered in EIR by another party.

4 **Registered in EIR** – Enter "yes" if the entity is registered at EIR.

5 **Credit Customer Name -** The name of the entity that will be providing secured and unsecured credit for the Market Participant's activities in the Integrated Marketplace in accordance with Attachment X of this Tariff.

6 **Asset Owner Name** - The name of the Asset Owner that is represented by the Market Participant. 7 **Asset Owner Acronym** - The Asset Owner acronym abbreviation that will be used for this Asset Owner will be the same as the acronym in the EIR if the entity is registered in the EIR. If the entity is not registered in the EIR, the abbreviated name should conform to the EIR format of no more than four (4) alpha numeric characters. Any abbreviation for an entity not registered in the EIR must also be unique from any abbreviation that is registered in the EIR by another party.

8 **Registered in EIR? -** This field is used to identify if the entity is registered at EIR. For Asset Owners not registered at EIR, the Transmission Provider will validate the acronym used is not registered at EIR by another party currently. To ensure uniqueness against EIR

in the future, the Transmission Provider will also append "_X" to the Asset Owner Acronym supplied for those that are not registered.

9 **Resource Owner -** This is a Yes or No answer indicating whether or not the Asset Owner is a Resource owner and will be registering Resources to participate in the Energy and Operating Reserves Market.

10 **Load Serving Entity** - This is a Yes or No answer indicating whether or not the Asset Owner is a Load Serving Entity and will be registering Load Assets to be supplied in the Energy and Operating Reserves Market.

11 **Transmission Customer (TC) Acronym** – The acronym of the Transmission Customer that is associated with the given Asset Owner, if applicable. This includes Transmission Customers that may have the same Registered Acronym as the Asset Owner.

12 **Meter Agent Name -** Any Market Participant with load and/or Resources will either be a Meter Agent or have a relationship with at least one Meter Agent (MA). Identify the Meter Agent(s) registered with the Transmission Provider that will be responsible for the acquisition of end-use meter data, aggregation of meter data, application of data to Settlement Intervals, and transfer of meter data to the Transmission Provider on behalf of this Market Participant. This entity can be a traditional utility entity or other competitive entity. Show the Meter Agent as the Entity's name as it is registered on the Meter Agent Agreement form in Attachment AM of the SPP Tariff.

13 **Meter Agent Acronym -** The applicable abbreviation that will be used for this Meter Agent which agrees with EIR if the Entity is registered in the EIR. If the entity is not registered in the EIR, the abbreviated name should conform to the EIR format of no more than four (4) alpha numeric characters. Any abbreviation for an entity not registered in EIR must be unique from any abbreviation that is registered in TSIN by another party.

14 **Registered in EIR -** This field is used to identify if the entity is registered at EIR. For Meter Agents not registered at EIR, the Transmission Provider will validate the acronym used is not registered at EIR by another party currently. To ensure uniqueness against EIR in the future, the Transmission Provider will also append "_X" to the MA Acronym supplied for those that are not registered.

15 **Contact Type** - Specific points of contact for each Market Participant for questions regarding the Network and Commercial Models as well as a Primary Market Operations contact for the Market Participant.

**Type A** - Primary Market Operations and Commercial Model Point of Contact - required

**Type B** - EMS and ICCP contacts - required for MPs with physical assets.

**Type C** - Secondary Market Operations Contacts - optional.

16 **Proposed Effective Date:** The date on which the Market Participant would like these changes to be effective in the Transmission Provider's models and systems.

# ATTACHMENT AI
# TRANSMISSION DEFINITION

# I. Reserved for Future Use

## II. Criteria for Inclusion of Transmission Facilities

A Transmission Facility is a facility that is included as part of the Transmission System that meets any of the following criteria:

1. All existing non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more Eligible Customers not Affiliates of each other. Rate treatment for transmission upgrades completed after October 1, 2005 will be determined pursuant to Attachment J of this Tariff. For the purpose of the application of this criterion, "open loops" are radial lines. Additionally, at such time an existing radial is incorporated into a looped transmission circuit, that existing radial would be eligible for inclusion in rates on the same basis as the remainder of the facilities in the loop.

2. Facility(ies) that are utilized for interconnecting the various internal Zones to each other as well as those facilities that interconnect the Transmission System with other surrounding entities.

3. Control equipment and facilities necessary to control and protect a facility qualifying as a Transmission Facility.

4. For a substation connected to the Transmission System, where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV, the facilities on the high voltage side of the transformer will be included with the exception of transformer isolation equipment.

5. The portion of the direct-current interconnections with areas outside of the SPP Region (DC ties) that are owned by a Transmission Owner in the SPP Region, including those portions of the DC tie that operate at a voltage lower than 60 kV.

6. A facility operated below 60 kV that has been determined to be transmission by the Commission pursuant to the seven (7) factor test set forth in Commission Order No. 888, 61 Fed Reg. 21,540, 21,620 (1996), or any applicable successor test.

## III. Excluded Facilities

The following facilities shall not constitute Transmission Facilities:

1. Generator step-up transformers and generator leads;
2. Radial lines from a generating station to a single substation or switching station on the Transmission System; and
3. Direct Assignment Facilities.

## IV. Implementation Schedule

Within three (3) years from the date of acceptance by FERC of this Attachment AI to the Tariff, each Transmission Owner shall file a request(s) based on this Attachment with its appropriate regulatory authority or authorities for a determination as to which of its facilities are Transmission Facilities. Each Transmission Owner that is not subject to regulation by a regulatory authority shall apply to SPP for such a determination.

Each Transmission Owner shall use reasonable efforts to cause the aforementioned determinations to be made and the applicable transmission service rates to be adjusted accordingly as soon as possible after such determinations are finalized.

# ATTACHMENT AJ
# RESERVED FOR FUTURE USE

# ATTACHMENT AK
# TREATMENT OF RESERVE SHARING CHARGES AND REVENUES

## I. Reserve Sharing Activation

In order to activate the Reserve Sharing System, a Balancing Authority operator shall notify the Transmission Provider in accordance with the SPP Criteria.

## II. Charges for Reserve Sharing Services

Charges for energy assistance supplied to the SPP Balancing Authority from another Reserve Sharing Group ("RSG") member during a reserve sharing activation will be calculated in accordance with the applicable contracts between members of the RSG and the Transmission Provider shall collect such charges and render payment to the applicable RSG members in accordance with the settlement procedures specified in Attachment AE.

## III. Energy Charges for Reserve Sharing Services

Energy charges for energy assistance supplied from the SPP Balancing Authority to another RSG member during a reserve sharing activation will be calculated in accordance with the applicable contracts between members of the RSG and the Transmission Provider shall receive payment from the applicable RSG members and distribute such revenues in accordance with the settlement procedures specified in Attachment AE.

## IV. Transmission Service Charges for Reserve Sharing Services

There shall be no Transmission Service charges for use of the Transmission System associated with the activation of the Reserve Sharing System by the Transmission Provider on behalf of the SPP Balancing Authority Area. There shall be Transmission Service charges for use of the Transmission System associated with the activation of the Reserve Sharing System for an RSG member that is external to the SPP Balancing Authority Area. Such charges shall include (a) the energy supplied to the external RSG member during a reserve sharing activation event multiplied by the applicable hourly non-firm transmission rates, and (b) any other charges applicable to the provision of non-firm Transmission Service as specified in this Tariff.

# ATTACHMENT AL
# FORM OF NON-DISCLOSURE AGREEMENT FOR AUTHORIZED REQUESTORS

THIS NON-DISCLOSURE AGREEMENT (the "Agreement") is made this ___ day of ___ by and between, _____, an Authorized Requestor employed or retained by an Authorized Agency with offices at _____, and Southwest Power Pool, Inc., an Arkansas not for profit corporation, with offices at 201 Worthen Drive, Little Rock, Arkansas 72223-4936 ("SPP" or "Transmission Provider"). The Authorized Requestor and the Transmission Provider shall be referred to herein individually as a "Party," or collectively as the "Parties." Unless otherwise stated herein, capitalized terms shall have the same meaning as set forth in Attachment AE to the Transmission Provider's Tariff on file with the Federal Energy Regulatory Commission.

## RECITALS

Whereas, the Transmission Provider serves as the Regional Transmission Organization with reliability and/or functional control responsibilities over transmission facilities in the states of the Transmission Provider region, and operates and oversees certain wholesale markets for electricity pursuant to the requirements of this Tariff; and

Whereas, the Transmission Provider's Market Monitor serves as the monitor for certain wholesale markets for electricity in the Transmission Provider's region as specified in the Transmission Provider's Tariff; and

Whereas, Attachment AE to the Transmission Provider's Tariff requires that the Transmission Provider and the Market Monitor maintain the confidentiality of Confidential Information; and

Whereas, Section 11.0 of Attachment AE to the Transmission Provider's Tariff requires the Transmission Provider and the Market Monitor to disclose Confidential Information to Authorized Requestors upon satisfaction of conditions stated in Attachment AE to the Transmission Provider's Tariff, including the execution of this Agreement by the Authorized Requestor; and

Whereas, the Transmission Provider desires to provide Authorized Requestors with the broadest possible access to Confidential Information, consistent with the Transmission Provider's and the Market Monitor's obligations and duties under the Transmission Provider's Tariff and applicable FERC Orders; and

Whereas, this Agreement is a statement of the conditions and requirements, consistent with the requirements of Attachment AE to the Transmission Provider's Tariff, whereby the Transmission Provider or the Market Monitor shall provide Confidential Information to the Authorized Requestor.

NOW, THERFORE, agreeing to be legally bound, the Parties hereby agree as follows:

**1. DEFINITIONS.**

**1.1 Information Request.** A written request in accordance with the terms of this Agreement for disclosure of Confidential Information pursuant to Section 11.0 of Attachment AE to the Transmission Provider's Tariff.

**1.2 Third Party Request**. Any request or demand by any entity upon an Authorized Requestor or an Authorized Agency for release or disclosure of Confidential Information. A Third Party Request shall include, but shall not be limited to, any subpoena, discovery request, request pursuant to state freedom of information or public records access statutes or regulations, or other request for Confidential Information made by any: (i) federal, state or local government subdivision, department, official, agency or court, or (ii) arbitration panel, business, company, entity or individual. This provision is subject to any applicable exception under Attachment AE to the Transmission Provider's Tariff.

**2. Protection of Confidentiality.**

**2.1 Representation as to Status and Acceptance of Duty to Not Disclose.**

The Authorized Requestor states that: (a) he or she is an Authorized Requestor as defined herein; (b) he or she is employed or retained by _____ [name of Authorized agency] as _____; (c) he or she is authorized by the _____

[name of Authorized Agency] to enter into and perform the obligations of this Non-Disclosure Agreement; (d) the Authorized Agency identified in Subsections (b) and (c) above has practices or procedures adequate to protect against the unauthorized release of Confidential Information received; (e) he or she is familiar with, and will comply with, all such applicable Authorized Agency practices or procedures; (f) he or she is authorized to represent and warrant and does so represent and warrant that the Authorized Agency identified in Subsections (b) and (c) above will deny Third Party Requests and defend, consistent with the terms of Section 2.4.6 below, against any legal process that seeks the release of any Confidential Information in contravention of the terms of the Non-Disclosure Agreement; and (g) he or she is not in breach of any Non-Disclosure Agreement entered into with the Transmission Provider. The Authorized Requestor also states that he or she will act consistently with the representations and confirmations made to SPP under Section 11.0 of Attachment AE of Transmission Provider's Tariff.

**2.2. Conditions Precedent.**

The Authorized Requestor agrees that as a condition of the execution, delivery and effectiveness of this Agreement by the Transmission Provider and the continued provision of Confidential Information pursuant to the terms of this Agreement, the Authorized Agency shall, prior to the initial Information Request for Confidential Information by an Authorized Requestor on its behalf, provide the Transmission Provider with information, documents and certifications required of the Authorized Agency and its Authorized Requestor under Transmission Provider's Tariff. The Authorized Agency and its Authorized Requestor also agree that as a condition of the execution, delivery and effectiveness of this Agreement that they will fully comply with any other terms of Section 11.0 of Attachment AE of the Transmission Provider's Tariff.

**2.3 Care and Use of Confidential Information.**

**2.3.1 Control of Confidential Information.** The Authorized Requestor shall be the custodian of any and all Confidential Information received pursuant to the terms of this Agreement from the Transmission Provider or the Market Monitor.

**2.3.2 Access to Confidential Information.** Except when inconsistent with state or federal law, the Authorized Requestor shall ensure that Confidential Information received by that Authorized Requestor is disclosed, only as allowed under Section 11.0 of Attachment AE of Transmission Provider's Tariff.

**2.3.3 Notice of Change in Status.** The Authorized Requestor or Authorized Agency shall promptly notify the Transmission Provider of any change that would affect the Authorized Requestor's status as an Authorized Requestor.

**2.3.4 Use of Confidential Information.** The Authorized Requestor shall use the Confidential Information only as provided in the Section 11.0 of Attachment AE of Transmission Provider's Tariff.

**2.3.5 Return of Confidential Information.** When the Authorized Agency determines that it no longer needs the Confidential Information that was disclosed to the Authorized Requestor (e.g., if for any reason the Authorized Requestor is not, or will no longer be an Authorized Requestor, and the Confidential Information he or she received is no longer needed by the Authorized Agency), the Authorized Agency or Authorized Requestor shall: (a) return the Confidential Information and all copies thereof to the Transmission Provider or the Market Monitor, or (b) certify to the Transmission Provider or the Market Monitor that all paper copies have been destroyed and all electronic copies of the Confidential Information have been deleted, or identify the time by which it will comply with either (a) or (b) above consistent with state document retention laws. The Transmission Provider or the Market Monitor shall waive this condition in writing if such Confidential Information has become publicly available or non-confidential in the course of business or pursuant to the Attachment AE to

Transmission Provider's Tariff or applicable rule or order of the FERC. Upon the request of the affected Market Participant, but in any event no later than one year from the date of disclosure, the Transmission Provider shall inquire of the Authorized Requestor as to when the need for the information as originally specified in the Information Request will be concluded. The Authorized Requestor shall respond to the Transmission Provider within 30 days.

**2.4 Ownership and Privilege.** Nothing in this Agreement, or incident to the provision of Confidential Information to the Authorized Requestor pursuant to any Information Request, is intended, nor shall it be deemed, to be a waiver or abandonment of any legal privilege that may be asserted against subsequent disclosure or discovery in any formal proceeding or investigation. Moreover, no transfer or creation of ownership rights in any intellectual property comprising Confidential Information is intended or shall be inferred by the disclosure of Confidential Information by the Transmission Provider or by the Market Monitor, and any and all intellectual property comprising Confidential Information disclosed and any derivations thereof shall continue to be the exclusive intellectual property of the Transmission Provider, Market Monitor, the affected Market Participant, and/or other owner(s) thereof.

**3. Unauthorized Disclosure, and Remedies for Breach of Agreement.**

**3.1 Notification of Unauthorized Disclosure to Third Parties.** As provided in Transmission Provider's Tariff, the Authorized Requestors and/or their respective Authorized Agency shall promptly notify the Transmission Provider or the Market Monitor, who shall, in turn, promptly notify any affected Market Participant of any unauthorized release of Confidential Information provided pursuant to any Non-Disclosure Agreement. The Authorized Requestor shall take steps to minimize any further release of Confidential Information, and shall take reasonable steps to attempt to retrieve any Confidential Information that may have been released.

**3.2 Breach.** The Authorized Requestor agrees that its release of Confidential Information to persons not authorized under this Agreement to receive it constitutes a breach of this Agreement, unless the Authorized Requestor is required under state or federal law to release such information. If the Transmission Provider or the Market Monitor determines on its own, or agrees with an Authorized Agency, or receives from an Authorized Requestor or Authorized Agency a written notice, that a breach has occurred, or FERC has made a ruling that a breach has occurred, the Transmission Provider and/or the Market Monitor shall terminate the Non-Disclosure Agreement and require either the immediate return of all Confidential Information obtained by the Authorized Requestor pursuant to the Non-Disclosure Agreement or a certification of its destruction. The Transmission Provider shall verify the breach in consultation with the Authorized Agency. If it is subsequently determined that there was no breach, the Transmission Provider shall restore the status of the Authorized Requestor, and may also restore such status if otherwise justified by circumstances described in Subsection (b) above.

**3.3 Post Employment or Post Retention Duties.** If an Authorized Requestor who has received Confidential Information pursuant to this Agreement terminates his or her employment with the sponsoring Authorized Agency or is otherwise no longer employed by the Authorized Agency, he or she shall:

(a) Notify the Authorized Agency, the Transmission Provider and the Market Monitor of the change in status; and

(b) Certify to the Transmission Provider that he or she has transferred control of the Confidential Information to another Authorized Requestor at the same Agency, has retained no personal copies of the Confidential Information and that any Confidential Information not transferred has been destroyed.

If these steps have been taken, then the limitations as to liability in Section 3.3 shall apply to the former employee.

**4. Notices.** All notices required pursuant to the terms of this Agreement shall be in writing, and served upon the following individuals in person, or at the following addresses or email addresses:

If to the Authorized Requestor:

_____

_____

_____

_____

(email address)

with a copy to

_____

_____

_____

_____

(email address)

If to the Transmission Provider:

_____

Southwest Power Pool, Inc.

201 Worthen Drive

Little Rock, AR 72223-4936

(email address)

with a copy to

_____

_____

_____

_____

(email address)

If to the Market Monitor:

_____

Southwest Power Pool, Inc.
201 Worthen Drive
Little Rock, AR 72223-4936
(email address)
with a copy to

_____

_____

_____

_____

(email address)

**5.** **Severability and Survival.** In the event any provision of this Agreement is determined to be unenforceable as a matter of law (including state Freedom of Information Act statutes), the Parties intend that all other provisions of this Agreement remain in full force and effect in accordance with their terms. In the event of conflicts between the terms of this Agreement and Transmission Provider's Tariff, the terms of Transmission Provider's Tariff shall in all events be controlling. The Authorized Requestor acknowledges that any and all obligations of the Authorized Requestor hereunder shall survive the severance or termination of any employment or retention relationship between the Authorized Requestor and its respective Authorized Agency.

**6.** **Representations.** The undersigned is able to perform all of the obligations and duties contained herein.

**7.** **Counterparts.** This Agreement may be executed in counterparts and all such counterparts together shall be deemed to constitute a single executed original.

**8.** **Amendment.** This Agreement may not be amended except by written agreement executed by authorized representatives of the Parties.

**9.** **Assignment**. This Agreement is not assignable without the written agreement of both Parties.

| **Southwest Power Pool, Inc.** | **AUTHORIZED REQUESTOR** |
|---|---|
| By: | By: |
| _____ | _____ |
| Name | Name |
| Title: | Title: |
| Date: | Date: |

# ATTACHMENT AM

# METER AGENT SERVICES AGREEMENT

# FOR

# SPP MARKET

# BETWEEN

# MARKET PARTICIPANT

# AND

# METER AGENT

# (DATE)

This Agreement made and entered this __ day of _____, _____, is between _____ ("Market Participant") and _____ ("Meter Agent"). Market Participant and Meter Agent are each sometimes referred to in the Agreement as a "Party" and collectively as the "Parties."

WITNESSETH:

WHEREAS, Market Participant and Meter Agent are registered entities of the Integrated Marketplace.

NOW, THEREFORE, in consideration of the premises and mutual covenants and agreements hereinafter set forth, the parties hereto mutually agree as follows:

# ARTICLE I

## Responsibilities of the Parties

1.1 **Market Participant Responsibilities:**

1. **Governing Documents:** In addition to this Agreement, Market Participant agrees that it will comply with the provisions of the SPP Open Access Transmission Tariff ("OATT") and Market Protocols as they may be amended from time to time which relate to implementation of this Agreement. In the event there is a conflict between this agreement and the SPP OATT, the OATT shall govern.

2. **Data Communications:** Market Participant shall provide or arrange for communication of meter data in a mutually acceptable format to the Meter Agent.

3. **Meter Data Submittal Location:** Market Participant shall provide in Exhibit A the meter(s) and calculations used to calculate the Meter Data Submittal Location value.

4. **Notice of Meter Changes:** Market Participant shall inform the Meter Agent of any additions, deletions, and modifications of metering that will impact the market data.

    a. Market Participant shall provide full details of the meter information to the Meter Agent a minimum of sixty (60) days prior to the implementation of the change, except when the meter equipment is changed or replaced due to equipment failure in which case notice of change will be provided as soon as possible. This information to be provided shall include the following:
        1. Information relating to retrieval of the meter data from the data source. This includes the method of doing so, communications, and full description of the meter.
        2. Information relating to the data and the processing of such data that will be applied for the new or modified Meter Data Submittal Location and the impact to other existing Meter Data Submittal Location or tie-line flow between Settlement Areas.
        3. Completing the SPP Market registration required, which includes real-time data exchange and modeling coordination with SPP.
        4. Updating of Exhibit A.

    b. In addition, Market Participant shall be responsible for developing and testing a complete system for submission of data under this Agreement.

    c. Market Participant shall notify Meter Agent of any significant metering issues related to the data provided to the Meter Agent within twenty four (24) hours after the issue is identified. This includes change out of a meter, meter failures, real-time data failures, etc.

5. **Meter Data Submittal Location Notification:** Market Participant shall notify any other Market Participant affected by the change in the Meter Data Submittal Location at least seven (7) days prior to the change.

6. **Data Exchange and Data Quality:** Market Participant shall provide meter data for each Meter identified in Exhibit A to the Meter Agent in a timely manner.

    a. Data shall be provided to the Meter Agent at least one (1) full business day prior to SPP's deadline for submission of meter data, as specified in Appendix D of the Market Protocols.

    b. Upon notification to or upon discovery by the Market Participant that the data exchange has failed or data quality is questionable, the Market Participant will resolve the issue at its source.

    c. In the absence of actual values for data required for settlement, it is the Market Participant's responsibility to provide estimated values for such data to the Meter Agent; however, if the Market Participant fails to provide the actual or estimated meter data in a timely manner, the Meter Agent will estimate the data for submission to SPP by the appropriate deadline. The Meter Agent will be held harmless as set forth in section 3.2.

7. **Submission Failures:** If the Meter Agent fails to submit the meter data, including Settlement Area tie-line meter data by the Final Settlement Statement data cutoff, the Market Participant is responsible for initiating and pursuing the SPP OATT Dispute process. The Meter Agent must provide to SPP any data it has available to help resolve the dispute.

1.2 **Meter Agent Responsibilities:**

1. **Governing Documents:** In addition to complying with this Agreement, Meter Agent shall provide services on behalf of the Market Participant in accordance with SPP's OATT and Market Protocols as they may be amended from time to time related to implementation of this Agreement. In the event there is a conflict between this agreement and the SPP OATT, the OATT shall govern.

2. **Meter Agent Registration:** Meter Agent shall be a registered Meter Agent with the Integrated Marketplace.

3. **Meter Data Submittal Location Development:** Meter Agent shall provide all settlement data required for the Meter Data Submittal Locations designated by the Market Participant in Exhibit A.

4. **Data Communications:** Meter Agent and the Market Participant shall mutually agree upon a format and method of exchange of settlement data required to be provided by the Market Participant.

5. **Meter Data Submittal Location Values**

   Meter Agent shall determine the Meter Value for each of the Meter Data Submittal Location identified in Exhibit A by applying all parameters as identified therein.

6. **Data Issue Notifications:**

   a. Meter Agent will notify the Market Participant, as soon as practicable, of any data exchange issues with the meter data source.

   b. Upon failure to receive meter data from the Market Participant by the data submission deadline, the Meter Agent will notify the Market Participant as soon as practicable and, if necessary, the Meter Agent will estimate the data pursuant to 1.1 6. c. of this agreement.

7. **Data Submission:** Meter Agent shall submit Meter Data Submittal Location Meter Values to the Transmission Provider by the deadlines outlined in Section 4.5.13 of the Market Protocols.

## ARTICLE II

## Term and Termination

2.1 **Initial Term:** This Agreement shall become effective on _____, _____ and shall continue until _____, _____.

2.2 **Extended Term:** This Agreement shall continue on a year to year basis at the conclusion of its Initial Term, unless terminated as specified in the Agreement.

2.3 **Termination:** This Agreement may be terminated at any time by mutual agreement of the Market Participant and Meter Agent. Either the Market Participant or the Meter Agent may terminate the Agreement after the Initial Term, upon giving sixty (60) calendar days written notice to the other Party.

## ARTICLE III

## Miscellaneous

3.1 **Force Majeure:** An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Party will not be considered in default as to any obligation under this Agreement to the extent such Party is prevented or delayed from fulfilling such obligation due to the effect of Force Majeure. A Party whose performance under this Agreement is prevented or delayed by Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement, and shall take all reasonable steps to eliminate the cause; however, neither Party shall be required to settle or resolve labor disturbances or strikes, or to accept or agree to governmental or regulatory orders or conditions without objection or contest except on any basis agreeable to such Party in its sole discretion. The affected Party, as soon as reasonably possible, shall give notice of Force Majeure.

3.2 **Indemnification:** Each Party hereto shall indemnify and hold harmless the other Party (in such case, the "Indemnified Party"), its officers, directors, agents and employees from and against any and all claims for death or injury to persons or destruction of or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorneys fees, and all other obligations by or to third parties (collectively "liabilities"), arising out of or resulting directly or indirectly from the Indemnified Party's performance of its obligations under this Agreement on behalf of the Indemnifying Party, except to the extent any such liability arises, directly or indirectly, from the Indemnified Party's gross negligence or intentional wrongdoing. For example, the provisions of this section 3.2 could apply in circumstances where equipment malfunction (or other inadvertent error not involving gross negligence or intentional wrongdoing) causes imbalance information to be inaccurately reported, resulting in billing errors.

3.3 **Successors and Assignment:** This Agreement shall be binding upon the Parties and their respective successors and assigns. This Agreement shall not be assignable by either Party except with the prior written consent of the other Party which shall not be unreasonably withheld.

3.4 **Good Utility Practices:** The Parties shall conduct their affairs under this Agreement in accordance with Good Utility Practices. Good Utility Practices shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, safety, and expedition. Good Utility Practices is not intended to be limited to the optimum practice, method or act to

the exclusion of all others, but rather to be acceptable practices, methods or acts, generally accepted by the region.

3.5 **No third party beneficiaries.** There shall be no third party beneficiaries to this Agreement.

3.6 **Amendment:** The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by each of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

3.7 **Modification by the Parties:** The Parties may by mutual agreement amend Exhibit A of this Agreement by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all Applicable Laws and Regulations.

3.8 **Notification to SPP**: The initial Agreement and any amendments thereto shall be provided to SPP upon execution.

## ARTICLE IV

## Notices

4.1 **Agreement Notices:** Any notice, demand or request required or authorized by this Agreement shall be deemed properly made, given to, or served on the party to whom it is directed when sent by written notification addressed as follows:

**Market Participant:**
Title
Company
Address
City, State, Zip
Email

**Meter Agent:**
Title
Company
Address
City, State, Zip
Email

Notice of change in the above addresses shall be given in the manner specified above.

## ARTICLE V

## Complete Agreement

**5.1 Complete Agreement:** This Agreement represents the Parties' final and mutual understanding concerning its subject matter. It replaces and supersedes any prior agreements or understandings, whether written or oral. No representations, inducements, promises, or agreements, oral or otherwise, have been relied upon or made by either Party, or anyone on behalf of a Party, that are not fully expressed in this Agreement. IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and attested by their duly authorized officers as of the day and year first above stated.

| **Market Participant:** | **Meter Agent:** |
|---|---|
| Company | Company |
| By: _____ | By: _____ |
| Printed Name: _____ | Printed Name:_____ |
| Title: _____ | Title: _____ |

# Exhibit A

## Market Participant Meter Data Submittal Location Definitions

**Resource Meter Locations:**

| # | Meter Data Submittal Location Name | Meter | Physical Location | Voltage Level | Losses | Operand |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
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| | | | | | | |

Gross Generation output is negative, auxiliary use is positive. MWh received by the Transmission System is negative.

**Load Meter Data Submittal Locations: (Name of Location)**

| # | Meter Data Submittal Location Name | Meter | Physical Location | Voltage Level | Distrib. Losses | * | Operand |
|---|---|---|---|---|---|---|---|
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
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| | | | | | | | |

** Engineered Adjustment with Assumption – reference SPP Protocols Appendix C and D

**Residual Load Meter Data Submittal Locations:**

| # | Meter Data Submittal Location Name | Meter | Operand |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |
| | | | |

Assumes sign of other Meter Data Submittal Location data used is in polarity required for submission to SPP Market.

**Tie-Line Meter data between Settlement Areas:**

| # | Tie-Line Meter Name | Meter | Operand |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

| | | | |
|---|---|---|---|
| | | | |

# ATTACHMENT AN

# AGREEMENT BETWEEN SOUTHWEST POWER POOL, INC. AND SOUTHWEST POWER POOL BALANCING AUTHORITY PARTICIPANTS RELATING TO THE IMPLEMENTATION OF THE SOUTHWEST POWER POOL BALANCING AUTHORITY

Southwest Power Pool, Inc. and the SPP BA Participants in the SPP Balancing Authority (as such terms are defined below) agree to the following terms.

## 1. RECITALS

1.1 In its May 1, 2007 Order in *Southwest Power Pool, Inc.*, Docket No. ER06-451-020, the FERC approved the EIS Agreement which provided for the performance of Balancing Authority responsibilities relating to implementation of the EIS Market through the SPP Open Access Transmission Tariff.

1.2 Through the EIS Agreement the Parties set out in detail the division and transfer of certain responsibilities between those entities identified as SPP Balancing Authorities in the EIS Agreement, and SPP relating to implementation of the EIS Market through the SPP OATT.

1.3 The Parties are replacing the EIS Agreement to accommodate the development and implementation of the SPP Integrated Marketplace and SPP becoming the Balancing Authority for the entire consolidated SPP Balancing Authority Area.

1.4 The Parties believe that this Agreement is in the public interest.

## 2. DEFINITIONS

2.01 **ACTUAL INTERCHANGE**. The metered interchange over a specific interconnection, including pseudo-ties, between two directly interconnected BAs.

2.02 **ADJACENT BALANCING AUTHORITY**. As defined in the NERC Glossary of Terms.

2.03 **AGREEMENT**. This "Agreement Between Southwest Power Pool, Inc. And Southwest Power Pool Balancing Authority Participants Relating To The Implementation Of The Southwest Power Pool Balancing Authority."

2.04 **AREA CONTROL ERROR (ACE)**. As defined in the NERC Glossary of Terms.

2.05 **AUTOMATIC GENERATION CONTROL (AGC)**. As defined in the NERC Glossary of Terms.

2.06 **BALANCING AUTHORITY (BA)**. As defined in the NERC Glossary of Terms.

2.07 **BA OPERATING PROTOCOLS**. The operating protocols entitled "BA Operating Protocols of the Participants and SPP" that are developed by the SPP BA, as may be amended from time to time, to describe in more detail the obligations of the Parties to implement this Agreement.

2.08 **BULK ELECTRIC SYSTEM**. As defined in the NERC Glossary of Terms.

2.09 **DYNAMIC SCHEDULE**. As defined in the NERC Glossary of Terms.

2.10 **EFFECTIVE DATE**. The effective date of this Agreement as specified in Section 16.2 of this Agreement.

2.11 **EIS AGREEMENT**. The "Agreement Between Southwest Power Pool, Inc. And Southwest Power Pool Balancing Authorities Relating To Implementation Of The EIS Market."

2.12 **ERO**. The Electric Reliability Organization approved by FERC.

2.13 **ERO BALANCING AUTHORITY RELIABILITY STANDARDS.** Those reliability standards and requirements applicable to Balancing Authorities as those standards and requirements exist or are hereafter modified or adopted by the ERO.

2.14 **ERO RELIABILITY STANDARDS**. Standards developed by the ERO and approved by the Commission to ensure reliability of the Bulk Power System, violation of which may result in the imposition of mitigation programs or monetary penalties.

2.15 **FEDERAL POWER MARKETING AGENCY.** This term shall include the term "Federal Power Marketing Administration" and have the same definition that is set forth in the Federal Power Act at 16 U.S.C. § 796(19), which defines "Federal power marketing agency" as "any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy[.]"

2.16 **FERC or the COMMISSION**. The Federal Energy Regulatory Commission or any successor agency.

2.17 **GENERATOR OPERATOR (GOP)**. As defined in the NERC Glossary of Terms.

2.18 **GENERATOR OWNER (GO).** As defined in the NERC Glossary of Terms.

2.19 **GOOD UTILITY PRACTICE**. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the

relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to the acceptable practices, methods, or acts generally accepted in the region.

2.20 **GOVERNING DOCUMENTS**. The following documents as may be amended from time to time: (a) Southwest Power Pool, Inc. OATT; (b) Southwest Power Pool, Inc. Membership Agreement; (c) Southwest Power Pool, Inc. Bylaws; (d) Joint Operating Agreement Between the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc.; (e) Joint Operating Agreement Among And Between Southwest Power Pool, Inc. and Associated Electric Cooperative Inc.; and (f) any joint operating agreements or seams agreements executed by SPP after the filing of this Agreement with the FERC.

2.21 **INTEGRATED MARKETPLACE**. The Day-Ahead Market, the Real-Time Balancing Market, the Transmission Congestion Rights Market and the Reliability Unit Commitment processes.

2.22 **INTERCONNECTION**. The Eastern Interconnection as defined by the NERC Glossary of Terms.

2.23 **LOAD SERVING ENTITY (LSE).** As defined in the NERC Glossary of Terms.

2.24 **MARKET MONITOR**. The entity that is responsible for performing the monitoring and mitigation activities described in Attachments AF and AG to the SPP OATT.

2.25 **MARKET PARTICIPANT**. As defined in the SPP OATT.

2.26 **MEMBERSHIP AGREEMENT**. The Membership Agreement of the Southwest Power Pool, Inc., an Arkansas non-profit corporation.

2.27 **NET ACTUAL INTERCHANGE**. As defined in the NERC Glossary of Terms.

2.28 **NET SCHEDULED INTERCHANGE**. As defined in the NERC Glossary of Terms.

2.29 **NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC)**. The North American Electric Reliability Corporation or its successor organization.

2.30 **OPEN ACCESS TRANSMISSION TARIFF (OATT)**. FERC approved Pro-Forma Open Access Transmission Tariff.

2.31 **OPERATING COMMITTEE**. A committee which shall perform the duties identified in Section 18.4.

2.32 **PARTIES**. The SPP BA Participant and SPP that have executed this Agreement. SPP and SPP BA Participant may be individually referred to as a "Party."

2.33 **PURCHASING AND SELLING ENTITY (PSE)**. As defined in the NERC Glossary of Terms.

2.34 **RESOURCE PLAN**. A Market Participant's plan to meet its energy obligations including specification of resource operating characteristics.

2.35 **SOUTHWEST POWER POOL (SPP)**. Southwest Power Pool, Inc., or any successor organization, that is designated as the SPP BAA under this Agreement.

2.36 **SPP BALANCING AUTHORITY (SPP BA)**. The responsible entity registered with the ERO as the BA, and that performs all the functions of the BA in the SPP BAA on behalf of the Parties to this Agreement.

2.37 **SPP BALANCING AUTHORITY AREA (SPP BAA)**. The SPP BAA consists of the transmission system, load and generation resources interconnected to the SPP Transmission System, as defined under the SPP OATT, that: (a) function as a centrally coordinated system and (b) operate subject to the single set of dispatch instructions determined and issued by the SPP BA. The SPP BA maintains load-resource balance within its SPP BAA.

2.38 **SPP BA PARTICIPANT.** An operational entity, which is: (a) a Party to this Agreement, excluding SPP, and (b) shown in Appendix A to this Agreement. For purposes of this Agreement, an SPP BA Participant may have previously been registered as a BA under the EIS Agreement.

2.39 **SPP BA PARTICIPANT AREA.** The collection of generation, transmission, and loads that are within the metered boundaries of the SPP BA Participant.

2.40 **SPP CRITERIA**. SPP's approved operating and planning criteria.

2.41 **TIE LINE**. As defined in the NERC Glossary of Terms.

2.42 **TRANSMISSION OPERATOR (TOP)**. As defined in the NERC Glossary of Terms.

2.43 **TRANSMISSION OWNER (TO)**. As defined in the NERC Glossary of Terms.

2.44 **WESTERN AREA POWER ADMINISTRATION-UPPER GREAT PLAINS REGION ("WESTERN-UGP"):** A division of the Western Area Power Administration that markets and transmits Federal power from reservoir projects under the control of the Department of the Army or the U.S. Bureau of Reclamation. Western-UGP operates the WAUW Balancing Authority Area in the

Western Interconnection, where certain of its transmission facilities are located and is also a Transmission Owner that has transferred Federal transmission facilities to the functional control of SPP.

2.45 **WESTERN INTERCONNECTION**: A major alternating current power grid in North America. The Western Interconnection stretches from Western Canada south to Baja California in Mexico, reaching eastward over the Rockies to the Great Plains. Western Interconnection is comprised of the states of Washington, Oregon, California, Idaho, Nevada, Utah, Arizona, Colorado, Wyoming, portions of Montana, South Dakota, Nebraska, New Mexico and Texas in the United States, the Provinces of British Columbia and Alberta in Canada, and a portion of the Comisión Federal de Electricidad's system in Baja California in Mexico.

## 3. GENERAL

3.1 PURPOSE. The purpose of this Agreement is to delineate the responsibilities between SPP, as the SPP BA, and the SPP BA Participants to establish the SPP BAA that facilitates the Integrated Marketplace to be implemented under the SPP OATT.

3.2 OBLIGATIONS. In carrying out obligations under this Agreement, SPP and the SPP BA Participants shall (a) follow Good Utility Practice, (b) comply with applicable policies, standards and requirements of the ERO Reliability Standards and SPP Criteria and their successors, and (c) follow applicable laws, regulations, and orders.

3.3. REGISTRATION AND CERTIFICATION. SPP shall be the SPP BA. The SPP BA will comply with the ERO's applicable BA registration and certification requirements. SPP BA Participants shall support those functions consistent with the tasks and responsibilities assigned under this Agreement.

3.4. RELATIONSHIP TO MEMBERSHIP AGREEMENT. Nothing in this Agreement shall be construed or intended to cause or effect a modification to the Membership Agreement. This Agreement is intended to be separate from the Membership Agreement. All rights and obligations currently existing under the Membership Agreement remain.

3.5 RELATIONSHIP TO EIS AGREEMENT. This Agreement shall supersede the EIS Agreement upon the effective date specified in the Agreement; provided, however, this shall not eliminate any rights or obligations relating to prior actions, which shall survive the EIS Agreement including, but not limited to, rights or obligations arising under the following provisions: (a) indemnification; (b) waivers of liability; (c) no agreement to jurisdiction; (d) default; (e) cost recovery; and (f) obligations upon termination by entities that terminated their participation in the EIS Agreement without executing this Agreement. Notwithstanding the foregoing in this Section 3.5, the SPP and the SPP BA Participants shall maintain the functionality necessary to comply with the EIS Agreement for a transition

period after Integrated Marketplace start-up as determined by the Operating Committee**.**

## 4. SPP RESPONSIBILITIES.

4.1 SPP BA. SPP shall perform all tasks necessary to fulfill the role as the SPP BA, including adherence to all applicable ERO BA Reliability Standards and requirements except as delineated in Section 5 of this Agreement.

4.2 SPP NORMAL OPERATIONS

4.2.1 SPP shall be responsible for the identification of its critical assets and related critical cyber assets necessary to support reliable operation of the Bulk Electric System. SPP shall have no responsibility to identify critical assets or related critical cyber assets of any SPP BA Participant.

4.2.2 SPP shall be responsible for maintaining its internal telecommunications facilities in an adequate and reliable manner for the exchange of interconnection and operating information necessary to maintain reliability within its respective scope of operations. SPP shall have no responsibility for maintaining any SPP BA Participant's internal telecommunications facilities for the exchange of interconnection and operating information of any SPP BA Participant.

## 5. SPP BA PARTICIPANT RESPONSIBILTIES

5.1 TIE LINE METERING AND TELEMETRY. Each SPP BA Participant that has or is taking actions to have, one or more Tie Line(s) with an Adjacent Balancing Authority shall have, or cause to have, the Tie Line metering and telemetry responsibilities as set forth in this Section 5.1.

5.1.1 Each SPP BA Participant having one or more Tie Line(s) with an Adjacent Balancing Authority shall provide all Tie Line flows to the SPP BA.

5.1.1.1 Each SPP BA Participant shall ensure that the Tie Line megawatt (MW) metering is telemetered to the SPP control center.

Such SPP BA Participant shall maintain and provide to SPP suitable documentation (i.e. prints, equipment specifications, records) that verifies Tie Line MW metering physical location and actual metering point

The SPP BA Participant shall operate such that the MW-hour data is telemetered or reported to the SPP BA at the end of each hour.

5.1.1.2 Each SPP BA Participant shall ensure the power flow measurements transmitted to SPP from the Tie Line meters are not filtered prior to transmission, except anti-aliasing Filters of Tie Lines.

5.1.1.3 Each SPP BA Participant shall ensure the installation of common metering equipment where Dynamic Schedules or pseudo-ties are implemented between SPP and an Adjacent Balancing Authority where applicable to account for the delivery of the output of units located external to the SPP BAA or to serve remote load physically external to the SPP BAA.

5.1.1.4 Each SPP BA Participant shall operate such that its sampling rate of data is compatible with the SPP's sampling rate of data, as specified by SPP.

5.1.1.5 Each SPP BA Participant shall provide SPP an inventory of all Tie Line(s) with Adjacent Balancing Authority(ies), including maps, prints, electrical drawings and diagrams, equipment descriptions as requested by SPP.

5.1.1.6 The SPP BA Participant shall timely inform SPP of any modifications, changes, status, and operability of the Tie Line metering equipment.

5.1.1.7 SPP and SPP BA Participant shall agree on the specific Tie Line (including pseudo ties), surrounding the SPP BAA.

5.1.1.8 Each SPP BA Participant shall maintain, re-calibrate and otherwise insure proper operation and accuracy of the Tie Line metering equipment at a frequency determined by SPP and documented in applicable SPP policies, procedures, and/or documents. Documents verifying such actions shall be provided to SPP as requested by SPP.

5.1.1.9 If SPP suspects inaccuracies or malfunction of Tie Line metering, SPP shall inform the SPP BA Participant. The SPP BA Participant shall take action necessary to verify timely Tie Line metering equipment accuracy and/or performance of the suspect Tie Line metering and take actions to restore data accuracy.

5.1.2 The addition of a Party or the withdrawal of a Party may result in the designation of an existing line as a Tie Line with an Adjacent Balancing Authority or result in an existing Tie Line with an Adjacent Balancing Authority to be no longer a Tie Line. If either event should occur, SPP shall so notify the affected SPP BA Participant. SPP and the impacted Party(ies) shall determine actions to be taken by SPP and/or the Party(ies) to conform to this Agreement in a timely manner.

5.2 FREQUENCY MEASUREMENTS. As may be reasonably requested by SPP, SPP BA Participants may be requested to supply SPP with frequency measurements from locations agreed to by the Parties. SPP BA Participants that are designated to provide frequency measurements to SPP shall provide accurate

frequency measurements from these location(s) with measurement quality indication.

SPP BA Participants shall perform annually, against a common reference, checks and calibrations of its time error and frequency devices used to supply SPP with data used by SPP to perform BA functions ("Actions"). For purposes of this section, "annually" shall mean "within a calendar year, with the calendar year beginning on January 1 and ending on December 31;" however, the period between subsequent annual checks and calibrations under this section shall not exceed fifteen (15) months. Documents verifying such Actions shall be provided to SPP BA as requested by SPP.

## 6. IMPLEMENTATION OF EMERGENCY OPERATING PLANS

6.1 SPP and each SPP BA Participant shall coordinate preparation and implementation of respective emergency operating plans. This coordination shall include, but not be limited to,

6.1.1 SPP BA Participant actions to interruption of load and/or exports as directed by SPP associated with capacity deficiencies; and,

6.1.2 SPP BA Participant actions to implement public appeals, voltage reductions, curtailment of interruptible and/or firm load as directed by SPP associated with capacity deficiencies.

## 7. BA OPERATING PROTOCOLS AND SPECIFIC ERO REQUIREMENT ASSIGNMENT

7.1 INITIAL ASSIGNMENT OF TASKS. Sections 4 and 5 of this Agreement set forth the tasks and responsibilities of the Parties to establish the single BA for the SPP BAA.

7.2 NEW OR MODIFIED RESPONSIBILITIES. When new and/or modified applicable responsibilities are required including those that might be initiated by the ERO, the Parties will negotiate in good faith to determine whether SPP and/or the SPP BA Participants shall ensure the performance of the new or modified responsibilities, and will amend this Agreement accordingly, pursuant to Section 17.4.

7.3 BA OPERATING PROTOCOLS. The SPP BA shall develop and maintain BA Operating Protocols that provide for operational requirements under this Agreement.

## 8. DATA EXCHANGE

8.1 PARTIES' DATA EXCHANGE. Each SPP BA Participant and SPP shall provide the information and data that a Party reasonably believes it needs and requests in order to carry out its responsibilities under this Agreement.

8.2 CONFIDENTIALITY. All data provided under this Section shall be considered information subject to the confidentiality provisions of Section 13 herein.

**9. SPP BA PARTICIPANT COST RESPONSIBILITY.** Each SPP BA Participant shall be responsible for all costs incurred by it to implement the provisions of this Agreement.

## 10. SANCTIONS, INQUIRIES AND ALLOWED ACTIONS

10.1 SANCTIONS. In the event the ERO assesses a monetary penalty against SPP as the Registered Entity BA for a violation of a Reliability Standard, SPP shall seek to recover the costs associated with the sanctions and/or monetary penalties pursuant to Attachment AP of the SPP OATT. For purposes of clarification, the term "Transmission Provider" as contained in Attachment AP shall mean SPP and the term "Member" in Attachment AP shall mean SPP BA Participants under this Agreement.

10.2 INQUIRIES. To the extent an SPP BA Participant's actions implementing SPP actions or directives pursuant to this Agreement are questioned, investigated or sanctioned by the ERO, the Market Monitor, or by an applicable regulatory agency, SPP shall aid the SPP BA Participant in responding to the inquiry, investigation, or sanctions.

10.3 ALLOWED ACTIONS. To the extent that the ERO, FERC or applicable regulatory agency determines that an SPP BA Participant's actions taken pursuant to this Agreement were inappropriate, SPP shall not require the SPP BA Participant to take such actions in the future. If the ERO, FERC or applicable regulatory agency requires that an SPP BA Participant take action inconsistent with this Agreement, SPP will allow such actions.

## 11. LIMITATIONS ON SPP ACTIONS

11.1 GOVERNING DOCUMENTS. Without limiting the generality of obligations provided in Section 3.2, SPP shall not issue any orders to any Party pursuant to this Agreement or take any action pursuant to this Agreement that SPP knows or should know is not in accordance with the Governing Documents.

11.2 APPLICABLE LAWS. SPP shall not issue any order to any other Party pursuant to this Agreement or take any action pursuant to this Agreement that SPP knows or should have known would cause a violation of applicable laws or tariffs.

## 12. INDEMNIFICATION, LIABILITIES, INSURANCE

12.1 INDEMNIFICATION FOR THIRD PARTY CLAIMS. Subject to Sections 12.1.1 and 12.1.2 hereof, each Party shall at all times indemnify, defend, and save harmless each

other Party to this Agreement and its officers, shareholders, directors, agents, contractors, employees, and members (*i.e.*, cooperative members and municipal joint action agency members) from and against any and all damages, losses, claims, including without limitation claims and actions relating to injury to, or death of, any person, or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties or other Parties (each, a "Claim"), but only to the extent caused by the Indemnifying Party's (as defined below) acts or omissions during performance of its obligations under this Agreement. The term Claim shall not include civil penalties, fines, assessments or any other charges levied against a Party and recovered pursuant to Section 10 of this Agreement.

12.1.1 SOVEREIGN IMMUNITY. Notwithstanding anything to the contrary in this Agreement, no Party which has been granted sovereign tort immunity under applicable law shall have any indemnification obligation in connection with any Claim that would be subject to such immunity if brought against that Party, and nothing contained in this Agreement shall be construed as a waiver by any Party of its sovereign tort immunity.

12.1.2 NOTICE. Upon obtaining knowledge of any Claim, a Party with a right to be indemnified ("Indemnified Party") shall promptly notify each Party who has an obligation to indemnify ("Indemnifying Party") in writing of such Claim, provided however, that failure of the Indemnified Party timely to give notice to the Indemnifying Party shall not release the Indemnifying Party from its indemnity obligations set forth in this Agreement except to the extent that the Indemnifying Party has been actually prejudiced by such failure. Following receipt of such notice, and unless counsel to the Indemnified Party shall have determined in good faith that the assumption of such defense by the Indemnifying Party would be inappropriate due to a conflict of interest, the Indemnifying Party shall have the option, at its cost and expense, to assume the defense of such matter and to retain counsel (not reasonably objected to by the Indemnified Party) to defend any such Claim, and the Indemnifying Party shall not be liable to the Indemnified Party for any fees of other counsel or any other expenses (except as expressly provided to the contrary herein) with respect to the defense of such Claim, other than reasonable fees and expenses of counsel employed by the Indemnified Party for any period during which the Indemnifying Party has not assumed the defense thereof. The Indemnified Party shall have the option of joining the defense of such Claim with its own counsel (which shall be at the sole cost and expense of the Indemnified Party) and counsel for each of the Indemnified and Indemnifying Party shall cooperate with each other to the extent consistent with such counsel's professional responsibilities. In effecting the settlement or compromise of, or consenting to the entry of any judgment with respect to, any such Claim ("Settlement"), the Indemnifying Party, or the Indemnified Party, as the case may be, shall act in good faith and shall consult with the other Party. The Indemnified Party shall enter into only such Settlement as the Indemnifying Party shall consent to, such prior written consent not to be unreasonably withheld, conditioned or delayed. An Indemnifying Party shall not

be liable for any Settlement not made in accordance with the preceding sentence. An Indemnifying Party shall notify the Indemnified Party reasonably in advance of entering into any Settlement of a Claim for which the Indemnifying Party has assumed the defense, and shall obtain the Indemnified Party's prior written consent thereto, not to be unreasonably withheld, conditioned or delayed, if such Settlement (i) imposes any obligation on the Indemnified Party other than, or in addition to, an obligation to pay money which the Indemnifying Party has assumed, (ii) involves any admission of wrongdoing, fault or liability on behalf of the Indemnified Party, whether express or implied, or (iii) does not fully and unconditionally release the Indemnified Party from all liability in connection with such Claim, which release shall be in form and substance reasonably satisfactory to the Indemnified Party.

12.1.3 NOTICE TO OTHER PARTIES. In the event an Indemnified Party provides notice to an Indemnifying Party pursuant to Section 12.1.2, an Indemnifying Party shall timely provide all other Parties the same notice the Indemnifying Party receives from the Indemnified Party.

12.1.4 WESTERN-UGP REQUIREMENTS. Section 12.1 does not apply to Western-UGP pursuant to the Antideficiency Act, 31 U.S.C. § 1341, et seq., as amended or supplemented. Western-UGP's liability is determined in accordance with the Federal Tort Claims Act, 28. U.S.C. § 1346(b), 2401(b), 2402, 2671, 2672, 2674-2680, as amended or supplemented.

12.2 LIABILITY LIMITATION FOR INTER-PARTY CLAIMS. No Party shall be liable to the SPP for any damages whatsoever, including, without limitation, direct, indirect, incidental, special, multiple, consequential (including without limitation attorneys' fees and litigation costs), exemplary, or punitive damages arising out of or resulting from any act or omission in any way associated with the performance of the Party's responsibilities under this Agreement, except to the extent, and only to the extent, that the Party is found liable for gross negligence or intentional misconduct, in which case the Party shall not be liable for any indirect, incidental, special, multiple, consequential (including without limitation attorneys' fees and litigation costs), exemplary or punitive damages. The SPP shall not be liable to any Party for any indirect, incidental, special, multiple, consequential (including without limitation attorneys' fees and litigation costs), exemplary or punitive damages.

12.3 INSURANCE. Each Party shall be self-insured and/or obtain adequate insurance coverage to cover liabilities, if any, under this Agreement to be effective as of the effective date of this Agreement.

## 13. STANDARDS OF CONDUCT, INFORMATION SHARING, CONFIDENTIALITY

13.1 SPP BA PARTICIPANTS. This Agreement does not require any SPP BA Participant to separate SPP BA Participant personnel from marketing personnel; nor does this Agreement waive any requirement of the Commission's Standards of Conduct or exempt any public utility SPP BA Participant from the Standards of

Conduct. This Section 13.1 applies to both the public utility SPP BA Participants and the non-public utility SPP BA Participants that are signatories to this Agreement.

13.1.1 In general, personnel of an SPP BA Participant performing functions under this Agreement shall keep all information received from SPP or other entities relating to its performance under this Agreement confidential and shall not disclose such information to Market Participants (including marketing personnel that are part of the same company as the SPP BA Participant) or entities which it reasonably believes may become Market Participants. Notwithstanding the foregoing, and subject to subparagraph 13.1.2(b) below, an SPP BA Participant with personnel who perform both SPP BA Participant and market functions may disclose information received from the SPP or other entities to its personnel.

13.1.2 SPP shall have the right to limit the sharing of market sensitive information related to non-affiliated Market Participants to an SPP BA Participant with personnel who perform both functions under this agreement and market functions; except when:

(a) no other Market Participant under the Integrated Marketplace with registered resource(s) controls generation connected to a Party's facilities, or

(b) the SPP BA Participant is a signatory to the NERC Confidentiality Agreement for Electric System Operating Reliability Data and Annex 1 thereto (Limited Operating Reliability Data Agreement for Small Bundled Entities). Each SPP BA Participant with personnel performing such dual functions shall notify SPP of that fact, and, to the extent permitted by law, the SPP BA Participant shall not disclose confidential information to third party Market Participants or third parties which it reasonably believes may become Market Participants.

13.1.3 Notwithstanding the above, SPP shall provide, to the extent necessary, information to allow the SPP BA Participant to perform its functions under this Agreement and to comply with ERO and regional reliability requirements.

13.1.4 There shall be no requirement to keep information confidential if such information is in the public domain or subject to open records laws. In addition, if the ERO requires that the SPP BA Participant provide information required to be confidential under this provision, the SPP BA Participant may provide such information to the requesting entity, provided that the SPP BA Participant shall make a good faith attempt to maintain the confidentiality of the information, notwithstanding the

information request, and provided further that, in the case of a request by a state regulatory agency for confidential information, the SPP BA Participant may provide confidential information to such state regulatory agency as necessary to satisfy state regulatory responsibilities and, subject to applicable law, only to the extent that the state regulatory agency executes a non-disclosure agreement.

13.2 SOUTHWEST POWER POOL. SPP, its directors, officers, employees, contractors, and agents shall adhere to the SPP Standards of Conduct with regard to all activities related to this Agreement.

## 14. DISPUTE RESOLUTION

14.1 GENERAL. These procedures are established for the equitable, efficient and expeditious resolution of disputes consistent with SPP's Bylaws. These procedures are intended to cover disputes between any two or more SPP BA Participants, or between SPP and any SPP BA Participant(s). SPP and SPP BA Participant(s) are strongly encouraged to take part in the complete process herein described prior to litigation or the utilization of other dispute resolution processes. SPP administrative involvement in the proceeding is to coordinate with an appropriate firm or panel to facilitate the resolution of the dispute and to provide meeting coordination and facilities. These procedures do not apply to disputes that are covered by the dispute resolution procedures of the SPP OATT.

14.2 INSTIGATION. Any SPP BA Participant may begin these dispute resolution procedures by notifying the SPP President in writing. The SPP President will inform the SPP Board of Directors of the initiation of any dispute resolution proceedings. This written notification must contain the authorized signatures of all Parties to the dispute. The notification must contain: (a) a statement of the issues in dispute; (b) the positions of each of the Parties relating to each of the issues; (c) the specific dispute resolution procedure desired; and (d) any agreed-upon modifications or specific additions to the proceedings described in this Agreement by which the dispute may be resolved.

14.3 DISPUTE RESOLUTION PROCESS.

14.3.1 In the event SPP is a party to the dispute, the parties shall engage a firm specializing in alternative dispute resolution to administer the dispute resolution process. The firm will be mutually determined by the parties and the process will be administered in accordance with this Agreement and such other SPP governing documents as may be relevant to the proceeding. In the event the parties cannot mutually agree to the engagement of a firm, the dispute resolution process will be abandoned and other available means for resolution will be pursued.

14.3.2 In the event SPP is not a party to the dispute, the parties to the dispute may engage a firm specializing in alternative dispute resolution to administer the dispute resolution process. The firm will be mutually determined by the parties and the process will be administered in accordance with this Agreement and such

other SPP governing documents as may be relevant to the proceeding. In the event the parties cannot mutually agree to the engagement of a firm, and do not determine some other mutually acceptable procedure, the President of SPP shall provide to each party to the dispute a list of candidates to be used in forming a three-person dispute resolution panel. The candidates shall be persons meeting the requirements for the SPP Board of Directors. The President shall then call a telephone conference meeting during which each party shall alternate striking names from the list until those remaining constitute the dispute resolution panel. This panel shall select a chair from its membership. Should any candidate decline to serve or resign from a current appointment for any reason, the candidate whose name was last struck from the list shall be contacted to serve. The President shall assign a Staff representative to assist the panel as secretary. The President shall manage the panel selection process to ensure its timely completion.

14.4 RESOLUTION PROCEDURES. The types of proceedings available for the resolution of disputes are:

(a) an advisory proceeding to assist each party through discussion and advice, on a separate and individual basis without active participation in the joint discussions and negotiations, to resolve the dispute informally by mutual agreement;

(b) a mediation proceeding to assist the parties through active participation in the joint discussions and negotiations (including specific recommendations of the issues in dispute) through which the parties indirectly attempt to resolve the dispute informally by mutual agreement;

(c) a non-binding dispute resolution proceeding to hear formal evidence on factual matters related to the issues submitted, make written findings and conclusions of fact, and issue specific written recommendations for resolution of each issue in dispute;

(d) a binding dispute resolution proceeding, provided the parties to the dispute agree to the proceeding, to hear formal evidence on factual matters related to the issues submitted, make written findings and conclusions of fact, and issue directives and awards for resolution of each issue in dispute.

The panel chair or representatives of the alternative dispute resolution firm (the "Facilitator") shall determine meeting arrangements and format necessary to efficiently expedite the resolution of the dispute, and the SPP staff secretary shall notify the parties of these details. Each party to the dispute must have at least one representative present at all related meetings with full authority to resolve the dispute. Upon conclusion of this process, the Facilitator shall notify the SPP President of its outcome. After consultation with the parties to the dispute and the Facilitator to determine the completion of the process as described herein, and/or as modified by the parties, the SPP President shall discharge the panel or firm, and notify the SPP Board of Directors of the results. The parties to the dispute agree to complete the process within 90 days from selection of the panel or firm.

The SPP staff secretary shall maintain minutes of the panel meetings, which shall become part of SPP's historical records.

14.5 EXPENSES. The parties to the dispute shall share equally all reasonable charges for the meeting location, administrative costs, and related travel expenses of panel members. The parties to the dispute shall also share equally all reasonable compensation for time and service of panel members and related incremental expenses of the SPP staff. The President shall determine reasonableness of time and service costs for panel members prior to process implementation. The SPP staff secretary shall account for these expenses. Each party to the dispute shall be responsible for their respective associated expenses.

14.6 LIABILITY. The parties to any dispute which is the subject of these dispute resolution procedures shall hold harmless SPP, its Members, Organizational Groups and each of their directors, officers, agents, employees or other representatives, and the panel members from any liabilities, claims, or damages resulting from any agreement or lack of agreement as a result of the dispute resolution proceedings. The foregoing hold harmless right shall not be extended to the parties to any given dispute or to their directors, officers, agents, employees, or other representatives.

## 15. NON-PERFORMANCE AND DEFAULT

15.1 NON-PERFORMANCE. Except as provided in Section 18.9, any failure to carry out any term of this Agreement shall be considered non-performance. A Party alleging non-performance shall provide written notice of such non-performance within seven calendar days to the alleged non-performing Party. The alleged non-performing Party then shall have seven calendar days (or some other time period agreed to by the Parties) to correct the non-performance or to dispute the non-performance pursuant to the provisions of Section 14. Each Party shall designate a person to receive notice and provide such designation to the other Parties.

15.2 DEFAULT. If a Party fails to correct the non-performance or fails to dispute the allegation of non-performance as provided in Section 14, or the Party is found to be a non-performing Party through the dispute resolution provisions in Section 14 and fails to take adequate corrective action, then the Party shall be considered to be in Default.

15.3 REMEDY FOR DEFAULT. One or more Parties, individually or collectively, may seek appropriate remedies in court, including, but not limited to, specific performance and equitable relief, in the event of a Default by another Party.

## 16. TERM, TERMINATION, EFFECTIVENSS, WITHDRAWAL

16.1 EFFECTIVE DATE AND TERM. This Agreement shall commence on the Effective Date of this Agreement as provided in Section 16.2. This Agreement shall remain in effect for two (2) years from the Effective Date and shall remain in effect from year to year thereafter unless either: (a) SPP or (b) three-fourths of

the SPP BA Participants then subject to this Agreement give one year advance notice in writing that they wish to terminate this Agreement. Termination of this Agreement is subject to approval by a regulatory agency with proper jurisdiction, including, but not limited to, FERC.

16.2 DETERMINATION AND LIMIT OF EFFECTIVENESS. The Agreement shall become effective on the date the Integrated Marketplace begins operations provided that the following events have occurred: (a) the ERO has certified, including on a conditional basis, that SPP can begin operations as the BA of the SPP BAA to comply with the ERO Balancing Authority Reliability Standards; (b) FERC accepts or approves the Agreement; and (c) any modifications ordered by FERC are accepted consistent with Sections 17.2 and 17.4 of this Agreement.

16.3 FILING. SPP has concluded that this Agreement must be filed with FERC under the Federal Power Act and its implementing regulations. Should FERC require any modification to this Agreement that adversely affects the rights or obligations of a Party, the Party may withdraw its participation in this Agreement consistent with the provisions of Section 16.5.

16.4 TERMINATION BY SPP. In the event SPP gives notice to terminate this Agreement, such termination shall not be effective until suitable arrangements for the provisions of its BA responsibilities are in place. Suitability of the arrangements will be determined by the BA Committee.

16.5 WITHDRAWAL. An SPP BA Participant may withdraw from this Agreement if: (a) the SPP BA Participant or entity of which SPP BA Participant is a part withdraws from SPP membership under the withdrawal provisions of the Membership Agreement; or (b) the SPP BA Participant or the entity of which SPP BA Participant is a part removes its transmission facilities from the SPP OATT subject to any applicable regulatory requirements; or (c) the SPP BA Participant unilaterally terminates its participation in the Agreement in its sole discretion. The SPP BA Participant shall provide at least one hundred eighty (180) days notice (or shorter time period if required by a regulatory authority with jurisdiction, or by law, or as agreed to by SPP) to SPP of such withdrawal, which withdrawal may not be effective any earlier than the date upon which the applicable conditions set forth in Section 16.5 are fully satisfied.

16.6 CONTINUING OBLIGATIONS. An SPP BA Participant and SPP shall be subject to the rights and responsibilities under this Agreement for any actions or inactions occurring prior to the effective date of the SPP BA Participants withdrawal or termination of this Agreement.

16.7 SURVIVABILITY. The provisions of this Agreement related to any indemnification obligation or any continuing obligation under Section 16 shall survive the termination of this Agreement under Section 16 or the withdrawal of a Party under Section 16 to the full extent necessary for their enforcement and the protection of the Party in whose favor they run with regard to actions or inactions occurring prior to the effective date of the termination or withdrawal, except that

in the case of withdrawal of an SPP BA Participant, no action or claim against that Participant related to this Agreement shall commence more than three years from the effective date of the withdrawal.

## 17. MODIFICATIONS AND AMENDMENTS

17.1 RESERVED.

17.2 OTHER MODIFICATIONS OR CONDITIONS. Except as provided in Section 17.4, the Parties intend that there will be no other modifications or conditions to this Agreement absent the agreement of the Parties. Notwithstanding anything to the contrary in this Agreement, in the event of any changes in ERO, Commission, Regional Entity, or Integrated Marketplace requirements, which materially affect this Agreement, the Parties will negotiate in good faith appropriate changes to this Agreement and will make written modifications hereto. If the Parties do not mutually agree to such changes in writing, then they will refer the issues to dispute resolution under Section 14.

17.3 MOBILE-SIERRA STANDARD. Absent a filing with the Commission to reflect the agreement of the Parties as detailed in Section 17.4, the standard of review for changes or conditions to this Agreement proposed by a Party shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) (the "*Mobile-Sierra*" doctrine). Notwithstanding the foregoing in this Section 17.3, if the Commission changes its policy (in existence at the time of execution) and imposes a standard different than the Mobile-Sierra presumption set forth in this provision, then the Parties shall modify this Agreement to reflect the new standard. Any changes to this Agreement shall be prospective only. The Commission's action on the initial filing of this Agreement shall be under the just and reasonable standard.

17.4 VOTING FOR ACCEPTANCE OF MODIFICATIONS OR CONDITIONS. This Agreement may be modified or conditioned only by at least a two-thirds affirmative vote of the SPP BA Participants (each SPP BA Participant receiving one vote regardless of size) with the assent of SPP; provided, however, no such modification or condition may be imposed on a Party that does not agree to the modification or condition to the extent that the modification or condition will cause the Party to no longer be in compliance with ERO or Regional Entity requirements. SPP shall file with the Commission any modifications to this Agreement resulting from this Section 17.4, which filing will be subject to the just and reasonable standard of review. Once the Commission accepts such modifications, then such modifications shall be considered as being part of this Agreement and all applicable terms of the Agreement, including Section 17.3, shall apply to the modifications.

## 18. MISCELLANEOUS PROVISIONS

18.1 ASSIGNMENT. Each SPP BA Participant may assign its rights and obligations under this Agreement to another entity subject to receiving the approval of SPP; such approval shall not be unreasonably withheld.

18.2 NO AGREEMENT TO JURISDICTION. By entering into this Agreement, which shall be filed with the Commission and notwithstanding any provision in this Agreement, the SPP BA Participants are not in any way agreeing individually or collectively that their activities under this Agreement are subject to Commission jurisdiction. In addition, nothing in this Agreement shall be construed (a) to confer Commission jurisdiction over SPP BA Participants that are not public utilities as defined by the Federal Power Act, or (b) as a consent or waiver with respect to such jurisdiction, or (c) to cause a non-public utility to take any action or participate in any filing or appeal that would confer Commission jurisdiction over a non-public utility or require a non-public utility to comply with any Order or Rule issued by the Commission. A Party's actions, decisions, and performance under this Agreement, including without limitation the exercise of its rights to withdraw from or terminate this Agreement, shall not be subject to Commission approval.

18.3 RESERVATION OF RIGHTS. Nothing in this Agreement shall affect a Party's rights to argue issues that are not resolved pursuant to this Agreement in proceedings at the Commission and in the courts.

18.4 OPERATING COMMITTEE. As soon as practicable after the Effective Date, the SPP BA Participants shall form an Operating Committee. The function of the Operating Committee shall be: (a) to review performance under this Agreement, (b) to discuss issues that may arise related to such performance, (c) to review BA Operating Protocols, and, (d) if necessary or advisable, to propose amendments to this Agreement for the Parties' consideration and/or vote pursuant to Section 17.4. The Operating Committee shall meet at least once each year on dates to be determined by SPP after consultation with the committee members. SPP shall facilitate such meetings and shall give reasonable written notice thereof to all Parties. At its first meeting, the Operating Committee shall, with the approval of at least two thirds of the Parties, establish procedures to govern its actions consistent with the terms of this Agreement.

18.5 CONSOLIDATION OF PARTICIPANTS. The Parties agree that any consolidations of SPP BA Participants shall be accommodated under this Agreement. This Agreement shall not be construed as inhibiting the consolidation of Participant Areas.

18.6 ADDITIONAL BALANCING AUTHORITIES. The Parties agree that any ERO certified BA or other entity that is not a signatory to this Agreement may become a signatory to this Agreement, subject to SPP approval, so long as the BA or other entity agrees to be bound by the provisions of this Agreement as an SPP BA Participant within the SPP BAA and ceases to be a BA.

18.7 GOVERNING LAW. This Agreement shall be governed by and construed in accordance with the laws of Arkansas, except to the extent preempted by Federal law applicable to a Federal Power Marketing Agency in a dispute involving such Party.

18.7.1 Compliance with Federal or State Law.

Notwithstanding any other provision of this Agreement, a non-jurisdictional SPP BA Participant shall not be required to take any action or do any other thing with respect to rates, charges, terms or conditions of service, the resolution of disputes under this Agreement or any other matter regarding its obligations and performance under this Agreement, that (i) the non-jurisdictional SPP BA Participant is not permitted by state law, or Federal law in the case of a Federal Power Marketing Agency, to undertake or that is prohibited in whole or in part by any Federal or state law or regulation applicable to the non-jurisdictional SPP BA Participant; or (ii) would require the non-jurisdictional SPP BA Participant to violate a provision of such state law, or Federal law in the case of a Federal Power Marketing Agency, or regulation in order to comply with this Agreement. Determination of compliance with and permissible action, conduct or obligations by a non-jurisdictional SPP BA Participant shall be within the sole jurisdiction of the non-jurisdictional SPP BA Participant's governing board, or in a dispute involving a Federal Power Marketing Agency, the Administrator of the Federal Power Marketing Agency, subject to applicable Federal or state court review. A non-jurisdictional SPP BA Participant shall not object to SPP's participation in any state proceedings that impact the non-jurisdictional SPP BA Participant's ability to perform under this Agreement or determinations regarding such impact. To the extent possible without violating state law, or Federal law in the case of a Federal Power Marketing Agency, a non-jurisdictional SPP BA Participant shall notify SPP in advance of any action that the non-jurisdictional SPP BA Participant is required to take that the non-jurisdictional SPP BA Participant believes would constitute a violation of state law, or Federal law in the case of a Federal Power Marketing Agency, and the non-jurisdictional SPP BA Participant and SPP promptly shall meet and confer regarding the matter. As necessary, the non-jurisdictional SPP BA Participant and SPP agree to negotiate in good faith to modify the Agreement as consistent as possible with the original intent to allow SPP to exercise operational authority over the non-jurisdictional SPP BA Participant's Tariff Facilities as otherwise provided in the Agreement. If the non-jurisdictional SPP BA Participant and SPP are unable to resolve the matter, the non-jurisdictional SPP BA Participant may terminate this Agreement pursuant to the withdrawal provisions of the Agreement.

18.7.2 Termination on Less Than Required Notice.

SPP BA Participant may terminate this Agreement with less than the required notice, in the event that the state law, or Federal law in the case of a Federal Power Marketing Agency, governing SPP BA Participant changes, or any provisions of this Agreement are changed or modified in a manner that causes a conflict with the SPP BA Participant's Federal or state law, regulations, or rate schedules, and the internal dispute resolution process described in Section 12 of the OATT is unable to resolve such conflict. In such event, SPP BA Participant and SPP shall meet and confer to facilitate the withdrawal as soon as practicable as necessary to ensure compliance with applicable Federal or state law.

18.7.3 Operational Authority.

A non-jurisdictional SPP BA Participant reserves the right to exercise operational authority over its tariff facilities (1) to protect public safety and the safety of its workers, to prevent damage to equipment, and to preserve reliability in compliance with NERC standards, and (2) as necessary to preserve a non-jurisdictional SPP BA Participant's rights, duties and obligations regarding electric service to its retail and wholesale native load customers pursuant to its state law, or Federal law in the case of a Federal Power Marketing Agency, and consistent with NERC standards, if SPP's exercise of operational authority over the tariff facilities would endanger said electric service or is contrary to or would curtail, surrender or delegate such state law rights, duties and obligations. A non-jurisdictional SPP BA Participant will, as soon as reasonably practicable thereafter, notify SPP of such actions taken by a non-jurisdictional SPP BA Participant. A non-jurisdictional SPP BA Participant and SPP will meet and confer regarding the matter and, as necessary, negotiate in good faith to modify the Agreement to address the matter.

18.8 COMPLETE AGREEMENT. This Agreement shall constitute the complete agreement of the Parties on the subject matters covered herein.

18.9 FORCE MAJEURE. No Party shall be considered to be in breach of this Agreement to the extent that a failure to perform its obligations, other than a payment obligation, is due to an "Uncontrollable Force." The term "Uncontrollable Force" means an event or circumstance which prevents one Party from performing its obligations, which event or circumstance is not within the reasonable control of, or the result of the negligence or intentional wrongdoing of, the claiming Party, and which by the exercise of due diligence, or Good Utility Practice, the claiming Party is unable to avoid, cause to be avoided, or overcome. Any Party rendered unable to fulfill any of its obligations by reason of an Uncontrollable Force shall give immediate notice of such fact to the other Parties and shall exercise due diligence to remove such inability within a reasonable time period. If a Party is unable to perform actions under this Agreement due to the actions of an independent third party (e.g. not a consultant or affiliate of the Party), that shall be considered an Uncontrollable Force. However, a Party whose

performance under this Agreement is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Agreement.

18.10 NO AGENCY RELATIONSHIP. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between or among the Parties, or any of the Parties, or to impose any partnership obligation or partnership liability upon any of the Parties. No Party shall have any right, power, or authority to enter into any agreement or undertaking for, or act on behalf of, or act as, or be, an agent or representative of, or otherwise bind, any other Party. Responsibilities undertaken or transferred to a Party shall be independently performed by that Party.

18.11 REPRESENTATIONS AND WARRANTIES. Each Party warrants that it possesses the necessary authority to enter into and agree to this Agreement.

18.12 EXECUTION BY COUNTERPARTS. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument as if all Parties had signed the same instrument.

18.13 NO THIRD PARTY BENEFICIARIES. Except as otherwise provided herein, this Agreement is not intended to, and does not create, any rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

18.14 NO MARKET PARTICIPANT. The performance of functions described in this Agreement shall not cause a Party to become a Market Participant.

18.15 NOTICE. Each Party shall designate an individual to receive notice under this Agreement by providing the individual's name, address, phone number, and email address to the Operating Committee. The Operating Committee shall maintain the list of individuals to receive notice. It shall be the responsibility of each individual Party to update its notice information when necessary.

18.16. ACCESS TO BOOKS AND RECORDS.

18.16.1 Upon request, SPP shall provide SPP BA Participant with access to the SPP BA's books, records, facilities, and procedures required of the BA under the ERO Reliability Standards which are reasonably necessary to determine SPP's compliance with this Agreement and/or to support the SPP BA Participant's compliance with applicable ERO Reliability Standards in the SPP BA Participant's registered roles as TO, TOP, GO, GOP, LSE, and/or PSE. Such access shall be upon reasonable notice, at reasonable times, and under reasonable conditions.

18.16.2 Upon request, each SPP BA Participant shall provide SPP with access to SPP BA Participant's books, records, facilities, and procedures as necessary to allow SPP to determine SPP BA Participant's adherence to this Agreement and/or to support SPP's compliance as a BA. Such access shall be upon reasonable notice, at reasonable times, and under reasonable conditions. Each Party shall be responsible for its own expenses related to any such request for information.

18.17 PARTICIPATION BY WESTERN-UGP SUBJECT TO FEDERAL LAWS AND REGULATIONS

18.17.1 Subject to Acts of Congress

The participation by the United States through Western-UGP in this Agreement is subject in all respects to acts of Congress and to regulations of the Secretary of Energy established thereunder, and to rate schedules promulgated by the Secretary of Energy. This reservation includes, but is not limited to, the statutory limitations upon the authority of the Secretary of Energy to submit disputes arising under this Agreement to arbitration. In the event of a conflict between this Section 18.17 and any other provision of this Agreement, this Section 18.17 shall have precedence with respect to the application of this Agreement to Western-UGP.

18.17.2 Contingent Upon Appropriations and Authorization

Where activities provided for in this Agreement extend beyond the current fiscal year, continued expenditures by the United States through Western-UGP are contingent upon Congress making the necessary appropriations required for the continued performance of the obligations of the Western-UGP under this Agreement. In case such appropriation is not made, the Parties hereby release the Western-UGP from its contractual obligations under this Agreement and from all liability due to the failure of Congress to make such appropriation.

18.17.3 Employment Practices; Contractor Agreement

For the purpose of this Federal participation provision, the term "Contract" shall mean this Agreement and the term "Contractor" shall mean a Party having transactions with Western-UGP. During the performance of this Contract, the Contractor agrees to the provisions set forth in Section 18.17 and its subdivisions. In addition, the Contractor will include the following provisions in every subcontract or purchase order involving Western-UGP unless exempted by rules, regulations, or order of the Secretary of Labor.

(i) Equal Opportunity Employment Practices

Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), which provides, among other things, that the Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated in the Contract by reference to same as if the specific language had been written into the Contract, except that Indian Tribes and tribal organizations may apply Indian Preference to the extent permitted by federal law.

(ii) Contract Work Hours and Safety Standards

The Contract, to the extent that it is of a character specified in Section 103 of the Contract Work Hours and Safety Standards Act ("Act"), 40 U.S.C. § 3701, as amended or supplemented, is subject to the provisions of the Act, 40 U.S.C. § 3701-3708, as amended or supplemented, and to regulations promulgated by the Secretary of Labor pursuant to the Act.]

(iii) Use of Convict Labor

The Contractor agrees not to employ any person undergoing sentence of imprisonment in performing the Contract except as provided by 18 U.S.C. § 3622(c), as amended or supplemented, and Executive Order No. 11755, 39 Fed. Reg. 779 (1973), as amended or supplemented.

IN WITNESS WHEREOF, the signatories have caused this Agreement Between Southwest Power Pool, Inc. and SPP BA Participant Relating to Implementation of the Southwest Power Pool Balancing Authority to be executed by their duly authorized representatives as of the dates set forth under their respective signatures.

**Company: _____**

By: _____

Name: _____

Title: _____

Date: _____

# APPENDIX A TO ATTACHMENT AN

## List of SPP BA Participants

American Electric Power

Board of Public Utilities of Kansas City, Kansas

City of Independence, Missouri

City Utilities of Springfield

The Empire District Electric Company

Evergy Kansas Central, Inc.

Evergy Metro, Inc.

Evergy Missouri West, Inc.

Grand River Dam Authority

Lincoln Electric System

Nebraska Public Power District

Oklahoma Gas and Electric Company

Omaha Public Power District

Southwestern Public Service Company

Sunflower Electric Power Corporation

Western Area Power Administration-Upper Great Plains Region (Upper Great Plains East Balancing Authority Area-WAUE)

Western Farmers Electric Cooperative

# ATTACHMENT AO

ADDENDUM 1: AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS NO APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING ATHORITY.

ADDENDUM 2: AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS AN APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING ATHORITY.

## ADDENDUM 1 TO ATTACHMENT AO

## AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS NO APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING AUTHORITY

This Agreement Establishing a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this "Agreement") is entered into this ____ day of _____ 20____ by and among _____("External Balancing Authority"), _____("Market Participant"), and the Southwest Power Pool, Inc. ("SPP"). External Balancing Authority, Market Participant and SPP are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority on the terms and conditions set forth in this Agreement; and

WHEREAS, there are no terms or conditions in a joint operating agreement or any other agreement that specifies the coordination between the SPP Balancing Authority and the External Balancing Authority for pseudo-tie electrical interconnection points between the SPP Balancing Authority and the External Balancing Authority; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the External Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant to the SPP Balancing Authority as defined below or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and

WHEREAS, the Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as a Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined below or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined below; and

WHEREAS, Market Participant represents the generator or load serving entity that is physically located within the balancing authority boundaries of the External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents the generator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.

NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. Creation of Pseudo-Tie Point. From and after the effective date hereof, the point at which pseudo-tie electrical interconnection is made between the Market Participant _____ (Name of the generation or load) _____ (generation or load location) (the "Facility") and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority (the "Pseudo-Tie Point"), whereby any energy delivered from or consumed by the Facility at the Pseudo-Tie Point shall be treated as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point.

2. Implementation. Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

(a) The entity representing the generator or load in the External Balancing Authority or the generator or load within the SPP Balancing Authority shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the External Balancing Authority or its generator or load located in the SPP Balancing Authority.

(b) This Agreement does not provide for the reservation or sale of transmission service under the SPP's Open Access Transmission Tariff or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and/or Ramp Capability Down) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting approval of the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant's expense, in order to provide the External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant's systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority's ICCP communication standards. Market Participant's system shall provide this signal to the External Balancing Authority in a manner mutually agreed to between the External Balancing Authority and the Market Participant.

(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP

Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(j) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(k) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(l) For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(m) The External Balancing Authority and the SPP Balancing Authority will include the real time pseudo-tie value in their respective calculations of Net Actual Interchange and Area Control Error.

(n) If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the External Balancing Authority and the SPP Balancing Authority will freeze at the last known value and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with the other Parties.

(o) Market Participant shall notify the other Parties of any real-time circumstances that affect the Market Participant's obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. A generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as a Resource under Attachment AE of the SPP Tariff. A generator pseudo-tying out of the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

(p) The External Balancing Authority and the SPP Balancing Authority shall integrate the real time pseudo-tie value on an hourly basis and maintain this information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the External

Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the External Balancing Authority's final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority's final daily checkout with the External Balancing Authority.

(q) The Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols.

(r) Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner constitutes a basis for the immediate suspension of this Agreement by the External Balancing Authority or the SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior to resumption of participation . In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the External Balancing Authority or the SPP Balancing Authority.

3. Losses. For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant's participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. Compensation. For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the External Balancing Authority for the reasonable implementation and operations related costs borne by the External Balancing Authority as a result of this Agreement unless the Market Participant and External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. Auditing. Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party's compliance with this Agreement. The Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and

records at the other Party's premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. Effective Date. The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. Termination. Other than as provided in Section 2(r), this Agreement shall terminate on _____(Date), unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ___ month's notice, subject to receiving all necessary regulatory approvals for such termination.

8. Governing Law. The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. Interpretation. In this Agreement:

(a) the words "include", "includes" and "including" are deemed to be followed by the words "without limitation";

(b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

(c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

(d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. Severability. If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.

11. Complete Agreement; Amendments. This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. Other Obligations. Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. Commission Filing. If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. Modification. Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.

15. Charges. The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. Disputes. Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP's Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. Breach. If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.

18. Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.

The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**External Balancing Authority**

By:_____
Name:_____
Title:_____

**SPP Balancing Authority**

By:_____
Name:_____
Title:_____

**Market Participant**

By:_____
Name:_____
Title:_____

# EXHIBIT A
# ONE-LINE DIAGRAM

# EXHIBIT B
# BLOCK DIAGRAM

## ADDENDUM 2 TO ATTACHMENT AO

## AGREEMENT ESTABLISHING A PSEUDO-TIE ELECTRICAL INTERCONNECTION POINT WHERE THERE IS AN APPLICABLE JOINT OPERATING AGREEMENT WITH AN EXTERNAL BALANCING AUTHORITY

This Agreement Establishing a Pseudo-Tie Electrical Interconnection Point (including its exhibits, this "Agreement") is entered into this ____ day of _____ 20____ between _____("Market Participant") and the Southwest Power Pool, Inc. ("SPP"). Market Participant and SPP are hereinafter referred to individually as a "Party" and collectively as the "Parties."

WHEREAS, in order to facilitate the foregoing, the Parties desire to establish a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and _____ ("External Balancing Authority") on the terms and conditions set forth in this Agreement; and

WHEREAS, SPP is a Regional Transmission Organization approved by the Federal Energy Regulatory Commission operating an Integrated Marketplace and is a NERC certified Balancing Authority; and

WHEREAS, the External Balancing Authority and the SPP Balancing Authority are parties to the Commission approved SPP - _____ [Name of the External Balancing Authority] Joint Operating Agreement ("JOA") and the JOA specifies the coordination between the SPP Balancing Authority and the External Balancing Authority for pseudo-tie electrical interconnection points between the SPP Balancing Authority and the External Balancing Authority; and

WHEREAS, the External Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant to the SPP Balancing Authority as defined in the JOA or the External Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined in the JOA; and

WHEREAS, the Market Participant is responsible for generation or load outside of the boundaries of the SPP Balancing Authority Area and desires to participate in the Integrated Marketplace as a Resource or load or the Market Participant is responsible for generation or load inside the SPP Balancing Authority Area and desires not to participate in the Integrated Marketplace; and

WHEREAS, the SPP Balancing Authority has agreed to accept the delivery of generation or the transfer of load into the Integrated Marketplace by the Market Participant from the External Balancing Authority as defined in the JOA or the SPP Balancing Authority has agreed to facilitate the delivery of generation or the transfer of load into the External Balancing Authority by the Market Participant from the SPP Balancing Authority as defined in the JOA; and

WHEREAS, Market Participant represents the generator or load serving entity that is physically located within the balancing authority boundaries of the External Balancing Authority or the SPP Balancing Authority; and

WHEREAS, Market Participant represents the generator or load serving entity registered with SPP and meeting all of the SPP qualifications in order to operate in the Integrated Marketplace and abiding by all the respective Market Protocols and rules as set forth by SPP.

NOW THEREFORE, in consideration of the mutual covenants and agreements in this Agreement and of other good and valuable consideration, the sufficiency and adequacy of which are hereby acknowledged, the Parties, intending to be legally bound, hereby agree as follows:

1. Creation of Pseudo-Tie Point. From and after the effective date hereof, the point at which pseudo-tie electrical interconnection is made between the Market Participant _____ (Name of the generation or load) _____ (generation or load location) (the "Facility") and the SPP Balancing Authority, which shall be defined in the one-line diagram attached hereto as Exhibit A, shall be a new pseudo-tie electrical interconnection point between the SPP Balancing Authority and the External Balancing Authority (the "Pseudo-Tie Point"), whereby any energy delivered from or consumed by the Facility at the Pseudo-Tie Point shall be treated as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority (for the avoidance of doubt, whether or not, at the time of delivery or consumption of such energy, the metering, data processing, telemetry and other equipment associated with the Pseudo-Tie Point is properly functioning). For the avoidance of doubt, the SPP Balancing Authority or the External Balancing Authority will not be taking title to any energy delivered from or consumed by the Facility at the Pseudo-Tie Point.

2. Implementation. Each Party shall design, construct, operate and maintain the equipment for which it is responsible under this Agreement, and shall take all other actions required of it, to create and have the Pseudo-Tie Point recognized by the SPP as a balancing authority interchange between the External Balancing Authority and the SPP Balancing Authority for the purpose of allowing the Facility to be treated as being in the SPP Balancing Authority or the External Balancing Authority. Without limiting the foregoing, each Party shall undertake the design, construction, operation and maintenance for which it is responsible under this Agreement according to North American Electric Reliability Corporation standards. A basic block diagram of the communications equipment required for the Pseudo-Tie Point is set forth in Exhibit B. As among the Parties:

(a) The entity representing the generator or load in the External Balancing Authority or the generator or load within the SPP Balancing Authority shall register with SPP to become a Market Participant in the Integrated Marketplace. Registration shall be done in accordance with the SPP Market Protocols. Each Facility must be registered separately with SPP and registration information shall be provided to the External Balancing Authority. Market Participant must register its generator or load located in the External Balancing Authority or its generator or load located in the SPP Balancing Authority.

(b) This Agreement does not provide for the reservation or sale of transmission service under the SPP's Open Access Transmission Tariff or on any other transmission system. Market Participant shall secure and pay for all cost associated with transmission service, across all transmission service providers necessary to deliver or consume power from the Facility to the interface point with the SPP Balancing Authority or to the interface point with the External Balancing Authority.

(c) In order to supply Energy and qualified Operating Reserve products (Regulation-Up, Regulation-Down, Contingency Reserve, Ramp Capability Up, and/or Ramp Capability Down) to the Integrated Marketplace or to transfer load to the Integrated Marketplace, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the SPP Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting participation and for continued participation in the Energy and Operating Reserve Markets.

(d) In order to supply energy to the External Balancing Authority or to transfer load to the External Balancing Authority, the Market Participant shall secure firm transmission service from where it is physically located through the path to the interface point with the External Balancing Authority. SPP shall confirm that the appropriate transmission service reservations are in place and maintained prior to granting approval of the movement of Resources and load out of the SPP Balancing Authority to the External Balancing Authority.

(e) Market Participant is solely responsible for all requirements as set forth for a Market Participant in the Market Protocols.

(f) Market Participant shall design, construct, operate and maintain systems and communications equipment in order to: (i) receive SPP deployment instructions for generators pseudo-tying into the SPP Balancing Authority; (ii) account for load pseudo-tying into the SPP Balancing Authority; and (iii) enable SPP to account for congestion and losses associated with generators and loads pseudo-tying out of the SPP Balancing Authority in accordance with the Market Protocols.

(g) Market Participant shall design, construct, operate and maintain real-time and historical systems and communications equipment, at Market Participant's expense, in order to provide the External Balancing Authority and the SPP Balancing Authority with the corresponding real-time pseudo-tie value. Market Participant's systems shall provide this signal to the SPP Balancing Authority per the SPP Balancing Authority's ICCP communication standards. Market Participant's system shall provide this signal to the External Balancing Authority in a manner mutually agreed to between the External Balancing Authority and the Market Participant.

(h) SPP, in accordance with the Market Protocols, will provide the Market Participant commitment and dispatch instructions for generators pseudo-tying into the SPP

Balancing Authority for participation in the Energy and Operating Reserve Markets consistent with such instructions issued to other registered Resources.

(i) For generators pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(j) For generators pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered generator output received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(k) For loads pseudo-tying into the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by SPP from the Market Participant. The Market Participant shall simultaneously provide this value to the External Balancing Authority.

(l) For loads pseudo-tying out of the SPP Balancing Authority, the real time pseudo-tie value will be equal to the real-time telemetered load consumption received by the External Balancing Authority from the Market Participant. The Market Participant shall simultaneously provide this value to the SPP Balancing Authority.

(m) The SPP Balancing Authority will coordinate with the External Balancing Authority to include the real time pseudo-tie value in their respective calculations of Net Actual Interchange and Area Control Error as required by the JOA.

(n) If communication is lost between any of the Parties (including communication between SPP and the Market Participant), the External Balancing Authority and the SPP Balancing Authority will freeze at the last known value, as required by the JOA, and it is the responsibility of the Market Participant to verbally communicate changes of the real time pseudo-tie values with SPP and the External Balancing Authority.

(o) Market Participant shall notify SPP and the External Balancing Authority of any real-time circumstances that affect the Market Participant's obligation or ability to meet the SPP Setpoint Instructions or External Balancing Authority instructions. A generator pseudo-tying into the SPP Balancing Authority will be subject to the same penalties as a Resource under Attachment AE of the SPP Tariff. A generator pseudo-tying out of the SPP Balancing Authority will be subject to the rules and procedures specified by the External Balancing Authority.

(p) The SPP Balancing Authority will coordinate with the External Balancing Authority to integrate the real time pseudo-tie value on an hourly basis and maintain this information for balancing authority checkout, inadvertent calculations and payback purposes in accordance with the applicable NERC standards, as required by the

JOA. For generators and loads pseudo-tying into the SPP Balancing Authority, it is the responsibility of the External Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the External Balancing Authority's final daily checkout with the SPP Balancing Authority. For generators and loads pseudo-tying out of the SPP Balancing Authority, it is the responsibility of the SPP Balancing Authority to checkout these hourly integrated values with the Market Participant prior to the SPP Balancing Authority's final daily checkout with the External Balancing Authority.

(q) The Market Participant for generators and loads pseudo-tying into or out of the SPP Balancing Authority Area is responsible for submission of settlement meter data for use in the settlement process of the Real-Time Balancing Market in accordance with the SPP Market Protocols.

(r) Except as otherwise provided in this Section 2, failure by the Market Participant to provide real-time pseudo-tie values in a timely manner constitutes a basis for the immediate suspension of this Agreement by the SPP Balancing Authority. In the event of such suspension, the Market Participant shall provide a remedy for the cause of the failure prior to resumption of participation. In the event of two suspensions within a thirty day period, this Agreement may be terminated, in accordance with Section 7 of this Agreement, at the sole discretion of the SPP Balancing Authority.

3. Losses. For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will be responsible for loss compensation to transmission provider(s) to deliver their energy to or receive their energy from the SPP Balancing Authority. Pseudo-tie value(s) will be considered net of losses external to SPP. Losses within the SPP Balancing Authority attributable to the Market Participant's participation in the Energy and Operating Reserve Markets, including generators and loads pseudo-tying out of the SPP Balancing Authority, shall be handled in the same manner as other Energy and Operating Reserve Markets transactions.

4. Compensation. For generators and loads pseudo-tying into the SPP Balancing Authority, Market Participant will compensate the External Balancing Authority for the reasonable implementation and operations related costs borne by the External Balancing Authority as a result of this Agreement unless the Market Participant and External Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement. For generators and loads pseudo-tying out of the SPP Balancing Authority, Market Participant will compensate the SPP Balancing Authority for the reasonable implementation and operations related costs borne by the SPP Balancing Authority as a result of this Agreement unless the Market Participant and SPP Balancing Authority agree to a different cost arrangement, which shall be filed with the Commission in a non-conforming agreement.

5. Auditing. Each Party reserves the right to audit records necessary to permit evaluation and verification of claims submitted, and the other Party's compliance with this Agreement. The Parties shall retain for a period of three years all information and records relating to the performance of this Agreement. Each Party may examine and copy such information and

records at the other Party's premises during regular business hours and upon advance notice given no less than 15 calendar days prior to such examination.

6. Effective Date. The Agreement is effective upon full execution if it is not filed with the Commission. If the Agreement is filed with the Commission, then it is effective upon the later of the date of execution or the date allowed by the Commission. If the parties are unable to resolve any issues, SPP shall file an unexecuted agreement with the Commission, including all agreed-upon non-conforming deviations.

7. Termination. Other than as provided in Section 2(r), this Agreement shall terminate on _____(Date), unless extended by agreement of all the Parties. Any Party shall have the right to terminate this Agreement upon ___ month's notice, subject to receiving all necessary regulatory approvals for such termination.

8. Governing Law. The interpretation and performance of this Agreement and each of its provisions shall be governed and construed in accordance with the applicable Federal and/or State laws without regard its conflicts of laws provisions that would apply the laws of another jurisdiction.

9. Interpretation. In this Agreement:

(a) the words "include", "includes" and "including" are deemed to be followed by the words "without limitation";

(b) references to contracts, agreements and other documents and instruments shall be references to the same as amended, supplemented or otherwise modified from time to time;

(c) references to laws or standards and to terms defined in, and other provisions of, laws or standards shall be references to the same (or a successor to the same) as amended, supplemented or otherwise modified from time to time; and

(d) references to a person shall include its successors and permitted assigns and, in the case of a governmental or other authority (including SPP and the North American Electric Reliability Corporation), any person succeeding to its functions and capacities.

10. Severability. If any provision of this Agreement is held invalid, illegal or unenforceable in any jurisdiction, then, the Parties agree, to the fullest extent permitted by law, that the validity, legality and enforceability of the remaining provisions hereof in such or any other jurisdiction and of such provision in any other jurisdiction shall not in any way be affected or impaired thereby. With respect to the provision held invalid, illegal or unenforceable, the Parties will amend this Agreement as necessary to effect the original intent of the Parties as closely as possible.

11. Complete Agreement; Amendments. This Agreement constitutes the entire agreement among the Parties with respect to the subject matter of this Agreement and supersedes other prior agreements and understandings, both written and oral, among the Parties with respect to the subject matter of this Agreement. This Agreement may be amended, supplemented or otherwise modified only by an instrument in writing signed by all Parties.

12. Other Obligations. Nothing in this Agreement is intended to modify or change any obligations or rights under any tariff (including the SPP Tariff), any rate schedule, or any other contract. This Agreement does not in any way provide transmission service or address rates, terms or conditions of transmission service or indicate in any way that transmission service is available or properly awarded. A Party seeking transmission service must still go through the full tariff process to obtain transmission service. This Agreement also does not establish any generation as a designated network resource under the Tariff; the requirements of the Tariff still must be satisfied. Nor does this Agreement make any Party a Market Participant under the SPP Tariff. A Party seeking to become a Market Participant must apply to SPP under the terms of the SPP Tariff and nothing in this Agreement affects its rights or obligations as a Market Participant.

13. Commission Filing. If unchanged, a signed version of this form agreement shall not be filed with the Commission. SPP will simply report the existence of a signed agreement in its quarterly reports. If the form agreement is substantively changed, then SPP shall file the revised form agreement with the Commission. The Parties shall be bound to the terms accepted or ordered by the Commission.

14. Modification. Nothing in this Agreement is intended to modify or limit the right of SPP to submit under FPA Section 205 or Section 206 unilateral changes to this Agreement (both the form Agreement and any signed agreement); the right of any other Party to seek unilateral changes under FPA Section 206, or the right of the Federal Energy Regulatory Commission to accept any FPA Section 205 filing or to make changes under FPA Section 206 or to initiate proceedings under FPA Section 206.

15. Charges. The provisions in this Agreement providing for compensation do not authorize Commission regulated public utilities to impose charges without a separately filed tariff or rate schedule being accepted by the Commission.

16. Disputes. Any disputes under this Agreement shall first be resolved pursuant to the dispute resolution procedures in the SPP's Open Access Transmission Tariff. Any disputes may be brought to the Commission.

17. Breach. If any Party breaches the terms of this Agreement, then a non-breaching Party may seek any relief it believes is appropriate at the Commission. A breach is considered a substantive violation of this Agreement. Prior to pursuing a remedy at the Commission for a breach, a non-breaching Party shall provide five business days notice of the breach to the breaching Party. If the breaching Party does not eliminate the breach within five (5) business days after the notice is received by the breaching Party, then the non-breaching Party may pursue its remedies at the Commission.

18. Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be an original but all of which, taken together, shall constitute only one legal instrument. It shall not be necessary in making proof of this Agreement to produce or account for more than one counterpart. The delivery of an executed counterpart of this Agreement by facsimile shall be deemed to be valid delivery thereof.

The Parties have caused this Agreement to be signed by their authorized representatives on the day and year first above written.

**SPP Balancing Authority**

By:_____
Name:_____
Title:_____

**Market Participant**

By:_____
Name:_____
Title:_____

# EXHIBIT A
# ONE-LINE DIAGRAM

# EXHIBIT B
# BLOCK DIAGRAM

# ATTACHMENT AP
# ALLOCATION OF COSTS ASSOCIATED WITH RELIABILITY PENALTY ASSESSMENTS

Under the NERC Functional Model and NERC Rules of Procedure, the Transmission Provider may be assessed penalties for confirmed violations of the NERC Reliability Standards. The purpose of this Attachment is to provide notice to all Market Participants, Members, and Terminated Members (as defined in this Attachment AP) that they may potentially be responsible for penalty costs assessed against the Transmission Provider for confirmed violations of any NERC Reliability Standard. Market Participants, Members, and Terminated Members may be either directly assigned such penalty costs, if it is determined that they are responsible for or have directly contributed to the confirmed violations at issue, or may be assigned a portion of the costs, if the Transmission Provider is assessed a monetary penalty either due to its own confirmed violation or its status, as a Registered Entity under the NERC Functional Model and NERC Rules of Procedure.

This Attachment also provides for the recovery of costs associated with penalties assessed against the Transmission Provider for confirmed violations of NERC Reliability Standards resulting from a confirmed violation of NERC Reliability Standards by a Market Participant(s), Member(s), Terminated Member(s), the Transmission Provider, or another entity for whom Transmission Provider is assessed a penalty due to its status as a Registered Entity under the NERC Functional Model and NERC Rules of Procedure. Under this Attachment, the Transmission Provider may seek recovery of the costs associated with any monetary penalty by filing under section 205 of the Federal Power Act for direct recovery of penalty costs from one or more Market Participants, Members, or Terminated Members and/or for an allocation of penalty costs among all Market Participants, Members, and Terminated Members. Additionally, this Attachment provides for the participation of Market Participants, Members, and Terminated Members in the penalty assessment process with the Transmission Provider if the Market Participant, Member, or Terminated Member is alleged to have been directly involved in the event causing the potential penalty.

## 1. Definitions

All defined terms in this Attachment shall have the meaning given to them in the Tariff unless otherwise stated below.

**Compliance Monitoring and Enforcement Program** – The program used by NERC and the Regional Entities to monitor, assess, and enforce compliance with Reliability Standards within the United States. This is accomplished through compliance monitoring and audits, as well as the conduct of investigations and the assessment of monetary and non-monetary penalties for violations.

**Electric Reliability Organization ("ERO")** – An organization certified by the Commission to develop and enforce mandatory reliability standards and assess penalties against users, owners and operators of the bulk power system that violate such standards.

**North American Electric Reliability Corporation ("NERC")** – The organization designated as ERO by the Commission on July 20, 2006.

**NERC Compliance Registry** – The registry maintained by NERC that records which Registered Entity is responsible for performing the set of functions required to ensure compliance with each NERC Reliability Standard.

**NERC Functional Model** – The Model defining the set of functions that must be performed to ensure the reliability of the electric bulk power system. The NERC Reliability Standards establish the requirements of the responsible entities that perform the functions defined in the Functional Model.

**NERC Reliability Standards** – Standards developed by NERC and approved by the Commission to ensure reliability of the bulk power system, violation of which may result in the imposition of mitigation programs or monetary penalties.

**NERC Rules of Procedure –** The rules and procedures developed by NERC and approved by the Commission. These rules include the process by which a responsible entity, who is to perform a set of functions to ensure the reliability of the electric bulk power system, must register as a Registered Entity.

**Registered Entity –** The entity registered under the NERC Functional Model and NERC Rules of Procedures for the purpose of compliance with NERC Reliability Standards and responsible for carrying out the tasks within a NERC function without regard to whether a task(s) is performed by another entity pursuant to the terms of its governing documents.

**Regional Entity ("RE")–** An entity to which NERC has delegated ERO functions.

**Terminated Member –** An entity that was a Member of SPP at the time that the conduct giving rise to a reliability penalty occurred, but that has since terminated its SPP Membership.

**2. Direct Assignment of Costs Where Violation Can Be Directly Assigned**

The purpose of this section of this Attachment is to provide notice to all Market Participants, Members, and Terminated Members that they may potentially be responsible for reliability penalty costs assessed in the event that the Market Participant's, Member's, or Terminated Member's conduct or omission contributed to the violation(s) for which a monetary penalty was assessed to the Transmission Provider. This section provides for notification for the potential direct assignment of costs related to reliability violations that may be assessed to the Transmission Provider. The Transmission Provider shall notify, in writing, any potentially affected Member(s), Market Participant(s), or Terminated Members of an alleged violation as soon as possible after notifications by the applicable RE or NERC of the commencement of procedures under the Compliance Monitoring and Enforcement Program. In addition, the Transmission Provider will invite the affected Member(s), Market Participant(s), or Terminated Member(s) to fully participate in all discussions and/or proceedings under the Compliance Monitoring and Enforcement Program.

If there is i) an assessment of a monetary penalty against the Transmission Provider as the Registered Entity for a confirmed violation of a NERC Reliability Standard(s) and ii) as a result of proceedings under the Compliance Monitoring and Enforcement Program, it is determined that one or more Market Participants, Members, Terminated Members, or Registered Entities are deemed to have directly contributed to or found to have been a "root cause(s)" of such confirmed violation(s), such Market Participant(s), Member(s), or Terminated Member(s) may be assessed a portion of or all of the monetary penalty; provided that all of the following conditions have been satisfied:

(1) During the course of an investigation by NERC, the applicable RE or the Commission regarding the possibility of a Transmission Provider alleged violation of a NERC Reliability Standard, if the Transmission Provider believes that a Market Participant(s), Member(s), or Terminated Member(s) may have contributed to the violation under investigation, the Transmission Provider will provide a) reasonable prior written notice to the Market Participant(s), Member(s), or Terminated Member(s) that the Transmission Provider believes may have contributed to the violation and that it intends to seek to hold the Market Participant(s), Member(s), or Terminated Member(s) responsible for a portion of or all of the monetary penalties that result; and b) the Market Participant(s), Member(s), or Terminated Member(s) is provided the opportunity to fully participate in all discussions and/or proceedings under the Compliance Monitoring and Enforcement Program.

(2) In addition to the Transmission Provider providing sufficient notice to a Market Participant(s), Member(s), or Terminated Member(s) under Section 2(1) of this Attachment, it will also provide notice to NERC, the applicable RE and the Commission of its allegations that the Market Participant(s), Member(s), or Terminated Member(s) may have contributed to the alleged violation and that the Transmission Provider intends to hold the Market Participant(s), Member(s), or Terminated Member(s) responsible for a portion of or all of the monetary penalties that result from the investigation which determines to what extent the Market Participant(s), Member(s), or Terminated Member(s) contributed to or was a "root cause(s)" of the confirmed violation; (3) If, as a

result of proceedings under the Compliance Monitoring and Enforcement Program, it is determined that the Market Participant(s), Member(s), or Terminated Member(s) cited by the Transmission Provider contributed to or was a "root cause(s)" of the alleged violation, the Transmission Provider will seek to hold the Market Participant(s), Member(s), or Terminated Member(s) responsible for a portion of or all of the monetary penalty assessed as a result of the confirmed violation by making a filing with the Commission under section 205 of the Federal Power Act to assign a portion of or all of the costs of the monetary penalty directly to the Market Participant(s), Member(s), or Terminated Member(s);

(4) If the Commission accepts the filing, the Market Participant(s), Member(s), or Terminated Member(s) shall be responsible for its portion of the monetary penalty as determined by the Commission's order on the section 205 filing.

**3. Spreading of Costs Where Violation Cannot Be Directly Assigned**

The purpose of this section of this Attachment is to provide notice to all Market Participants, Members, and Terminated Members that they may potentially be responsible for reliability penalty costs assessed to the Transmission Provider that cannot be directly assigned under Section 2 of this Attachment. This section provides for a spreading of a portion of or all of such reliability penalty costs among all Market Participants, Members, and Terminated Members where the Transmission Provider itself is responsible for a confirmed violation of a Reliability Standard or where the Transmission Provider is assessed a penalty because of its status as a Registered Entity for a given Reliability Standard and the entity responsible for the violation cannot be assessed a penalty because of its status. The Transmission Provider shall notify, in writing, any potentially affected Market Participant(s), Member(s), or Terminated Member(s) of an alleged or confirmed violation as soon as possible after notifications by the applicable RE or NERC of the commencement of procedures under the Compliance Monitoring and Enforcement Program. In addition, the Transmission Provider will i) invite the affected Member(s), Market Participant(s), or Terminated Member(s) to fully participate in all discussions and/or proceedings under the Compliance Monitoring and Enforcement Program and ii) timely report status and

results of the findings and remedies to the Market Participants, Members, and Terminated Members.

If there is an assessment of a monetary penalty against the Transmission Provider as the Registered Entity for a confirmed violation of a NERC Reliability Standard(s), either: (1) as a result of the Transmission Provider's own conduct or omission that resulted in a confirmed violation; or (2) as a result of a violation by another entity for whom the Transmission Provider is the Registered Entity where the entity is not on the NERC Compliance Registry and therefore cannot be directly assessed a penalty because of its status; Market Participants, Members, and Terminated Members may be assessed a portion of the monetary penalty providing the following conditions have been satisfied:

(1) The Transmission Provider has made a filing under section 205 of the Federal Power Act proposing a methodology to allocate a portion of or all of the costs of the monetary penalty among the Market Participants, Members, and Terminated Members;

(2) If the Commission accepts the filing and finalizes such penalty allocations to the Market Participants, Members, and Terminated Members.

**4. Penalties allocated or attributable to Western-UGP**

Notwithstanding anything in this Attachment to the contrary, Western-UGP has not waived or conceded any defense it may have, including sovereign immunity, intergovernmental immunity, or lack of subject matter jurisdiction in any action against it by an Enforcement Authority, nor has Western-UGP accepted any liability, responsibility, or obligation to pay any civil monetary penalties or fines imposed by an Enforcement Authority to which it would not have been subject in the absence of this Agreement. "Enforcement Authority" in this Agreement means the Commission, ERO, or RE with enforcement authority pursuant to a delegation from an ERO or FERC for the purpose of proposing and enforcing reliability standards. The Transmission Provider does not concede or accept responsibility for any portion of a penalty or fine attributable to the actions or omissions of Western-UGP. The Transmission Provider will

identify the amount of any penalty or fine that the Transmission Provider allocates to Western-UGP or that the Transmission Provider determines is attributable to Western-UGP and will identify that amount to FERC as uncollectable and not otherwise owed by the Transmission Provider.

# ATTACHMENT AQ
# DELIVERY POINT ASSESSMENT PROCESS

**1.0 Introduction:** When it becomes necessary or desirable to make changes in delivery point facilities, to upgrade, retire, replace or establish a delivery point, including metering or other facilities at such location, or for unexpected step load changes at an existing delivery point at the discretion of the Host Transmission Owner, the provisions of this Attachment AQ shall apply. For the purposes of this Attachment, Host Transmission Owner is defined as the owner of that portion of the Transmission System to which such connection or modification is to be made.

**2.0 Study Requests for Changes in Local Delivery Facilities:** The Transmission Customer shall make requests for changes in local delivery facilities, including facility upgrades, retirements and replacements, or the establishment of any new delivery point in writing to (a) the Transmission Provider and the Host Transmission Owner as specified in Section 20 of the Network Operating Agreement or to (b) the Transmission Provider as specified in Section 8 of the Point to Point Transmission Service Agreement, as applicable. Such request shall contain as much information as is known or projected at the time of the request as set forth in "Sample Request for Change in Local Delivery Facilities" attached hereto as Addendum 1.

Requests for changes in local delivery facilities that meet the following criteria do not need to be submitted through the process described in Attachment AQ:

1. Any increase of capacity at a delivery point without a corresponding change to the load at the delivery point;
2. Any distribution transformer changes without a corresponding load change; or
3. Increase to a facility rating at a delivery point.

Notwithstanding the above, the Transmission Customer or Host Transmission Owner may elect to submit the request through the process described in Attachment AQ.

**3.0 Studies:** The Transmission Provider and Host Transmission Owner shall conduct all necessary studies associated with the delivery point change. Such studies shall be conducted at Transmission Customer's expense pursuant to the provisions of this section. In the event that such change in delivery point configuration results in a Delivery Point Network Study (DPNS) as described in Section 3.2 of this Attachment AQ, Transmission Provider will coordinate the studies necessary to evaluate such addition, modification, or retirement. Otherwise, the Host Transmission Owner will coordinate the studies.

**3.1 Load Connection Study:** Host Transmission Owner shall respond within ten (10) Business Days of receipt of such request and, if necessary, provide a Load Connection Study ("LCS") Agreement and a list of any additional information that Host Transmission Owner would require from the Transmission Customer to proceed with such study. Unless otherwise agreed, the LCS Agreement shall commit the Transmission Customer to pay Host Transmission Owner the actual cost to complete the study. The Host Transmission Owner may require an advance deposit equal to the estimated study cost or $25,000, whichever is less. In conducting the LCS, the Host Transmission Owner shall assess the feasibility of modifying an existing delivery point or establishing the new delivery point using power flow and short circuit analyses and any other analyses that may be appropriate. It shall also determine the details and estimated cost of facilities necessary for establishing the requested delivery point and any system additions/upgrades needed to address any problems identified in the LCS.

If the Transmission Customer fails to return an executed LCS Agreement within thirty (30) Calendar Days of receipt along with the required deposit, or at a later date as the Parties may mutually agree, Host Transmission Owner shall deem the study request to be withdrawn. The Transmission Customer may withdraw its study request at any time by written notice of such withdrawal to Host Transmission Owner. Host Transmission Owner shall complete the LCS and issue a Load Connection Report to the Transmission Customer and Transmission Provider within sixty (60) Calendar Days after receipt of an executed LCS Agreement, deposit and necessary data, or at a later date as the Parties may mutually agree.

Upon completion of the LCS, the Transmission Customer shall reimburse Host Transmission Owner for the unpaid cost of the LCS if the cost of LCS exceeds the deposit. Host Transmission Owner shall refund to the Transmission Customer any portion of the deposit that exceeds the cost of the LCS with interest earned in the interest-bearing account in which Host Transmission Owner has placed the deposit, or if such account does not exist, with interest calculated in accordance with 18 C.F.R. § 35.19a(a)(2).

**3.2 Transmission System Study:** Upon receipt of the Request for Change in Local Delivery Facilities, Transmission Provider shall perform a preliminary assessment of the impact of the requested delivery point configuration change on the Transmission System. The Transmission Provider shall conclude its preliminary assessment of the impact of each requested delivery point configuration change on the Transmission System for all Requests for Change in Local Delivery Facilities and notify the Transmission Customer of the findings within ten (10) Business Days of receipt of all necessary information to conduct the preliminary assessment. In the event that a Request for Change in Local Delivery Facilities contains elements that are not applicable to the scope of Attachment AQ process, the Transmission Provider reserves the right to extend the ten (10) Business Day requirement for providing the preliminary assessment for up to an additional ten (10) Business Days. SPP will notify the Transmission Customer of any extension required for a Request for Change in Local Delivery Facilities that contains elements beyond the scope of the Attachment AQ process within ten (10) Business Days of receipt. SPP shall post on the SPP website by the 20$^{th}$ day of each month all Requests for Change in Local Delivery Facilities that have received a preliminary assessment during the prior calendar month. For all requests for which the Transmission Provider finds no significant impact on the Transmission System, Host Transmission Owner will coordinate completion of such change in local delivery facilities, including all required studies. For all requests for which the Transmission Provider finds that there is significant impact on the Transmission System, it shall, within five (5) Business Days of when the preliminary assessment results are provided, deliver to the Transmission Customer a Delivery Point Network Study ("DPNS") Agreement and a request for any additional information that it requires from the

Transmission Customer to proceed with such study. The study agreement shall commit the Transmission Customer to pay the Transmission Provider the actual cost to complete the study and to make an advance deposit equal to the estimated study cost or $10,000, whichever is less. The Transmission Customer shall execute and deliver the DPNS Agreement and required deposit to the Transmission Provider as soon as reasonably possible, but not later than thirty (30) Calendar Days following its receipt or at a later date as the Parties may mutually agree. Upon receipt of the executed study agreement, study data, and the required deposit, Transmission Provider shall perform the DPNS. During the conduct of the DPNS, Transmission Provider shall assess the impacts on the Transmission System caused by modifying an existing delivery point or establishing the new delivery point using power flow and short circuit analyses and any other analyses that may be appropriate.

If the Transmission Customer fails to return an executed DPNS Agreement within thirty (30) Calendar Days of receipt or at a later date as the Parties may mutually agree, Transmission Provider and Host Transmission Owner shall deem the study request to be withdrawn. The Transmission Customer may withdraw its study request at any time by written notice of such withdrawal to the Transmission Provider and the Host Transmission Owner.

Transmission Provider shall issue a study report to the Transmission Customer and Host Transmission Owner within sixty (60) Calendar Days of the receipt of an executed DPNS Agreement and the required deposit, or at a later date as the Parties may mutually agree. If Transmission Provider is unable to complete such study in the allotted time, Transmission Provider shall provide an explanation to the Transmission Customer and Host Transmission Owner regarding the cause(s) of such delay and a revised completion date and study cost estimate.

Upon completion of the DPNS, the Transmission Customer shall reimburse Transmission Provider for the unpaid cost of the DPNS if the cost of the study exceeds the deposit.

Transmission Provider shall refund the Transmission Customer, with interest earned in the interest-bearing account in which Transmission Provider shall have placed the deposit, any portion of the deposit that exceeds the cost of the DPNS.

**3.3 Modifications to Study Request:** During the course of a LCS or DPNS, the Transmission Customer, Host Transmission Owner or Transmission Provider may identify desirable changes in the planned facilities that may improve the costs and/or benefits (including reliability) of the planned facilities. To the extent the revised plan and study schedule are acceptable to Host Transmission Owner, Transmission Customer, and if applicable, Transmission Provider, such acceptance not to be unreasonably withheld, Host Transmission Owner and if applicable, Transmission Provider, shall, at Transmission Customer's Expense, proceed with any necessary restudy.

**3.4 Integrated Transmission Planning Assessment Evaluation:** All requests with a Network Upgrade(s) identified in the DPNS will be subject to further evaluation in the soonest available Integrated Transmission Planning Assessment that is able to include the load changes, if it is determined that the Network Upgrade(s) will be able to meet the study timeframe requirements pursuant to the standardized project timelines in SPP Business Practices, based on the SPP determined Network Upgrade(s) need date.

**3.5 Posting of DPNS Report(s):** If it is determined that a Network Upgrade(s) identified from a DPNS is unable to be further evaluated pursuant to the Integrated Transmission Planning Assessment as described in Section 3.4 of this Attachment AQ, the corresponding DPNS report will be posted on the SPP website once SPP is notified by the Transmission Customer to update the applicable Network Integration Transmission Service Agreement to reflect the changes in delivery points and the Network Upgrade(s).

**4.0 Engineering, Design and Construction of New Facilities:** The Transmission Customer and Host Transmission Owner shall agree to and specify in writing each party's responsibility for engineering, design, construction, and cost of facilities described in the final Load Connection Report.

## Addendum 1 to Attachment AQ

## Sample Request for Change in Local Delivery Facilities

Pursuant to the Delivery Point Assessment Process in Attachment AQ of the Tariff notice is hereby provided on _____ (date of notice) to _____(the Host Transmission Owner) and Transmission Provider that Transmission Customer requests certain changes in delivery point(s) under the agreement.

Responses marked with an asterisk (*) are required. Supply all details that are known or projected.

### Requested Modification

1) Description of delivery point modification*
   a) Type of change requested (new delivery point, upgrade of an existing delivery point, retirement or abandonment of an existing delivery point, etc.) *
   b) Proposed in service date of the modification*
   c) Reason for the requested change (i.e. upgrade, retirement, replacement of existing delivery point facilities; establishment of a delivery point and facilities; unexpected step load changes at an existing delivery point) *
   d) Related transmission service agreement*
   e) Location of the delivery point change and identification of the facilities involved*
      i) Geographic location of the new delivery point or the delivery point to be modified*
      ii) The transmission facilities of the Host Transmission Owner involved in the change*
      iii) Voltage of the facilities involved*
      iv) Desired meter location*

v) Expected impact on other delivery points, if any*

(1) Load transfer from another delivery point and, if so, estimated amount*

(2) Anticipated modifications to other delivery points due to this change, if any*

vi) Facilities of others that may be involved*

2) Facilities to be constructed

a) Facilities to be constructed or provided by the Host Transmission Owner

b) Facilities to be constructed or provided by the Transmission Customer

3) Technical Aspects of a new delivery point

a) Location

i) Located near structure number

ii) 911 address

iii) State, County and ¼ of ¼ Section number

iv) GPS Coordinates

b) Technical aspects

i) Anticipated service voltage

ii) Number of wires (3 or 4 wire connection)

iii) Service voltage

iv) Meter

(1) Type

(2) Voltage

(3) Supplied by

(4) Owned by

(5) PTs and CTs required

(6) Communications configuration

v) Anticipated starting load

vi) Transformer size and voltages

vii) Transmission line conductor size and impedance rating

viii) Type and location of protective devices

4) Other pertinent information

**Attachments:**

1) Ten year load forecast for the delivery point being added or modified and any associated changes in the load forecast for other delivery points.

2) One-line diagram showing existing and proposed changes to local delivery facilities pertaining to the request.

3) Idev modeling file(s) for anticipated load.

**Requestor Contact:**

Name: _____

Title: _____

Mailing Address: _____

Email Address: _____

Voice Phone No.: _____

By: _____

(Representative of Transmission Customer)

Title: _____

Date: _____

# ATTACHMENT AR
# SCREENING STUDY

# 1 INTRODUCTION

A Screening Study will be used to evaluate: (a) potential Long-Term Service request (LTSR) options or (b) proposed Delivery Point Transfer. To obtain a Service Agreement, Eligible Customers that request Screening Studies to evaluate LTSR options must apply for service and follow the application process set forth in the Tariff.

Network Customers or Transmission Customers that request Screening Studies to evaluate Delivery Point Transfers: (a) to proceed with a Delivery Point Transfer request and receive a Service Agreement, must enter a request for study in the Aggregate Transmission Service Study process, if the Screening Study determines that the proposed Delivery Point Transfer will have a significant impact on the Transmission System, or (b) will be tendered a Service Agreement, if the Screening Study results indicate that no third party issues and no Network Upgrades for thermal or voltage mitigations are required as a result of the Delivery Point Transfer.

# 2 LTSR OPTION SCREENING STUDIES

Section 2 of Attachment AR sets forth the procedures for screening potential LTSR options prior to the start of the Aggregate Transmission Service Study. The purpose of the LTSR Option Screening Study is to provide the Eligible Customer with an approximation of the transmission remediation costs of each potential LTSR and a reasonable cost differential between alternatives for the purpose of an Eligible Customer's ranking of its potential LTSRs. The Eligible Customer is responsible for all costs associated with the Screening Studies. The results of the Screening Study are not binding and the Eligible Customer retains the rights to enter the Aggregate Transmission Service Study with as many LTSRs as desired.

## 2.1 Scope of LTSR Option Screening Study

At the request of an Eligible Customer, Transmission Provider will perform a Screening Study for each potential LTSR. The principle objectives of the study are to:

A) Identify any system problems or constraints associated with the implementation of the LTSR studied;

B) Determine potential system modifications that might be necessary to grant transmission service into, out of or across the Transmission System while maintaining system reliability under steady state operations; and

C) Estimate the costs associated with those system modifications.

The steady-state analysis will consider the impact of the potential LTSR for the firm delivery of the requesting Eligible Customer's energy on the Transmission System by monitoring the Transmission System's facility loading and bus voltages for applicable outages.

The Screening Study will result in an evaluation of necessary transmission improvements to grant the potential LTSR. Interconnection and stability cost impacts are the Eligible Customer's responsibility and outside of the scope of this process. The Screening Study assumes the potential resources associated with LTSR being studied are stable. Any additional system improvements required for stability are the Eligible Customer's responsibility.

The Screening Study results will not assess the third party impacts and upgrades required.

The Screening Study will be performed consistent with Applicable Reliability Standards and Good Utility Practice.

Each Screening Study will provide the estimated engineering and construction cost for any transmission facility upgrades required to correct thermal overloads and voltage violations caused by granting the potential LTSR.

**2.2 Screening Study Timing Requirements**

All Eligible Customers desiring a Screening Study to evaluate potential LTSRs are responsible for determining when to make the request based on Transmission Provider study timeframes to coordinate with the open seasons used by the Aggregate Transmission Service Study Process in accordance with Attachment Z1. Upon receipt of a successfully completed application pursuant to Section 2.4 and an executed Screening Study Agreement the Transmission Provider will use due diligence to complete the Screening Study within a ninety (90) day period. If the Transmission Provider is unable to complete the Screening Study in the specified time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to conclude the study along with an explanation of the reasons that the additional time is required to complete the study.

If the Eligible Customer elects not to execute the Screening Study Agreement, its application for a Screening Study shall be deemed withdrawn and its Financial Security required in accordance with Section 2.4 of this Attachment and Section 17.3 of the Tariff shall be returned with interest, if any.

**2.3 LTSR Option Screening Study Process**

Screening Studies will be conducted by Transmission Provider staff or consultants. In performing the studies, the latest and most accurate model from the preceding Aggregate Transmission Service Study will be used. Transmission Provider staff will be available for questions regarding the results of the Screening Studies. Transmission Provider will conduct the Screening Studies. Screening Studies are for informational purposes. Transmission Provider does not guarantee the results of the Screening Studies will match the results of the Aggregate Transmission Service Study.

**2.3.1 AC Screening Studies are available to Eligible Customers for evaluating potential LTSRs:**

- Calculate thermal loading of transmission lines and transformers.
- Calculate system voltage.
- Report loading and voltage limit violations.

**2.3.2 Eligible Customer may request that Screening Studies to evaluate potential LTSRs be conducted in one of the following ways:**

- Single Eligible Customer with many requests;
- Multiple Eligible Customers from same resource or with related requests; or
- Multiple Eligible Customers from multiple resources or with unrelated requests.
- Multiple Eligible Customers and/or LTSRs will be studied concurrently using a similar method to the method used for the performance of the official Aggregate Transmission Service Study. Such studies shall determine cost sharing of required upgrades based on MW impact.

## 2.4 Application Procedures

To request a Screening Study to evaluate a potential LTSR, an Eligible Customer must submit an application for a Screening Study, which includes all information required for Transmission Provider to complete a Credit Assessment pursuant to its Credit Policy set forth in Attachment X and satisfaction of all requirements set forth therein. Such applications must be submitted by entering an OASIS request with a statement in the comment field "For Screening Purposes Only."

The completed application must provide the required information for the Screening Study including but not limited to the following:

**Screening Study Application Requirements for Long-Term Firm Point-to-Point Transmission Service Request**

a. The identity, address, telephone number and facsimile number of the entity requesting service;
b. Need to include the dispatch order of generation units;

c. The location of the POR(s) and POD(s) and the identities of the Delivering Parties and the Receiving Parties;
d. The location of the generating facility(ies) (source) supplying the capacity and energy and the location of the load served (sink) by the capacity and energy transmitted. This information will be treated as confidential except to the extent that is required by this Tariff, by regulatory or judicial order, by law or by statute, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. SPP will treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;
e. A description of the supply characteristics of the capacity and energy to be delivered;
f. The capacity and energy expected to be delivered to the Receiving Party;
g. The Service Commencement Date and the term of the requested Transmission Service;
h. The transfer capability requested for each POR and each POD on SPP's Transmission System; transmission customers may combine their requests for service in order to satisfy the minimum transfer capability requirement; and
i. The Transmission Provider may request any additional information necessary to conduct the screening study, including but not limited to, the data requirements outlined in Tariff for the request for type of services being studied.

**Screening Study Application Requirements for Long-Term Firm Network Integrated Transmission Service Request**

j. The identity, address, telephone number and facsimile number of the party requesting service;
k. Need to include the dispatch order of generation units;
l. The location of the POR(s) and POD(s) and the identities of the Delivering Parties and the Receiving Parties;

m. The location of the generating facility(ies) (source) supplying the capacity and energy and the location of the load served (sink) by the capacity and energy transmitted. This information will be treated as confidential except to the extent that is required by this Tariff, by regulatory or judicial order, by law or by statute, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. SPP will treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

n. A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

o. The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to subsection (l) above;

p. A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

    i. Unit size and amount of capacity from that unit to be studied for Network Resource;

    ii. VAR capability (both leading and lagging) of all generators;

    iii. Operating restrictions

        a) Minimum and maximum seasonal loading level of unit;

        b) Normal operating level of unit;

c) Any must-run designations required for system reliability or contract reasons.

For each off-system Network Resource, such description shall include:

iv. Identification of the Network Resource as an off-system resource;

v. Unit size and amount of capacity from the unit t be studied;

vi. VAR capability (both leading and lagging) of all generators;

vii. Operating restrictions, if any

a) Minimum and maximum season loading level of unit;

b) Normal operating level of unit;

c) Any must-run designations required for system reliability or contract reasons, and

q. The Transmission Provider may request any additional information necessary to conduct the Screening Study, including but not limited to, the data requirements outlined in Tariff for the request for type of services being studied.

Unless Eligible Customer and Transmission Provider agree to a different time frame, the Transmission Provider must acknowledge the application within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Screening Study Service Agreement, will be sent to the Eligible Customer. If an application fails to meet the requirements of this section, the application will be deemed incomplete; and the Transmission Provider shall notify the Eligible Customer requesting the Screening Study within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the application without prejudice to the Eligible Customer, who may pursue filing a new or revised application that fully complies with the requirements of this section. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

### 2.5 On-Line Tools

There are certain on-line tools made available to the Eligible Customer to assist them in deciding which projects to enter into the Screening Study, such as the Scenario Analyzer tool on the Transmission Provider's OASIS currently used for studying short-term transmission for up to a 16-month period.

### 2.6 Reporting Options

The Screening Study report for the potential LTSRs on the Transmission System will give an Eligible Customer the following options for reviewing the Screening Study results: (a) a written report containing information such as contingency, limiting element, estimated upgrade costs, and the estimated start date for transmission service without redispatch; or (b) the raw data from the analysis.

### 2.7 Study Costs

The Eligible Customer shall be responsible for all actual costs incurred by Transmission Provider to perform each of the Screening Studies requested by the Eligible Customer. An estimate of such costs shall be specified in the Screening Study Agreement. Billing and payment shall be as specified in Section 7 of the Transmission Provider's Tariff.

### 2.8 Service Agreements

Service will not be granted based on the Screening Study for potential LTSRs on the Transmission System. To obtain a Service Agreement, Eligible Customers must apply for service and follow the application process set forth in Parts II and III of the Tariff.

# 3 PROCEDURES FOR SCREENING POTENTIAL DELIVERY POINT TRANSFERS

Section 3.0 of Attachment AR sets forth the procedures for evaluating potential Delivery Point Transfers.

## 3.1 Scope

At the request of a Network Customer or Transmission Customer, Transmission Provider will perform a Screening Study to evaluate a potential Delivery Point Transfer. The principle objectives of the study are to:

A) Identify any system problems or constraints associated with the implementation of the potential Delivery Point Transfer;

B) Determine potential system modifications that might be necessary to grant service necessary to facilitate the potential Delivery Point Transfer, while maintaining system reliability under steady state operations; and

C) Assess the need for any third party impacts and upgrades required. The Screening Study will be performed consistent with Applicable Reliability Standards and Good Utility Practice.

## 3.2 Screening Study Timing Requirements

The same Screening Study timing requirements and obligations identified in Section 2.2 of this Attachment AR are applicable to the Screening Study process for Delivery Point Transfers set forth in this Section 3 of Attachment AR.

## 3.3 Delivery Point Transfer Screening Study Process

The Screening Study for analyzing a Delivery Point Transfer will be performed by the Transmission Provider as an AC study that simulates the analysis process of the Aggregate Transmission Service Study by accomplishing the following:

A) Calculating thermal loading of transmission lines and transformers between the existing Network Customer's Designated Resources and the proposed Network Customer's Designated Resources;

B) Calculating system voltage;

C) Reporting loading and voltage limit violations; and

D) Evaluation of difference in MW impacts between the existing Network Customer's Designated Resources and the proposed Network Customer's Designated Resources.

**3.4 Application Procedures**

To request a Screening Study to evaluate a potential Delivery Point Transfer, a Network Customer or Transmission Customer must enter an OASIS request with a statement in the comment field "For Existing Delivery Point Only" and submit a Completed Application in accordance with Section 29 of the Tariff. The same timing requirements with regard to applications set forth in section 2.4 of this Attachment AR and in the chart in Appendix 1 to this Attachment AR apply to applications for Screening Studies to evaluate potential Delivery Point Transfers pursuant to Section 3 of this Attachment AR.

**3.5 On-Line Tools**

There are no on-line tools for Delivery Point Transfer Screening Studies.

**3.6 Reporting Options**

The Screening Study report for a potential Delivery Point Transfer will be provided in a format similar to the Aggregate Transmission Study report.

**3.7 Study Costs**

The Network Customer or Transmission Customer shall be responsible for all actual costs incurred by Transmission Provider to perform each of the Screening Studies requested by the Network Customer or Transmission Customer. An estimate of such costs shall be specified in the Screening Study Agreement. Billing and payment shall be as specified in Section 7 of the Transmission Provider's Tariff.

**3.8 Service Agreements**

If based on the results of a Screening Study the Transmission Provider determines that a potential Delivery Point Transfer will not result in any third party issues and that no Network Upgrades for thermal or voltage mitigations will occur, the Transmission Provider will tender the Network Customer or Transmission Customer a draft Service Agreement. The Network Customer or Transmission Customer shall execute a Service Agreement or request the filling of an unexecuted Service Agreement within the time period set forth in Attachment P of the Tariff or its Completed Application shall be

deemed terminated and withdrawn. If based on the results of the Screening Study, Transmission Provider determines that a Delivery Point Transfer will have a significant impact on the Transmission System, to proceed with the Delivery Point Transfer request and to obtain a Service Agreement, the Network Transmission Customer or Transmission Customer must enter the request for study in the Aggregate Transmission Service Study process to obtain a Service Agreement.

# Appendix 1 to Attachment AR

| Screening Study: Application and Study Timing Requirements | |
|---|---|
| Transmission Provider Acknowledges Receipt of Screening Study Application | No later than 10 days after Transmission Provider Receipt of Screening Study Application (Sections 2.4, 3.4) |
| Notice of Deficiency of Screening Study Application | No later than 15 days after Transmission Provider Receipt of Screening Study Application (Sections 2.4, 3.4) |
| Completion of Screening Study | Transmission Provider will use due diligence to complete Screening Study within 90 days of receiving a successfully completed application for a Screening Study (Sections 2.2, 3.2) |

# ATTACHMENT AS

# CONTRACT SERVICES AGREEMENT BETWEEN WESTERN AREA POWER ADMINISTRATION AND SOUTHWEST POWER POOL, INC.

# Contract No. 15-UGPR-10.2

UNITED STATES
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

CONTRACT SERVICES SECOND AMENDED AGREEMENT

Between

UNITED STATES OF AMERICA

and

SOUTHWEST POWER POOL, INC.

This revised AGREEMENT ("Second Amended Agreement"), made and entered into on this 13th day of November, 2020, by and between the UNITED STATES OF AMERICA, represented by the Secretary of Energy, acting by and through the Administrator, Western Area Power Administration ("Western"), an Administration within the Department of Energy, and SOUTHWEST POWER POOL, INC. ("SPP"), incorporated as a not-for-profit corporation in the State of Arkansas, acting in its capacity as a Regional Transmission Organization ("RTO"), and acting through its duly authorized officials; each which may be individually referred to herein as a "Party" and collectively as "Parties." Capitalized terms not defined herein shall have the definitions prescribed in the SPP Open Access Transmission Tariff ("OATT" or "Tariff").

Western has assigned Contract No. 15-UGPR-10.2 to this Second Amended Agreement for its record-keeping purposes.

## RECITALS

WHEREAS, SPP provides operating and/or reliability functions in portions of the states of Arkansas, Oklahoma, Kansas, Missouri, Louisiana, Texas, Nebraska, New Mexico, Montana, North Dakota, South Dakota, Minnesota, Iowa, and Wyoming. As an RTO, SPP administers open access transmission service across the facilities of SPP's Transmission Owners, administers the Integrated Marketplace, a centralized day ahead and real-time energy and operating reserve market with locational marginal pricing and market-based congestion management, and operates as the consolidated Balancing Authority for the SPP Balancing Authority Area ("SPP BAA").

WHEREAS, Western-Upper Great Plains Region ("Western-UGP") markets and delivers hydroelectric power and related services within Iowa, Minnesota, Montana, Nebraska, North Dakota, and South Dakota, and owns and operates transmission facilities within its marketing area. Western-UGP joined SPP fully as a Transmission Owner, effective October 1, 2015, under its SPP Membership Agreement (Contract No. 14-UGPR-82), transferred functional control of its eligible transmission facilities in the Eastern Interconnection to SPP fully under the SPP OATT, placed such transmission facilities within the SPP Integrated Marketplace, and merged its Western Area Power Administration – Upper Great Plains East Balancing Authority Area ("WAUE") into the SPP BAA.

WHEREAS, Western-UGP owns and operates transmission facilities in the Western Interconnection ("West Facilities-UGP", listed in Exhibit #1) that are separated from the rest of Western-UGP's transmission facilities in the Eastern Interconnection by a back-to-back DC tie (Miles City) and normally open AC interconnections (Fort Peck). Additionally Basin Electric Power Cooperative owns or leases similarly situated transmission facilities in the Western Interconnection that are integrated with the facilities of Western-UGP and located within the Western Area Power Administration – Upper Great Plains West Balancing Authority Area ("WAUW"). These facilities in the Western Interconnection were historically integrated with the facilities in the Eastern Interconnection, and transmission services were offered under Western-UGP's Tariff under a single rate zone across both Western-UGP's Western and Eastern Interconnection transmission facilities. There is need and are opportunities to include the use of Western-UGP's eligible transmission facilities in the Western Interconnection in certain functions of SPP and in a limited basis under the SPP OATT within the SPP Transmission System ("Transmission System").

WHEREAS, SPP's Integrated Marketplace and SPP BAA was not extended to include the West Facilities-UGP when Western-UGP transferred functional control of the West Facilities-UGP on October 1, 2015, for a number of reasons; therefore, Western-UGP will maintain and continue to operate its WAUW in the Western Interconnection. Western-UGP will also continue to contract for Reliability Coordinator ("RC") services for its transmission facilities in the Western Interconnection from SPP or make other arrangements for Reliability Coordinator services for the West Facilities-UGP, if necessary. In addition, certain West Facilities-UGP are also located within the NorthWestern Energy Balancing Authority Area ("NWMT") or Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM") in the Western Interconnection.

WHEREAS, SPP and Western-UGP previously entered into an original Contract Services Agreement, Contract No. 15-UGPR-10, on July 31, 2015 ("Original Agreement"), with an effective date of October 1, 2015. SPP and Western-UGP replaced the Original Agreement with the First Amended Agreement, Contract No. 15-UGPR-10.1, on September 17, 2019, with an effective date of November 16, 2019. SPP and Western-UGP desire to now replace the First Amended Agreement with this Second Amended Agreement.

WHEREAS, Western-UGP transferred functional control of its West Facilities-UGP to SPP, and appointed SPP to provide services for its West Facilities-UGP under the Original Agreement under terms found within the SPP OATT, with SPP functioning as the Transmission Service Provider, and Planning Coordinator, and also Reliability Coordinator under the First Amended Agreement beginning when SPP provided RC services in the Western Interconnection, as these functions are defined by the North American Electric Reliability Corporation ("NERC"), including but not limited to administration of transmission and ancillary services and generation interconnection service, Open Access Same-Time Information System ("OASIS") administration, transmission planning, RC services, and associated compliance requirements. Western-UGP desires SPP to provide certain services pursuant to the arrangements set forth under this Second Amended Agreement related to its West Facilities-UGP.

WHEREAS, SPP began providing RC services in the Western Interconnection on December 3, 2019.

WHEREAS, Western-UGP started taking RC services from SPP for the Bulk Electric System ("BES") facilities it operates in the Western Interconnection on the date that SPP began providing RC services in the Western Interconnection.

WHEREAS, The Parties accordingly amended the Original Agreement with the First Amended

Agreement (Contract for Services, dated September 17, 2019, identified as 15-UGPR-10.1) to reflect that SPP shall provide RC services to Western-UGP as provided for under Western-UGP's SPP Membership Agreement, effective as of the date that SPP began providing RC services in the Western Interconnection.

WHEREAS, SPP intends to begin administering an energy imbalance service market (the "Western Energy Imbalance Service Market" or "WEIS Market") in the Western Interconnection on or about February 1, 2021, under the Western Energy Imbalance Service Tariff ("WEIS Tariff"), as approved by the Federal Energy Regulatory Commission ("FERC"), including all schedules or attachments thereto, as amended from time to time and approved by FERC.

WHEREAS, Western-UGP and Western Area Power Administration, Rocky Mountain Region ("Western-RMR") have executed agreements with SPP and joined the WEIS Market and placed their respective WAUW and WACM Balancing Authority Areas in the Western Interconnection into the WEIS Market.

WHEREAS, Energy Imbalance Service – Western Interconnection under Schedule 4 of this Agreement and Generator Imbalance Service – Western Interconnection under Schedule 9 of this Agreement will be provided by SPP, as the WEIS Market Operator as defined in the WEIS Tariff, in the Western-UGP WAUW and Western-RMR WACM Balancing Authority Areas in the Western Interconnection.

WHEREAS, a new, as available, real-time intra-hour non-firm transmission service ("Joint Dispatch Transmission Service" or "JDTS") is required to accommodate the delivery of energy under the WEIS Market pursuant to the provisions of the WEIS Tariff.

WHEREAS, The Parties accordingly wish to amend the First Amended Agreement to incorporate the necessary changes to accommodate Western-UGP's participation in the WEIS Market.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the Parties contract and agree as follows:

## ARTICLE I
## GENERAL PROVISIONS

Section 1. Services Provided By SPP.

(a) During the term of this Second Amended Agreement, SPP shall provide Western-UGP all of the following services for the West Facilities-UGP, and as set forth below:

(i) Provide services as the Transmission Service Provider ("TSP"), as defined in the NERC Functional Model, as may be amended from time to time ("Functional Model"), for the West Facilities-UGP under the SPP OATT in accordance with Section 1(b) of this Second Amended Agreement, including but not limited to administration of transmission service, generation interconnection service, ancillary services, and the transition of existing transmission, generation, and ancillary services on the West Facilities-UGP in place prior to October 1, 2015, to the SPP OATT;

(ii) SPP shall maintain and administer the OASIS in accordance with the provisions contained in the SPP OATT and this Second Amended Agreement;

(iii) SPP shall perform the role of Planning Coordinator ("PC"), as defined in the NERC

Functional Model, for the West Facilities-UGP, including transmission planning;

(iv) SPP provides services as a Reliability Coordinator, as defined in the NERC Functional Model, in the Western Interconnection to Western-UGP in its capacity as the WAUW Balancing Authority Area operator and as a Transmission Operator ("TOP") for the BES facilities it operates in the Western Interconnection, as provided for under Western-UGP's SPP Membership Agreement and described in RC coordination procedures between the Parties.

(b) SPP, on behalf of Western-UGP, shall administer and provide Transmission Service, JDTS subject to the conditions set forth in Article III of this Second Amended Agreement, and ancillary services as the TSP on the West Facilities-UGP. The term Transmission Service, where used herein, shall include both Point-to-Point Transmission Service ("PTP") and Network Integration Transmission Service ("NITS") as defined under the SPP OATT for the use of the West Facilities-UGP for the movement of electric capacity or energy on either a firm or non-firm basis. The term Transmission Customer shall be as defined in the SPP OATT. Transmission Service provisions and charges, Schedule 1 and Schedule 2 ancillary services provisions and charges, and losses, shall be according to the SPP OATT; SPP's Administration Charge shall be according to Schedule 1-A of the SPP OATT. The term "Administration Charge" as used herein shall be as defined in SPP's OATT. Ancillary services applicable only to the Balancing Authority Area(s) in the Western Interconnection shall be according to the following Western Interconnection-related ancillary service schedules set forth in Exhibit #2 of this Second Amended Agreement:

(i) Schedule 1 – NorthWestern Energy Balancing Authority Area ("NWMT") or Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM"); Scheduling, System Control and Dispatch Service – NWMT/WACM

(ii) Schedule 3 – Western Interconnection; Regulation and Frequency Response Service – Western Interconnection

(iii) Schedule 4 – Western Interconnection; Energy Imbalance Service – Western Interconnection

(iv) Schedule 5 – Western Interconnection; Operating Reserve – Spinning Reserve Service – Western Interconnection

(v) Schedule 6 – Western Interconnection; Operating Reserve – Supplemental Reserve Service – Western Interconnection

(vi) Schedule 9 – Western Interconnection; Generator Imbalance Service – Western Interconnection

Notwithstanding Schedule 4 of the SPP OATT, loads on the West Facilities-UGP included in the Transmission System will not be subject to settlement in the Real-Time Balancing Market, except in the limited case where the loads are temporarily connected to the Eastern Interconnection inside the SPP BAA as described in Article I at Section 6(a)(i) of this Second Amended Agreement.

(c) SPP shall perform billing services for Transmission Service and associated ancillary services on the West Facilities-UGP in accordance with the SPP OATT, except as otherwise provided in this Second Amended Agreement. Western-UGP shall provide rate schedules for the WAUW-related ancillary services identified in Section 1(b) herein to SPP to bill Transmission Customers for ancillary services provided by Western-UGP as the Balancing Authority in the WAUW. SPP's Administration Charge shall be applied by SPP to Transmission Service administered by SPP.

(d) For Transmission Service administered by SPP under SPP's OATT pursuant to Section

1(b) of this Article I, SPP shall determine whether there is Available Transfer Capability to allow the approval of the Transmission Service. The term "Available Transfer Capability" as used herein shall be defined as a measure of the transfer capability remaining in the Transmission System for further commercial activity over and above already committed uses. Available Transfer Capability will be determined pursuant to the provisions and procedures of the SPP OATT and applicable NERC Reliability Standards. For any new Transmission Service, modifications to existing Transmission Service, and applicable generation interconnection requests, SPP shall perform all necessary tariff studies, including but not limited to feasibility, system impact, and facilities studies in accordance with SPP's Aggregate Transmission Study and Generation Interconnection study processes. SPP shall notify the requestor of SPP's approval or denial of the transmission service request per the procedures of the SPP OATT.

(e) All requests for new Transmission Service on the West Facilities-UGP after October 1, 2015, shall be made on the SPP OASIS and be subject to the provisions of the SPP OATT. Western-UGP shall terminate all existing transmission service contracts under Western-UGP's Open Access Transmission Tariff effective October 1, 2015, and Western-UGP shall not offer any services on the West Facilities-UGP under its own tariff beginning October 1, 2015. SPP shall be shown as the TSP on the energy tag for the schedules across the West Facilities-UGP in the Balancing Authority Area(s) in the Western Interconnection. SPP shall approve or deny such schedules as the Transmission Service Provider. Western-UGP shall be shown as the Balancing Authority on the energy tag for schedules in the WAUW and Western-UGP shall approve or deny such schedules as the Balancing Authority. NorthWestern Energy shall be shown as the Balancing Authority on the energy tag for schedules in the NWMT. Western-RMR shall be shown as the Balancing Authority on the energy tag for schedules in the WACM. SPP shall decrement Available Transfer Capability by the amount of the approved reservation.

(f) Settlement of Transmission Services for PTP and NITS sold on West Facilities-UGP and distribution of revenues to Western-UGP for Transmission Services and ancillary services shall be done in accordance with the applicable provisions of the Membership Agreement, SPP OATT, and this Second Amended Agreement.

Section 2. Reimbursable Services. Upon mutual agreement by Western-UGP and SPP, and in accordance with applicable laws and regulations, SPP or Western-UGP may perform services for each other on a reimbursable basis related to the West Facilities-UGP. Such reimbursable services shall be evidenced by a separate written agreement between Western-UGP and SPP.

Section 3. Tariff Application. SPP's OATT shall apply to Transmission Service utilizing the West Facilities-UGP; except that ancillary services applicable only to the Balancing Authority Area(s) in the Western Interconnection shall be according to the Western Interconnection-related ancillary service schedules set forth in Exhibit #2 of this Second Amended Agreement. Western-UGP shall provide rate schedules including revenue requirements and/or rates to SPP for the WAUW-related ancillary services that Western-UGP, as the Balancing Authority, provides to SPP as the Transmission Provider, if it is capable of doing so. SPP shall provide ancillary services to a Transmission Customer with Transmission Service on the West Facilities-UGP located in the NWMT or WACM if such Transmission Customer does not obtain the necessary ancillary services directly from NorthWestern Energy or Western-RMR, as applicable, or self-supply such ancillary services.

Section 4. Operating and Planning. The Parties shall comply with NERC and North American Energy Standards Board ("NAESB") Standards, Western Electricity Coordinating Council ("WECC") Regional Reliability Standards, and SPP Criteria, as applicable, and as specified in Western-UGP's Membership Agreement and the SPP OATT. SPP shall be responsible to maintain its compliance with standards applicable to the TSP, PC, and RC. SPP shall not be responsible for Western-UGP's compliance with applicable NERC standards. Western-UGP's performance under this Second Amended Agreement shall be subject to all Federal statutes and regulations applicable to Western-UGP, as set forth

in Section 39.3 of the SPP OATT.

Section 5. Reservation Priority of Existing Transmission Service. Existing firm transmission service, provided by Western-UGP prior to the transfer of functional control of the West Facilities-UGP to SPP, shall be recognized as firm by SPP and transitioned to comparable service under the SPP OATT upon request of the Transmission Customer.

Section 6. Reliability.

(a) The West Facilities-UGP are in the SPP Reliability Coordinator footprint and SPP is the NERC registered Reliability Coordinator for the West Facilities-UGP, SPP shall have compliance responsibility for applicable Reliability Coordinator related mandatory NERC or WECC Reliability Standards for the BES facilities in the Western Interconnection that Western-UGP operates.

(i) In the event that portions of the West Facilities-UGP are temporarily interconnected to the Eastern Interconnection (e.g. portions of the West Facilities-UGP from Fort Peck Substation to Havre Substation are periodically connected to the Eastern Interconnection during maintenance outages of certain West Facilities-UGP that would otherwise result in loss of electric service) the Parties agree to make the necessary arrangements with the Reliability Coordinator in the Western Interconnection responsible for the West Facilities-UGP and SPP, acting as the Reliability Coordinator for Western-UGP's transmission facilities in the Eastern Interconnection, to ensure that the Reliability Coordinators are prepared to address such operating scenarios and to delineate each Reliability Coordinator's operating and compliance responsibilities during times when West Facilities-UGP are temporarily connected to the Eastern Interconnection.

(ii) Western-UGP and SPP shall agree to the uniform line identifiers for the West Facilities-UGP, and either Party desiring to change a uniform line identifier shall notify the other Party of desired modifications or additions to the applicable uniform line identifiers.

(iii) Western-UGP shall submit outages of the West Facilities-UGP and Western-UGP generation in the Western Interconnection into the Control Room Operations Window ("CROW") Outage Scheduler web tool of Western-UGP's Western Interconnection RC. Western-UGP shall not be required to submit duplicate outage data into the SPP CROW Outage Scheduler web tool for the Eastern Interconnection. SPP shall query the outage information for the West Facilities-UGP and Western-UGP generation in the Western Interconnection directly from the applicable CROW Outage Scheduler web tool for the Western Interconnection.

(b) Subject to the provisions of this Second Amended Agreement, SPP provides Tariff administration and is the NERC registered TSP, PC, and RC for the West Facilities-UGP. As the TSP, PC, and RC, SPP shall be responsible to perform such responsibilities pursuant to applicable SPP Criteria, SPP Membership Agreement, NERC and WECC Regional Reliability Standards, and the following requirements:

(i) In the event SPP, as the Transmission Provider, WEIS Market Operator, or Reliability Coordinator, requests the redispatch of hydroelectric generation owned and operated by the U.S. Army Corps of Engineers ("Corps") or Bureau of Reclamation ("Bureau") located in the Western Interconnection and marketed by Western-UGP, Western-UGP shall coordinate its operations with the Corps and Bureau pursuant to the provisions of Section 39.3 of the SPP OATT.

(c) Western-UGP is registered with NERC as a Transmission Owner ("TO") and TOP and retains all compliance responsibility for applicable mandatory NERC Reliability Standards for the West Facilities-UGP. Western-UGP will support SPP in its role as the TSP, and RC, if applicable, by performing the following TO and TOP functional activities:

(i) Seasonal, next-day, and current-day Bulk Electric System studies for the West Facilities-UGP to determine System Operating Limits ("SOLs"), including both determining new limits and identifying potential exceedances of pre-defined SOLs.

(ii) Western-UGP shall update these Bulk Electric System studies for the West Facilities-UGP as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to SPP.

(iii) Western-UGP shall notify SPP of protective relay or equipment failure that reduces system reliability which potentially affects SPP, and shall coordinate new protective systems and protective system changes on the West Facilities-UGP that potentially affect SPP. Western-UGP shall provide documentation to SPP pursuant to the SPP Criteria of all existing protective systems that impact the West Facilities-UGP, such as Special Protection Systems ("SPS"), Remedial Action Schemes ("RAS"), WECC Wide Area Protection Schemes ("WAPS"), WECC Local Area Protection Schemes ("LAPS"), Undervoltage Load Shedding ("UVLS") and Underfrequency Load Shedding ("UFLS"). These protective systems include but are not limited to the Western Montana Generation Dropping Scheme LAPS, Miles City Converter Station Tripping RAS, Shelby Area UVLS, and Western-UGP's UFLS Program in the Western Interconnection.

(d) SPP shall make available sufficient information related to Section 6(b) of this Article I for Western-UGP to verify that SPP's performance complies with applicable NERC Reliability Standard requirements, including;

(i) Provide evidence of such compliance, at a minimum, upon request to Western-UGP, the WECC Regional Entity, or applicable compliance enforcement authority. This may arise with respect to, but is not limited to, audits, compliance investigations, or other compliance monitoring activities and could include on-site visits to the SPP locations; and

(ii) Provide self-certifications, self-reports, or other information to the WECC Regional Entity or applicable compliance enforcement authority, regarding tasks performed by SPP.

(iii) For disputes regarding SPP's performance under Section 6(b) and 6(d), the Parties will utilize the dispute resolution procedures of Section 16 of this Article I.

(e) By entering into this Second Amended Agreement, Western-UGP has not waived or conceded any defense it may have, including sovereign immunity, intergovernmental immunity, or lack of subject matter jurisdiction in any action against it by an Enforcement Authority, nor has Western-UGP accepted any liability, responsibility, or obligation to pay any civil monetary penalties or fines to which it would not have been subject in the absence of this Second Amended Agreement that may be imposed by an Enforcement Authority. Enforcement Authority in this Second Amended Agreement means the FERC, Electric Reliability Organization ("ERO"), or Regional Entities with enforcement authority pursuant to a delegation from an ERO or FERC for the purpose of proposing and enforcing reliability standards.

Section 7. Transmission Maintenance. Western-UGP shall coordinate with SPP for all planned maintenance of the West Facilities-UGP consistent with its corresponding SPP Criteria and on a consistent basis with its transmission facilities in the Eastern Interconnection.

Section 8. Generation Maintenance and Switchyard Facilities Owned by the Corps and Bureau. Western-UGP shall coordinate with SPP for all planned maintenance of the generation facilities and switchyard facilities owned by the Corps or Bureau in the Western Interconnection, consistent with the provisions of Section 39.3 of the SPP OATT.

Section 9. Operating Reserve Sharing. SPP shall not provide necessary Operating Reserve Sharing services for Transmission Customers on Western-UGP's transmission system in the Western Interconnection, unless SPP agrees to do so by separate written agreement with those Transmission Customers. Western-UGP shall be responsible for making separate arrangements to address its participation as a member of a reserve sharing group in the Western Interconnection for its West Facilities-UGP or WAUW. As of the effective date of this Second Amended Agreement, Western-UGP is a member of the Northwest Power Pool ("NWPP") Reserve Sharing Program for its transmission system in the Western Interconnection. The provisions of SPP Criteria 6.0 shall not be applicable to the West Facilities-UGP nor to Western-UGP's transmission system in the Western Interconnection.

Section 10. Scheduling Services and Requirements. Western-UGP shall retain its WAUW in the Western Interconnection. The Parties shall each meet their own responsibilities under NERC Reliability Standards as the Balancing Authority, and shall coordinate the operations of their respective Balancing Authority Areas as set forth in separate Adjacent Balancing Authority agreements, as appropriate. Western-UGP's scheduling requirements in the WAUW, including requirements for scheduling of loss energy associated with the SPP Transmission Customer's Transmission Service on the West Facilities-UGP in the WAUW, will be set forth in a Western-UGP Business Practice, which shall be provided to SPP, and updated as necessary, by Western-UGP for posting on the SPP OASIS.

Section 11. Information. The Parties shall furnish to each other such information as is necessary to perform their respective obligations under this Second Amended Agreement. Confidentiality of information shall be governed by the provisions the SPP OATT and any other non-disclosure agreement entered into by the parties for the purposes of satisfying applicable law, regulations, or standards, or the confidentiality requirements of either party.

Section 12. SPP Criteria and Federal Requirements.

(a) The term "SPP Criteria" as used herein shall be the currently approved SPP Criteria as defined in the SPP Membership Agreement. The SPP Criteria shall apply to the West Facilities-UGP, unless excluded herein, or by mutual written agreement between the Parties.

(b) Western-UGP's performance of obligations under this Second Amended Agreement shall be subject to and in accordance with all Federal statutes, regulations, and limitations of Western-UGP's hydroelectric resources and provisions of Section 39.3 of the SPP OATT.

(c) Western-UGP shall communicate and coordinate with the Corps and Bureau on any request by SPP connected to the operation of, and maintenance, modification, or addition to the Corps' or Bureau's generation and transmission facilities in the Western Interconnection to comply with SPP Criteria; Provided, That, compliance with the SPP Criteria involving Corps' or Bureau's facilities shall be within the discretion of and subject to the respective approval of the Corps or Bureau.

Section 13. Transmission Expansion, Interconnections, Modifications, and Additions.

(a) It is recognized that SPP will, from time to time, evaluate potential expansion of the transmission facilities that are utilized to implement SPP's OATT which, pursuant to this Second Amended Agreement, also include the West Facilities-UGP. SPP may recommend the upgrade of transmission facilities that involve Western-UGP West Facilities-UGP and/or facilitate new or existing

service under the SPP OATT. Western-UGP's participation, if any, shall be pursuant to its Membership Agreement and Federal provisions included in Section 39.3 of the SPP OATT.

(b) Western Facilities shall be included as part of the SPP Planning Region to the extent defined herein. The purpose for Western-UGP's participation in the SPP transmission planning processes for the West Facilities-UGP shall be to meet Western-UGP's compliance obligations for the NERC Reliability Standards related to transmission planning (including transmission planning and TPL reliability standards), to facilitate information exchange in compliance with NERC Modeling, Data, and Analysis ("MOD") reliability standards, and to provide data and information for SPP regional and interregional planning functions including the development of transmission planning models, transmission assessments, transmission expansion plans, studies for transmission service, generation interconnections, transmission interconnections, and flowgate determination.

(c) Pursuant to the SPP OATT, no interconnections to Western-UGP's West Facilities-UGP shall be made without written contractual agreements between Western-UGP and the interconnecting party which satisfy Western-UGP's Environmental Review Procedures and National Environmental Policy Act ("NEPA") requirements and which establish the terms and conditions of the interconnection. Such agreements shall be made pursuant to Western-UGP's then-current General Requirements for Interconnection as posted on Western-UGP's web site.

(d) For interconnecting generation to Western-UGP's West Facilities-UGP, the provisions of the SPP OATT shall be used for determining the feasibility and facility requirements of the Transmission System to accommodate the interconnection, except that Western-UGP will determine the requirements for the facilities at the interconnection site.

(e) Transmission additions and modifications to the West Facilities-UGP identified through the SPP transmission planning process shall be accomplished pursuant to the SPP OATT. Additions and modifications to the West Facilities-UGP shall not be included in the Schedule 11 Region-wide Charge for the Eastern Interconnection. In the absence of any other SPP rate Zones in the Western Interconnection other than the UMZ, the costs of additions and modifications to the West Facilities-UGP shall be included in the UMZ Zonal Annual Transmission Revenue Requirement. In the event that additional SPP rate Zones are added in the Western Interconnection under the SPP OATT, the Parties agree to review and revise the allocation of costs for additions and modifications of the West Facilities-UGP, if necessary.

(f) Costs and cost allocations for modifications to Western-UGP or other SPP Transmission Owner transmission facilities required to accommodate SPP OATT transmission service on the West Facilities-UGP shall be pursuant to the SPP OATT; Provided, That, any costs allocable to Western-UGP shall be pursuant to Western-UGP's Federal Service Exemption as set forth in Western-UGP's Membership Agreement and the SPP OATT.

Section 14. Coordinating Committee. The Parties can by mutual agreement, if necessary, establish a Coordinating Committee for the purposes of developing procedures for the implementation of the operating and technical requirements of this Second Amended Agreement and any other matters referred to herein or necessary for implementation, administration, or operation of this Second Amended Agreement.

Section 15. Protection from Liability. SPP agrees that Western-UGP will have the same protection from liability, for SPP's administration of Western-UGP's West Facilities-UGP under the SPP OATT, as any other Transmission Owner under the SPP OATT except as otherwise provided in the Membership Agreement and the SPP OATT. Western-UGP's liability to SPP shall be governed by Section 39.3(j) of the SPP OATT.

Section 16. Dispute Resolution. Any dispute arising out of or relating to this Second Amended Agreement shall be resolved under the dispute resolution procedures of SPP's OATT.

Section 17. Participation by Western-UGP Subject to Federal Laws and Regulations. Section 39.3 of the SPP OATT is incorporated as if it were a part hereof.

Section 18. Conflicts Between Second Amended Agreement and OATT. Unless specifically provided for in this Second Amended Agreement to limit the application of the SPP OATT to the West Facilities-UGP, in the event there is a conflict between this Second Amended Agreement and the terms of the SPP OATT, the SPP OATT shall prevail.

Section 19. Renewable Resources. Western supports the installation of renewable sources of energy but recognizes that certain operational constraints exist in managing the significant fluctuations that are a normal part of their operation. Western has marketed the maximum practical amount of power from each of its projects, leaving little or no flexibility for provision of additional power services. Consequently, provided that Western-UGP is able to purchase additional power resources delivered into its WAUW to provide Regulation and Frequency Response Service to intermittent renewable generation resources serving load within WAUW, costs for these regulation resources will become part of Western-UGP's Regulation and Frequency Response Service. However, pursuant to Western-UGP's rate schedules, Western-UGP will not regulate for the difference between the output of an intermittent generator located within WAUW and a delivery schedule from that generator serving load located outside of WAUW. Intermittent generators taking transmission service from SPP within the Western Interconnection inside the WAUW and serving load outside WAUW will be required to pseudo-tie or dynamically schedule their generation to another Balancing Authority Area.

An intermittent resource, for the limited purpose of Western-UGP's rate schedules, is an electric generator that is not dispatchable and cannot store its fuel source and, therefore, cannot respond to changes in demand or respond to transmission security constraints.

Section 20. Entire Agreement. This Second Amended Agreement, including applicable appendices, exhibits, and their duly approved replacements, constitute the entire agreement among the Parties with respect to the subject matter of this Second Amended Agreement, and no previous oral or written representation, agreement, or understanding made by any officers, agent, or employee of any Party shall be binding on any such Party unless contained in this Second Amended Agreement or applicable appendices.

Section 21. Counterparts. This Second Amended Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon the Parties, notwithstanding that they may not have executed the same counterpart.

Section 22. Modification. No modification of the terms of this Second Amended Agreement shall be valid unless made in writing and signed by authorized representatives of the parties.

Section 23. Digital Signature. The Parties agree that this Second Amended Agreement may be signed and executed by digital signature, digitally signed using Adobe Sign or Adobe E-Signature. A digital signature is the same as a handwritten signature and shall be considered valid and acceptable.

## ARTICLE II

## TRANSMISSION SERVICE UNDER SPP'S OATT

Section 1. Transmission Service. All Transmission Service which uses the West Facilities-UGP shall be under the SPP OATT.

Section 2. Western-UGP's Internal WAUW Balancing Authority Area Customers, and the SPP Integrated Marketplace. SPP, as the WEIS Market Operator, shall apply the WEIS Tariff to loads and resources on the West Facilities-UGP in the WEIS Market; except during times that such loads and resources are connected to the Eastern Interconnection and inside the SPP BAA and the SPP Integrated

Marketplace as described in Article I at Section 6(a) (i) of this Second Amended Agreement.

Section 3. Compensation. Western-UGP shall submit and recover its annual transmission revenue requirement and Scheduling, System Control and Dispatch Service revenue requirement for the West Facilities-UGP pursuant to the terms and conditions set forth in Western-UGP's Membership Agreement and the SPP OATT. SPP shall distribute revenues to Western-UGP pursuant to the applicable ancillary service schedules for ancillary services provided by Western-UGP as the BA that are billed by SPP as the Transmission Provider to the SPP Transmission Customers. Compensation to Western-UGP for losses associated with Transmission Service in the WAUW shall be in accordance with Attachment M of the SPP OATT; except that loss energy shall be provided by the SPP Transmission Customer to Western-UGP pursuant to the requirements in Section 10 of Article I, utilizing the loss factors in Appendix 1 of Attachment M.

## ARTICLE III

## WEIS MARKET RELATED PROVISIONS

Section 1. Applicability of WEIS Market to Loads and Resources. Loads and resources on the West Facilities-UGP that are connected to the Western Interconnection and inside the WAUW or WACM shall be subject to settlement under the WEIS Market in accordance with Attachment A of the WEIS Tariff.

Section 2. SPP OATT Provisions and Transmission Customers on the West Facilities-UGP.

(a) Network Resources: Notwithstanding the limitations in Sections 1 (Network Resource definition), 30.1, 30.2, and 30.4 of the SPP OATT that may apply, Network Customers may also utilize Network Resources for purposes of fulfilling obligations under the WEIS Market. Notwithstanding the provisions in Section 28.6 of the SPP OATT, Network Customers may utilize JDTS for purposes of fulfilling obligations under the WEIS Market.

(b) Ancillary Services: Notwithstanding the provisions in Section 3 of the SPP OATT, Energy Imbalance Service and Generator Imbalance Service for loads and resources within the WAUW are described in Schedule 4 – Western Interconnection and Schedule 9 – Western Interconnection, respectively, included in Exhibit #2 to this Second Amended Agreement.

Section 3. Joint Dispatch Transmission Service. SPP as the Transmission Provider for the West Facilities-UGP, shall provide JDTS on the West Facilities-UGP to a Joint Dispatch Transmission Service Customer ("JDTS Customer") pursuant to the applicable terms and conditions set forth in this Article III. A JDTS Customer is a Transmission Customer receiving JDTS for energy dispatched in the WEIS Market. JDTS is provided on the West Facilities-UGP commensurate with, and to accommodate, the energy dispatched within the WEIS Market, as set forth in the WEIS Tariff, as follows:

(a) Term: JDTS shall be available on a real-time intra-hour basis.

(b) Reservation Priority: JDTS is non-firm, and shall be available from transfer capability in excess of that needed for Transmission Customers taking any other transmission service under the SPP OATT.

(c) Restrictions on the use of JDTS: JDTS may be used on the West Facilities-UGP only for receipt or delivery of energy dispatched by SPP as the WEIS Market Operator within a Balancing Authority Area in the WEIS Market pursuant to the provisions of the WEIS Tariff.

The JDTS Customer shall not use JDTS for (i) off-system sales of capacity or energy not related to fulfilling obligations under the WEIS Market or (ii) direct or indirect provision of transmission service by the JDTS Customer to any third party.

(d) Scheduling: JDTS Customers are not required to submit schedules for JDTS.

(e) Curtailment of JDTS: The Transmission Provider reserves the right to curtail (or cause to be curtailed), in whole or in part, JDTS provided under this Second Amended Agreement for reliability reasons when, an emergency or other unforeseen conditions threatens to impair or degrade the reliability of the Transmission System or the systems directly or indirectly interconnected with the Transmission Provider's Transmission System.

(f) Transmission Provider's Limited Obligations to provide JDTS: The Transmission Provider, shall have no obligation to plan, construct, or maintain its Transmission System for the benefit of any JDTS Customer.

(g) Procedures for Arranging JDTS: JDTS does not need to be reserved by the JTDS Customer. No application or service agreement is required.

(h) Compensation for JDTS: Rates for JDTS are provided in Schedule 8W – Western Interconnection set forth in Exhibit #2.

(i) Real Power Losses: Notwithstanding the provisions in Sections 15.7 and 28.5 of the SPP OATT, real power loss energy associated with JDTS due to WEIS Market dispatch is addressed in the settlement of imbalance energy pursuant to the WEIS Tariff.

## ARTICLE IV

## TERM, TERMINATION OF AGREEMENT, AND NOTICES

Section 1. Term. This Second Amended Agreement shall become effective on February 1, 2021, or the date upon which the WEIS Tariff becomes effective ("Effective Date"); and shall expire by its own terms at midnight on February 1, 2061, or concurrent with termination of Western-UGP's Membership Agreement, whichever is earlier. The Parties may extend the term of this Second Amended Agreement by written amendment. The Parties agree that concurrently with this Second Amended Agreement becoming effective, the First Amended Agreement (Contract for Services, dated September 17, 2019, identified as 15-UGPR-10.1) shall terminate.

Section 2. Renegotiation. If any provision of this Second Amended Agreement, or the application thereof to any person, entity, or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, or if a modification or condition to this Second Amended Agreement is imposed by a regulatory authority exercising jurisdiction over this Second Amended Agreement, then the Parties shall endeavor in good faith to negotiate such amendment or amendments to this Second Amended Agreement as will restore the relative benefits and obligations of the signatories under this Second Amended Agreement immediately prior to such holding, modification, or condition. Substantive changes to the FERC regulations governing the relative tariffs, the NERC functional model, the NERC mandatory Reliability Standards, or any other law or regulation implicating this Second Amended Agreement, or which substantively alters the obligations of either Party shall be cause to renegotiate the Second Amended Agreement under this section. The Parties agree that the objectives of this Second Amended Agreement can be fulfilled efficiently and economically only if the

Parties, from time to time, review and as appropriate revise the requirements stated herein, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

Section 3. Notice. Any written notice, demand, or request required or authorized under this Second Amended Agreement shall be deemed properly given to or served on Western-UGP if mailed or transmitted electronically to:

Vice President of Operations for Upper Great Plains Region
Western Area Power Administration
Upper Great Plains Region
P.O. Box 790
1330 41st Street SE
Watertown, SD 57201
Fax Number: (605) 882-7409

Any such notice, demand, or request shall be deemed properly given to or served on SPP if mailed or transmitted electronically to:

President and CEO
Southwest Power Pool, Inc.
201 Worthen Dr.
Little Rock, AR 72223-4936
Fax Number: (501) 482-2022

The designation of the persons to be notified, or the addresses of such persons, may be changed at any time by either Party by written notice to the other Party.

IN WITNESS WHEREOF, the Parties have executed this Second Amended Agreement as of the day and year first above written, each of which shall constitute an original.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

By */s/ Craig Speidel*
Title Acting Vice President of Operations
for Upper Great Plains Region
Western Area Power Administration
Upper Great Plains Region

SOUTHWEST POWER POOL, INC.

By */s/ Lanny Nickell*

Title Executive Vice President and COO

ATTEST:

I, Paul Suskie, certify that I am the Corporate Secretary of SOUTHWEST POWER POOL, INC., and that Lanny Nickell, who signed this Second Amended Agreement on behalf of said Corporation, was then, Executive Vice President and Chief Operating Officer of said Corporation, and that the said Second Amended Agreement was duly signed for and on behalf of the said Corporation by authority of its governing body, which has within the scope if its corporate powers the authority to legally bind the Corporation under the foregoing Second Amended Agreement.

(SEAL)

By */s/Paul Suskie*

# EXHIBIT #1

## WEST FACILITIES-UGP

**Table 1**

| Transmission Lines/Equipment | Description | Balancing Authority Area |
|---|---|---|
| Canyon Ferry-Lake Helena 100kV "A" Line | CF-LAH "A" (Note 1) | **NWMT** |
| Canyon Ferry-Lake Helena 100kV "B" Line | CF-LAH "B" (Note 1) | **NWMT** |
| Conrad-Shelby #2 230kV | CON-SH2 | **NWMT** |
| Fort Peck-Havre 161kV | FP-HV | WAUW |
| Fort Peck-Whatley 69kV | FP-WH | WAUW |
| Great Falls (NWE[5])-Conrad 230kV | GTF(NWE)-CON | **NWMT** |
| Havre-Verona 161kV | HV-VR | WAUW |
| Havre-Shelby #2 115kV | HV-SH2 | WAUW |
| Miles City #3-Custer 230kV | MC3-CU | WAUW |
| Tiber Tap-Tiber 115kV | TT-TI | WAUW |
| Verona-Great Falls (WAPA[6]) 161kV | VR-GTF(WAPA) | WAUW |
| Yellowtail-Custer 230kV | YT-CU, Yellowtail-Crossover-Custer | WAUW |
| Yellowtail-Yellowtail (PACE[7]) 230kV | YT-PY, Western-UGP Capacity rights in Western's 230kV line, Tie Line between WACM and PACE | **PACE Tie Line with WACM[8]** |

Note 1 – The Canyon Ferry-Lake Helena 100kV lines are connected to NorthWestern Energy facilities and do not have a direct contiguous connection to other SPP Transmission System facilities or to the other West Facilities-UGP; therefore SPP as the Transmission Provider may only provide partial path service across these transmission facilities.

**Table 2**

| Substations | Facilities ID, Description | Balancing Authority Area |
|---|---|---|
| Bole | BOL, 230kV & 69kV (portion) | **NWMT** |
| Canyon Ferry | CF, 100kV (See Note 1 in Table 1 above) | **NWMT** |
| Conrad | CON, 230kV & 115kV (portion) | **NWMT** |
| Crossover | CRO, 230kV, Phase Shifter | WAUW |
| Custer | CU, 230kV & 69kV (portion) | WAUW |
| Fort Peck | FP, 161kV & 69kV (portion) – Western Interconnection | WAUW |
| Great Falls (WAPA) | GTF (WAPA), 230kV & 115kV | WAUW |
| Great Falls (NWE) | GTF (NWE), 230kV | **NWMT** |

[5] NorthWestern Energy
[6] Western-UGP facilities
[7] PacifiCorp East
[8] Tie Line interface between WACM and PACE. Schedules into/out of PACE at this interface must be scheduled across WACM.

| | | |
|---|---|---|
| Havre | HV, 161kV, 115kV, 12.47kV (portion) | WAUW |
| Miles City #3 | MC3, 230kV | WAUW |
| Miles City Converter Station | MC4, Converter Station and East/West DC equipment | WAUW |
| Rudyard | RY, 115kV | WAUW |
| Shelby #2 | SH2, 230kV and 115kV (portion) (Note 1) | **NWMT** |
| Tiber | TI, 115kV Line Disconnects | WAUW |
| Tiber Tap | TT, 115kV | WAUW |
| Verona | VR, Substation Control Equipment (Note 2) | WAUW |
| Whatley | WH, 69kV (portion) | WAUW |
| Yellowtail (USBR) | YT, Western-UGP portion of Western owned 230kV and 115kV facilities to Western-UGP generation at YT, and to Yellowtail(PACE) interconnection | **WACM** |
| Yellowtail (PACE) | PY, Western-UGP Capacity rights in 230kV line bay owned by Western at the end of the Yellowtail-Yellowtail (PACE ) 230kV transmission line | **PACE Tie Line with WACM** |

Note 1 – Shelby Substation (SH) and associated 115kV transmission line Shelby-Shelby #2 (SH-SH2) does not meet SPP transmission eligibility qualifications at the present time and is not included.

Note 2 – Assumption is that Verona 161kV substation equipment, which is leased by Basin Electric Power Cooperative (Basin Electric), will be included in the SPP Transmission System by Basin Electric and addressed in separate agreement between SPP and Basin Electric.

The following substations are not owned by Western; however they sectionalize Western-UGP West Facilities-UGP. These are not included in the West Facilities-UGP. However, Western-UGP has rights to utilize the sectionalizing equipment in these substations as noted below (for NWE substations under Contract No. 00-UGPR-25 between Western-UGP and NorthWestern Energy, or successor agreement; and for Norval substations under Contract No. 04-UGPR-25 between Western-UGP and Central Montana Electric Power Cooperative, Inc., or successor agreement).

**Table 3**

| **Non-Western Substations** | **Facility ID, Description** | **Balancing Authority Area** |
|---|---|---|
| Harlem | HA, NWE Substation (Note 3) | WAUW |
| Malta | MT, NWE Substation (Note 3) | WAUW |
| Richardson Coulee | RE, NWE Substation (Note 3) | WAUW |
| | | |
| New Deal | ND, Norval Electric Cooperative Substation (Note 4) | WAUW |

Note 3 - These substations are owned by NorthWestern Energy and are not included directly under the SPP OATT. These substations sectionalize Western-UGP's Fort Peck-Havre 161kV line, and pursuant to the Interconnection Agreement (Contract 00-UGPR-25 or successor agreement) between Western-UGP and NorthWestern, Western-UGP has rights to use the 161kV sectionalizing facilities in these substations at no charge for Transmission Service across its Fort Peck-Havre 161kV line.

Note 4 - This substation is owned by Norval Electric Cooperative and is not included directly under the SPP OATT. This substation sectionalizes Western-UGP's Fort Peck-Whatley 69kV line, and pursuant to the Agreement (Contract No. 04-UGPR-25 or successor agreement) between Western-UGP and Central Montana Electric Power Cooperative, Inc., Western-UGP has rights to use the 69kV sectionalizing facilities in this substation at no charge for Transmission Service across its Fort Peck-Whatley 69kV line.

## EXHIBIT #2

## SCHEDULE 1 – NORTHWESTERN ENERGY BALANCING AUTHORITY AREA ("NWMT") OR WESTERN AREA POWER ADMINISTRATION, COLORADO-MISSOURI REGION BALANCING AUTHORITY AREA ("WACM") SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE – NWMT/WACM

Scheduling, System Control and Dispatch Service – NWMT/WACM is required to schedule the movement of power through, out of, within, or into the NorthWestern Energy Balancing Authority Area ("NWMT") or the Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM"). This service can be provided only by the Balancing Authority in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service – NWMT/WACM is provided indirectly by the Transmission Provider making arrangements with NWMT or WACM, as the Balancing Authority that performs this service for the Transmission Provider's transmission facilities used for transmission service located within the NWMT or WACM. The Transmission Customer must purchase this service from the Transmission Provider or from NorthWestern Energy or Western Area Power Administration, Rocky Mountain Region ("Western-RMR") as the Balancing Authority.

To the extent NorthWestern Energy or Western-RMR performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by NorthWestern Energy or Western-RMR as the Balancing Authority.

In the event that NorthWestern Energy provides such service, the Transmission Provider shall assess the Scheduling, System Control and Dispatch Service – NWMT/WACM charge to the Transmission Customer in the NWMT as specified in NorthWestern Energy's currently effective Rate Schedule for Scheduling, System Control and Dispatch Service in NWMT, as posted on NorthWestern Energy's Open Access Same-Time Information System.

In the event that Western-RMR provides such service, the Transmission Provider shall assess the Scheduling, System Control and Dispatch Service – NWMT/WACM charge to the Transmission Customer in the WACM as specified in Western-RMR's currently effective Rate Schedule for Scheduling, System Control and Dispatch Service in WACM, as posted on Western-RMR's Open Access Same-Time Information System.

# SCHEDULE 3 – WESTERN INTERCONNECTION REGULATION AND FREQUENCY RESPONSE SERVICE – WESTERN INTERCONNECTION

Regulation and Frequency Response Service – Western Interconnection is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz) in the Balancing Authority Area(s) in the Western Interconnection. Regulation and Frequency Response Service – Western Interconnection is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Balancing Authority that performs this function for the Transmission Provider. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service – Western Interconnection obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will obtain this service from the affected Balancing Authority(s), or elsewhere, where approved, and the Transmission Customer shall pay the Transmission Provider for this service when the Transmission Provider provides the services to the Transmission Customer. Charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority or other suppliers. The Transmission Provider shall pass through the revenues it receives for this service to the Balancing Authority or other suppliers providing this service.

In the event that Western-UGP provides such Regulation and Frequency Response Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Regulation and Frequency Response Service – Western Interconnection charge ("Regulation Charge") to load in the Western Area Power Administration, Upper Great Plains West Balancing Authority Area ("WAUW") as follows:

The Transmission Customer shall pay a monthly WAUW Regulation Charge, which shall be determined by multiplying its WAUW Load Ratio Share by one twelfth (1/12) of the WAUW Regulation

Annual Revenue Requirement specified in Western-UGP's currently effective Rate Schedule for Regulation and Frequency Response Service – WAUW, which will be posted on the Transmission Provider's Open Access Same-Time Information System, where the WAUW Load Ratio Share of a Transmission Customer is the ratio of the Transmission Customer's load in WAUW to the total load in WAUW calculated on a calendar year basis (based upon average of previous year's 12 monthly peaks). The Transmission Customer's monthly peak load in WAUW is its integrated hourly load in WAUW coincident with the total monthly peak load in WAUW.

In the event that NorthWestern Energy provides such Regulation and Frequency Response Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Regulation and Frequency Response Service – Western Interconnection charge to load in the NorthWestern Energy Balancing Authority Area ("NWMT") as specified in NorthWestern Energy's currently effective Rate Schedule for Regulation and Frequency Response Service in NWMT, as posted on NorthWestern Energy's Open Access Same-Time Information System.

In the event that Western Area Power Administration, Rocky Mountain Region ("Western-RMR") provides such Regulation and Frequency Response Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Regulation and Frequency Response Service – Western Interconnection charge to load in the Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM") as specified in Western-RMR's currently effective Rate Schedule for Regulation and Frequency Response Service in WACM, as posted on Western-RMR's Open Access Same-Time Information System.

## SCHEDULE 4 – WESTERN INTERCONNECTION
## ENERGY IMBALANCE SERVICE – WESTERN INTERCONNECTION

Energy Imbalance Service – Western Interconnection is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within the Balancing Authority Area(s) in the Western Interconnection over a single hour or dispatch interval in the WEIS Market. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service – Western Interconnection obligation. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will obtain this service from the affected Balancing Authority Areas or elsewhere, where appropriate, and the Transmission Customer shall pay the Transmission Provider for this service when the Transmission Provider provides this service to the Transmission Customer. Charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority or other suppliers. The Transmission Provider shall pass through the revenues it receives for this service to the Balancing Authority or other suppliers providing the service. All loads on the West Facilities-UGP in the WEIS Market receiving this service will be subject to settlement in the WEIS Market in accordance with Attachment A of the WEIS Tariff.

In the event that Western-UGP provides such Energy Imbalance Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Energy Imbalance Service – Western Interconnection charge to load in the Western Area Power Administration, Upper Great Plains West Balancing Authority Area ("WAUW") as specified in Western-UGP's currently effective Rate Schedule for Energy Imbalance Service – WAUW, which will be posted on the Transmission Provider's Open Access Same-Time Information System.

In the event that NorthWestern Energy provides such Energy Imbalance Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Energy Imbalance Service – Western Interconnection charge to load in the NorthWestern Energy Balancing Authority Area ("NWMT") as specified in NorthWestern Energy's currently effective Rate Schedule for Energy Imbalance Service in NWMT, as posted on NorthWestern Energy's Open Access Same-Time Information System.

In the event that Western Area Power Administration, Rocky Mountain Region ("Western-RMR") provides such Energy Imbalance Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Energy Imbalance Service – Western Interconnection charge to load in the Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM") as specified in Western-RMR's currently effective Rate Schedule for Energy Imbalance Service in WACM, as posted on Western-RMR's Open Access Same-Time Information System.

# SCHEDULE 5 – WESTERN INTERCONNECTION OPERATING RESERVE - SPINNING RESERVE SERVICE – WESTERN INTERCONNECTION

Spinning Reserve Service – Western Interconnection is needed to serve load in the Balancing Authority Area(s) in the Western Interconnection immediately in the event of a system contingency. Spinning Reserve Service – Western Interconnection may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service – Western Interconnection obligation. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will obtain the service from the affected Balancing Authority Areas, and the Transmission Customer shall pay the Transmission Provider for this service when the Transmission Provider provides this service to the Transmission Customer. Charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority or other suppliers. The Transmission Provider shall pass through the revenues it receives for this service to the Balancing Authority or other suppliers providing the service.

In the event that Western-UGP provides such Spinning Reserve Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Spinning Reserve Service – Western Interconnection charge ("Spinning Reserve Charge") to load and generation in the Western Area Power Administration, Upper Great Plains West Balancing Authority Area (WAUW) as follows:

The Transmission Customer shall pay a monthly WAUW Spinning Reserve Charge, which shall be determined by multiplying its WAUW Load Ratio Share by one twelfth (1/12) of the WAUW Spinning Reserves Annual Revenue Requirement specified in Western-UGP's currently effective Rate Schedule for Operating Reserves – Spinning Reserve – WAUW, which will be posted on the Transmission Provider's Open Access Same-Time Information System, where the WAUW Load Ratio Share of a Transmission Customer is the ratio of the sum of the Transmission Customer's load in WAUW and generation in WAUW to the sum of the total load in WAUW and total generation in WAUW calculated on a calendar year basis (based upon average of previous year's 12 monthly peaks). The Transmission Customer's monthly peak load in WAUW is its integrated hourly load in WAUW coincident with the total monthly peak load in WAUW. The Transmission Customer's monthly peak generation in WAUW is its integrated hourly generation in WAUW coincident with the total monthly peak load in WAUW. In addition, the Transmission Customer will be assessed any other applicable

charges specified in Western-UGP's currently effective Rate Schedule for Operating Reserves – Spinning Reserve – WAUW.

In the event that NorthWestern Energy provides such Spinning Reserve Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Spinning Reserve Service – Western Interconnection charge to the Transmission Customer in the NorthWestern Energy Balancing Authority Area ("NWMT") as specified in NorthWestern Energy's currently effective Rate Schedule for Spinning Reserve Service in NWMT, as posted on NorthWestern Energy's Open Access Same-Time Information System.

In the event that Western Area Power Administration, Rocky Mountain Region ("Western-RMR") provides such Spinning Reserve Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Spinning Reserve Service – Western Interconnection charge to the Transmission Customer in the Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM") as specified in Western-RMR's currently effective Rate Schedule for Spinning Reserve Service in WACM, as posted on Western-RMR's Open Access Same-Time Information System.

## SCHEDULE 6 – WESTERN INTERCONNECTION OPERATING RESERVE - SUPPLEMENTAL RESERVE SERVICE – WESTERN INTERCONNECTION

Supplemental Reserve Service – Western Interconnection is needed to serve load in the Balancing Authority Area(s) in the Western Interconnection in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service – Western Interconnection may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service – Western Interconnection obligation. Unless the Transmission Customer makes alternative comparable arrangements, the Transmission Provider will obtain this service from the affected Balancing Authority Areas, and the Transmission Customer shall pay the Transmission Provider for this service when the Transmission Provider provides this service to the Transmission Customer. Charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority or other suppliers. The Transmission Provider shall pass through the revenues it receives for this service to the Balancing Authority or other suppliers providing the service.

In the event that Western-UGP provides such Supplemental Reserve Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Operating Reserve – Supplemental Reserve Service – Western Interconnection charge ("Supplemental Reserve Charge") to load and generation in the Western Area Power Administration, Upper Great Plains West Balancing Authority Area ("WAUW") as follows:

The Transmission Customer shall pay a monthly WAUW Supplemental Reserve Charge, which shall be determined by multiplying its WAUW Load Ratio Share by one twelfth (1/12) of the WAUW Supplemental Reserves Annual Revenue Requirement specified in Western-UGP's currently effective Rate Schedule for Operating Reserves – Supplemental Reserve – WAUW, which will be posted on the Transmission Provider's Open Access Same-Time Information System, where the WAUW Load Ratio Share of a Transmission Customer is the ratio of the sum of the Transmission Customer's load in WAUW and generation in WAUW to the sum of the total load in WAUW and total generation in WAUW calculated on a calendar year basis (based upon average of previous year's 12 monthly peaks). The Transmission Customer's monthly peak load in WAUW is its integrated hourly load in WAUW coincident with the total monthly peak load in WAUW. The Transmission Customer's monthly peak generation in WAUW is its integrated hourly generation in WAUW coincident with the total monthly peak load in WAUW. In addition, the Transmission Customer will be assessed any other applicable

charges specified in Western-UGP's currently effective Rate Schedule for Operating Reserves – Supplemental Reserve – WAUW.

In the event that NorthWestern Energy provides such Supplemental Reserve Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Supplemental Reserve Service – Western Interconnection charge to the Transmission Customer in the NorthWestern Energy Balancing Authority Area ("NWMT") as specified in NorthWestern Energy's currently effective Rate Schedule for Supplemental Reserve Service in NWMT, as posted on NorthWestern Energy's Open Access Same-Time Information System.

In the event that Western Area Power Administration, Rocky Mountain Region ("Western-RMR") provides such Supplemental Reserve Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Supplemental Reserve Service – Western Interconnection charge to the Transmission Customer in the Western Area Power Administration, Colorado-Missouri Region Balancing Authority Area ("WACM") as specified in Western-RMR's currently effective Rate Schedule for Supplemental Reserve Service in WACM, as posted on Western-RMR's Open Access Same-Time Information System.

## SCHEDULE 8W – WESTERN INTERCONNECTION JOINT DISPATCH TRANSMISSION SERVICE

The JDTS Customer shall compensate the Transmision Provider for JDTS commensurate with the receipt or delivery of energy dispatched for JDTS Customer pursuant to the WEIS Tariff at the following rate:

(1) Hourly delivery:

a. On-Peak Hours: the on-peak rate $0.00/MWh.

b. Off-Peak Hours: the off-peak rate $0.00/MWh.

# SCHEDULE 9 – WESTERN INTERCONNECTION
# GENERATOR IMBALANCE SERVICE – WESTERN INTERCONNECTION

Generator Imbalance Service – Western Interconnection is provided when a difference occurs between the output of a generator located in the Balancing Authority Area(s) in the Western Interconnection and a delivery schedule from that generator to (1) another Balancing Authority Area or (2) a load within the Balancing Authority Area(s) in the Western Interconnection over a single hour or dispatch interval in the WEIS Market. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within the Balancing Authority Area(s) in the Western Interconnection. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service – Western Interconnection obligation. Charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority or other suppliers. The Transmission Provider shall pass through the revenues it receives for this service to the Balancing Authority or other suppliers providing the service. All resources on the West Facilities-UGP in the WEIS Market receiving this service will be subject to settlement in the WEIS Market in accordance with Attachment A of the WEIS Tariff.

In the event that Western-UGP provides such Generator Imbalance Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Generator Imbalance Service – Western Interconnection charge to the Transmission Customer in the Western Area Power Administration, Upper Great Plains West Balancing Authority Area ("WAUW") as specified in Western-UGP's currently effective Rate Schedule for Generator Imbalance Service – WAUW, which will be posted on the Transmission Provider's Open Access Same-Time Information System.

In the event that NorthWestern Energy provides such Generator Imbalance Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Generator Imbalance Service – Western Interconnection charge to the Transmission Customer in the NorthWestern Energy Balancing Authority Area ("NWMT") as specified in NorthWestern Energy's currently effective Rate Schedule for Generator Imbalance Service in NWMT, as posted on NorthWestern Energy's Open Access Same-Time Information System.

In the event that Western Area Power Administration, Rocky Mountain Region ("Western-RMR") provides such Generator Imbalance Service – Western Interconnection as a Balancing Authority, the Transmission Provider shall assess the Generator Imbalance Service – Western Interconnection charge to the Transmission Customer in the Western Area Power Administration, Colorado-Missouri Region

Balancing Authority Area ("WACM") as specified in Western-RMR's currently effective Rate Schedule for Generator Imbalance Service in WACM, as posted on Western-RMR's Open Access Same-Time Information System.

# ATTACHMENT AT

# CONTRACT SERVICES AGREEMENT BETWEEN BASIN ELECTRIC POWER COOPERATIVE AND SOUTHWEST POWER POOL, INC.

CONTRACT SERVICES SECOND AMENDED AGREEMENT

Between

BASIN ELECTRIC POWER COOPERATIVE

and

SOUTHWEST POWER POOL, INC.

This revised AGREEMENT ("Second Amended Agreement"), made and entered into on November 13, 2020, by and between Basin Electric Power Cooperative ("Basin Electric") a North Dakota electric cooperative corporation and SOUTHWEST POWER POOL, INC. ("SPP"), incorporated as a not-for-profit corporation in the State of Arkansas, acting in its capacity as a Regional Transmission Organization ("RTO"), and acting through its duly authorized officials; each which may be individually referred to herein as a "Party" and collectively as "Parties." Capitalized terms not defined herein shall have the definitions prescribed in the SPP Open Access Transmission Tariff ("OATT" or "Tariff").

## RECITALS

WHEREAS, SPP provides operating and/or reliability functions in portions of the states of Arkansas, Oklahoma, Kansas, Missouri, Louisiana, Texas, Nebraska, New Mexico, Montana, North Dakota, South Dakota, Minnesota, Iowa, and Wyoming. As an RTO, SPP administers open access transmission service across the facilities of SPP's Transmission Owners, administers the Integrated Marketplace, a centralized day ahead and real-time energy and operating reserve market with locational marginal pricing and market-based congestion management, and operates as the consolidated Balancing Authority for the SPP Balancing Authority Area ("SPP BAA").

WHEREAS, Basin Electric joined SPP fully as a Transmission Owner, effective October 1, 2015, under its SPP Membership Agreement, transferred functional control of its eligible transmission facilities in the Eastern Interconnection to SPP under the SPP OATT, and placed such transmission facilities within the SPP Integrated Marketplace.

WHEREAS, Basin Electric owns, leases, and/or operates transmission facilities in the Western Interconnection located in the Western Area Power Administration – Upper Great Plains Region Balancing Authority Area ("WAUW") ("West Facilities-Basin Electric", listed in Exhibit #1) that are separated from the rest of Basin Electric's transmission facilities in the Eastern Interconnection by a back-to-back DC tie (Miles City) and normally open AC interconnections (Fort Peck). Additionally Western Area Power Administration - Upper Great Plains ("Western-UGP") owns and operates similarly situated transmission facilities in the Western Interconnection that are integrated with the facilities of Basin Electric. There is need and are opportunities to include the use of Basin Electric's West Facilities-Basin Electric in

certain functions of SPP and on a limited basis under the SPP OATT within the SPP Transmission System ("Transmission System").

WHEREAS, SPP's Integrated Marketplace and SPP BAA was not extended to include the West Facilities-Basin Electric when Basin Electric transferred functional control of the West Facilities-Basin Electric on October 1, 2015, for a number of reasons; therefore, the West Facilities-Basin Electric will continue to be located within the Western Area Power Administration – Upper Great Plains West Balancing Authority Area ("WAUW"). Basin Electric will continue to arrange for Reliability Coordinator ("RC") services for its West Facilities-Basin Electric from SPP or make other arrangements for Reliability Coordinator services for those facilities, if necessary.

WHEREAS, SPP and Basin Electric previously entered into an original Contract Services Agreement on July 31, 2015 ("Original Agreement"), with an effective date of October 1, 2015. SPP and Basin Electric replaced the Original Agreement with the First Amended Agreement effective December 3, 2019. SPP and Basin Electric desire to now replace the First Amended Agreement with this Second Amended Agreement.

WHEREAS, Basin Electric transferred functional control of its West Facilities-Basin Electric to SPP, and appointed SPP to provide services for its West Facilities-Basin Electric under the Original Agreement under terms found within the SPP OATT, with SPP functioning as the Transmission Service Provider and Planning Coordinator, and also Reliability Coordinator under the First Amended Agreement beginning when SPP provided RC services in the Western Interconnection, as these functions are defined by the North American Electric Reliability Corporation ("NERC"), including but not limited to administration of transmission and ancillary services and generation interconnection service, Open Access Same-Time Information System ("OASIS") administration, transmission planning, RC services, and associated compliance requirements.

WHEREAS, Basin Electric desires SPP to provide certain additional services pursuant to the arrangements set forth under this Second Amended Agreement related to its West Facilities-Basin Electric.

WHEREAS, SPP began providing RC services in the Western Interconnection on December 3, 2019.

WHEREAS, Basin Electric started taking RC services from SPP for the Bulk Electric System ("BES") facilities it operates in the Western Interconnection on the date that SPP began providing RC services in the Western Interconnection.

WHEREAS, the Parties accordingly amended the Original Agreement with the First Amended Agreement to reflect that SPP shall provide RC services to Basin Electric as provided for under Basin Electric's SPP Membership Agreement, effective as of the date that SPP began providing RC services in the Western Interconnection.

WHEREAS, SPP intends to begin administering an energy imbalance service market (the "Western Energy Imbalance Service Market" or "WEIS Market") in the Western Interconnection on or about February 1, 2021, under the Western Energy Imbalance Service Tariff ("WEIS

Tariff"), as approved by the Federal Energy Regulatory Commission ("FERC"), including all schedules or attachments thereto, as amended from time to time and approved by FERC.

WHEREAS, Basin Electric has executed an agreement with SPP and is a Market Participant in the WEIS Market and placed its Western Facilities-Basin Electric in the Western Interconnection into the WEIS Market.

WHEREAS, a new, as available, real-time intra-hour non-firm transmission service ("Joint Dispatch Transmission Service" or "JDTS") is required to accommodate the delivery of energy under the WEIS Market pursuant to the provisions of the WEIS Tariff.

WHEREAS, the Parties accordingly wish to amend the First Amended Agreement to incorporate the necessary changes to accommodate Basin Electric's participation in the WEIS Market.

NOW, THEREFORE, in consideration of the mutual covenants herein contained, the Parties contract and agree as follows:

## ARTICLE I
## GENERAL PROVISIONS

Section 1. Services Provided By SPP.

(a) During the term of this Second Amended Agreement, SPP shall provide Basin Electric all of the following services for the West Facilities-Basin Electric as defined in Exhibit #1:

(i) Provide services as the Transmission Service Provider ("TSP"), as defined in the NERC Functional Model, as may be amended from time to time ("Functional Model"), for the West Facilities-Basin Electric under the SPP OATT in accordance with Section 1(b) of this Second Amended Agreement, including but not limited to administration of transmission service, generation interconnection service, ancillary services, and the transition of existing transmission, generation, and ancillary services on the West Facilities-Basin Electric in place prior to October 1, 2015, to the SPP OATT;

(ii) SPP shall maintain and administer the OASIS in accordance with the provisions contained in the SPP OATT and this Second Amended Agreement;

(iii) SPP shall perform the role of Planning Coordinator ("PC"), as defined in the NERC Functional Model, for the West Facilities-Basin Electric, including transmission planning.

(iv) SPP provides services as a Reliability Coordinator, as defined in the NERC Functional Model, in the Western Interconnection, to Basin Electric for the West Facilities-Basin Electric located in the WAUW Balancing Authority Area and for which Basin Electric has Transmission Operator ("TOP") obligations for such BES facilities it operates in the Western Interconnection, as provided for under Basin Electric's SPP Membership Agreement and described in RC coordination procedures between the Parties.

(b) SPP, on behalf of Basin Electric, shall administer and provide Transmission Service, JDTS subject to the conditions set forth in Article III of this Second Amended Agreement, and ancillary services as the TSP on the West Facilities-Basin Electric. The term Transmission Service, where used herein, shall include both Point-to-Point Transmission Service ("PTP") and Network Integration Transmission Service ("NITS") as defined under the SPP OATT for the use of the West Facilities-Basin Electric for the movement of electric capacity or energy on either a firm or non-firm basis. The term Transmission Customer shall be as defined in the SPP OATT. Transmission Service provisions and charges, Schedule 1 and Schedule 2 ancillary services provisions and charges, and losses, shall be according to the SPP OATT; SPP's Administration Charge shall be according to Schedule 1A of the SPP OATT. The term "Administration Charge" as used herein shall be as defined in SPP's OATT.

Notwithstanding Schedule 4 of the SPP OATT, loads on the West Facilities-Basin Electric included in the Transmission System will not be subject to settlement in the Real-Time Balancing Market, except in the limited case where the loads are temporarily connected to the Eastern Interconnection inside the SPP BAA. For transmission service on the West Facilities-Basin Electric included in the WAUW, SPP's Transmission Customers shall self-provide or take ancillary services from SPP pursuant to Ancillary Service Schedules 3, 4, 5, and 6 as provided in the Agreement between the United States of America and the Southwest Power Pool for Contract Services for the Western Area Power Administration ("WAPA-SPP West Contract"). Basin Electric shall have no obligation to provide these ancillary services.

(c) SPP shall perform billing services for Transmission Service and associated ancillary services on the West Facilities-Basin Electric in accordance with the SPP OATT, except as otherwise provided in this Second Amended Agreement. SPP's Administration Charge shall be applied by SPP to Transmission Service administered by SPP.

(d) For Transmission Service administered by SPP under SPP's OATT pursuant to Section 1(b) of this Article I, SPP shall determine whether there is Available Transfer Capability to allow the approval of the Transmission Service. The term "Available Transfer Capability" as used herein shall be defined as a measure of the transfer capability remaining in the Transmission System for further commercial activity over and above already committed uses. Available Transfer Capability will be determined pursuant to the provisions and procedures of the SPP OATT and applicable NERC Reliability Standards. For any new Transmission Service, modifications to existing Transmission Service, and applicable generation interconnection requests, SPP shall perform all necessary tariff studies, including but not limited to feasibility, system impact, and facilities studies in accordance with SPP's Aggregate Transmission Study and Generation Interconnection study processes. SPP shall notify the requestor of SPP's approval or denial of the transmission service request per the procedures of the SPP OATT.

(e) All requests for new Transmission Service on the West Facilities-Basin Electric after midnight on September 30, 2015, shall be made on the SPP OASIS and shall be subject to the provisions of the SPP OATT. Basin Electric shall not offer any services on the West Facilities-Basin Electric after October 1, 2015. SPP shall be shown as the TSP on the energy tag for the schedules across the West Facilities-Basin Electric in the WAUW. SPP shall approve or deny such schedules as the Transmission Service Provider. SPP shall decrement Available Transfer Capability by the amount of the approved reservation.

(f) Settlement of Transmission Services for PTP and NITS sold on West Facilities-Basin Electric and distribution of revenues for Transmission Services shall be distributed to Basin Electric in accordance with the applicable provisions of the Membership Agreement, SPP OATT, and this Second Amended Agreement.

Section 2. Reimbursable Services. Upon mutual agreement by Basin Electric and SPP, and in accordance with applicable laws and regulations, SPP or Basin Electric may perform services for each other on a reimbursable basis related to the West Facilities-Basin Electric. Such reimbursable services shall be evidenced by a separate written agreement between Basin Electric and SPP.

Section 3. Tariff Application. SPP's OATT shall apply to Transmission Service utilizing the West Facilities-Basin Electric.

Section 4. Operating and Planning. The Parties shall comply with NERC and North American Energy Standards Board ("NAESB") Standards, Western Electricity Coordinating Council ("WECC") Regional Reliability Standards, and SPP Criteria, as applicable, and as specified in Basin Electric's Membership Agreement and the SPP OATT. SPP shall be responsible to maintain its compliance with standards applicable to the TSP and PC. SPP shall not be responsible for Basin Electric's compliance with applicable NERC standards.

Section 5. Reserved

Section 6. Reliability.

(a) The West Facilities-Basin Electric are in the SPP Reliability Coordinator footprint and SPP is the NERC-registered Reliability Coordinator for the West Facilities-Basin Electric. SPP shall have compliance responsibility for applicable Reliability Coordinator-related NERC or WECC Reliability Standards for the BES facilities in the Western Interconnection that Basin Electric operates.

(i) Basin Electric and SPP shall agree to the uniform line identifiers for the West Facilities-Basin Electric. Either Party desiring to change a uniform line identifier shall notify the other Party of desired modifications or additions to the applicable uniform line identifiers, or such modifications or additions shall become effective upon mutual agreement of the Parties.

(ii) Basin Electric or its agent shall submit outages of the West Facilities-Basin Electric and Basin Electric generation in the Western Interconnection into the Control Room Operations Window ("CROW") Outage Scheduler web tool of Basin Electric's Western Interconnection RC. Basin Electric shall not be required to submit duplicate outage data into the SPP CROW Outage Scheduler web tool for the Eastern Interconnection. SPP shall query the outage information for the West Facilities-Basin Electric and Basin Electric generation in the Western Interconnection directly from the applicable CROW Outage Scheduler web tool for the Western Interconnection.

(b) Subject to the provisions of this Second Amended Agreement, SPP provides Tariff administration and is the NERC registered TSP, PC, and RC for the West Facilities-Basin Electric. As the TSP, PC, and RC, SPP shall be responsible to perform such responsibilities pursuant to applicable SPP Criteria, SPP Membership Agreement, and NERC and WECC

Regional Reliability Standards.

(c) Basin Electric is registered with NERC as a Transmission Owner ("TO") and retains all compliance responsibility for applicable mandatory NERC Reliability Standards for the West Facilities-Basin Electric. Basin Electric will support SPP in its role as the TSP, and RC, if applicable, by coordinating with its agent for TOP services to ensure the performance of the following TOP functional activities:

(i) Basin Electric's agent for TOP services shall perform seasonal, next-day, and current-day Bulk Electric System studies for the West Facilities-Basin Electric to determine System Operating Limits ("SOLs"), including both determining new limits and identifying potential exceedances of pre-defined SOLs.

(ii) Basin Electric's agent for TOP services shall update these Bulk Electric System studies for the West Facilities-Basin Electric as necessary to reflect current system conditions and shall make the results of Bulk Electric System studies available to SPP.

(iii) Basin Electric shall notify SPP of protective relay or equipment failure that reduces system reliability which potentially affects SPP, and shall coordinate new protective systems and protective system changes on the West Facilities-Basin Electric that potentially affect SPP. Basin Electric shall provide documentation to SPP pursuant to the SPP Criteria of all existing protective systems that impact the West Facilities-Basin Electric, such as Special Protection Systems ("SPS"), Remedial Action Schemes ("RAS"), WECC Wide Area Protection Schemes ("WAPS"), WECC Local Area Protection Schemes ("LAPS"), Undervoltage Load Shedding ("UVLS") and Underfrequency Load Shedding ("UFLS").

(d) SPP shall make available sufficient information related to Section 6(b) of this Article I for Basin Electric to verify that SPP's performance complies with applicable NERC Reliability Standard requirements, including;

(i) Provide evidence of such compliance, at a minimum, upon request to Basin Electric, the WECC Regional Entity, or applicable compliance enforcement authority. This may arise with respect to, but is not limited to, audits, compliance investigations, or other compliance monitoring activities and could include on-site visits to the SPP locations.

(ii) Provide self-certifications, self-reports, or other information to the WECC Regional Entity or applicable compliance enforcement authority, regarding tasks performed by SPP.

(iii) For disputes regarding SPP's performance under Section 6(b) and 6(d), the Parties will utilize the dispute resolution procedures of Section 16 of this Article I.

Section 7. Transmission Maintenance. Basin Electric shall coordinate with SPP for all planned maintenance of the West Facilities-Basin Electric consistent with its corresponding SPP Criteria and on a consistent basis with its transmission facilities in the Eastern Interconnection.

Section 8. Reserved.

Section 9. Operating Reserve Sharing. SPP shall not provide necessary Operating Reserve Sharing services for Transmission Customers on the West Facilities-Basin Electric unless SPP agrees to do so by separate written agreement with those Transmission Customers. Absent such agreement, the provisions of SPP Criteria 6.0 shall not be applicable to the West Facilities-Basin Electric or to Basin Electric's transmission system in the Western Interconnection.

Section 10. Reserved.

Section 11. Information. The Parties shall furnish to each other such information as is necessary to perform their respective obligations under this Second Amended Agreement. Confidentiality of information shall be governed by the provisions of the SPP OATT and any other non-disclosure agreement entered into by the Parties for the purposes of satisfying applicable law, regulations, or standards, or the confidentiality requirements of either Party.

Section 12. SPP Criteria. The term "SPP Criteria" as used herein shall be the currently approved SPP Criteria as defined in the SPP Membership Agreement. The SPP Criteria shall apply to the West Facilities-Basin Electric, unless excluded herein, or by mutual written agreement between the Parties.

Section 13. Transmission Expansion, Interconnections, Modifications, and Additions.

(a) It is recognized that SPP will, from time to time, evaluate potential expansion of the transmission facilities that are utilized to implement SPP's OATT which, pursuant to this Second Amended Agreement, also include the West Facilities-Basin Electric. SPP may recommend the upgrade of transmission facilities that involve the West Facilities-Basin Electric and/or facilitate new or existing service under the SPP OATT.

(b) The West Facilities-Basin Electric shall be included as part of the SPP Planning Region to the extent defined herein. The purpose for Basin Electric's participation in the SPP transmission planning processes for the West Facilities-Basin Electric shall be to meet Basin Electric's compliance obligations for the NERC Reliability Standards related to transmission planning (including transmission planning and TPL reliability standards), to facilitate information exchange in compliance with NERC Modeling, Data, and Analysis ("MOD") reliability standards; and to provide data and information for SPP regional and interregional planning functions including the development of transmission planning models, transmission assessments, transmission expansion plans, studies for transmission service, generation interconnections, transmission interconnections, and flowgate determination.

(c) Pursuant to the SPP OATT, no interconnections to the West Facilities-Basin Electric shall be made without written contractual agreements between Basin Electric and the interconnecting party which establish the terms and conditions of the interconnection. Such agreements shall be made pursuant to Basin Electric's then-current General Requirements for Interconnection as posted on Basin Electric's web site.

(d) For interconnecting generation to the West Facilities-Basin Electric, the provisions of the SPP OATT shall be used for determining the feasibility and facility requirements of the Transmission System to accommodate the interconnection, except that Basin Electric will determine the requirements for the facilities at the interconnection site.

(e) Transmission additions and modifications to the West Facilities-Basin Electric

identified through the SPP transmission planning process shall be accomplished pursuant to the SPP OATT. Additions and modifications to the West Facilities-Basin Electric shall not be included in the Schedule 11 Region-wide Charge for the Eastern Interconnection. In the absence of any SPP rate Zones in the Western Interconnection other than the UMZ, the costs of additions and modifications to the West Facilities-Basin Electric shall be included in the UMZ Zonal Annual Transmission Revenue Requirement. In the event that additional SPP rate Zones are added in the Western Interconnection under the SPP OATT, the Parties agree to review and revise the allocation of costs for additions and modifications of the West Facilities-Basin Electric, if necessary.

(f) Costs and cost allocations for modifications to Basin Electric or other SPP Transmission Owner transmission facilities required to accommodate SPP OATT transmission service on the West Facilities-Basin Electric shall be pursuant to the SPP OATT.

Section 14. Coordinating Committee. The Parties may by mutual agreement, if necessary, establish a Coordinating Committee for the purposes of developing procedures for the implementation of the operating and technical requirements of this Second Amended Agreement and any other matters referred to herein or necessary for implementation, administration, or operation of this Second Amended Agreement.

Section 15. Liability and Indemnification. The Parties agree that the Tariff shall control in all issues related to liability and indemnification between the Parties.

Section 16. Dispute Resolution. Any dispute arising out of or relating to this Second Amended Agreement shall be resolved under the dispute resolution procedures of SPP's OATT.

Section 17. Reserved.

Section 18. Conflicts Between Second Amended Agreement and OATT. Unless specifically provided for in this Second Amended Agreement to limit the application of the SPP OATT to the West Facilities-Basin Electric, in the event there is a conflict between this Second Amended Agreement and the terms of the SPP OATT, the SPP OATT shall prevail.

Section 19. Reserved.

Section 20. Entire Agreement. This Second Amended Agreement, including applicable appendices, exhibits, and their duly approved replacements, constitute the entire agreement among the Parties with respect to the subject matter of this Second Amended Agreement, and no previous oral or written representation, agreement, or understanding made by any officers, agent, or employee of any Party shall be binding on any such Party unless contained in this Second Amended Agreement or applicable appendices.

Section 21. Counterparts. This Second Amended Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon the Parties, notwithstanding that they may not have executed the same counterpart.

Section 22. Modification. No modification of the terms of this Second Amended Agreement shall be valid unless made in writing and signed by authorized representatives of the Parties.

Section 23. Leased facilities. Basin Electric may have agreements with third parties to lease facilities that are included as West Facilities-Basin Electric under this Second Amended

Agreement. Basin Electric's rights to contract with SPP with respect to the West Facilities-Basin Electric pursuant to this Second Amended Agreement are subject to the terms and conditions of any such lease, including the contract term of such lease. In the event any such lease is modified, including but not limited to termination, and such modification impacts a party's ability to satisfy the terms and conditions of the Second Amended Agreement, the Parties agree that such event is cause for renegotiation under Article IV.2(a) of this Second Amended Agreement.

Section 24. Digital Signature. The Parties agree that this Second Amended Agreement may be signed and executed by digital signature, digitally signed using Adobe Sign or Adobe E-Signature. A digital signature is the same as a handwritten signature and shall be considered valid and acceptable.

## ARTICLE II

## TRANSMISSION SERVICE UNDER SPP'S OATT

Section 1. Transmission Service. All Transmission Service which uses the West Facilities-Basin Electric shall be under the SPP OATT.

Section 2. SPP Integrated Marketplace. SPP, as the WEIS Market Operator, shall apply the WEIS Tariff to loads and resources on the West Facilities-Basin Electric in the WEIS Market except during times that such loads and resources are connected to the Eastern Interconnection and inside the SPP BAA and the SPP Integrated Marketplace.

Section 3. Compensation. Basin Electric shall submit and recover its annual transmission revenue requirement and Scheduling, System Control and Dispatch Service revenue requirement for the West Facilities-Basin Electric pursuant to the terms and conditions set forth in Basin Electric's Membership Agreement and the SPP OATT.

## ARTICLE III

## WEIS MARKET RELATED PROVISIONS

Section 1. Applicability of WEIS Market to Loads and Resources. Loads and resources on the West Facilities-Basin Electric that are connected to the Western Interconnection and inside the WAUW shall be subject to settlement under the WEIS Market in accordance with Attachment A of the WEIS Tariff.

Section 2. SPP OATT Provisions and Transmission Customers on the West Facilities-Basin Electric.

(a) Network Resources: Notwithstanding the limitations in Sections 1 (Network Resource definition), 30.1, 30.2, and 30.4 of the SPP OATT that may apply, Network Customers may also utilize Network Resources for purposes of fulfilling obligations under the WEIS Market. Notwithstanding the provisions in Section 28.6 of the SPP OATT, Network Customers may utilize JDTS for purposes of fulfilling obligations under the WEIS Market.

Section 3. Joint Dispatch Transmission Service. SPP as the Transmission Provider for the West Facilities-Basin Electric, shall provide JDTS on the West Facilities-Basin Electric to a Joint Dispatch Transmission Service Customer ("JDTS Customer") pursuant to the applicable terms and conditions set forth in this Article III. A JDTS Customer is a Transmission Customer receiving JDTS for energy dispatched in the WEIS Market. JDTS is provided on the West Facilities-Basin Electric commensurate with, and to accommodate, the energy dispatched within the WEIS Market, as set forth in the WEIS Tariff, as follows:

(a) Term: JDTS shall be available on a real-time intra-hour basis.

(b) Reservation Priority: JDTS is non-firm, and shall be available from transfer capability in excess of that needed for Transmission Customers taking any other transmission service under the SPP OATT.

(c) Restrictions on the use of JDTS: JDTS may be used on the West Facilities-Basin Electric only for receipt or delivery of energy dispatched by SPP as the WEIS Market Operator within a Balancing Authority Area in the WEIS Market pursuant to the provisions of the WEIS Tariff. The JDTS Customer shall not use JDTS for (i) off-system sales of capacity or energy not related to fulfilling obligations under the WEIS Market or (ii) direct or indirect provision of transmission service by the JDTS Customer to any third party.

(d) Scheduling: JDTS Customers are not required to submit schedules for JDTS.

(e) Curtailment of JDTS: The Transmission Provider reserves the right to curtail (or cause to be curtailed), in whole or in part, JDTS provided under this Second Amended Agreement for reliability reasons when, an emergency or other unforeseen conditions threatens to impair or degrade the reliability of the Transmission System or the systems directly or indirectly interconnected with the Transmission Provider's Transmission System.

(f) Transmission Provider's Limited Obligations to provide JDTS: The Transmission Provider, shall have no obligation to plan, construct, or maintain its Transmission System for the benefit of any JDTS Customer.

(g) Procedures for Arranging JDTS: JDTS does not need to be reserved by the JTDS Customer. No application or service agreement is required.

(h) Compensation for JDTS: The JDTS Customer shall compensate the Transmission Provider for JDTS commensurate with the receipt or delivery of energy dispatched for JDTS Customer pursuant to the WEIS Tariff at the following rate:

Hourly delivery:

On-Peak Hours: the on-peak rate $0.00/MWh.
Off-Peak Hours: the off-peak rate $0.00/MWh.

(i) Real Power Losses: Notwithstanding the provisions in Sections 15.7 and 28.5 of the SPP OATT, real power loss energy associated with JDTS due to WEIS Market dispatch is addressed in the settlement of imbalance energy pursuant to the WEIS Tariff.

## ARTICLE IV

## TERM, TERMINATION OF AGREEMENT, AND NOTICES

Section 1. Term. This Second Amended Agreement shall become effective on February 1, 2021, or the date upon which the WEIS Tariff becomes effective ("Effective Date"); and shall expire by its own terms at midnight on February 1, 2061, or concurrent with termination of Basin Electric's Membership Agreement, whichever is earlier. Notwithstanding the foregoing, this Second Amended Agreement shall automatically renew for successive one (1) year terms unless either Party elects to terminate the Second Amended Agreement by providing written notice of termination to the other Party at least one (1) calendar year prior to the start of any renewal term. The Parties agree that concurrently with this Second Amended Agreement becoming effective, the First Amended Agreement (Contract Services Agreement dated October 4, 2019) shall terminate.

Section 2. Renegotiation.

(a) If any provision of this Second Amended Agreement, or the application thereof to any person, entity, or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, or if a modification or condition to this Second Amended Agreement is imposed by a regulatory authority exercising jurisdiction over this Second Amended Agreement, then the Parties shall endeavor in good faith to negotiate such amendment or amendments to this Second Amended Agreement as will restore the relative benefits and obligations of the signatories under this Second Amended Agreement immediately prior to such holding, modification, or condition. Substantive changes to the FERC regulations governing the relevant tariffs, the NERC functional model, the NERC mandatory Reliability Standards, or any other law or regulation implicating this Second Amended Agreement, or which substantively alters the obligations of either Party shall be cause to renegotiate the Second Amended Agreement under this section. The Parties agree that the objectives of this Second Amended Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein, including deleting, adding, or revising requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

(b) The Parties agree that the Parties' respective rights and obligations under this Second Amended Agreement and the purposes for which this Second Amended Agreement is being entered into are dependent upon the existence and enforceability of the separate agreement between SPP and the Western Area Power Administration for the West Facilities-UGP. Should such agreement be terminated, or subject to renegotiation

between SPP and the Western Area Power Administration that will affect either Party's substantive rights under this Second Amended Agreement, the terms of this Section 2(a) shall be applicable to any renegotiation of this Second Amended Agreement.

Section 3. Notice. Any written notice, demand, or request required or authorized under this Second Amended Agreement shall be deemed properly given to or served on Basin Electric if mailed or transmitted electronically to:

Sr. Vice President, Transmission
Basin Electric Power Cooperative
1717 E. Interstate Ave.
Bismarck, ND 58503-0564
Fax Number: (701) 557-5332

Any such notice, demand, or request shall be deemed properly given to or served on SPP if mailed or transmitted electronically to:

President and CEO
Southwest Power Pool, Inc.
201 Worthen Dr.
Little Rock, AR 72223-4936
Fax Number: (501) 482-2022

The designation of the persons to be notified, or the addresses of such persons, may be changed at any time by either Party by written notice to the other Party.

IN WITNESS WHEREOF, the Parties have executed this Second Amended Agreement in several counterparts as of the day and year first above written, each of which shall constitute an original.

BASIN ELECTRIC POWER COOPERATIVE

By */s/ Paul Sukut*
Name Paul Sukut
Title CEO and General Manager

SOUTHWEST POWER POOL, INC.

By */s/ Lanny Nickell*

Name Lanny Nickell

Title Executive Vice President and COO

ATTEST:

I, Paul Suskie, certify that I am the Corporate Secretary of SOUTHWEST POWER POOL, INC., and that Lanny Nickell, who signed this Second Amended Agreement on behalf of said Corporation, was then, Executive Vice President and Chief Operating Officer of said Corporation, and that the said Second Amended Agreement was duly signed for and on behalf of the said Corporation by authority of its governing body, which has within the scope if its corporate powers the authority to legally bind the Corporation under the foregoing Second Amended Agreement.

(SEAL) By */s/ Paul Suskie*

# EXHIBIT #1

## WEST FACILITIES-BASIN ELECTRIC

**Table 1**

| Transmission Lines/Equipment | Description | Balancing Authority Area |
|---|---|---|
| None | N/A | N/A |

**Table 2**

| Substations | Facilities ID, Description | Balancing Authority Area |
|---|---|---|
| Verona | VR, Substation Equipment | WAUW |

# ATTACHMENT AU
# PROCEDURES FOR ALLOCATION OF REVENUES RESULTING FROM THE SETTLEMENT AGREEMENT IN COMMISSION DOCKET NOs. EL11-34-002, et al.

## I. DISTRIBUTION OF REVENUES

This Attachment AU sets forth the procedures by which the Transmission Provider shall distribute revenues received from the Midcontinent Independent System Operator Inc. ("MISO") and NRG Energy, Inc. ("NRG") pursuant to the Settlement Agreement in Docket Nos. EL11-34-002, et al. ("JOA Settlement Agreement") addressing matters related to the MISO-SPP Joint Operating Agreement. Such revenues, hereinafter "JOA Settlement Revenues", shall be allocated to Transmission Owners based on the estimated flow impacts resulting from energy transfers between MISO north and south subregions, as described in this Attachment AU.

## II. DISTRIBUTABLE JOA SETTLEMENT REVENUES

A. Components of Distributable JOA Settlement Revenues

The JOA Settlement Revenues subject to distribution and allocation under this Attachment AU shall consist of:

1. For the period of January 29, 2014 through January 31, 2016, Transmission Provider's allocable share of the payments associated with "Compensation Phase I", as described in Section 2.6.1 of the JOA Settlement Agreement;
2. For the period of February 1, 2016 through January 31, 2017, Transmission Provider's allocable share of the payments received from MISO and associated with "Compensation Phase II", as described in Section 2.6.2 of the JOA Settlement Agreement;
3. For all years (with each such year extending from February 1 to January 31) after Compensation Phase II, Transmission Provider's allocable share of payments received from MISO and associated with "Compensation Phase III", as described in Section 2.6.3 of the JOA Settlement Agreement; and
4. All payments received by the Transmission Provider from NRG in accordance with Article IV of the JOA Settlement Agreement.

B. Offsets to Distributable JOA Settlement Revenues

1. The JOA Settlement Revenues subject to distribution and allocation as described in Section II.A.1 through Section II.A.4 of this Attachment AU starting in 2016 shall annually be reduced by an amount of $250,000 to cover the Transmission Provider's annual costs of administering the JOA Settlement Agreement in the first month in which such revenues are received in each calendar year.

## III. DETERMINATION OF FLOW IMPACTS

A. Timing of Flow Impact Analyses

1. For the period identified in Section II.A.1 of this Attachment AU and continuing until the initial MW-mile analysis described in Section III.A.2 of this Attachment AU, the Transmission Provider shall conduct appropriate MW-mile analyses, based on Transmission System topology and facility ownership for each Transmission Owner during the period using the 2014 and 2015 summer peak models from the ITP reliability assessment model series approved by the Transmission Provider during the period.
2. At least once each calendar year, the Transmission Provider shall conduct a MW-mile analysis to determine flow impacts across the Transmission Provider's system. The results of the MW-mile analysis shall be posted to the Transmission Provider's website. For purposes of conducting the MW-mile analysis, Transmission System topology and facility ownership for each Transmission Owner will be determined using the current calendar year summer peak model from the latest ITP reliability assessment model series approved by the Transmission Provider. A commercially available power systems analysis software package will be used to perform the necessary network flow calculations. The resulting analysis shall be used for the following 12-month period.
3. The Transmission Provider shall re-evaluate flow impacts mid-cycle and conduct an updated MW-mile analysis in the event of (i) a new Transmission Owner transferring functional control to Transmission Provider under this Tariff, (ii) a departure of a Transmission Owner from SPP membership, or (iii) as directed by

the SPP Board of Directors to account for other events that could significantly alter the allocation of flow impacts. The new analysis shall be conducted during the month following the event precipitating the change and shall apply for each month following the analysis until the next annual analysis is conducted and applied.

B. Calculation of Flow Impacts

1. The MW-mile analysis described in Section III of this Attachment AU shall be performed by modeling a power transfer between the MISO north and south subregions and taking the difference between the pre-transfer and post-transfer MW amounts on each transmission line, and multiplying that by the number of miles of the transmission line. The power transfer shall be modeled by proportionally scaling up all generation modeled online in the MISO north subregion and proportionally scaling down all generation modeled online in the MISO south subregion. The MW-mile values for each line owned by a Transmission Owner are summed to yield a Transmission Owner's MW-mile impact; the sum of all Transmission Owners' MW-mile impacts equals total system MW-mile impacts.

## IV. DISTRIBUTION OF JOA SETTLEMENT REVENUES

Effective February 1, 2016, the distribution of JOA Settlement Revenues will be based on the ratio of each Transmission Owner's MW-mile impact to the total system MW-mile impacts as determined in accordance with Section III of this Attachment AU. This distribution shall be subject to the date each Transmission Owner's facilities were placed under the functional control of the Transmission Provider. Distributions shall be made monthly corresponding to the monthly payments prescribed by the JOA Settlement Agreement. For the period of January 29, 2014 to January 31, 2016, the distribution of JOA Settlement Revenues will be pursuant to Exhibit A to the Settlement Agreement in Docket No ER16-791-000. Distributions shall be subject to any true-up or revised payment or refund that may be made pursuant to the JOA Settlement Agreement.

## V. TREATMENT OF DISTRIBUTED REVENUES

JOA Settlement Revenues shall result in a reduction of transmission service charges under this Tariff in the same manner as revenues associated with Point-to-Point Transmission Service. JOA Settlement Revenues distributed to Transmission Owners shall be subject to the provisions of Sections 34.1, 34.2 and 34.3 of this Tariff, as applicable, and shall be subject to the provisions of Section II.A of Schedule 11 of this Tariff. To facilitate the application of Sections 34.1, 34.2 and 34.3 and Section II.A of Schedule 11, the Transmission Provider shall allocate the applicable revenue distributed to each Transmission Owner in proportion to the amount of Schedule 7, 8 and 11 revenues that Transmission Owner received for Point-To-Point Transmission Service in the previous calendar year, with such revenues as determined in January of the current year. For each Transmission Owner utilizing a formula rate, the resulting allocated revenues are to be treated consistently with the treatment of Schedule 7, Schedule 8, and Schedule 11 Point-To-Point Transmission Service revenues under its formula rate.